Jemena Electricity Networks (Vic) Ltd

2016-20 Electricity Distribution Price Review Regulatory Proposal

Revocation and substitution submission

Attachment 7-4 ACIL Allen - Demand forecast report

Public

6 January 2016

ACIL ALLEN CONSULTING

A REPORT TO
JEMENA ELECTRICITY NETWORKS

14 DECEMBER 2015

ELECTRICITY DEMAND FORECASTS

UPDATED FOLLOWING THE AER'S PRELIMINARY DECISION

ACIL ALLEN CONSULTING PTY LTD
ABN 68 102 652 148

161 WAKEFIELD STREET
ADELAIDE SA 5000
AUSTRALIA
T +61 8 8122 4965

LEVEL FIFTEEN
127 CREEK STREET
BRISBANE QLD 4000
AUSTRALIA
T+61 7 3009 8700
F+61 7 3009 8; OVERALL IT799

LEVEL TWO
33 AINSLIE PLACE
CANBERRA ACT 2600
AUSTRALIA
T+61 2 6103 8200
F+61 2 6103 8233

LEVEL NINE
60 COLLINS STREET
MELBOURNE VIC 3000
AUSTRALIA
T+61 3 8650 6000
F+61 3 9654 6363

LEVEL ONE
50 PITT STREET
SYDNEY NSW 2000
AUSTRALIA
T+61 2 8272 5100
F+61 2 9247 2455

LEVEL TWELVE, BGC CENTRE
28 THE ESPLANADE
PERTH WA 6000
AUSTRALIA
T+61 8 9449 9600
F+61 8 9322 3955

ACILALLEN.COM.AU

EXECUTIVE SUMMARY

Jemena Electricity Networks (JEN) is an electricity Distribution Network Service Provider (DNSP). It distributes electricity to over 300,000 customers throughout the north-west of Melbourne.

As with all electricity DNSPs in the National Electricity Market (NEM), JEN is subject to economic regulation administered by the Australian Energy Regulator (AER) under the National Electricity Rules (NER). JEN's current regulatory period will end on 31 December 2015.

JEN submitted its regulatory proposal for the next five-year period on 30 April 2015 including, among other things, forecasts of maximum demand.

In September 2015, ACIL Allen was engaged to update some of the earlier forecasts, specifically, customer numbers and system maximum demand. The updated maximum demand forecasts are provided in this report and in a spreadsheet that accompanies it. The methodology used here is the same as that described in our report of November 2014 and, as such should be read in conjunction with it.

The AER's draft determination

On Thursday, October 29 2015 the AER published its preliminary decision in relation to JEN's proposal.

Insofar as maximum demand is concerned, the AER determined that the forecasting methodology used in our November 2014 report "is reasonably likely to reflect a realistic expectation of demand over the 2016–20, in particular as more up-to-date information is adopted".[1] In summary, the AER has accepted the forecasting methodology, though it has called for updates to the inputs.

In reviewing the forecasts, the AER had regard to forecasts published by the Australian Energy Market Operator (AEMO) in the National Electricity Forecasting report (NEFR) for 2014 and a paper prepared by Dr Biggar, in which he reviewed the forecasting methodologies of all of the Victorian distribution businesses.

In the November 2014 report we had forecast electricity retail prices internally and taken forecasts of economic activity from the Victorian Government. In this report we respond to the AER's preliminary determination by updating the inputs to our forecasts, including by adopting forecasts of economic activity and electricity retail prices from AEMO's 2015 NEFR.

Dr Biggar's concerns did not change the AER's final conclusion that the methodology we employed was fundamentally sound. Our response to his concerns are set out in the report.

[1] AER, Preliminary decision, p. 6-111

Revised forecasts

Table ES 1 provides a summary of our revised forecasts and, for reference, reproduces the original forecasts produced in November 2014. **Figure ES 1** provides the same comparison, though it only shows the 50 % probability of exceedance (POE) forecasts whereas **Table ES 1** shows 10, 50 and 90 POE forecasts.

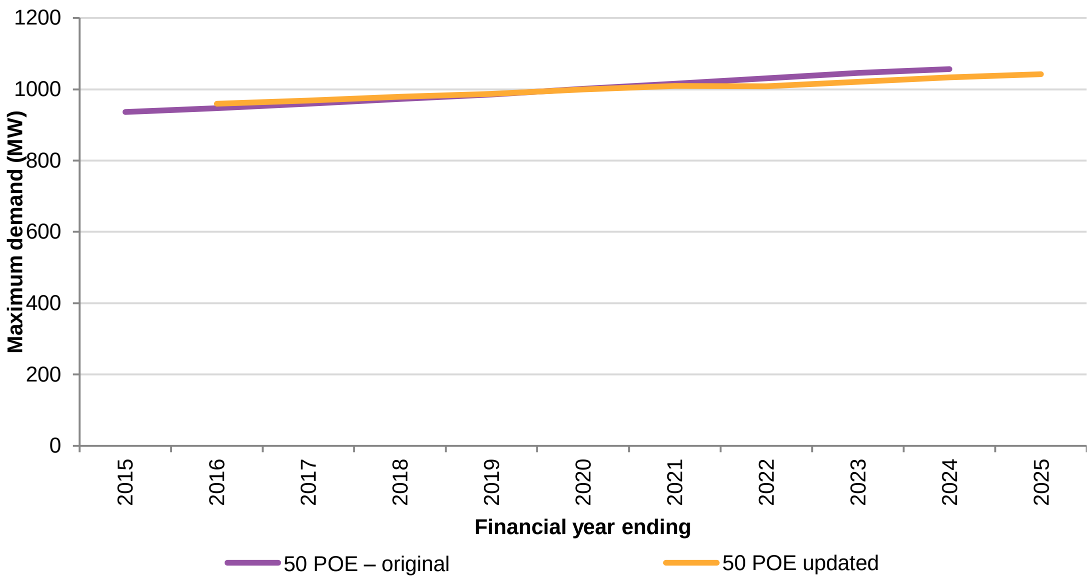
As is shown, the update leads to a small increase in the forecasts at each POE level in the early years and decreases in later years.

TABLE ES 1 SYSTEM MAXIMUM DEMAND FORECASTS – ORIGINAL AND UPDATED

	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	CAGR
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%
Original (Nov 2014)											
10 POE	1032.8	1046.3	1062.6	1077.1	1095.7	1111.6	1124.5	1146.1	1160.8	*N/A*	1.46
50 POE	946.6	959.5	973.0	985.5	1001.7	1015.5	1031.2	1046.2	1056.6	*N/A*	1.35
90 POE	877.0	889.8	898.8	916.2	927.1	938.4	951.0	968.5	973.5	*N/A*	1.28
Revised (Nov 2015)											
10 POE	1048.3	1059.2	1071.7	1082.6	1094.2	1108.9	1109.8	1119.0	1137.5	1144.9	0.98
50 POE	959.8	968.4	978.9	986.9	999.6	1009.5	1008.4	1020.6	1033.1	1042.5	0.92
90 POE	887.7	896.8	904.2	910.9	921.9	932.1	927.8	936.9	949.4	957.4	0.84

SOUTCE: ACIL ALLEN CONSULTING

FIGURE ES 1 SYSTEM MAXIMUM DEMAND FORECASTS – ORIGINAL AND UPDATED



SOURCE: ACIL ALELN CONSULTING

C O N T E N T S

C O N T E N T S

FIGURES

TABLES

1 INTRODUCTION

Jemena Electricity Networks (JEN) is an electricity Distribution Network Service Provider (DNSP). It distributes electricity to over 300,000 customers throughout the north-west of Melbourne. JEN's network comprises seven terminal stations (comprising of ten separate connection supply points) and 23 zone substations owned by JEN as shown in **Figure 1.1**.

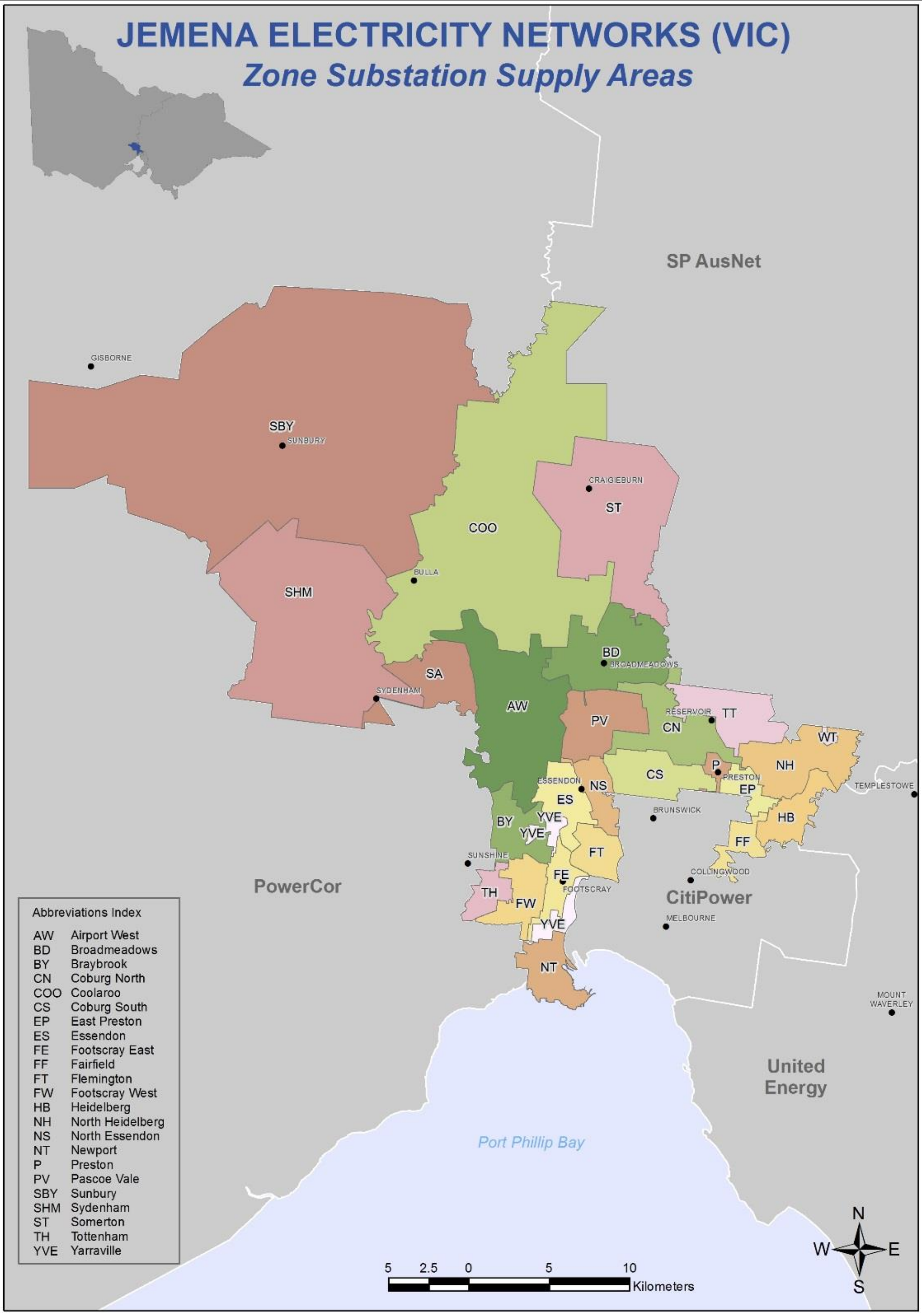
As with all electricity DNSPs in the National Electricity Market (NEM), JEN is subject to economic regulation administered by the Australian Energy Regulator (AER) under the National Electricity Rules (NER). JEN's current regulatory period will end on 31 December 2015. JEN submitted its regulatory proposal for the next five-year period on 30 April 2015. Among many other things, JEN's proposal included forecasts of maximum demand, energy consumption and customer numbers.

