Victorian Electricity Distribution Price Review

Review of maximum demand forecasts

Final report

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ACIL Tasman

Economics Policy Strategy

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Executive summary

In November 2009, the five Victorian electricity distribution businesses (collectively "the distribution businesses") submitted their regulatory proposals for the 2011 to 2015 regulatory control period to the Australian Energy Regulator ("AER"). The proposals included forecasts of demand, customer numbers and energy sales for the region served by each of the distribution businesses.

The AER engaged ACIL Tasman to review the forecasts. This report provides the results of ACIL Tasman's review of the forecasts of maximum demand. Views relating to the energy and customer numbers forecasts are contained in a separate report.

An excerpt of ACIL Tasman's terms of reference relevant to the review of demand forecasts is at Appendix A. To summarise, the AER tasked ACIL Tasman to review the demand forecasts produced by each of the distribution businesses. In reviewing these forecasts, the AER sought ACIL Tasman's advice as to whether the forecasts are robust, represent good electricity industry practice and therefore produce realistic forecasts of maximum demand. In undertaking the review, ACIL Tasman was asked to comment on a number of details of the various methodologies used, including:

1. The use of top-down and bottom-up methodologies and the way forecasts prepared by these two means are reconciled
2. the use of weather normalisation
3. the treatment of spot loads
4. whether the forecasts any given distribution business has put forward are consistent with themselves at different levels of aggregation.

The distribution business's forecasts were summarised in a template spreadsheet that was prepared by the AER and appended to Regulatory Information Notices served on each business in October 2009. In addition to this template, ACIL Tasman had regard to forecasts that each business had commissioned from the National Institute of Industry and Economic Research that were contained in a series of reports, one for each business, entitled "*Maximum demand forecasts for* (each distribution business's) *terminal stations to 2019"* (the NIEIR demand reports). ACIL Tasman's understanding of the distribution business's maximum demand forecasts was augmented by a series of meetings and subsequent correspondence with each distribution business and NIEIR.

Best practice distribution load forecasting

As is described in this report, ACIL Tasman considers that a best practice distribution load forecasting methodology is one that is transparent and repeatable, takes account of all the relevant explanatory variables (or drivers) and is based on a logical, coherent model. In preparing forecasts, steps should be taken to minimise the impact of bias. Further, best practice distribution load forecasting requires that:

- forecasts are made independently of the impact of weather, requiring that models are calibrated using weather corrected data
- where spot loads are incorporated into models explicitly, steps are taken to avoid double counting between these and trend growth
- spatial level forecasts (bottom up) are prepared independently of, and reconciled to, system level forecasts (top down).

In ACIL Tasman's view bottom up forecasts should be reconciled to independently derived top down forecasts because the latter are capable of incorporating the relevant economic drivers and policy variables and can employ a more sophisticated temperature correction methodology based on a large number of observations.[1] By contrast, bottom up forecasts are usually unable to take account of economic conditions explicitly (appropriate economic variable forecasts are not available at such a disaggregated level), tend to rely on temperature correction methodologies that are based on a single data point for each year and include the individual judgement of forecasters.

Review of maximum demand forecasts for 2011 to 2015

Reconciliation

Reconciling top down and bottom up forecasts is a significant issue in the methodologies that have been used by each of the distribution businesses. Of the five forecasts that were put forward:

- two were prepared with no attempt to reconcile between top down and bottom up forecasts
- two were reconciled in terms of growth, but not levels, of demand
- one was reconciled, approximately, in the final year of the regulatory period without regard for earlier years.

[1] In respect of weather correction, ACIL Tasman notes that AEMO (formerly VENCorp) has recently moved to this approach in preference to the approach that is typically applied at the spatial level.

Policy impacts

ACIL Tasman also remains cautious about the manner in which policy changes were treated in preparing the forecasts. In recent years, a number of policies have been proposed by both the Victorian and Commonwealth Governments that would be expected to influence electricity demand. Generally speaking, these are policies designed to reduce energy usage and greenhouse gas emissions. As such, they are, typically, concerned primarily with reducing energy sales rather than maximum demand, although it is likely that they will have some effect on demand as well, even if small.

As is discussed in more detail in section 5 of this report, most of the analysis that has been undertaken with respect to these policies has focussed on their impact on energy sales, not maximum demand. This presented the distribution businesses with a difficult task, which has not been assisted by the fact that there have been several significant changes in the policy environment during the course of the review, in particular the defeat of the Carbon Pollution Reduction Scheme legislation in the Senate in December 2009 and the more recent abandonment of the Commonwealth insulation rebate scheme.

ACIL Tasman recommends that the forecast impact on maximum demand of the one watt standby, insulation rebate and AMI rollout policies should be disregarded in the final set of maximum demand forecasts.

Economic drivers

The system level forecasts that were prepared by NIEIR are underpinned by a set of economic forecasts that were prepared in mid 2009. ACIL Tasman notes that economic conditions in Australia have been uncertain in recent years with the result that economic forecasts have been changing dramatically over relatively short periods of time. As is discussed below, the Reserve Bank of Australia recently noted that Australia's economic performance in 2009 defied forecasts from the year before. ACIL Tasman does not produce macroeconomic forecasts, however we note that it is at least possible that further changes in the economic outlook may occur over the next year.

For the purposes of this review we have compared the economic forecasts that underpin the current demand forecasts with those published by the Victorian Treasury and those used by the Australian Energy Market Operator in preparing its forecasts for Victoria. This comparison, which is discussed in section 3.4 below, shows that the forecasts are similar when averaged over the regulatory period, although NIEIR's forecasts are more volatile than the alternatives. However, each of these forecasts was prepared during 2009 and, accordingly, each is susceptible to the rapidly changing outlook. ACIL Tasman recommends that the AER consider whether a revised forecast prepared in the current economic outlook would be sufficiently different to those used in preparing the submitted forecasts to require estimating new system level demand forecasts for each distribution business.

Further, the population growth forecast upon which these maximum demand forecasts are based is equivalent to the most pessimistic ABS forecast, which ACIL Tasman considers to be unreasonably pessimistic, particularly in light of recent population growth. It is unlikely that birth rates will change significantly over such a short time frame and hence the NIEIR forecasts would imply significantly lower migration rates over the period. As unemployment appears to have peaked below 6% in the current cycle, it is unlikely that migration rates would be slowed. ACIL Tasman recommends that the final set of maximum demand forecasts should be based on the ABS' B series projections.

Conclusion

Based on its review of the distribution business's maximum demand forecasts and the methodology by which they were prepared, ACIL Tasman recommends that each forecast be adjusted so that the bottom up, spatial forecasts do not exceed the top down, system level forecasts taking into account coincidence factors. In some cases, this may require adjustments to one or the other of the forecasts to ensure consistent treatment of embedded generation and high voltage customer load.

In implementing this adjustment, ACIL Tasman recommends that, as a general rule, each zone substation forecast should be adjusted proportionally so that the relativity between zone substations is preserved. This rule should be followed unless the AER is satisfied that there is a detailed and specific reason to expect that growth at a particular zone substation should deviate from this approach.

Similarly, in the absence of any detailed and specific reasons to expect that diversity between a particular zone substation and the terminal station to which it is connected will vary during the regulatory period, ACIL Tasman recommends that forecast diversity should be held constant over the next regulatory period at a level that reflects recent experience. Some judgement may be required in determining the appropriate level. One approach would be to adopt average diversity over recent years. A more detailed description of this recommendation is outlined in relation to each of the distribution businesses below.

In addition, ACIL Tasman recommends that the AER consider making two categories of amendments to the maximum demand forecasts, namely changes to the estimated policy impacts and changes to the forecasts of economic growth and population that drive the electricity sales forecasts.