In 2014 JEN engaged ACIL Allen Consulting (ACIL Allen) to assist it in preparing its submission to the AER in relation to consumption and demand forecasting. Reports and spreadsheet models containing ACIL Allen's forecasts of demand, consumption and customer numbers accompanied JEN's proposal and are on the AER's website.

In September 2015 ACIL Allen was engaged to update some of the earlier forecasts, specifically, customer numbers and system maximum demand. The updated maximum demand forecasts are provided in this report and in spreadsheets that accompany it. The updated customer numbers forecast are in a separate report. These update reports should be read in conjunction with ACIL Allen's earlier reports.

On Thursday, October 29 2015 the AER published its preliminary decision in relation to JEN's proposal. It accepted JEN's maximum demand forecasts, though it indicated the updated inputs such as those included in this report should be included now that the passage of time has made them available.

FIGURE 1.1 JEN DISTRIBUTION REGION



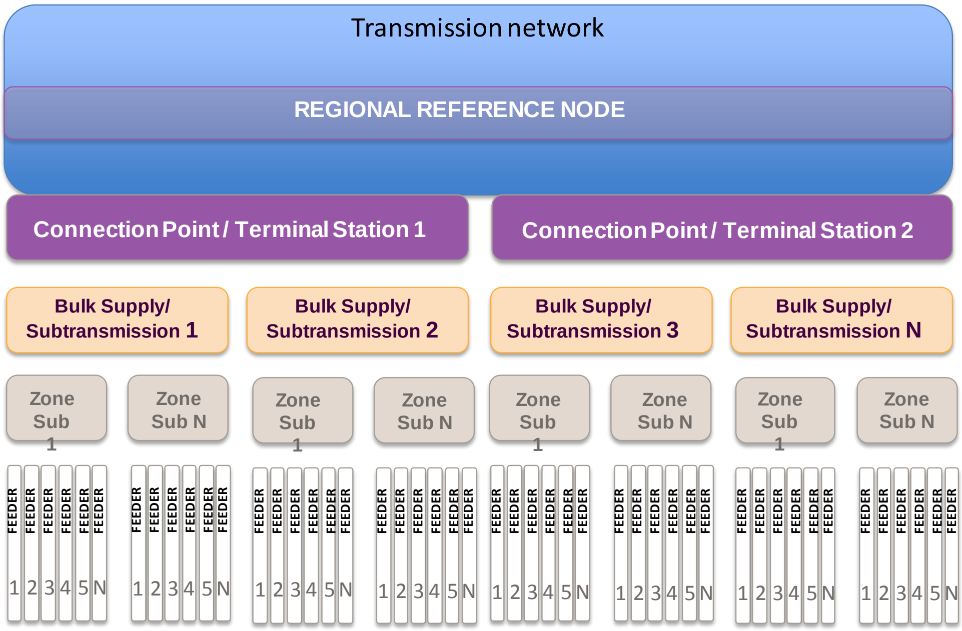
SOURCE: JEN DISTRIBUTION ANNUAL PLANNING REPORT 2013

1.1 Definitions

The general configuration of an electricity network is illustrated in **Figure 1.2**

- electricity is generated and transferred on a transmission network at high voltage
- a transmission network meets a distribution network at a terminal station
- a distribution network transfers electricity from a terminal station to a zone substation at a lower voltage[2]
- a distribution network transfers electricity to small customers at a further reduced voltage on a feeder.

FIGURE 1.2 TYPICAL HIERARCHY OF ELECTRICITY DISTRIBUTION NETWORK



This following are definitions of important terms used in this report.

Consumption refers to the quantity of energy used over a period of time. Consumption is commonly reported on a monthly, quarterly and annual basis, though any time period is possible subject to measurement constraints. Consumption is measured in a multiple of watt hours[3] (at the network level, usually gigawatt hours, or GWh). Mathematically, consumption is equal to average demand multiplied by the number of hours over which demand is measured.

Demand refers to the rate of electrical power flow through a given element of a network at any given time. Theoretically, demand occurs, and can change, almost instantaneously. In practice, demand is usually reported once for each half hour interval and is the average of instantaneous recordings over the half hour period. Demand is measured in a multiple of watts (at the network level usually megawatts, or MW). Demand is measured at a particular point in the network. It may be less than latent demand due to the influence of embedded generation.

Latent demand is the total demand at a given time, including that which does not pass through the network element where demand is measured. It may be greater than demand due to an embedded generator(s) which supplies electricity to customers in a way that is not reflected in demand as measured at a given network element.

[2] Some networks have sub-transmission stations between these two levels.
[3] Joules can also be used.

Terminal station is a physical point at which JEN's network is connected to the electricity transmission network. There are seven terminal stations with a total of 10 independent bus groups supplying JEN's network, listed in **Table 1.1**.

TABLE 1.1 JEN TERMINAL STATIONS

Terminal station	Abbreviation
Brooklyn TS 22kV	blts22
Brooklyn TS 66kV	blts66
Brunswick TS	bts
Keilor TS East	ktseast
Keilor TS West	ktswest
South Morang TS	smts
Templestowe TS	tsts
Thomastown TS	ttsb1b2
Thomastown TS	ttsb3b4
West Melbourne TS	wmts

SOURCE: JEN

System level demand is the sum of the demand observed at each of JEN's terminal stations at any given time.

Coincident maximum demand exists at a given element of the network, either a terminal station or zone substation. It is the demand observed at that element when system level demand is at its maximum (that is, when the sum of demand at all network elements is at its maximum). Coincident maximum demand can be equal to or less than non-coincident maximum demand for that network element.

Non-coincident maximum demand is the maximum demand observed at a given element of the network. It may be equal to or greater than coincident maximum demand. It can be identified without regard to system level demand, and can occur at a different time to system level maximum demand.

Coincidence factor is the ratio of coincident to non-coincident demand.

Diversity factor is the reciprocal of coincidence factor.

Probability of exceedence (POE) refers to the likelihood that a given level of maximum demand will be met or exceeded:

– 50 POE maximum demand is the level of annual demand that is expected to be exceeded one year in two.
– 10 POE maximum demand is expected to be exceeded one year in ten.
– 90 POE maximum demand will be exceeded nine years in ten.

Summer is the period from 1 November to 31 March each year.

Winter is the period from 1 April to 31 October each year.

1.2 Structure of this report

This report is structured as follows.

The forecasts themselves are presented first, in chapter 2.

Chapter 3 addresses issues raised by the AER in its preliminary decision.

The subsequent chapters address the inputs and methodology, in that order. Specifically:

- Chapter 4 provides an overview of the history of demand within the JEN region.
- Chapter 5 provides a detailed description of the methodology by which the forecasts were prepared
- Chapter 6 provides an overview of the history of the drivers of demand.

Forecasts were prepared for summer and winter independently. The forecast periods are:

- for summer, 2015-16 to 2024-25
- for winter, 2015 to 2024.

This report forecasts presented herein were prepared by Jeremy Tustin, Jim Diamantopoulos and Tim Weterings. Jeremy, Jim and Tim have extensive expertise in and experience in econometric modelling and demand forecasting. Our curricula vitae are provided in Appendix A. The opinions set out in this report are based on this expertise and experience.

The terms of reference for this report are provided in Appendix B.

In preparing this report we have been provided with a copy of the Federal Court practice note CM7, entitled Expert Witnesses in Proceedings in the Federal Court of Australia (the CM7 Guidelines). We have read and understood the CM7 Guidelines and have complied with them in preparing this report. We confirm that we have made all inquiries that we believe are desirable and appropriate, and that no matters of significance that we regard as relevant have, to our knowledge, been withheld.

2 UPDATED FORECASTS – MAXIMUM DEMAND

This chapter summarises the updated forecasts:

- section 2.1 relates to forecasts of maximum demand in summer
- section 2.2 relates to forecasts of maximum demand in winter.

The earlier maximum demand report contained forecasts at both the *system* and *terminal station* level. This update is limited to the *system* level.

2.1 Summer forecasts

The updated forecasts of system level maximum demand are for each summer from 2015-16 to 2024-25.

The methodology used to develop these forecasts is as described in our previous report, submitted with JEN's regulatory proposal, and in section 5 of this report.

Forecasts have been updated using updated data for certain forecast drivers. As explained in section 6 of this report, the key updates are as follows:

- forecasts of economic activity and electricity retail prices have been taken from AEMO's 2015 NEFR economic forecasts were previously taken from the Victorian Government and retail price forecasts were previously prepared internally by ACIL allen);
- actual demand data for the period to mid 2015 were incorporated
- Weather data were updated for the same period to mid 2015.

As with the initial forecasts prepared for JEN's regulatory proposal, the forecasts presented here have not been adjusted for the impact of embedded generators other than solar PV. This was done to allow JEN to incorporate its own view of the likely peak demand impact of those generators at the distribution feeder level.

The forecasts of maximum demand are shown in **Table 2.1**. This shows the raw forecasts, the amount of solar PV, and the final forecasts, which are net of the output of solar PV.

TABLE 2.1 SYSTEM MAXIMUM DEMAND FORECASTS, 2015-16 TO 2024-25

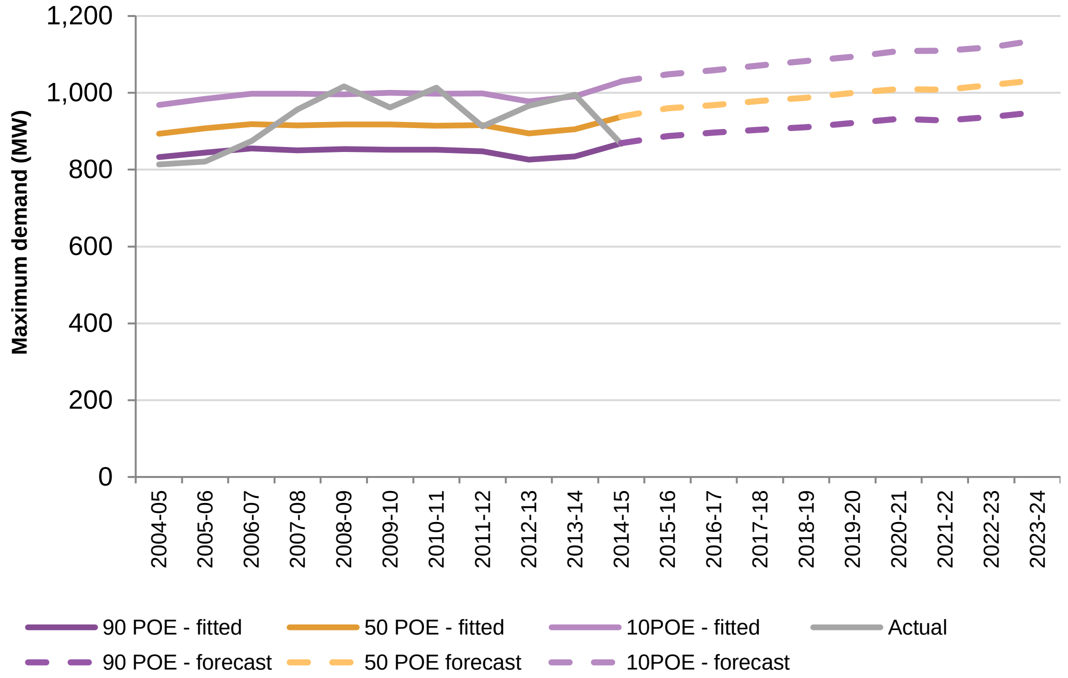
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2024-25	2024-25	CAGR
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%
10 POE – raw	1052.1	1064.9	1079.6	1092.6	1103.3	1119.6	1122.1	1133.1	1153.3	1162.5	1.12
50 POE – raw	963.5	974.1	986.7	996.9	1008.7	1020.2	1020.8	1034.7	1048.9	1060.1	1.07
90 POE – raw	891.4	902.6	912.0	920.9	930.9	942.8	940.2	951.0	965.3	975.0	1.00
Solar PV (new systems only)	3.72	5.77	7.86	10.00	9.04	10.69	12.37	14.08	15.81	17.61	18.84
10 POE - final	1048.3	1059.2	1071.7	1082.6	1094.2	1108.9	1109.8	1119.0	1137.5	1144.9	0.98
50 POE – final	959.8	968.4	978.9	986.9	999.6	1009.5	1008.4	1020.6	1033.1	1042.5	0.92
90 POE - final	887.7	896.8	904.2	910.9	921.9	932.1	927.8	936.9	949.4	957.4	0.84