Adopting ACIL Tasman's recommendations in relation to policy impacts and constraining these to the existing set of system forecasts (i.e. those based on NIEIR's estimates of growth in economic product and population) would result in maximum demand forecasts as shown in Table ES 1.

Table ES 1 **Maximum demand forecasts adjusted for policy impacts**

Year	2011	2012	2013	2014	2015
Powercor					
Original 50 POE zone subs (MW)	2488	2557	2610	2659	2716
Adjusted 50 POE zone substations (MW)	2327	2437	2569	2669	2747
Percentage change (%)	-6.5%	-4.7%	-1.6%	0.4%	1.1%
CitiPower					
Original 50 POE zone subs (MW)	1539	1581	1649	1691	1734
Adjusted 50 POE zone substations (MW)	1465	1509	1573	1603	1627
Percentage change (%)	-4.8%	-4.5%	-4.6%	-5.2%	-6.2%
Jemena					
Original 50 POE zone subs (MW)	1111	1136	1161	1188	1209
Adjusted 50 POE zone substations (MW)	1067	1096	1134	1168	1184
Percentage change (%)	-4.0%	-3.5%	-2.3%	-1.7%	-2.1%
United Energy					
Original 10 POE zone subs (MW)	2285	2374	2422	2528	2577
Adjusted 10 POE zone substations (MW)	2266	2352	2406	2509	2558
Percentage change (%)	-0.8%	-0.9%	-0.7%	-0.7%	-0.7%
SP AusNet					
Original 50 POE zone subs (MW)	1856	1968	2052	2140	2231
Adjusted 50 POE zone substations (MW)	1858	1928	2032	2125	2212
Percentage change (%)	0.1%	-2.0%	-1.0%	-0.7%	-0.9%

Data source: Table 11 of RIN for each distribution business, ACIL Tasman calculations

ACIL Tasman does not have sufficient information to estimate the effect that changing the forecasts of economic and population growth would have on the maximum demand. This would require NIEIR's models to be rerun. On the assumption that a more up to date economic forecast would be for higher growth than the forecast that was used here, and noting that the B-series population forecast is also higher than NIEIR's, these amendments would increase the forecast maximum demand forecasts above the levels shown in Table ES 1 above.

1 Introduction

In November 2009, the five Victorian distribution businesses (collectively "the distribution businesses") submitted their regulatory proposals for the 2011 to 2015 regulatory control period to the Australian Energy Regulator ("AER"). The proposals included forecasts of demand, customer numbers and energy sales for the region served by each of the distribution businesses.

The AER engaged ACIL Tasman to review the forecasts. This report provides the results of ACIL Tasman's review of the forecasts of maximum demand. Views relating to the energy and customer numbers forecasts are contained in a separate report.

Section 2 sets out a number of elements that ACIL Tasman regards as critical to best practice load forecasting.

Each of the businesses engaged the National Institute for Economic and Industry Research ("NIEIR") to prepare system level forecasts. Section 3 describes the approach the methodology that was used and discusses it in light of the best practice requirements set out in section 2.

A key element of NIEIR's system level forecasts is the economic and other drivers upon which they are based. Section 3.4 discuses these drivers and compares them to similar forecasts published by the Victorian Government and the Australian Energy Market Operator ("AEMO").

There are a number of energy efficiency and greenhouse policies being pursued by both the Commonwealth and Victorian governments that will impact maximum demand over the next regulatory period. Section 5 discussed the way that each of these was accounted for in NIEIR's forecasting methodology.

Sections 6 to 10 discuss the forecasting methodology and results put forward by each of the five distribution businesses. Conclusions in relation to each business's forecast are presented in each of these sections.

2 Best practice in distribution load forecasting

2.1 Spatial forecasts validated by independent system level forecasts

Best practice distribution load forecasting requires that both top-down and bottom-up spatial forecasts are produced independently of one another. [2]

Top down macro level forecasts have the advantage of allowing the methodology to incorporate the impacts of broader macroeconomic and demographic aggregates. System level data is better behaved with respect to explanatory variables and more amenable to the fitting of econometric models which can be used to generate forecasts which are statistically sound.

Bottom up spatial forecasts are required to capture the underlying characteristics of the areas serviced by individual zone substations. Spatial level forecasts are therefore necessary to capture the relative growth rates of individual substations. Producing accurate forecasts at the spatial level is made difficult however by a number of factors:

- Spatial time series should be adjusted for network transfers which if not done correctly adds spurious values to the time series and makes any time series analytical techniques such as trend analysis or regression analysis unreliable
- Spatial time series exhibit greater degrees of randomness which cannot be easily explained by analytical techniques
- The more disaggregated nature of demand at the substation level compared with the system level means that weather related explanatory variables are less reliable and hence weather normalisation tends to be more simplistic and crude compared with system level simulation approaches
- Forecasting and estimating potential movements in key drivers at the system level also tend to be much more reliable than at the disaggregated local level associated with each substation (e.g. economic growth, appliance take-up).

These factors mean that while it is possible to estimate the relativities between individual zone substations reasonably accurately, the aggregation of individual zone substation forecasts is likely to result in forecasts that deviate substantially from those that would be derived from a top-down system level forecast.

[2] This means independent in a methodological sense: i.e. drawing on independent data.

It is important that the forecasts generated by the methodology should be consistent: i.e. the forecasts produced at the zone substation should be consistent with the terminal station forecasts to which they are connected which in turn should be consistent with the system level forecasts. Hence, while substations usually peak at different times to the system peak, each substation's coincidence factor[3] with the system peak is expected to be relatively stable over time meaning that forecast peak demand growth for each substation should be constrained by this relationship.

There are a number of reasons why the bottom up spatial forecast should be constrained to match the system level forecast rather than the other way around:

- The system level maximum demand is more reliably explained by independent key drivers and consequently is more amenable to the application of statistical and econometric forecasting procedures
- As such an independent system level methodology is amenable to the incorporation of key macroeconomic drivers such as population growth, economic growth, appliance usage (e.g. air conditioner sales) and Government policy changes – which are important factors in determining future system level maximum demand, especially in the current context, but the use of which is impractical or not feasible at the spatial level
- Weather normalisation at the system level is more reliable than at the spatial level
- Network transfers have no impact on system level maximum demands but are present at the substation and distribution feeder levels of the network, further complicating the spatial level data set
- Inputs to spatial forecasting methodologies, for practical reasons, are typically limited to historical growth adjusted for network planner judgement. This process lacks the desirable properties of transparency and repeatability that is possible at the system level.

For these reasons, ACIL Tasman considers that best practice load forecasting requires that spatial forecasts of distribution network demand are formally reconciled with a system level forecast that is produced independently of the spatial forecast. Analytical techniques applied to spatial level forecasts are largely limited to trend analysis which assumes a continuation of historical conditions into the future. If the past is not expected to be a good indication of the future (e.g. change in economic growth conditions, introduction of CPRS), then the spatial level forecasts will perform poorly. Reconciling them with an independent system level forecast which takes these expected changes into account helps to reduce this problem.

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3 Proportion of substation peak demand at the time of system peak demand

2.2 Weather normalisation

A key aspect of any electricity demand forecasting methodology is weather normalisation (or weather correction). It is well established that electricity demand is sensitive to weather as a consequence of heating and cooling loads. Hot conditions in summer or cold conditions in winter (in some places) coincide with peak electricity demand.

The stochastic nature of weather means that any comparison of historical electricity loads over time requires these loads to be adjusted to standardised weather conditions. Typically, actual demand is standardised to either, or both, of 10 and 50 probability of exceedence levels (POE). The 50 (10) POE demand level is the annual maximum demand level that, on average, would be met or exceeded 50% (10%) of the time. It can be thought of as the annual maximum demand that would be observed or exceeded once every two (ten) years on average.[4]

Given that the intent of load forecasting is to forecast maximum demand at a given POE level, any derived relationships with maximum demand that is based on non-normalised data will be susceptible to bias. Conclusions reached on the basis of forecasting with non-weather normalised data are likely to be erroneous and the accuracy of such models will be compromised. Hence, it is imperative that any demand forecasting methodology incorporate an appropriate form of weather normalisation or correction.

2.2.1 Weather normalisation at system level versus spatial level

The impact that weather has on electricity demand is relevant at both the system and spatial level. However, weather normalisation at the system level can be undertaken in a more sophisticated manner than at the spatial level. System level forecasting methodologies are able to employ more statistically robust procedures which establish a relationship between maximum demand and temperature using high frequency data (often at 30 minute intervals). These methodologies allow for a more complex relationship to be established between temperature and demand (often involving some combination of minimum and maximum temperatures and lags etc).

The established relationship between demand and some function of temperature may then be used to simulate a long run probability distribution of demands using a long record (usually in excess of 50 years) of weather data. The resulting distribution can then be used to establish the 90, 50 and 10 POE levels of demand.

[4] It does not follow from this that half of the maximum demands in any given sample of years are necessarily below the 50 POE level.

While this approach would be theoretically possible at the spatial level, it is both computationally and data intensive and thus generally impractical at the spatial level. For this reason, temperature normalisation or correction at the spatial level usually takes a more simplistic form. The usual approach is to establish a relationship between the maximum demand and average temperature for a given season from which specific maximum demands are derived coinciding with 10 and 50 POE temperatures. The observed maximum demand in a given year is then adjusted to what would have been observed at the 50 or 10 POE long run average temperature. In this approach, there is only a one for one relationship between demand and average temperature.

Such an approach is inferior to the simulation based approaches, which allow for more complex and better fitting relationships between demand and temperature. It is not as statistically robust because it entails weather correcting or normalising only a single day (i.e. the day on which the annual maximum occurred) in a given season. Simulation methods on the other hand construct an entire distribution of maximum demands over a large number of years from which the 50 and 10 POE maximum demand are obtained.[5]

A more simplistic form of weather correction applied by some distribution businesses is to fit a simple linear time trend through the actual season maximum demands over time and assume that the trend line represents the 50 POE demand point. This approach would tend towards the 50 POE level of demand if a sufficiently long time series was used so as to represent the full range of observed weather conditions that occur in the long run. However, ACIL Tasman's experience is that this approach is usually applied to a time series of between 5 and 10 years in length, which is not likely to be sufficient to obtain a 50 POE line. Relevant to this particular case, as Table 1 below shows, the summer peak demand in 2008/09 occurred at a temperature that was substantially above the 10 POE level for Melbourne and was substantially higher than in the years leading up to it.

[5] For this reason a number of Jurisdictional planning bodies, including VENCorp in Victoria, have been moving for some time towards simulation based weather normalization in preference to other methods. The Annual Planning Reports of the Electricity Supply Industry Planning Council and VENCorp (now both part of AEMO) provide further discussion of these issues.

Table 1 **Victorian Maximum demands and corresponding average daily temperature, 2001-02 to 2008-09**

Year	Max demand (MW)	Date	Average daily temp (°C)
2001-02	7620.5	14-02-2002	27.6
2002-03	8207.3	24-02-2003	28.9
2003-04	8592.3	17-12-2003	30.1
2004-05	8524.9	25-01-2005	27.3
2005-06	8768.8	24-02-2006	27.8
2006-07	9103.4	16-01-2007	28.8
2007-08	9858.5	17-03-2008	29.7
2008-09	10466.8	29-01-2009	35.0

Data source: NIEIR, Maximum demand forecasts for United Energy terminal stations to 2019-20, p31

A casual inspection of Table 1 shows that the average daily temperature on 29 January 2009, when the 2008/09 summer peak demand occurred, was more than 5°C, or 17%, higher than had been the case in the years leading up to it. The heatwave associated with that day has been described by the Australian Government Bureau of Meteorology as exceptional with the average mean temperatures on 29 and 30 January being the highest ever recorded in Victoria.[6]

To see the impact this has on a regression line across a small sample, consider the following regression equations:

- If a linear regression is taken across the maximum demands from 2001-02 to 2007-08 (i.e. if 2008-09 is discarded), the regression equation is:

  Max Demand = 310.1*(year) + 7427.6

- If a linear regression is taken across the maximum demands from 2002-03 to 2008-09 (i.e. if the sample size remains the same as above but 2008-09 is retained), the regression equation is:

  Max Demand = 353.19*(year) + 7661.8

- If a linear regression is taken across the whole sample, the regression equation is:

  Max Demand = 356.63*(year) + 7288

Thus by including (excluding) the 2008-09 observation the estimated annual growth in demand in this simple temperature regression model is increased (decreased) by approximately 40 MW per annum. Clearly, this is due to the impact of an unusual weather event, not to a fundamental shift in the underlying 50 POE demand. This highlights the statistical problems with small data samples and shows that a regression line taken over a few years of data is not guaranteed to yield a 50 POE estimate.

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6 2009, Bureau of Meteorology, *Special Climate Statement 17*, p. 3, retrieved from www.bom.gov.au on 24 September 2009

The difficulties with weather correction at the spatial level lend further weight to the need to reconcile the spatial level forecasts with those generated at the system level.

2.3 Spatial time series adjusted for temporary transfers

Network configuration changes over time. Under peak conditions some loads may be shifted between existing substations to balance and share demand across the network. At other times, loads may be shifted to facilitate taking equipment out of service for maintenance. As new substations are built, some loads on existing substations may be shifted to the newly built substations. In the same way that weather normalisation is essential to allow for the comparison of maximum demand over time, it is also imperative that actual maximum demands at the spatial level are corrected to system normal conditions by adjusting for the impact of temporary and permanent network transfers arising from peak load sharing and maintenance.

In practice, this requires that growth forecasting is based on an amended historical series that reflects what demand *would have* been at each substation if the network had always been configured in the normal state. If these corrections are not made any analysis of historical trends will be subject to potential bias at the substation level, with erroneous conclusions likely to be drawn as a result. In this case, the bias could be in either direction.

2.4 Discrete block loads incorporated into spatial forecasts effectively

Apart from the normal organic growth which will occur at the substation level there are also larger discrete jumps in demand over time arising from block or spot loads. Block loads arise as new developments such as shopping centres and housing developments come online. These loads show up as discrete jumps in the demand at particular zone substations.

Block loads should be incorporated into the forecasts at the spatial level. Forecasting block loads can be difficult and involves the expert knowledge of local asset managers.

The difficulty in accurately predicting these discrete loads arises mainly because of three sources of uncertainty. These are related to:

- The timing of the new load
- The size of the new load
- The likelihood of the new load going ahead

ACIL Tasman considers that there will be a tendency to overstate the likely size of future block loads. This is because there is often no account taken of the fact that there is some probability that the project will not proceed. The degree of coincidence of the new load with the peak of the substation is often not evaluated correctly so that the true contribution to the substation peak is often less than anticipated. Also, on average there is a greater likelihood that a project will experience delays rather than being completed ahead of schedule. These issues are discussed below in the context of each business's forecasting methodology.

2.4.1 Potential double counting of block loads

Where trend analysis is applied to a historical time series at a substation and individual block loads are added to the same forecast, there is a prospect of double counting the impact of block or discrete loads. Because block loads are included in the historical data, any trend line will incorporate their contribution to the growth in the maximum demand at the zone substation over time. Hence adding expected new block loads to the forecasts may result in double-counting which will inflate forecasts.

The potential for double counting is typically reduced by applying a threshold to the size of future discrete loads, with only loads exceeding a certain size being added onto the forecast. Smaller loads are assumed to comprise part of the underlying growth determined by the historical trend.

Discrete loads do not generally pose a problem at the distribution system level because there are usually no loads connected or likely to be connected to the distribution system which are large enough to cause a significant discrete jump in demand.