NOTE: THE IMPACT OF SOLAR PV AT PEAK TIMES SHOWN HERE IS FOR NEW SYSTEMS ONLY SO IT COMES OFF A VERY LOW BASE. THIS EXAGGERATES THE SOLAR PV COMPOUND ANNUAL GROWTH RATE (CAGR). ALSO NOTE THAT THIS IS NOT THE FORECAST CAPACITY OF PV SYSTEMS, BUT THE FORECAST IMPACT AT PEAK TIMES.
SOURCE: ACIL ALLEN CONSULTING

Figure 2.1 shows the forecasts from **Table 2.1 i**n graphical form. To place these in context it also shows historical maximum demand, both actual and weather normalised.

As Figure 2.1 and Table 2.1 show, maximum demand is forecast to grow over the forecast period largely driven by a projected return to trend GDP growth and a stabilisation of electricity prices as discussed in chapter 6. The projected growth is slightly slower than in the earlier forecasts, due to a downward revision in the economic outlook. At the 50 POE level the projection is for annual growth of 0.92 per cent compared to 1.35 per cent earlier.

FIGURE 2.1 JEN SYSTEM LEVEL MAXIMUM SUMMER DEMAND - ACTUAL AND FORECAST, 2004-05 TO 2024-25



SOURCE: ACIL ALLEN CONSULTING

2.2 Winter forecasts

This section presents forecasts of maximum demand for each winter from 2015 to 2024

The winter forecasts have been updated in the same way as the summer forecasts. That is:

— forecasts of economic activity and electricity retail prices have been taken from AEMO's 2015 NEFR economic forecasts were previously taken from the Victorian Government and retail price forecasts were previously prepared internally by ACIL Allen);

— actual demand data for the period to mid 2015 were incorporated

— Weather data were updated for the same period to mid 2015.

The forecasts of maximum winter demand at the system level are shown in **Table 2.2**.

TABLE 2.2 SYSTEM MAXIMUM DEMAND FORECASTS, 2015 TO 2024

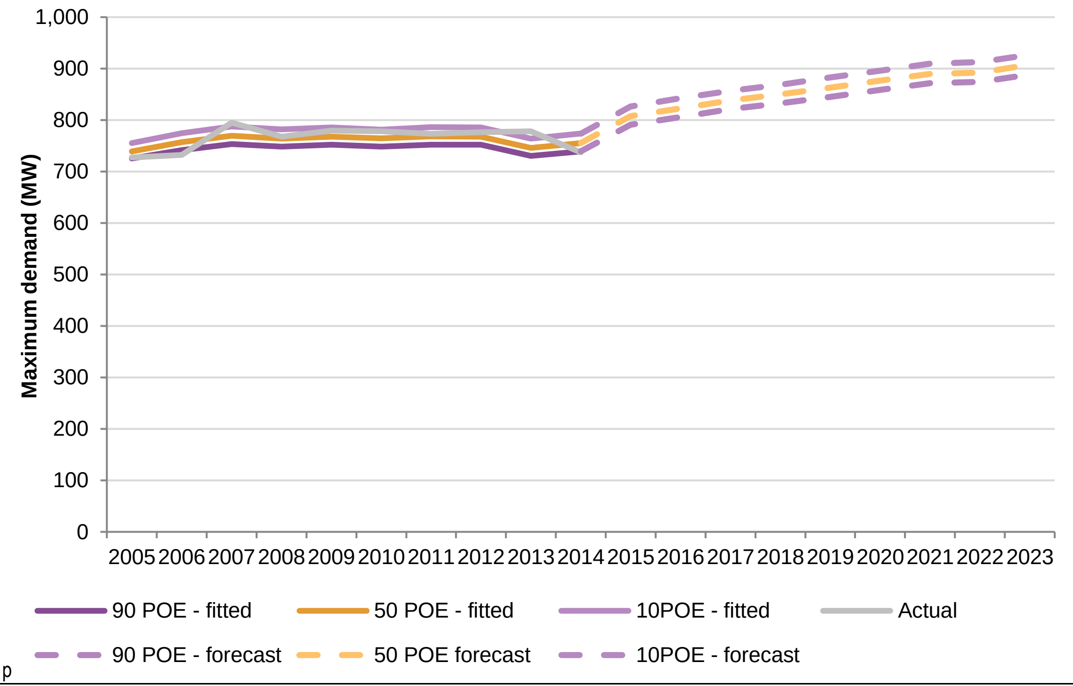
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	CAGR
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%
10 POE	826.7	842.6	856.8	868.8	883.1	896.2	909.9	912.8	927.2	944.6	1.49
50 POE	807.8	823.1	838.5	850.2	863.3	877.0	889.8	892.4	907.7	923.5	1.50
90 POE	791.1	806.3	821.6	832.5	845.5	858.6	872.0	874.4	888.7	904.9	1.50

NOTE: THE IMPACT OF SOLAR PV IS OMITTED FROM WINTER PEAK DEMAND DUE TO THE TIME OF DAY WHEN THOSE PEAKS OCCUR.
SOURCE: ACIL ALLEN CONSULTING

Figure 2.2 shows the forecasts from **Table 2.2** in graphical form. To place these in context it also shows historical, system level maximum winter demand both actual and weather normalised.

As **Table 2.2** and **Table 2.2** show, maximum demand is forecast to increase throughout the forecast period at all POE levels. This is largely driven by a return to trend GDP growth, as well as a stabilisation of electricity prices over the period. At the 50 POE level the projection is for annual growth of 1.50 per cent. Winter MD growth is forecast to outstrip summer MD growth due largely to the impact of solar PV systems. Uptake of solar PV systems is forecast to continue growing (see **Figure 6.4**) but the forecast impact is constrained to summer because winter MD in JEN's region occurs either too early or too late in the day for solar PV to have a significant impact.

FIGURE 2.2 JEN SYSTEM LEVEL MAXIMUM WINTER DEMAND - ACTUAL AND FORECAST



SOURCE: ACIL ALLEN CONSULTING

3 AER REVIEW OF METHODOLOGY – RESPONSE TO CONCERNS RAISED

In the preliminary decision the AER considered the forecasts JEN had submitted, developed in our earlier report, as well as a paper prepared by Dr Biggar. The AER accepted that our "forecasts reflect a realistic expectation of demand over the 2016-20 regulatory period."[4] However, it also called for more up to date information to be included and expressed a preference for input projections published by AEMO over some other sources. In saying this, it noted with approval that JEN was in the process of completing the updates summarised in this report.

In reaching that decision the AER considered a paper prepared by Dr Biggar. In that paper, Dr Biggar said that:

> *[ACIL Allen] adopt[s] a conventional approach of assuming a fixed approach between underlying drivers and peak demand over time.*
>
> *…this approach is appropriate as long as the assumed relationship effectively captures all of the key drivers…*
>
> *It is not clear that ACIL Allen's model has achieved this. In particular [our model] treats all of the recent downturn in demand as due to an increase in electricity prices or a decrease in GSP. If there is some other change in the market…it is not clear that this would be adequately captured…*

Specifically, Dr Biggar is concerned that we did not take account of the impact of:

1. Solar PV
2. Energy efficiency
3. the changes in tariff structure JEN proposed in its Tariff Structure Statement (TSS)

Our response to the these three concerns is provided in turn in this chapter

Further, Dr Biggar was concerned that our forecasts were prepared in November 2014 and thus did not take account of more recent demand data. Those more recent data have been taken into account in the forecasts presented in this report, which we trust will allay that concern.

3.1 The impact of Solar PV

We agree with Dr Biggar that it is important to take account of the impact of increased solar PV in forecasting maximum demand. However, we do not accept that our model does not do this. On the contrary, we described the way adjustments for the impact of PV were made in our report of November 2014. A summary is provided below.

The same adjustments have been made in this update (at the system level).

[4] AER, Preliminary decision, p. 6-101.

3.1.1 Solar PV at the terminal station level

Section 5.7 of our report of 20 November 2014 (p.43) relates to the methodology for forecasting at the terminal station level (i.e. the 'bottom up' part of the forecasts)

In section 5.7 we say that "a post model adjustment was made to take account of the impact of increased solar PV." It refers to chapter 6 for details.

Chapter 6 of our report describes, in detail, the way that we projected uptake of solar PV.

Section 5.7 goes on to say that, after the capacity of systems had been estimated (using the chapter 6 method) their likely output at peak time was "estimated and subtracted from the projected latent demand."

The report says that:

The outputs were adjusted to account for the impact of solar PV systems forecast to be installed in future.[5] Consistent with the terminal station models, no adjustment was made for other forms of embedded generation or other disruptive technologies.

This was done by taking the capacity projections discussed in chapter ***Error! Reference source not ound.*** *and multiplying by a 'capacity factor' to reflect the expected output of those systems during peak times. The capacity factor, which was calculated from AEMO's 2014 National Electricity Forecasting Report, varies over the forecast period as shown in (table 15 from the earlier report).*

Therefore, in summary, the adjustment was made using our projection of PV uptake and AEMO's estimate of the ratio of system size to contribution to maximum demand.

3.1.2 Solar PV at the system level

In addition to the adjustment made at the terminal station level described above, we made an adjustment at the system level (if one is made the other must be as well).

Section 5.8 of our report describes the system level forecasting methodology.

On page 46 we say that "the outputs were adjusted to account for the impact of solar PV systems forecast to be installed in future." We go on to say that this was done using the capacity projections in chapter 6 and capacity factors taken from AEMO (shown in table 15).

Section 5.8.2 deals with the methodology for forecasting maximum winter demand. There we say that no adjustment was made for the impact of PV systems because PV output is limited when winter peaks occur (early morning or evening, when it is dark/ low light).

3.1.3 Summary

We note, though, that in the appendix to his paper, Dr Biggar reproduces figure 34 from our November 2014 report (chapter 6), citing it as "from a report by ACIL Allen for Jemena." He points to this figure as evidence of the broadly held view that solar PV uptake will increase in future. However, he does not acknowledge that this is from the same report that he reviews earlier in his paper.

Other than this Dr Biggar does not comment on the approach we took to adjusting for the impact of PV systems. It appears that, rather than being a criticism of the way we made our PV adjustments this is an oversight. If this is not the case we would welcome the opportunity to respond to any particular concerns that may exist with our approach.

Otherwise, we remain of the view that adjustments should be made to demand forecasts to account for increased use of solar PV and that we made appropriate adjustments to account for this in JEN's forecasts. To be clear, the adjustment we made in these updated forecasts, at JEN's system level, are shown in **Table 3.1** (excerpted from **Table 2.1**).

---

5 The impact of existing systems was reflected in the data upon which the model was based. Therefore, unlike the terminal station models, this model makes a post model adjustment only for new systems.

TABLE 3.1 ADJUSTMENT FOR IMPACT OF SOLAR PV ON SYSTEM MAXIMUM DEMAND FORECASTS, 2015-16 TO 2024-25

	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2024-25	2024-25	CAGR
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%
Solar PV (new systems only)	3.72	5.77	7.86	10.00	9.04	10.69	12.37	14.08	15.81	17.61	18.84

NOTE: THE IMPACT OF SOLAR PV AT PEAK TIMES SHOWN HERE IS FOR NEW SYSTEMS ONLY SO IT COMES OFF A VERY LOW BASE. THIS EXAGGERATES THE SOLAR PV COMPOUND ANNUAL GROWTH RATE (CAGR). ALSO NOTE THAT THIS IS NOT THE FORECAST CAPACITY OF PV SYSTEMS, BUT THE FORECAST IMPACT AT PEAK TIMES.
SOURCE: ACIL ALLEN CONSULTING

3.2 Energy efficiency

Dr Biggar is correct in his conclusion that we did not make an explicit adjustment for increased uptake of energy efficiency. While it is not discussed in the report, there are three reasons:

1. we are not satisfied that energy efficiency improvements will/ do have the effect of reducing peak demand
2. we are not satisfied that there will be *increased* policy emphasis in relation to energy efficiency during the regulatory period – rather we expect energy efficiency improvements to continue along recent trends
3. we are concerned that including *both* price and an energy efficiency adjustment introduces a risk of double counting.

3.2.1 Relationship between energy efficiency policies and peak demand

From time to time a number of policies have been used to increase the energy efficiency of Australian homes and businesses. These range from the Energy Efficiency Opportunities program, which was targeted at a relatively small number of very large energy users to policies such as Mandatory Energy Performance Standards which target a range of domestic appliances.

As far as we are aware these policies have been targeted exclusively at reducing energy consumption rather than peak demand.

In some cases these policies might reduce demand as well, but in others they can lead to increases in demand. For example designing a building to reduce its heating load can increase its cooling load. If the increase in energy required for cooling is smaller than the decrease in energy required for heating, the building would use less energy over a year (i.e. be more energy efficient). However, its demand at the time of system peak may be higher.

Other policies may increase energy efficiency at the wrong time of day to reduce peak demand. For example policies focussed on increasing the energy efficiency of domestic lighting would have had little or no impact on peak demand because this peak occurs during daylight hours (they are also understood to be largely saturated now).

In our view the impact of energy efficiency policies on demand (as distinct from energy consumption) is ambiguous (it could be positive or negative). If it is demand reducing, it is likely to be small. As such, our view is that it does not warrant adjustments in peak demand models.

It is important to note that this view is based on the current policy environment. We do not say that it is impossible for energy efficiency to reduce demand, but that we do not expect it to happen in the immediate future.

We made the same point in our methodology report for AEMO, which Dr Biggar uses as a basis for his general review of the issues. On page 53 of that report we say the following:

This is not to say that energy efficiency cannot cause reductions in maximum demand. There is no doubt that it could do so. However, it is insufficient to assume that a general improvement in energy efficiency will lead to the same change in maximum demand.

3.2.2 Increased policy emphasis on energy efficiency

As noted above, there have been various efforts to improve Australia's energy efficiency over the last decade or so. This means that, holding other drivers constant, there would be a downward trend in energy consumption in Australia.

Setting aside the issues discussed in the previous section and assuming that this trend is also evident in peak demand, it would seem appropriate to expect this trend to continue in future if 'policy effort' in respect of energy efficiency is maintained.

However, this does not warrant an adjustment in our model. The reason is that the price variable is inherently 'trendy'. If a second 'trend' variable were added to the model, whether to account for energy efficiency or otherwise this would potentially introduce multicollinearity.

It should also be noted that the terminal station forecasts are reconciled to a system level forecast which is 'driven' by other variables with trend components.

Simply put, this means that the price variable plays two roles in the model:

— the first order role is to account for the impact of price explicitly
— the second order role is to 'pick up' other trends.

This means that the price coefficient must be interpreted with care and, more broadly, that our model cannot truly be interpreted as a *causal* model. However, this does not hinder its performance as a forecasting model unless there is a fundamental change in the underlying trends.

If there were to be a fundamental change in underlying trends, this would need to be taken into account explicitly. However, we are not satisfied that there is likely to be such a change during the forthcoming regulatory period. That is, we do not see signs of an *acceleration* of energy efficiency effort in the forthcoming regulatory period.

To summarise, the model we used accounts for trend improvement in energy efficiency in the coefficient on the price variable. It does this by default because there is no separate measure of the changing extent of energy efficiency.

It is not entirely clear how one would measure the extent of energy efficiency for this purpose if such a variable was to be added.

More importantly, though, it is view that it is neither necessary nor entirely appropriate to include an explicit measure of the extent of energy efficiency because doing so would introduce multicollinearity and would not add to the forecasting capability of the model (assuming, as noted above, that the trend in price and energy efficiency will not diverge from one another in future).

Therefore, our model is based on the assumption that trends in energy efficiency that have been observed in the last decade will continue in future and that whatever impact those trends have had on peak demand will continue as before. As discussed in the previous section we do not necessarily accept that the sign of that impact is negative.

3.2.3 Double counting the price effect

A third reason why we considered it inappropriate to make an adjustment for energy efficiency in these models is the risk of double counting between the impact of price changes and energy efficiency.[6]

The issue arises because, as electricity price increases, the incentive on customers to be more energy efficient also increases. For example, appliance choices that are not worthwhile at 'low' electricity prices are more worthwhile at 'high' electricity prices because the avoided cost is larger.

Therefore, the price coefficient in the model is capturing increases in energy efficiency.

Therefore, as well as identifying policies that cause an acceleration in the trend in energy efficiency, it would be necessary to consider whether their impact is *additional* to the improvements that would be

[6] This is distinct from double counting the impact of energy efficiency and other trend effects.

driven by projected changes in price. Unless both conditions are met we would be reluctant to make a post model adjustment for the impact of an energy efficiency policy on peak demand.

In this case we are not aware of a policy intervention that can be expected to make a sufficiently large impact on energy efficiency that it would warrant inclusion in these models.

3.3 Cost reflective tariffs

Dr Biggar notes that our forecasts do not account for a change in tariff structures towards demand based tariffs.

This reflects the timing of our engagement, which was about a year before JEN published its TSS and six months before the AEMC made the rule change that requires cost reflective pricing.

We have subsequently developed a methodology to apply cost reflective pricing to demand forecasts which could be applied here. However it should be noted that it relies heavily on the assumed relationship between electricity price and peak demand. The assumption we make is reasonable in our view, but it is difficult to calibrate, so the results would be somewhat speculative.

4 HISTORICAL DATA - MAXIMUM DEMAND

Figure 4.1 shows maximum demand at the system level for summer (from 2004-05 to 2014-15) and winter (2005 to 2014. Generation is a relatively minor adjustment to observed demand, never contributing more than 11 MW at a time of maximum demand. Maximum demand in summer appears to exhibit a broad upward trend. In contrast, in winter it appears to be relatively steady.

The maximum demand levels considered in the forecasting process are temperature corrected. The maximum demand levels shown in **Figure 4.1** are not.

FIGURE 4.1 SYSTEM LATENT MAXIMUM DEMAND BY COMPONENT

DATA SOURCE: JEN

5 METHODOLOGY – MAXIMUM DEMAND

The process for generating maximum demand forecasts at the system level was the same as the system level methodology outlined in the earlier maximum demand report. As such, it was also consistent with the terminal station methodology outlined in that report.

Broadly, the approach to forecasting system level maximum demand was:

— estimate an econometric model relating daily maximum demand to the drivers considered in chapter 6
— for each forecast year, estimate maximum demand:
  - for all days other than weekends, public holidays and an extended Christmas and New year period
  - using temperature data from each day from 1980 until 31 March 2015 (for summer – end October 2014 for winter) (i.e. 3078 forecasts in summer, 5229 forecasts in winter)
  - using the values of other drivers relating to that forecast year (e.g. GSP, price, PV capacity)
  - generating a draw from the distribution of the error term
— store the maximum demand for each year of temperature data (36 summer and 35 winter observations for each forecast year)
— repeat this process 99 times (3,600 total simulated maximum demand values (3,500 in winter)).

The 10, 50 and 90 PoE levels are then determined by considering percentiles of the 3,600 simulated maximum demand values.

Separate forecasts were developed for summer and winter.

The process was the same as that used to produce the original forecasts, which included considering alternative functional forms of the regression models. The decision was to use the same functional form on this occasion as had been used previously. Partly this was for consistency, but also because this model performed similarly well to the alternatives.

Two factors were not included in the methodology that are worth noting, namely the price of gas (a substitute in some cases) and the impact of so called ‘disruptive technologies’.

The price of gas could potentially influence demand for electricity. Conceptually this would be accounted for using a cross price elasticity. However, given that the parameter of interest in this report is maximum demand and that, particularly in summer, this is sensitive to cooling load, the relationship with gas prices was assumed to be zero. There may be some impact in winter, though we expect it would be small. In any case, JEN’s terminal stations are ‘summer peaking’, meaning that maximum demand in summer is higher than it is in winter. For this reason this factor was not considered in winter either.

Similarly, no explicit adjustment was made for disruptive technologies that are not yet present in JEN’s network.[7] The impact that these technologies may have on maximum demand is highly uncertain and subject to the way they are used. For example, charging load from electric cars would potentially

[7] This does not apply to solar PV systems, which were taken into account in both the system and spatial forecasts.

increase electricity demand substantially, but this is unlikely to occur at peak times. In fact, the batteries in these cars could be used to reduce peak demand, though this would require substantial coordination and planning.

5.1 System level maximum demand - summer

At the system level, summer maximum demand was modelled from a dataset showing daily maximum demand for all 'non-mild' days.[8] The model expresses daily maximum demand as a function of the following factors:

— **GSP_t:** gross state product
— **Min_t*GSP_t:** minimum daily temperature, multiplied by gross state product
— **Max_t*GSP_t:** maximum daily temperature, multiplied by gross state product
— **Max_{t-1}:** maximum daily temperature on the previous day
— **Max_{t-2}:** maximum daily temperature on two days prior
— **Maxgt34**: indicator variable set to 1 when maximum temperature (max_t) is greater than 34 C
— **$Price_t$:** retail electricity price
— **$February_t$:** indicator variable, equal to '1' if month is February, '0' otherwise
— **$Friday_t$:** indicator variable, equal to '1' if day is Friday, '0' otherwise

This specification provided a good balance between explanatory power, sensible coefficients, and model parsimony. The final model is shown in equation (1).

$$
\begin{aligned}
MD_t = 504.0 - 6.82 \times 10^{-4} \times GSP_t + 2.05 \times 10^{-5} \times Min_t \times GSP_t + 3.98 \\
\times 10^{-5} \times Max_t \times GSP_t + 1.77 \times Max_{t-1} + 1.09 \times Max_{t-2} \\
+ 20.00 \times MAXgt34 - 6.26 \times Price_t + 15.11 \times February_t \\
- 17.4 \times Friday_t + e_t
\end{aligned}
\tag{1}
$$

Table 5.1 summarises the model estimated using this specification. For comparison the coefficients from the earlier model are included as well.