The fact that block loads may result in overstated forecasts as a consequence of double counting and the poor ability to predict the eventuality and size of the loads, again reinforces the importance of reconciling spatial forecasts to an independent system level forecast.

2.5 Spatial time series incorporate maturity profile of service area

ACIL Tasman's understanding of the behaviour of zone substations is that they exhibit several phases of growth.

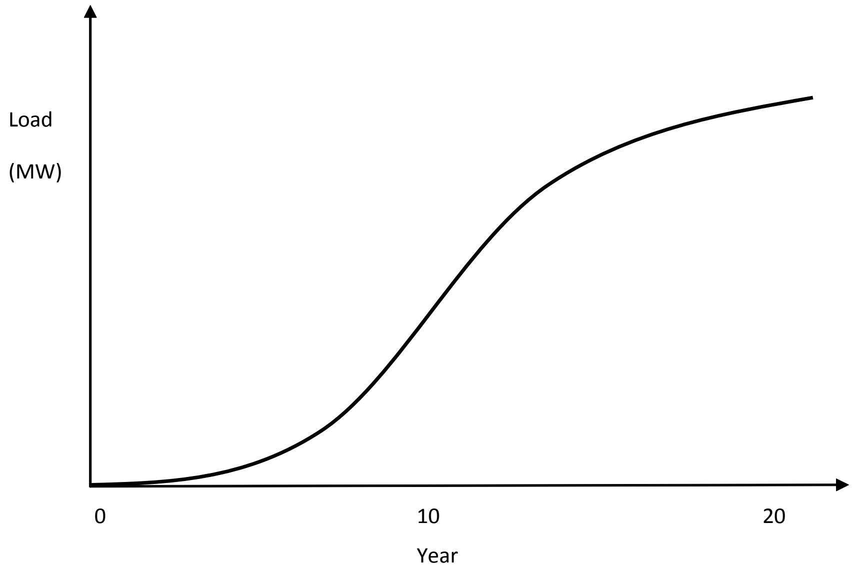
Typically, zone substations commence growing slowly as they are constructed in and around land that was otherwise vacant.

The second phase is a ramp up phase as new developments within the area occur. During this phase they typically exhibit quite high rates of growth. This high growth rate is driven predominantly by increasing customer numbers. This phase can persist for an extended period (up to 10 years depending on the pace of development).

As the area serviced by the zone substation approaches saturation, growth in demand begins to slow. Increasing demand at the zone substation during this phase of growth generally comes from increases in demand per customer rather than increasing customer connections.

The pattern of load growth for a zone substation over time from its establishment to the point where it reaches maturity point is characterised by the diagram shown in Figure 1.

Figure 1 **Typical life cycle behaviour of a zone substation**



In assessing individual zone substations, it is important to recognise which phase of growth a particular zone substation is in. Knowledge of where an individual zone substation fits in its life cycle can help inform the forecaster as to what kind of growth rate can be expected from that zone substation in the future. The diagram also highlights the importance of being able to determine the inflection points in the curve which may signal the transition from a low growth zone substation to a high growth zone substation and vice versa.

The above approach must be applied with care as while the large majority of zone substations will follow this growth path, some zone substations may not fit the profile (e.g. zone substations could be installed in inner city areas to absorb load from surround zone substations or an inner city area may be redeveloped).

2.6 Accuracy and unbiasedness

A key aspect of any forecasting methodology is that it should meet minimum accuracy requirements. All models will include errors by nature of the fact that they are an approximation of the real world and these errors will limit the model's accuracy.

One persistent source of inaccuracy in forecasts is bias. A biased forecast is one which consistently over or under-predicts the actual outcomes the methodology it is trying to forecast. Forecasting bias can be avoided or at least minimised by careful data management (e.g. removal of outliers, data normalisation etc.) and forecasting model construction (choosing a parsimonious model which is based on sound theoretical grounds and which closely fits the sample data).

In the event that a forecasting methodology consistently results in biased forecasts, it should be possible to adjust the forecasts by the amount of the estimated bias to remove the bias from the forecasts.

2.7 Transparency and repeatability through effective documentation

A transparent forecasting process is one that is easily understood and well documented to the extent that a forecast prepared by a person who was not involved in the initial process would be reasonably similar.

The functional form of any specified models should be clearly described to those seeking to understand the forecast, including:

- The variables used in the model
- The number of years of data used in the estimation process
- The estimated coefficients from the model used to derive the forecasts
- Detailed description of any thresholds or cut-offs applied to the data inputs
- Details of the forecast assumptions used to generate the forecasts

The process should also clearly describe the methods used to validate and select the model chosen to undertake the forecasts. Any judgements applied throughout the process should be documented and justified. Adjustments to forecasts that are outside of the formal modelling process that are not documented with a clear rationale justifying that course of action should be treated with caution.

2.8 Incorporating key drivers

A best practice forecasting methodology should incorporate all the key drivers either directly or indirectly. It should rest on a sound theoretical base.

In the case of a distribution load forecast the list of relevant drivers would normally include, but not necessarily be limited to, the following:

- Economic growth
- Population growth
- Growth in the number of households
- Temperature, humidity and rainfall/wind data
- Growth in the number of air conditioning systems
- Growth in the number of heating systems

2.9 Model validation

Models derived and used as part of any forecasting process should be validated and tested. This is usually done in a number of ways:

- Assessment of the statistical significance of explanatory variables
- Goodness of fit
- In sample forecasting performance of the model against actual data
- Diagnostic checking of the model residuals
- Out of sample forecast performance

Validation and testing should be performed at the same 'level' at which the forecasts are produced. For example, in this case, where the forecasts are at the distribution region level that is the level where the validation and testing should occur. Ideally, the results of these validation procedures should be provided to those assessing the forecasts, or at a minimum enough data provided such that the assessor may reproduce the validation procedures.

3 NIEIR's approach to system maximum demand forecasting

This section of the report considers the NIEIR approach to forecasting maximum system demand. Each of the businesses obtained a demand forecast from NIEIR. Each of these five forecasts was prepared using the same methodology, which is also the methodology that was used by VENCorp (now AEMO) in preparing its 2009 Annual Planning Report.[7]

NIEIR prepared a forecast for each business at the system level using its PeakSim model, which ACIL Tasman has attempted to describe below based on the limited information provided in the NIEIR reports. ACIL Tasman has also drawn on the description of NIEIR's model in VENCorp's 2009 electricity forecast report on the basis that NIEIR advised the AER that the forecasting methodology used there was the same as that used to prepare the current set of forecasts. [8]

In order to supplement NIEIR's reports to the distribution businesses, the AER and ACIL Tasman held meetings with NIEIR and the distribution businesses in relation to the forecasts and forecasting methodology. In advance of the discussions, NIEIR made it clear that it considers the models and modelling process used in preparing these forecasts to be commercially confidential as they contain a significant amount of intellectual property.

The distribution businesses declined to provide more than a general and high level description of how their forecasts had been prepared on the basis of the confidential and proprietary nature of the NIEIR modelling. Hence, while some additional information was provided during the meetings, the overall level of information provided did not meet the transparency and repeatability requirements set out in Section 2.7. This is reflected in the descriptions below.

Actions in the descriptions attributed by ACIL Tasman to NIEIR are based on the reports and statements made by NIEIR representatives during meetings with ACIL Tasman and AER staff. ACIL Tasman was not able to independently verify that the forecasting methodology as stated was applied in developing the forecasts that were presented because of the limited information provided.

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7 This is limited to the methodology. The forecasts for AEMO were based on different data and economic forecasts.

8 See "VENCorp, "2009 Electricity Forecast Report", 2009, available at http://www.aemo.com.au/planning/v400-0016.pdf

3.1 NIEIR's approach - overview

It should be noted that the following description presents the model as sequential and staged. This is done for ease of presentation. In practice, NIEIR's model may work in a different sequence or simultaneously.