[8] 'non-mild' days means that weekends, public holidays and days with mild temperatures were omitted as for the spatial models.

TABLE 5.1 SUMMER MAXIMUM DEMAND MODEL - ESTIMATED COEFFICIENTS AND REGRESSION STATISTICS

Variable	Updated coefficient	Standard error (updated)	t-statistic (updated)	p-value (updated)	Original coefficient
Constant	503.97	42.93	11.74	0.00	441.1
GSP	0.00	0.00	-3.55	4.00E-04	-4.36E-04
MIN*GSP	2.05E-05	1.89E-06	1.09E+01	0.00	2.00E-05
MAX*GSP	3.98E-05	1.34E-06	2.97E+01	0.00	3.96E-05
MAXt-1	1.77	0.41	4.30	0.00	1.76
MAXt-2	1.09	0.32	3.45	0.00	1.07
MAXgt34	20.00	5.71	3.50	0.00	20.42
PRICEt	-6.26	0.92	-6.78	0.00	-6.91
FEB	15.11	3.22	4.69	0.00	15.65
FRI	-17.37	3.61	-4.81	0.00	-18.08
R^2 (Adjusted):		0.87			
Standard error of regression:		33.3			

SOURCE: ACIL ALLEN CONSULTING

The updated model has substantially the same features as the original model.

The coefficients on lagged temperature are positive, meaning that as temperature increases maximum demand is forecast to increase also. The GSP coefficient must be interpreted in conjunction with the minimum and maximum temperature interactions. While the coefficient on GSP itself is negative, the interaction terms with temperature more than compensate. The positive coefficients on interactions between temperature and GSP suggest that sensitivity to temperature increases as economic growth continues. This is true for both daytime (the maximum temperature interaction) and night-time (minimum temperature interaction).

These coefficients were combined with:

- forecasts of the variables/drivers
- historical temperature data from 1980 to 2014
- simulated draws from a normal distribution, with a mean of zero, and standard deviation of 33.3.

The outputs were adjusted to account for the impact of solar PV systems forecast to be installed in future.[9]

This was done by using the methodology, and projections, described in the earlier report.

As with the earlier forecasts, no adjustment was made for other forms of embedded generation or other disruptive technologies.

5.2 System level maximum demand - winter

For system level forecasts, maximum demand was modelled as a function of the following factors:

- **GSP_t:** gross state product
- **Min_t*GSP_t:** minimum daily temperature, multiplied by gross state product
- **Max_t*GSP_t:** maximum daily temperature, multiplied by gross state product
- **Max_{t-1}:** maximum daily temperature on the previous day

[9] The impact of existing systems was reflected in the data upon which the model was based. Therefore, unlike the terminal station models, this model makes a post model adjustment only for new systems.

— **Max_{t-2}:** maximum daily temperature on two days prior

— **Price:** retail electricity price

— **April:** indicator variable, equal to '1' if month is April, '0' otherwise

— **June:** indicator variable, equal to '1' if month is June, '0' otherwise

— **September:** indicator variable, equal to '1' if month is September, '0' otherwise

— **October:** indicator variable, equal to '1' if month is October, '0' otherwise

— **$Monday_t$:** indicator variable, equal to '1' if day is Monday, '0' otherwise

— **$Friday_t$:** indicator variable, equal to '1' if day is Friday, '0' otherwise

This specification provided a good balance between explanatory power, sensible coefficients, and model parsimony. The final model is shown in equation (2).

$$\begin{aligned} MD_t = 451.8 - 8.60 \times 10^{-6} \times Min_t \times GSP_t - 1.87 \times 10^{-5} \times Max_t \times GSP_t \\ - 1.38 \times Max_{t-1} - 1.50 \times Max_{t-2} - 6.95 \times Price_t + 1.69 \\ \times 10^{-3} \times GSP_t - 31.45 \times April_t + 8.68 \times June_t - 26.83 \\ \times September_t - 32.81 \times October_t - 7.38 \times Monday_t \\ - 15.48 \times Friday_t + e_t \end{aligned} \tag{2}$$

Table 5.2 summarises the coefficients estimated using this specification. The coefficients from the earlier model are included for comparison.

TABLE 5.2 WINTER MAXIMUM DEMAND MODEL - ESTIMATED COEFFICIENTS AND REGRESSION STATISTICS

Variable	Coefficient	Standard error	t-statistic	p-value	Coefficient (original)
C	451.08	17.24	26.17	0.00	456.86
GSP	1.69E-03	7.37E-05	22.97	0.00	1.64E-03
MAX*GSP	-8.60E-06	6.75E-07	-12.73	0.00	-1.85E-05
MIN*GSP	-1.87E-05	6.80E-07	-27.49	0.00	-8.88E-06
MAX1	-1.38	0.23	-6.00	0.00	-1.41
MAX2	-1.50	0.19	-8.05	0.00	-1.52
RPRICET	-6.95	0.35	-19.61	0.00	-6.56
APR	-31.45	2.13	-14.75	0.00	-30.76
JUN	8.68	1.50	5.80	0.00	9.39
SEPT	-26.83	1.64	-16.40	0.00	-26.65
OCT	-32.81	1.93	-17.01	0.00	-32.33
MON	-7.38	1.34	-5.52	0.00	-7.92
FRI	-15.48	1.34	-11.59	0.00	-14.91
R^2 (Adjusted):		0.84			
Standard error of regression:		18.4			

SOURCE: ACIL ALLEN CONSULTING

As with the model for summer, the winter model is substantially similar to the earlier model.

The positive coefficient on GSP suggests that demand increases with higher levels of economic activity. The negative coefficients on the interactions between GSP and temperature indicate that the impact of higher GSP is lessened on warmer winter days. This is consistent with reasoning that as economic activity increases the use of electric heating increases also. Negative coefficients on lagged temperature imply an impact of sequences of cold days, in the same way as sequences of hot days increase electricity demand in summer.

The price in the previous year is found to have a negative impact on demand, and the coefficient on the interaction between price and maximum temperature suggests that as temperature increases price has even more of an impact on demand.

Finally, Demand in June is found to be higher than in July or August, while demand in April. September, and October is lower on average. As with the summer model, demand is forecast to be lower on Friday than on other weekdays.

These coefficients were combined with:

- forecasts of the variables/drivers
- historical temperature data from 1980 to 2014.
- simulated draws from a normal distribution, with a mean of zero, and standard deviation of 18.4.

No adjustment was made to the winter forecasts to account for the impact of PV. This reflects the fact that demand in JEN’s region peaks in the morning or the evening, when PV output is limited.

6 DRIVERS – HISTORICAL AND PROJECTED

This chapter provides an overview of the history of likely drivers of demand and customer numbers in JEN's region. Data series that are discussed in this chapter are:

- economic activity - section 6.1
- photovoltaic (PV) generation capacity - in section 6.2
- electricity prices - section 6.3
- weather - in section 6.4.

The historical data series presented in these sections were used as the explanatory variables in the regression models described in chapter 5. The projections of drivers presented in this chapter were used as inputs into the maximum demand forecasts.

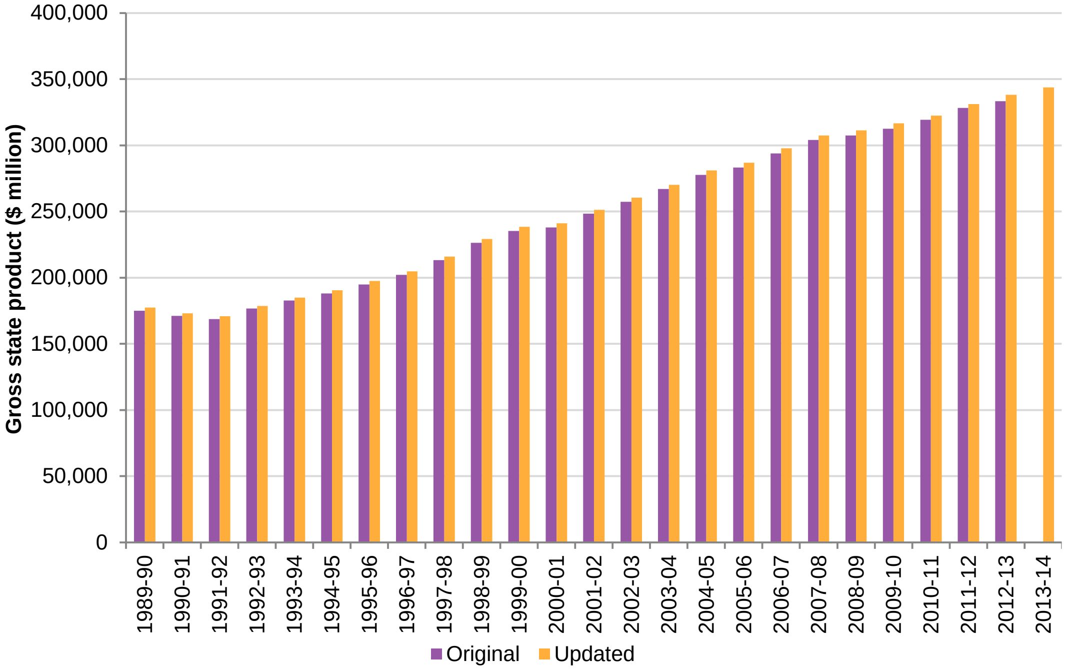
6.1 Economic activity

Growth in economic activity is a major driver of rising incomes. Demand for electricity is, in part, driven by the ownership of appliances that can be used in peak demand conditions. Two important examples are air-conditioners, and electric space heating. Economic activity is likely to interact with temperature in its impact on maximum demand.

Figure 6.1 shows the historical time series of Victorian economic activity, as measured by Gross State Product (GSP), from 1989-90 to 2013-14.[10] It shows small variations in the historical data since the original forecasts were prepared. These variations were made by the Australian Bureau of Statistics. They are sufficiently small that we did not re-estimate the models to account for them. Therefore, our models are based on the ABS' view of history as it was in 2014.

[10] GSP growth is forecast on a financial year basis. Therefore, for consistency of presentation we present history on a financial year basis as well. However, JEN's regulatory periods are based on calendar years. Therefore GSP growth is rebased to calendar years for modelling purposes.

FIGURE 6.1 VICTORIAN GROSS STATE PRODUCT (GSP), 1989-90 TO 2013-14, $M (CHAIN VOLUME MEASURE)

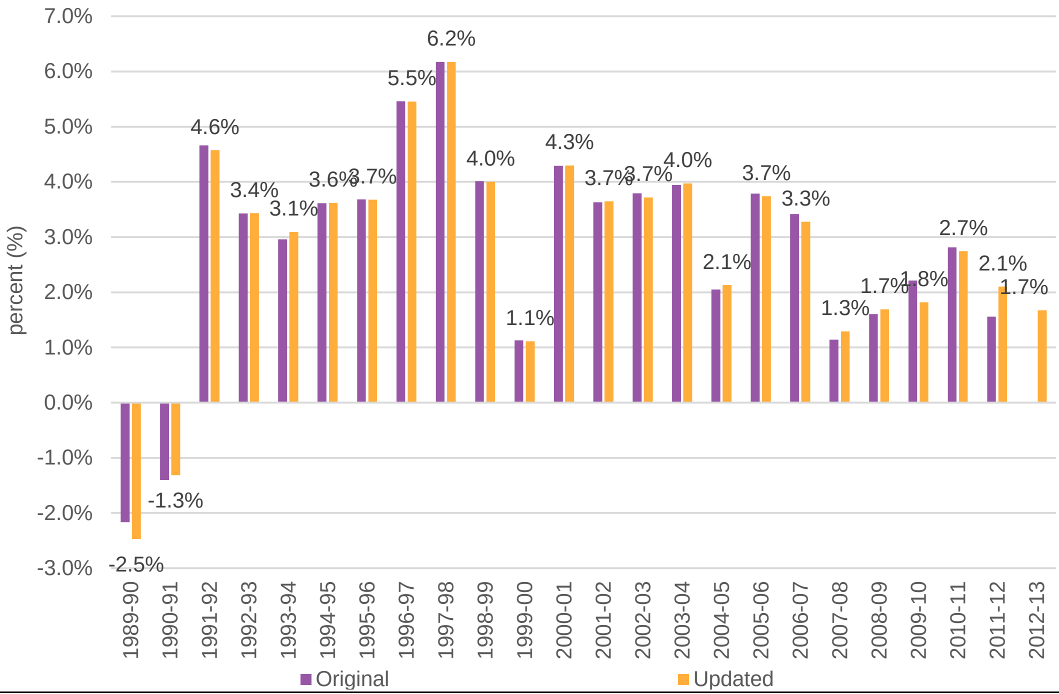


SOURCE: ABS, 5220.0 AUSTRALIAN NATIONAL ACCOUNTS: STATE ACCOUNTS

Figure 6.2 shows that Victorian economic growth has been positive in all but two years since 1989-90. In 1990-91 Victorian GSP declined by 2.5 per cent. This was followed by a further decline of 1.3 per cent in 1991-92.

Victorian GSP growth slowed in the period following 2008-09. In the five years since then it has averaged just 2.0 per cent per annum. This is compared to a long term average of 2.8 per cent per annum from 1990-91 to 2013-14.

FIGURE 6.2 YEAR ON YEAR GSP GROWTH, VICTORIA 2011-12 TO 2013-14



Note: Data labels are for the updated series

SOURCE: ABS, 5220.0 AUSTRALIAN NATIONAL ACCOUNTS: STATE ACCOUNTS

Economic growth forecasts

Several economic growth projections were considered for application in the original model developed for JEN. They are summarised in the earlier report.

In the earlier report we selected the Victorian Government's forecasts of GSP as the basis for forecasting maximum demand in JEN's region. The Victorian Government forecasts were towards the centre of the available forecasts so they were selected as the basis of GSP forecasts used in the consumption model.

However, in its preliminary decision the AER expressed a preference that AEMO's forecasts be used. Therefore we have substituted AEMO's 2015 economic forecasts from the National Electricity Forecasting report for those of the Victorian Government.

In most years AEMO's growth assumptions are less optimistic than those used in the original forecasts, as shown in **Figure 6.3**.

FIGURE 6.3 VICTORIAN ECONOMIC GROWTH PROJECTIONS, 2015 TO 2020

SOURCE: ACIL ALLEN CONSUILTING

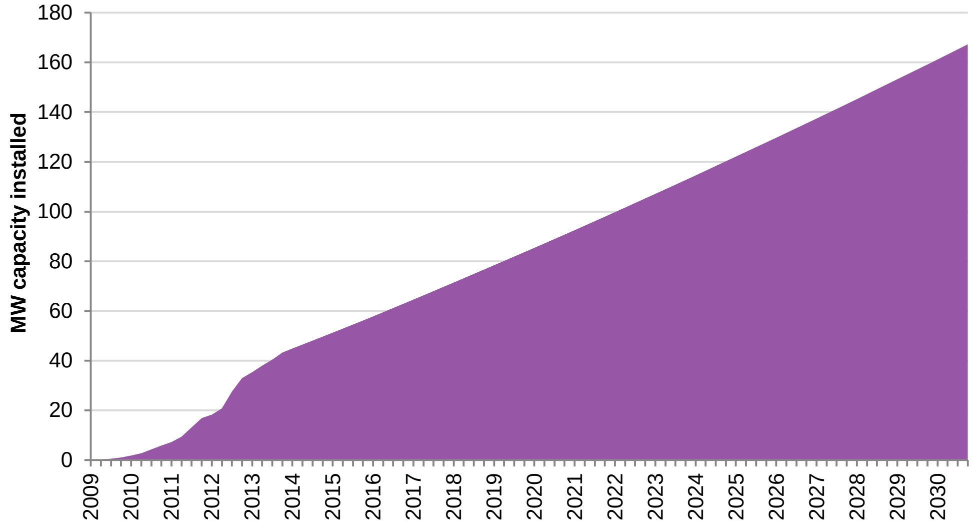
6.2 PV generation capacity

The take-up and usage of rooftop PV systems has a negative impact on demand at the terminal station level. This is because energy generated from these systems is used to offset demand from the owner of the system. Excess energy generated from these systems is also exported to other households within JEN's distribution region without passing through a terminal station. Hence all generation from PV systems can be considered to offset demand. This is in contrast to measures of consumption, where the relevant measurement occurs at individual household meters.

Increased uptake of rooftop PV is a relatively recent phenomenon. Changes in the uptake level of rooftop PV can be attributed to the range of financial incentives households have been offered to install such systems from 2009 onwards. The model described in the earlier report forecasts rooftop PV capacity into the forecast period, based on a set of assumptions around the financial incentives that are likely to apply. These projections were not changed for this update.

Figure 6.4 shows the cumulative level of PV capacity projected using this model.

FIGURE 6.4 CUMULATIVE CAPACITY OF INSTALLED SOLAR PV SYSTEMS



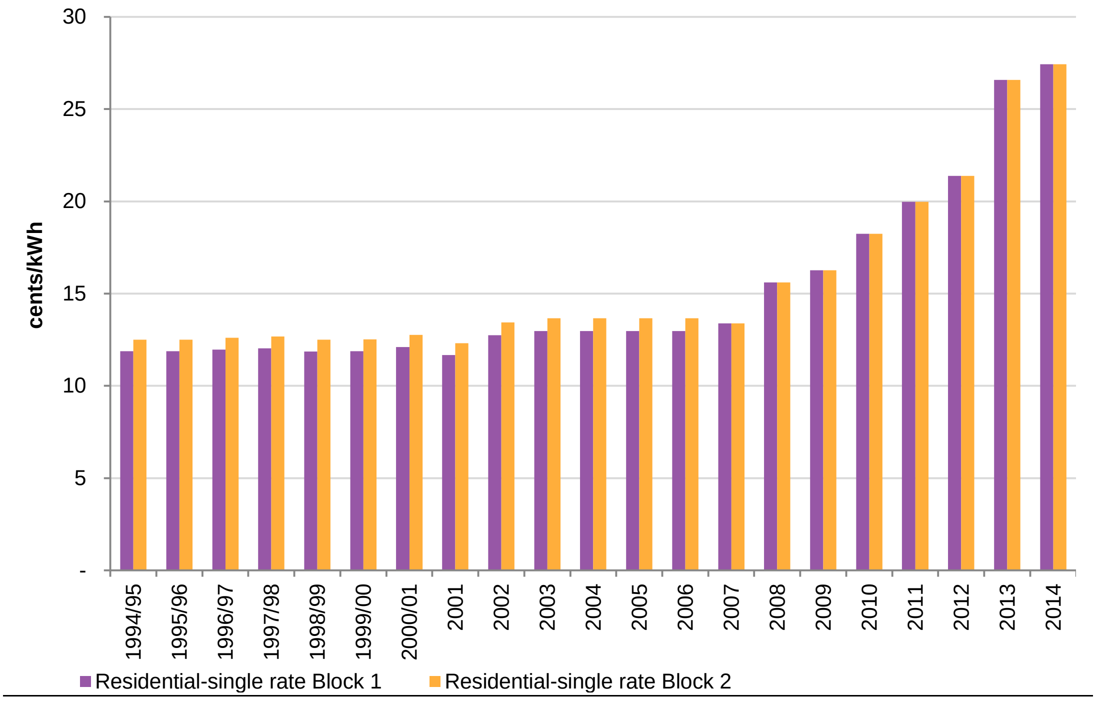
Source: ACIL Allen Consulting

6.3 Electricity prices

Another likely driver of demand is the price of electricity. Higher electricity prices would be expected to decrease maximum demand by creating incentives for customers to become more energy efficient (through appliances and housing design).

Figure 6.5 shows a time series for electricity prices for the residential tariffs from 1995 to 2014. Tariffs were relatively stable until 2007, before commencing a more rapid ascent. It is reasonable to expect that the strong price rises of recent years have had a dampening effect on demand.

FIGURE 6.5 RESIDENTIAL SINGLE RATE TARIFF- BLOCKS 1 AND 2



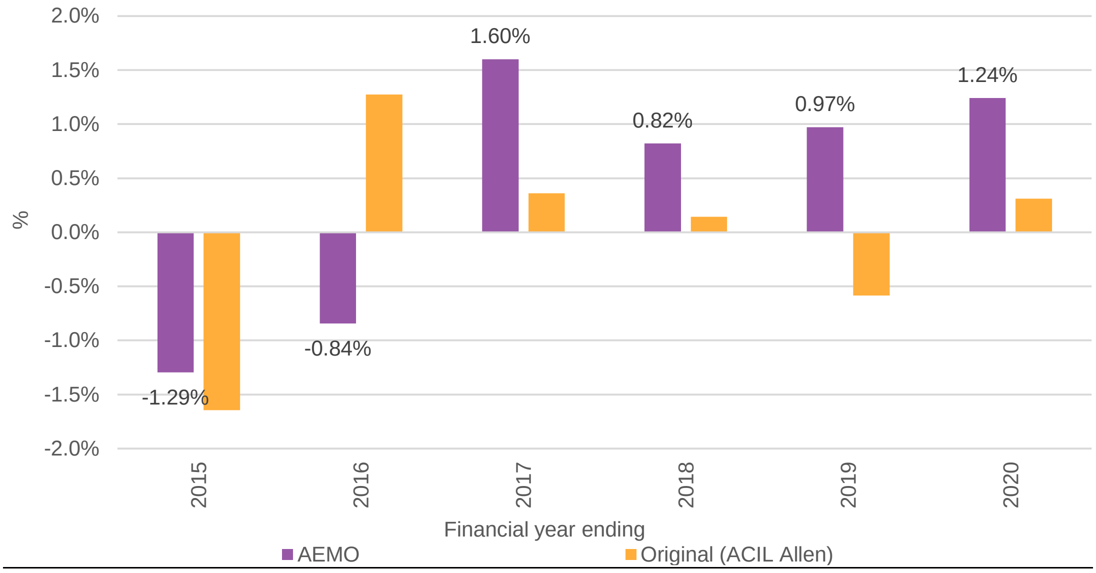
DATA SOURCE: ESSENTIAL SERVICES COMMISSION

Forecast electricity price changes

Forecasts of real electricity prices are an input into the forecasting models. For the November 2014 report ACIL Allen forecast electricity prices internally, treating each component separately (i.e. wholesale, network and other costs including retail margin). However, on this occasion the AER's preference appears to be that we use the economic growth forecasts provided by AEMO. Given this we have elected to adopt AEMO's retail price forecasts as well. It is important to retain consistency between economic forecasts and forecasts of electricity prices given that the latter are an important input to the economy.

The particular projection that was adopted is from the 2015 National Electricity Forecasting Report. It is summarised in **Figure 6.6** alongside the forecast from our November 2014 report.

FIGURE 6.6 FORECAST CHANGE IN REAL ELECTRICITY PRICES



SOURCE: ACIL ALLEN CONSULTING

Perhaps the most notable characteristic in the projected price series is a substantial reduction in forecast retail price in 2015. We understand that this is generally attributable to reduction in the cost of metering services due to the completion of the smart meter rollout. However, we do not have sufficient information about the projection to comment on this decrease other than to note that it is much larger than changes forecast for other years.