Broadly, NIEIR's approach can be thought of as dividing demand into temperature sensitive and temperature insensitive components and forecasting each of these independently. Next NIEIR sums these forecasts and then makes further adjustments to account for the impact of policy interventions.

Temperature insensitive demand was forecast based on growth in temperature insensitive energy consumption projections, driven by economic and industry drivers such as NIEIR's forecasts of gross regional product in each of the five distribution areas.

Temperature sensitive demand was forecast using a simulation approach based on synthetically generated distributions of temperature and demand. These distributions are generated using half hourly maximum demand data provided by the businesses. The forecast of temperature sensitive load also takes account of NIEIR's forecasts of air conditioner sales.

NIEIR estimated the impact of a number of policy interventions externally to the PeakSim model and then reduced the PeakSim forecasts accordingly.

The first two of these steps are discussed in further detail below. The third step, relating to policy impacts, is discussed in section 5.

3.2 Temperature insensitive demand

The temperature insensitive component of maximum demand is estimated through projected growth in weather insensitive energy consumption. NIEIR's projections are driven by:

- Economic conditions
- Take up and changing technology of appliances
- Relevant policy measures
- Forward energy price assumptions

In preparing these forecasts, NIEIR relied on its own forecast of gross product for each of the distribution regions. This forecast is based on NIEIR's forecasts of various economic indicators for the regulatory period. These are summarised in the following table.

Table 2 **NIEIR forecasts of economic indicators for Victoria (annual % change)**

	2010-11	2011-12	2012-13	2013-14	2014-15	Compound growth rate 2008-09 to 2014-15
Gross state product	2.2	4.4	2.0	0.2	0.0	1.6
Private consumption	1.6	3.5	3.3	1.1	0.1	1.7
Private business investment	18.9	16.8	5.2	3.5	-5.1	4.3
Population	1.3	1.2	1.1	1.2	1.2	1.2
Private dwelling investment	4.2	-6.3	-6.6	-1.5	12.1	1.0
Government consumption	3.6	1.9	2.0	3.8	3.4	3.0
Government investment	2.2	17.2	-1.8	1.5	6.2	8.0
State final demand	4.6	5.3	2.6	1.9	0.5	2.6
Employment	0.3	2.3	2.2	0.6	-0.6	0.3

Data source: NIEIR maximum demand reports to distribution businesses, table 3.2,

NIEIR's forecast is for strong economic growth in gross state product for Victoria in the first half of the regulatory period followed by a decline in the second half. The decline is due to NIEIR's expectation of sharp increases in interest rates in the second half of the regulatory period, mainly due to the severe blow out it expects to see in the current account deficit. NIEIR also forecasts that these high interest rates will slow the rate of growth in private consumption expenditure in the second half of the regulatory period.

Similarly to private consumption, NIEIR forecasts that private business investment will grow rapidly until 2011-12 and then slow down before declining in 2014-15.

Consistent with the decline in private business investment and private consumption, private housing expenditure is also forecast to decline following the rise in interest rates that NIEIR forecasts for approximately the middle of the regulatory period.

In contrast to gross state product and private consumption, NIEIR forecasts that population growth will be relatively steady through the forecast period, albeit at a lower level than was observed/ forecast between 2007 and 2010.

Table 3 **Victorian Economic Projections**

	2010-11 Forecast	2011-12 Forecast	2012-13 Forecast
Real gross state product	2.25	3.00	3.00
Employment	0.50	1.50	1.50
Population (b)	1.50	1.40	1.40

Data source: Department of Treasury and Finance (Vic)

Notes:

(a) Year-average per cent change on previous year unless otherwise indicated. All economic projections are rounded to the nearest 0.25 percentage point, except population projections which are rounded to the nearest 0.1 percentage point.

(b) June quarter, per cent change on previous June quarter.

Table 3 contains the Victorian Government's own forecasts of key economic drivers. While the Victorian Government does not forecast as much volatility in the series as NIEIR, the forecast levels are much the same to 2012-13. There is no comparison in the Victorian Government forecast with the latter period of the NIEIR forecast where gross state product goes into significant decline.

3.3 Temperature sensitive demand

In NIEIR's model, total demand is a function of:

- Temperature insensitive demand
- Temperature
- Calendar effects, outliers and holidays

Given the growth in temperature insensitive demand, the remaining task undertaken by NIEIR is to forecast increases in the temperature sensitive component of demand.

The temperature variable takes account of the ambient temperature in each half hourly interval as well as the daily maximum and minimum temperatures. Together, these are used to estimate the temperature sensitivity of demand in the region in question. This coefficient is then projected forward at the same growth rates as temperature sensitive energy consumption, thus taking account of changes in the take up of weather sensitive appliances, in particular air conditioners.

Similarly, the estimated coefficients associated with the calendar effects, outliers and holidays are increased in line with growth in temperature insensitive energy consumption.

The relationship between temperature and maximum demand is then estimated using a simulation approach. NIEIR's PeakSim model takes half hourly load and temperature data into account to produce a model of the intra-day relationship between temperature and electricity demand. NIEIR stated that synthetic distributions of demand and temperature are then produced using bootstrapping methods that preserve the relationship between temperature and demand while allowing for the effects of urban and global warming on both recent and future temperature trends. This is done by sampling from recent years with a higher probability than earlier years (using a re-weighted bootstrap technique).

The distribution businesses declined to provide detailed information about this (or any other) aspect of NIEIR's model, so ACIL Tasman cannot comment on the magnitude of the effect that this approach has on the maximum demand forecasts. For the purposes of this review, ACIL Tasman has assumed that the methodology NIEIR applies is statistically robust, i.e. the coefficients used in forecasting are shown to be statistically significant in an appropriately controlled regression model.

However, by increasing the probability assigned to recent years, as compared to earlier years, NIEIR is taking the view that recent years are more likely to be typical in the years to come than the earlier years. NIEIR has advised the AER and ACIL Tasman that it chose to weight recent years more heavily based on trends it observed in temperature records, in particular in overnight minimum temperatures. The distribution businesses did not provide this analysis for consideration in this review, nor were the probabilities assigned to each year disclosed.

There are two key factors that may cause a noticeable trend in temperatures over time. The first is related to trends in climatic conditions which would potentially include both anthropogenic and non-anthropogenic causes. The second is related to the so called heat island effect which is due to the transformation of the landscapes as cities are formed and grown.

ACIL Tasman notes that both of these effects are reasonably long term and slow moving. For example, climatic trends identified by the Intergovernmental Panel on Climate Change (IPCC) in its fourth Assessment Report published in 2007 indicate that average temperatures have increased by 0.76°C over the 150 year period ending in 2005[9]. This is approximately 0.005°C per annum. In terms of heat islands, these are attributable to the reduced vegetation and large quantities of concrete and similar products found in cities. These do not

[9] 2007, IPCC, A report of Working Group I of the Intergovernmental Panel on Climate Change Summary for Policymakers, p.5, available at http://www.ipcc.ch/publications_and_data/publications_ipcc_fourth_assessment_report_wg1_report_the_physical_science_basis.htm

change rapidly. In the same assessment report the IPCC identified a trend of no more than 0.006°C per decade or 0.0006°C per year.[10]

ACIL Tasman understands that the weather series are sampled from data from the period 1995-96 to 2008-09, a period of only 13 years.[11] This period is unlikely to be long enough to provide a reasonable sample of extreme high and low temperature conditions and hence accurate estimates of the distributions tails. ACIL Tasman expects that a longer time series of at least 30 years would provide a reasonable representation of the possible variation in future weather conditions and thus improve the estimate of 10 and 50 POE weather conditions[12]. Simply put, the relatively high number of hot summers in recent years would tend to overstate the estimated 10 and 50 POE weather conditions where future weather patterns revert to longer run averages.

As noted above, temperature trends that have been identified over the last 150 years indicate that the effect is small over a 13 year period and hence it is questionable whether the effects would be statistically significant over such a short period. The forecasts that have been produced would not be expected to vary much as a consequence. As ACIL Tasman has not been provided with the specifics of the forecasting model, it is not possible to draw a conclusion as to the impact this treatment of weather has on the forecasts beyond noting (above) that the model performed well in the testing that has been conducted in other reviews. ACIL Tasman also notes that this approach is broadly consistent with the approach NIEIR takes to forecasting energy sales, in that both forecasts include a modelled change in temperatures.

However ACIL Tasman considers that it would be reasonable for the AER to request further information with respect to the temperature trend aspect of the forecast including:

- the temperature trend coefficients used by NIEIR
- the MW increase in system demand in each year for each distribution business as a consequence of the temperature trend effect.

3.4 Model validation and testing

This methodology is relatively new in Victoria. It was introduced in an attempt to deal with the fact that the methodology that preceded it tended to over-forecast the summer maximum demand.[13]

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10 *ibid,* p.5.

11 VENCorp "Victorian electricity forecast report", 2009, p. 9.

12 Typically, ACIL Tasman uses 50 years of temperature data in such simulations and analysis.

13 AEMO, "2009 Statement of Opportunities", pC17

In recent years, VENCorp has engaged the National Institute of Economic and Industry Research (NIEIR) to produce independent long-term electricity demand forecasts. In 2008, following a review by the consultancy KEMA, the methodology was changed to that described here with the exception that, at least for its 2009 forecasts, VENCorp used economic inputs prepared by KPMG Econtech rather than NIEIR. A description of the methodology NIEIR uses to prepare VENCorp's forecasts is contained in the Victorian Electricity Forecasts Report 2009, which is available from AEMO's website.

The new methodology has proven, in VENCorp's view, to be substantially more accurate than its predecessor. The accuracy of the new methodology is illustrated in Figure 2 below, which shows the result of an out of sample backcast using the methodology.

Figure 2 **Victorian Summer MD Backcast**

Source: AEMO, 2009 Statement of Opportunities, p C18

Figure 2 shows the result of a backcasting process whereby the new methodology was calibrated using data from before 2002-03 and then used to 'predict' maximum demand in the years from 2002-03 to 2008-09 using actual data for all relevant inputs. The result is a comparison where any difference between forecast and actual values is a result of the simulation method applied, rather than due to incorrect forecasts of the inputs.

NEMMCO (now AEMO) reported that the root mean squared error of this backcast was 1.69%, which ACIL Tasman regards as a good result for a backcast of this kind and indicates that the forecasting model used has reasonable accuracy.

One point of concern in relation to this testing is that it has been done at the state level. ACIL Tasman is not aware that it has been validated or tested at the distribution region level. The model may perform equally well at the distribution region level as it did at the state level, but this inference was not able to be tested because of the limited information provided on the modelling methodology by the distribution businesses.

3.5 NIEIR's forecasting approach- Conclusions

While it is difficult to draw concrete conclusions about NIEIR's methodology due to a lack of detailed information, ACIL Tasman considers that, it has a number of features that are a necessary and desirable part of any demand forecasting process.

These are:

- NIEIR's models of maximum demand incorporate the key underlying drivers, both economic, demographic and weather related
- The approach is based on econometric techniques which aim to establish a relationship between demand and its underlying drivers based on historical data. These estimated relationships are then used as the basis for projecting forward.
- NIEIR's approach to temperature correction and the derivation of a distribution of maximum demands is based on a simulation approach that is statistically more sophisticated and valid than other more simplistic and crude approaches to temperature correction.
- NIEIR correctly recognises that there are certain policy impacts that are not able to be captured within the estimated econometric relationships and so estimates of these impacts are generated outside of the basic econometric framework and the original forecasts adjusted accordingly.

While ACIL Tasman questions some of the forecast input assumptions into the process and has not been able to gain access to high level detail regarding NIEIR's proprietary models, we consider that NIEIR's approach to forecasting maximum demand is generally sound.

4 Macro level drivers of demand

This section considers some of the underlying drivers of maximum demand. The section focuses on the historical behaviour of the underlying drivers as well as assessing NIEIR's forecast input assumptions.

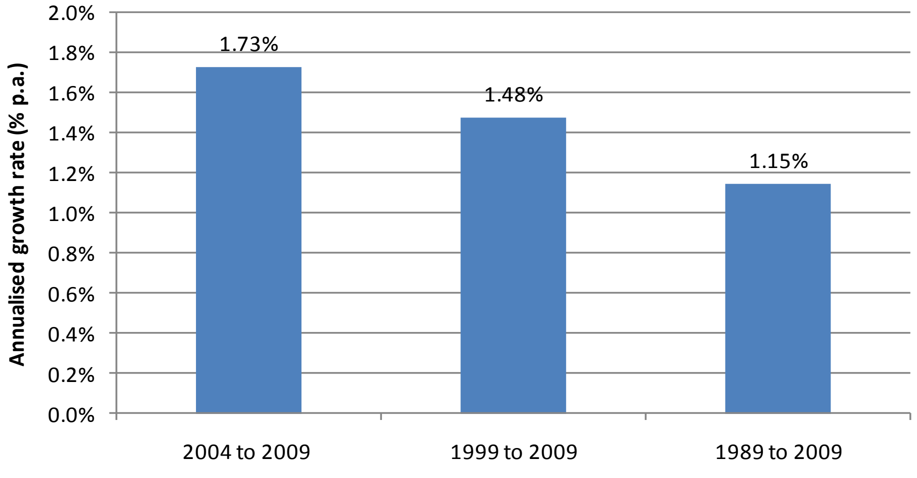
4.1 Population growth

Population growth is important to electricity demand because it drives household formation and hence domestic customer numbers for the distribution businesses.

Figure 3 shows the historical rate of population growth for Victoria over three distinct time periods, 2004 to 2009, 1999 to 2009 and 1989 to 2009.

The figure shows that in the 5 years to June 2009, the Victorian population has grown at a rate of 1.73% p.a. Growth has been very rapid in the last five years compared to that observed over longer time horizons, with annualised growth over the last 10 years of 1.48% p.a. Over a 20 year time horizon Victorian population growth has averaged 1.15% p.a.

Figure 3 **Victorian population growth, 2004 ~ 09, 1999 ~ 09, 1989 ~ 09, % p.a.**



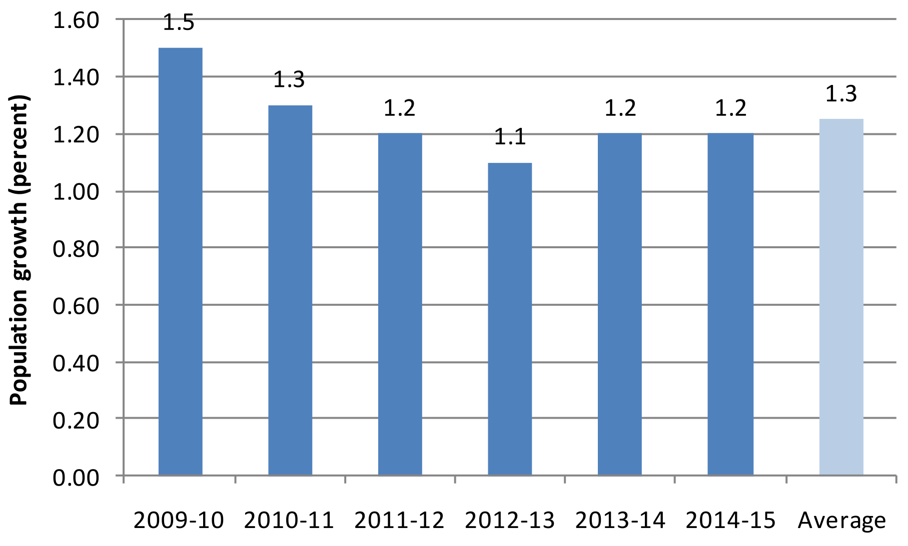
Data source: ABS, 3101.0 Australian Demographic Statistics

NIEIR points out that the main drivers of Victoria's population growth in the last 5 years have been a strong natural increase, large gains from overseas migration and relatively few interstate migration losses.