6.4 Weather

The weather is a key driver of demand in both summer and winter.

In winter, demand that varies with weather conditions is driven primarily by the 'heating requirement'. Generally, cooler seasons would be associated with a greater heating requirement, and therefore a greater maximum demand. In summer this pattern is reversed, with cooling becoming the driver of weather-related demand.

The impact of weather is strongly related to the availability of appliances, and hence economic activity. The impact of weather may also change depending on whether the day's conditions are at the end of a warm or cool streak. Forecasts of weather are not used within the maximum demand forecasting. Rather, historical weather conditions since 1970 are used to develop a confidence interval around maximum demand forecasts.

Weather measurements were taken from the Melbourne Airport weather station, as reported to the Bureau of Meteorology website.

Weather inputs are not forecast. Rather, forecasts are produced at 10, 50 and 90 POE levels based on historical analysis of the relationship between demand and weather.

The only change to the way weather was accounted for between the original forecasts and those presented in this report was to include more recent weather data to correspond with the more recent demand data.

A

CURRICULA VITAE

Jeremy Tustin, Principal

Bachelor of Economics University of Adelaide

Jeremy Tustin is a Principal in the Melbourne Office of ACIL Allen Consulting.

Jeremy's expertise is in economics and policy analysis specialising in market analysis and policy. He began his career working on competition and consumer protection matters with the Australian Competition and Consumer Commission. He transitioned from there to a period of research and lecturing at the University of South Australia. During that time he conducted research into the use of choice experiments and econometric analysis in consumer protection matters.

Jeremy then spent several years in Energy and Water policy in the South Australian Governments at both line and central agencies. His Government career included periods as Markets and Sustainability and Director, Retail frameworks in the Energy Division. He was also Director, Economic Regulation in the South Australian Department of Treasury and Finance.

After moving to Melbourne in 2009, Jeremy began consulting with ACIL Allen. He has since managed and contributed to a wide range of consulting projects for Government and private sector clients. Many of these have been in the energy sector.

Jeremy's projects include:

- **Electricity tariffs -** projects for the Victorian Government relating to energy tariffs. Jeremy is currently leading a team that has surveyed a sample of almost 3,000 residential customers, collecting demographic data as well as highly detailed energy consumption data. Jeremy and his team have since used those datasets to:
  - prepare algorithms to assist customers in choosing between electricity and gas retail packages
  - analyse the impact of electricity tariff reform for residential customers
- **Solar power –** since 2012 Jeremy has conducted a series of projects estimating the value of electricity exported by household solar panels for the Essential Services Commission of South Australia, the Victorian Competition and Efficiency Commission and the Essential Services Commission (Victoria). Those projects have underpinned the mandatory payment made for electricity exported to the grid from solar panels in South Australia and Victoria from 2012 to the present. They were in three stages:
  - Stage 1 – (for ESCOSA (2011) and VCEC (2012)) develop conceptual approach to valuing electricity generated by domestic solar panels and exported to the grid (the value of exported PV output)
  - Stage 2 – develop quantitative method for applying the conceptual approach developed in stage 1

- Stage 3 ((ESCOSA 2012, 2013, 2014, 2015 (ongoing)) and ESC Vic 2014, 2015) periodic updating of quantitative methodology to update the (forecast) value of exported PV output

— **Energy demand forecasting** projects in three related fields:
- for the **Australian Energy Regulator** (2009, 2010, 2012, 2015) **–** review demand forecasts submitted by electricity and gas network businesses in support of regulatory proposals
- for **energy network businesses –** prepare demand forecasting tool and/or demand forecasts for submission to the AER in support of regulatory proposals (various, ongoing)
- for the **Australian Energy Market Operator -** develop and implement nationally consistent methods for forecasting electricity and gas demand in consultation with electricity and gas network businesses and industry stakeholders

— **Energy policy analysis**
- a review of the Northern Territory's Electricity standards of Service Code and of the categorisation of feeders on Power and Water Corporation's network
- a review of certain principles underpinning the Essential Services Commission of South Australia's upcoming determination of the standing contract price for gas in South Australia
- a review of competitiveness, and barriers to increased competitiveness, in the South Australian retail energy markets.

— Other projects including
- preparation of a paper outlining the potential for competition in the vocational education and training (VET) sector in Victoria and identifying likely pitfalls, such as 'races to the bottom' in quality. Jeremy subsequently worked closely with DEECD staff identifying market segments in the VET sector
- participating in an ACIL Allen team preparing a forecasting tool for the
- assisting DEECD with analysis surrounding the implementation of principles for VET in Schools including drafting and refining policy papers
- a review of the regulatory arrangements applicable to the Western Australian plumbing industry

Jim Diamantopoulos, Consultant

Jim Diamantopoulos specialises in the application of financial, statistical and quantitative methods to solve complex problems for both the private and public sectors. At ACIL Allen, Jim carries out financial modelling, econometric modelling, including model construction, evaluation and testing, demand forecasting and efficiency benchmarking for regulated utilities. Jim has accumulated considerable expertise in the development of demand forecasting methodologies across a range of sectors, particularly in energy and water.

Jim has over 15 years of practical experience in the application of financial and econometric techniques to real world problems. Before joining ACIL Allen, Jim spent six years as a statistician with the Australian Bureau of Statistics. Prior to this he held quantitative roles for several banks.

Demand Forecasting

Jim has extensive experience in producing demand forecasts for regulated utilities in the energy and water sectors, including:

— Ongoing preparation of energy, customer numbers and maximum demand forecasts and modelling tools for several Electricity Distribution Network Service Providers (DNSPs) (2007-14)

— Development of sophisticated connection point and zone substation load demand forecasting models for Aurora Energy and SA Power Networks. The models incorporated weather correction as well as adjustments for permanent transfers, major block loads, embedded generation and demand side management initiatives

— Development of a new maximum demand and energy forecasting methodology at the connection point level for AEMO. The assignment involved all aspects of the forecasting process from model specification, development and estimation to weather normalisation

- Estimation of short and long run cost functions for several Electricity Distribution Network Service Providers (DNSPs)
- For the Australian Energy Market Commission, an analysis of the impact of the Small Scale Renewable Energy Scheme (SRES). Specifically Jim developed a non-linear econometric model of the take-up of solar PV installations by state jurisdiction, with the economic payback of installation as the main driving variable.
- Development of a comprehensive model of water demand for SA Water. The model is econometrically driven and generates water demand forecasts by sector for South Australia after estimating suitable relationships between water use and its key drivers
- In a pricing submission for the Lower Murray Urban and Rural Water Authority, Jim undertook an econometric analysis to generate forecasts of urban water demand in the Lower Murray region.

Demand model assessments and forecast reviews

In addition to his experience in demand forecasting, Jim has also been engaged on numerous occasions to review the models and forecasts of others. For example:

- A review of maximum electricity demand and energy forecasts for the Independent Market Operator (IMO) in Western Australia
- A review the energy and maximum demand forecasts of the Victorian DNSPs for the Australian Energy Regulator as part of a regulatory price review
- Multiple reviews and evaluations of forecasting methodologies on behalf of several Electricity Distribution Network Service Providers (DNSPs) (2007-2014)
- Reviewing of SA Water's water and wastewater demand forecasts and associated forecasting methodology for ESCOSA in South Australia
- VET training demand, review of forecasting methodology – Jim conducted a review of the methodology used by the Higher Education Skills Group (HESG) to forecast demand for VET places in the (then brand new) market driven model. The significance of those forecasts was that they related directly to the Government's financial exposure to make subsidy payments and, therefore, to its commitment to deliver a budget surplus

Qualifications

Jim holds a Master of Economics degree from Monash University, specialising in econometrics, a Bachelor of Economics degree with Honours, and a Graduate Diploma of Applied Finance and Investment (FINSIA).

Timothy Weterings, Consultant

Tim Weterings is a consultant in ACIL Allen's Melbourne office with significant experience in the application of econometric and statistical techniques. He has a PhD in Econometrics from Monash University and has published econometric papers in multiple international peer-reviewed academic journals. He also has several years' experience teaching econometrics and modelling techniques at the undergraduate level.

Tim has worked extensively within the energy sector. He was involved in both the development of the gas forecasting methodology for AEMO and in the later stages of the electricity forecasting advisory project. In both projects he applied his statistical expertise to recommend improvements to methodological approaches.

He has also worked with Jeremy and others to prepare demand forecasts for electricity distribution networks as part of their regulatory submission process. This has included forecasts of photovoltaic generation capacity based on a rational financial modelling approach. Tim also built models to assess the impact of time-of-use tariffs on both demand for and consumption of electricity, and forecast consumption based on a wide range of demographic and economic variables.

Tim was recently involved in the development of algorithms for the *My Power Planner* website for a Victorian Government Department. This involved econometric analysis of a significant amount of smart meter data. This was matched to demographic data from a survey of Victorian households. Tim identified the variables that best explain both the level and shape of electricity consumption profiles. This has been used to design the website, including the website structure, the types of questions asked of website users, and the generation of consumption profiles used to recommend retail tariffs.

Using the *My Power Planner* dataset, Tim also analysed the impacts of demand-based tariffs on bills for Victorian consumers. This involve the analysis of approximately 2,300 households' consumption and demographic data, to find which households will benefit the most from the transition to demand-based tariffs. As this work was undertaken before the 2015 submission of tariff structure statements, a set of assumptions were used to inform the structure and level of tariffs.

Tim also has substantial experience applying advanced analytics and econometrics in a range of other contexts. This includes:

— *VET forecasting for the Victorian Department of Education and Training (2014):* Tim applied advanced econometric analysis to Vocational Education and Training data to quantify the impact of subsidies, the economic environment, and the policy environment on commencement levels. He also built a sophisticated model to forecast VET activity and expenditure, and to investigate the impact of a wide range of policy scenarios.

— *Analysis and reporting of Check-up Digital for the National Archives of Australia:* Tim analysed and reported on the digital capabilities of a range of Australian Government agencies. This included advanced exploratory analysis to uncover deeper insights into the way in which different agencies develop digital capabilities.

B

TERMS OF REFERENCE

Expert Terms of Reference for 2015 Electricity Demand Forecasts

Jemena Electricity Networks (Vic) Limited
2016 Electricity Price Determination Review

EDPR-5280-000X

Version A – 23 November 2015

Contact Person

Ana Dijanosic

Regulatory Projects Manager

Email: ana.dijanosic@jemena.com.au

Phone: (03) 8544 9000

Jemena Limited

ABN 82 064 651 083

321 Ferntree Gully Road
Mt Waverley VIC 3149

Postal Address:

Locked Bag 7000
Mt Waverley VIC 3149

Ph: (03) 8544 9000

Fax: (03) 8544 9888

Version	Status	Date	Prepared	Checked	Authorised
A	Draft	7/09/2015	A Lloyd	C Herbert	A Dijanosic

Contents

1 Background

Jemena Electricity Networks (Vic) Limited (**JEN**) is an electricity distribution network service provider in Victoria. JEN supplies electricity to approximately 300,000 homes and businesses through its 10,285 kilometres of distribution system. JEN's electricity distribution system services 950 square kilometres of northwest greater Melbourne. JEN's electricity network is maintained by infrastructure management and services company, Jemena Asset Management Pty Ltd.

JEN is currently preparing its revised regulatory proposal to be submitted to the Australian Energy Regulator (**AER**) on 6 January 2016. The proposal covers the period 2016-2020 (calendar years).

When considering approval of JEN's regulatory proposal, the AER must have regard to the National Electricity Objective, which is:

> …to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system.

The AER must take into account the revenue and pricing principles in section 7A of the National Electricity Law when exercising a discretion in making those parts of a distribution determination relating to direct control network services, and may take into account these principles when performing or exercising any other AER economic regulatory function or power:

> *A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in:*
>
> *(a) providing direct control network services; and*
>
> *(b) complying with a regulatory obligation or requirement or making a regulatory payment.*

Some of the key rules that JEN must comply with in submitting its revised regulatory proposal are set out below.

Clause 6.5.6(c) of the National Electricity Rules:

> *The AER must accept the forecast of required operating expenditure of a Distribution Network Service Provider that is included in a building block proposal if the AER is satisfied that the total of the forecast operating expenditure for the regulatory control period reasonably reflects:*
>
> > *(1) the efficient costs of achieving the operating expenditure objectives; and*
> >
> > *(2) the costs that a prudent operator would require to achieve the operating expenditure objectives; and*

(3) a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.

Clause 6.5.7(c) of the National Electricity Rules:

The AER must accept the forecast of required capital expenditure of a Distribution Network Service Provider that is included in a building block proposal if the AER is satisfied that the total of the forecast capital expenditure for the regulatory control period reasonably reflects:

(1) the efficient costs of achieving the capital expenditure objectives; and

(2) the costs that a prudent operator would require to achieve the capital expenditure objectives; and

(3) a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.

Accordingly, the independent opinion of a suitably qualified expert is sought to prepare a set of 10 year maximum demand forecasts for the JEN network area, as outlined in section 2 of this document.

2 Scope of Work

The independent expert will provide its realistic forecasts of the following for each year during the period 2015-2024 that can form the basis of JEN's January 2016 revised regulatory proposal under the National Electricity Rules, in particular:

1. Network maximum demand forecasts:
    - summer and winter maximum demand forecasts (kW) for the total JEN area
    - summer forecasts are to be provided for the period 1 November to 31 March, from 2015/16 to 2024/25, and winter forecasts are to be provided for the period 1 April to 31 October, from 2015 to 2024
    - maximum demand forecasts to be provided for 10%, 50% and 90% probability of exceedance (POE) levels, which provide an estimate of the temperature sensitive component of demand; and
2. Number of new connections to JEN, split into residential, small business and large business.

Quantity and maximum demand forecasts must be based on the same underlying assumptions.

The expert will have regard to following factors that will have an impact of JEN's demand:

- population and economic growth: current global and local economic forecasts, new housing activity, household discretionary spending on energy and energy consuming appliances, business production levels, business longevity
- market trends affecting electricity consumption: including but not limited to installing energy efficient lighting (LED), installing energy efficient appliances, installing gas heating in lieu of reverse cycle air conditioning, customer response to price increases over recent years, and impacts of water conservation measures on the consumption of hot water
- Government and other relevant Policy impacts: in arriving at these forecasts, the expert is to consider the impact of major energy, energy efficiency and climate change policies, and to quantify the impact of each of these policies
- Environmental factors: such as weather warming trends and the increasing frequency of extreme weather events; and
- Change in customer consumption behaviour resulting from the installation of Advanced Metering Infrastructure (AMI).

3 Information from JEN

The expert is encouraged to draw upon the following information which JEN will make available:

- historical annual data on customer numbers, from 1 January 2006 to 31 December 2014
- historical terminal station half hourly demand data, including contribution from embedded generators, over the period 1 January 2006 to 30 June 2015
- a list of large business customers who have either indicated an intention to cease production in the near future, or have reduced their consumption considerably over the 2 years ending 31 December 2014 (if applicable); and
- a list of new large business customers that have either increased/decreased consumption considerably over the 2 years ending 31 December 2014, or those who have indicated to increase consumption considerably in the near future (if applicable).

4 Other Information to be considered

The expert is also expected to draw upon the following additional information:

- the AER's preliminary decision on JEN's regulatory proposal, October 2015
- the report by the AER's consultant – Darry Biggar, 2015 Victorian EDPR: An assessment of the Vic DNSP's demand forecasting methodology

- AEMO's 25 Sep 15 updated peak demand forecast
- published scientific and other relevant literature; and
- such information that, in expert's opinion, should be taken into account to address the questions outlined above.

5 Deliverables

At the completion of its review the expert will provide transparent and clearly-explained forecasting models and an independent expert report which:

- includes an executive summary which highlights key aspects of the expert's conclusions
- (without limiting the points further below) carefully sets out the facts that the expert has assumed in putting together his or her report as well as identifying those assumptions made, the basis for those assumptions
- explains how the expert's forecasting methodology, the data and inputs used, and any assumptions results in a realistic expectation of the demand forecast
- is of a professional standard capable of being submitted to the AER – recognising that the AER and its experts in evaluating this material will need to fully trace the inputs and assumptions through the model and be able to replicate the results, so the deliverables need to be prepared so that this can be done
- is prepared in accordance with the Federal Court Guidelines for Expert Witnesses set out in Attachment 1 and acknowledges that the expert has read the guidelines[1]
- contains a section in the report summarising the expert's experience and qualifications, and attaches the expert's curriculum vitae (preferably in a schedule or annexure)
- identifies any person and their qualifications, who assists the expert in preparing the deliverables or in carrying out any research or test for the purposes of the deliverables; and
- summarises the instructions and attaches these terms of reference (or equivalent).

The expert's report will include the findings for each of the parts defined in the scope of works (Section 2).

We request that the expert address queries or responses (including any drafts, as well as general correspondence) to Gilbert + Tobin and clearly mark each as "confidential and subject to legal privilege".

[1] Available at: http://www.fedcourt.gov.au/law-and-practice/practice-documents/practice-notes/cm7.

6 Timetable

As part of their proposal, the expert consultant is required to deliver a project plan for the following two work streams, which will finalise some of the indicative timeframes presented below.

Network Maximum Demand (MD) Forecasts	Due date
JEN to provide MD historical data to Expert	5 October 2015
Expert to provide draft MD forecasts to JEN	**20 November 2015**
JEN to provide feedback on draft MD forecasts	24 November 2015
Expert to provide final MD forecasts to JEN	**30 November 2015**
Expert to provide final report to JEN	30 November 2015

7 Terms of Engagement

The terms on which the Expert will be engaged to provide the requested advice shall be provided in accordance with the Regulatory Consultancy Services Panel arrangements applicable to the Expert.

ATTACHMENT 1: FEDERAL COURT PRACTICE NOTE

Practice Note CM 7

EXPERT WITNESSES IN PROCEEDINGS IN THE FEDERAL COURT OF AUSTRALIA

Commencement

1. This Practice Note commences on 4 June 2013.

Introduction

2. Rule 23.12 of the Federal Court Rules 2011 requires a party to give a copy of the following guidelines to any witness they propose to retain for the purpose of preparing a report or giving evidence in a proceeding as to an opinion held by the witness that is wholly or substantially based on the specialised knowledge of the witness (see **Part 3.3 - Opinion** of the *Evidence Act 1995* (Cth)).

3. The guidelines are not intended to address all aspects of an expert witness's duties, but are intended to facilitate the admission of opinion evidence[2], and to assist experts to understand in general terms what the Court expects of them. Additionally, it is hoped that the guidelines will assist individual expert witnesses to avoid the criticism that is sometimes made (whether rightly or wrongly) that expert witnesses lack objectivity, or have coloured their evidence in favour of the party calling them.

<u>Guidelines</u>

1. General Duty to the Court[3]

1.1 An expert witness has an overriding duty to assist the Court on matters relevant to the expert's area of expertise.

1.2 An expert witness is not an advocate for a party even when giving testimony that is necessarily evaluative rather than inferential.

1.3 An expert witness's paramount duty is to the Court and not to the person retaining the expert.

2. The Form of the Expert's Report[4]

2.1 An expert's written report must comply with Rule 23.13 and therefore must

(a) be signed by the expert who prepared the report; and

(b) contain an acknowledgement at the beginning of the report that the expert has read, understood and complied with the Practice Note; and

(c) contain particulars of the training, study or experience by which the expert has acquired specialised knowledge; and

(d) identify the questions that the expert was asked to address; and

---

2 As to the distinction between expert opinion evidence and expert assistance see *Evans Deakin Pty Ltd v Sebel Furniture Ltd* [2003] FCA 171 per Allsop J at [676].

3 The "*Ikarian Reefer*" (1993) 20 FSR 563 at 565-566.

4 Rule 23.13.

(e) set out separately each of the factual findings or assumptions on which the expert's opinion is based; and

(f) set out separately from the factual findings or assumptions each of the expert's opinions; and

(g) set out the reasons for each of the expert's opinions; and

(ga) contain an acknowledgment that the expert's opinions are based wholly or substantially on the specialised knowledge mentioned in paragraph (c) above[5]; and

(h) comply with the Practice Note.

2.2 At the end of the report the expert should declare that "[the expert] has *made all the inquiries that* [the expert] *believes are desirable and appropriate and that no matters of significance that* [the expert] *regards as relevant have, to* [the expert's] *knowledge, been withheld from the Court*."

2.3 There should be included in or attached to the report the documents and other materials that the expert has been instructed to consider.

2.4 If, after exchange of reports or at any other stage, an expert witness changes the expert's opinion, having read another expert's report or for any other reason, the change should be communicated as soon as practicable (through the party's lawyers) to each party to whom the expert witness's report has been provided and, when appropriate, to the Court[6].

2.5 If an expert's opinion is not fully researched because the expert considers that insufficient data are available, or for any other reason, this must be stated with an indication that the opinion is no more than a provisional one. Where an expert witness who has prepared a report believes that it may be incomplete or inaccurate without some qualification, that qualification must be stated in the report.

2.6 The expert should make it clear if a particular question or issue falls outside the relevant field of expertise.

2.7 Where an expert's report refers to photographs, plans, calculations, analyses, measurements, survey reports or other extrinsic matter, these must be provided to the opposite party at the same time as the exchange of reports[7].

3. Experts' Conference

3.1 If experts retained by the parties meet at the direction of the Court, it would be improper for an expert to be given, or to accept, instructions not to reach agreement. If, at a meeting directed by the Court, the experts cannot reach agreement about matters of expert opinion, they should specify their reasons for being unable to do so.

J L B ALLSOP
Chief Justice
4 June 2013

[5] See also *Dasreef Pty Limited v Nawaf Hawchar* [2011] HCA 21.

[6] The *"Ikarian Reefer"* [1993] 20 FSR 563 at 565

[7] The *"Ikarian Reefer"* [1993] 20 FSR 563 at 565-566. See also Ormrod *"Scientific Evidence in Court"* [1968] Crim LR 240

ACIL ALLEN CONSULTING PTY LTD
ABN 68 102 652 148

ACILALLEN.COM.AU

ABOUT ACIL ALLEN CONSULTING

ACIL ALLEN CONSULTING IS ONE OF THE LARGEST INDEPENDENT, ECONOMIC, PUBLIC POLICY, AND PUBLIC AFFAIRS MANAGEMENT CONSULTING FIRMS IN AUSTRALIA.

WE ADVISE COMPANIES, INSTITUTIONS AND GOVERNMENTS ON ECONOMICS, POLICY AND CORPORATE PUBLIC AFFAIRS MANAGEMENT.

WE PROVIDE SENIOR ADVISORY SERVICES THAT BRING UNPARALLELED STRATEGIC THINKING AND REAL WORLD EXPERIENCE TO BEAR ON PROBLEM SOLVING AND STRATEGY FORMULATION.