4.1.1 NIEIR's population projections

NIEIR has projected a slowdown in Victorian population growth in the next regulatory period. In the six years from June 2009-10 to 2014-15, NIEIR projects an average rate of population growth for Victoria of 1.3% p.a. This is compared to an average growth rate between 2004 and 2009 of 1.7% p.a.

Figure 4 **NIEIR projected Victorian population growth rate, 2009-10 to 2014-15**



Data source: NIEIR, Demand reports prepared for distribution businesses.

NIEIR's projections are relatively conservative compared to those obtained from other sources. Table 4 compares NIEIR's population projections against those sourced from the Victorian Treasury and the ABS.

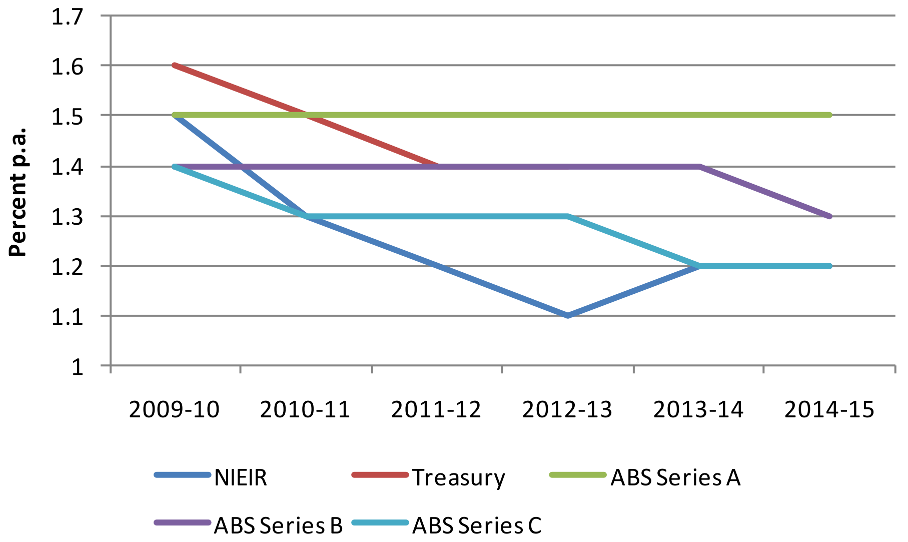
Table 4 **Population growth projections from various sources, 2009-10 to 2014-15**

Population forecasts	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	Average
NIEIR	1.5	1.3	1.2	1.1	1.2	1.2	1.3
Treasury	1.6	1.5	1.4	1.4	NA	NA	1.5
ABS Series A	1.5	1.5	1.5	1.5	1.5	1.5	1.5
ABS Series B	1.4	1.4	1.4	1.4	1.4	1.3	1.4
ABS Series C	1.4	1.3	1.3	1.3	1.2	1.2	1.3

Data source: ABS, 3220.0 Population Projections, Australia 2006 to 2101, Victorian Treasury, Victorian Budget Papers 2009-10, NIEIR, Demand reports prepared for distribution businesses.

The table shows that NIEIR's forecasts most closely resemble the ABS's Series C population projections which are the most pessimistic of the ABS scenarios. NIEIR's population growth forecasts are also lower than those produced by the Victorian Treasury although the Treasury forecasts do not extend beyond 2012-13. The data in the table are shown graphically in Figure 5.

Figure 5 **Population growth projections from various sources, 2009-10 to 2014-15**



Data source: ABS, 3220.0 Population Projections, Australia 2006 to 2101, Victorian Treasury, Victorian Budget Papers 2009-10, NIEIR, Demand reports prepared for distribution businesses.

The population growth rate assumed by NIEIR assumes that population growth in the next 5 years will revert to levels that more closely resemble long run behaviour, but which are significantly below the levels observed in the last decade. This forecast is equivalent to the most pessimistic ABS forecast, which ACIL Tasman considers to be unreasonably pessimistic, particularly in light of recent population growth. It is unlikely that birth rates will change significantly over such a short time frame and hence the NIEIR forecasts would imply significantly lower migration rates over the period. As unemployment appears to have peaked below 6% in the current cycle, it is unlikely that migration rates would be slowed. Taking these factors into account, ACIL Tasman recommends that the AER adopt the ABS B series as a reasonable forecast of the likely future growth in Victoria's population.

4.2 Economic Growth

The demand for electricity is driven to a significant extent by economic growth. In the residential sector, economic growth drives increases in disposable income, which in turn leads to additional demand for appliances and comfort in the home. Economic growth is also a driver of population growth, which helps to contribute to customer number growth over time.

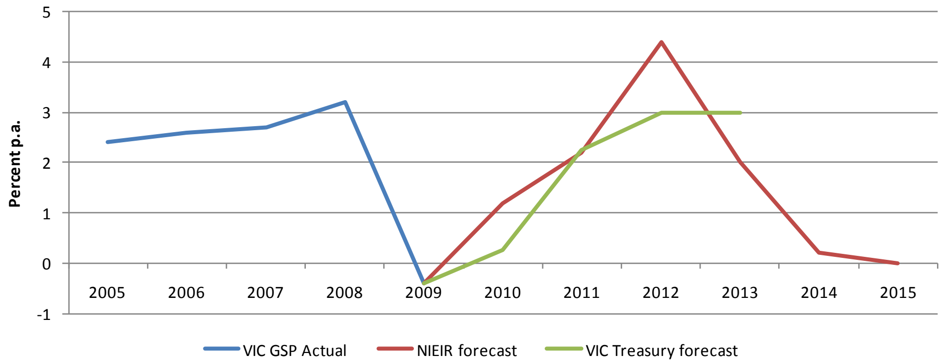
Commercial and industrial electricity demand is also driven by economic growth. Increases in industrial output and commercial activity will lead to higher electricity demand over time.

A sound forecast of economic growth is essential in forecasting demand on a distribution network. Further, significant changes in economic growth in Victoria will have important implications for growth in the demand for electricity.

The forecasts NIEIR prepared are based on its own projections of economic growth for the region supplied by each distribution business. These are created by disaggregating NIEIR's GSP projections to the regional level. The key drivers are discussed in relation to each of the five businesses in sections 6 to 10 below.

It is informative to compare NIEIR's forecasts of economic growth with forecasts published by other organisations. Figure 6 shows the rate of growth in Victorian GSP from 2005 to 2009 and the GSP forecasts from NIEIR covering 2010 to 2015. As a basis of comparison, Victorian Treasury's forecasts of GSP growth to 2013 are also presented.

Figure 6 **NIEIR and treasury Victorian GSP growth forecasts, 2010 to 2015**



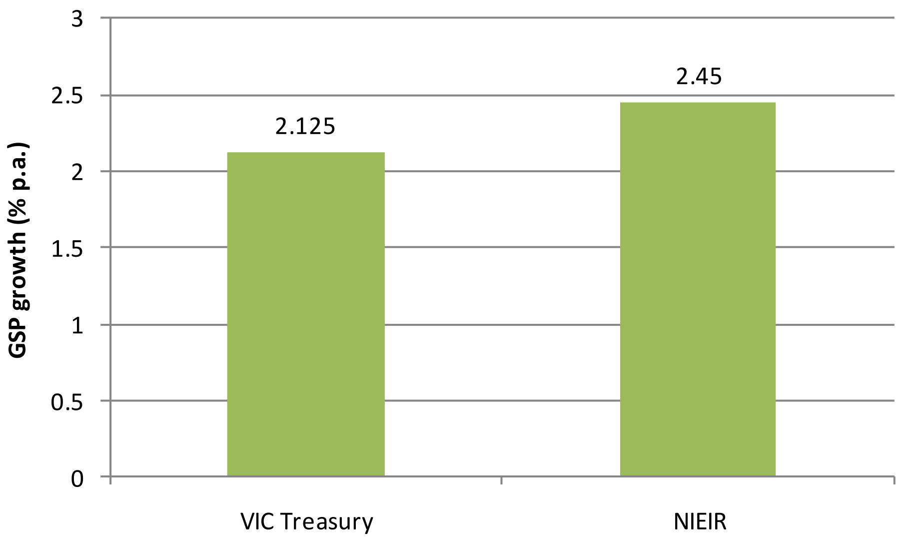
Data source: NIEIR, Demand reports prepared for the five distribution businesses, Victorian Treasury, Victorian Budget 2009-10, Budget Paper Number 2, Strategy and Outlook.

The figure shows the effects of the pronounced economic slowdown affecting Victoria in 2009. NIEIR expects Victorian economic growth to be lower in the next regulatory period compared to the period between 2005 and 2009. Between 2005 and 2009, Victorian GSP growth has average 2.1% p.a. By comparison, NIEIR expects GSP growth to average 1.8% between 2011 and 2015.

Figure 7 compares NIEIR's average growth forecast against the Victorian Treasury's over the period in which common forecasts are available.

The figure shows that between 2009-10 and 2012-13 NIEIR projects an average rate of economic growth for Victoria of 2.5% p.a. compared with 2.1% for the Treasury. While this presents that impression that NIEIR's forecasts are more optimistic, this is misleading. In the last 2 years of the 2011 to 2015 regulatory period, which are excluded from the calculation, NIEIR is forecasting a rate of GSP growth close to zero in both years.

Figure 7 **Average Victorian GSP growth, 2009-10 to 2012-13**

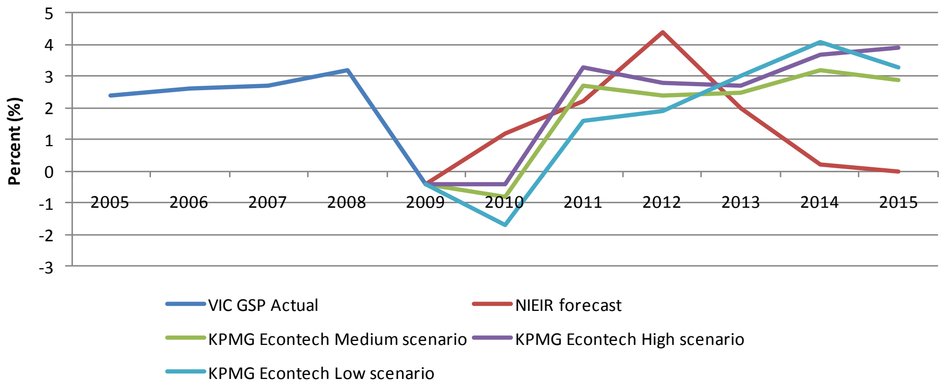


Data source: NIEIR, Demand reports prepared for the five distribution businesses, Victorian Treasury, Victorian Budget 2009-10, Budget Paper Number 2, Strategy and Outlook.

Further comparison can be made between the economic growth forecasts generated by NIEIR and those provided by KPMG Econtech in the VENcorp Victorian Annual Planning Report of 2009.

Figure 9 compares NIEIR's economic growth forecasts with applied by KPMG Econtech in the VENCorp Annual planning report published in 2009.

Figure 8 **NIEIR economic growth forecasts versus KPMG Econtech**



Data source: NIEIR and VENCorp annual planning report 2009

The charts show a deviation between the NIEIR and KPMG Econtech forecasts, with NIEIR projecting a higher rate of economic growth for Victoria in 2010 and 2012 compared to the medium scenario of KPMG Econtech. In 2014 and 2015, NIEIR's forecasts of Victorian GSP growth diverge substantially from those provided by KPMG Econtech. NIEIR's projections of GSP growth of 0.2% and 0.0% in 2014 and 2015 contrast sharply with KPMG Econtech's medium scenario forecast growth rates of 3.2% and 2.9%. This difference is partly compensated for by NIEIR by projecting a more pronounced business cycle with substantially higher growth rate in 2010 and 2012 compared the KPMG Econtech's medium scenario.

Over the entire forecast period from 2010 to 2015, NIEIR's average growth rate of 1.7% is 0.5 percentage points below the KPMG Econtech medium scenario, which averages 2.2% per annum over the same period.

Based on the NIEIR forecasts of Victorian population and economic growth, there should be a tendency for growth in the NIEIR electricity demand forecasts to exhibit some degree of slowdown relative to that observed over the last 5 years; which have been characterised by strong population growth and stronger economic growth than is expected in the next 5 years.

ACIL Tasman notes that the Assistant Governor (Economic) of the Reserve Bank of Australia recently expressed the view that Australia's economic performance in 2009 was significantly better than was expected one year ago.[14] We highlight NIEIR's advice that the economic forecasts underpinning the current set of demand forecasts were prepared in the second half of 2009. ACIL Tasman considers it likely, or at least possible, that, if these forecasts were constructed again today, they would be somewhat different, perhaps

[14] "The Current Economic Landscape" speech by Mr Philip Lowe, Assistant Governor (Economic), Reserve Bank of Australia, available online at http://www.rba.gov.au/speeches/2010/sp-ag-180210.html

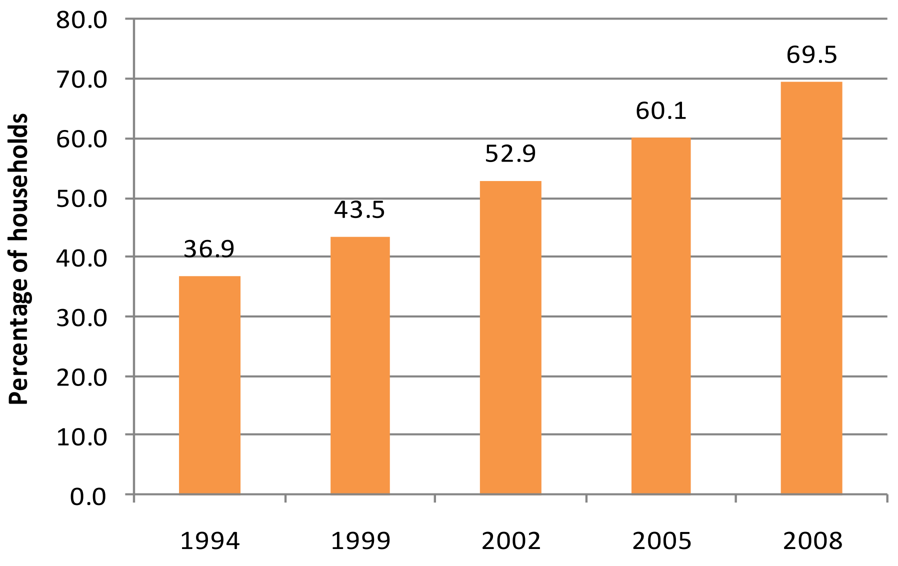
higher. In light of the fact that NIEIR's forecasts are the lowest of the three discussed here, it may be worthwhile to explore the impact of using more up to date input forecasts.

4.3 Air conditioning sales

The use of air conditioning systems on extreme summer days has a significant impact on peak electricity demand in Victoria. The growth in the number of air conditioning systems is essentially a function of growth in the number of new households and increases in the market penetration of air conditioning systems.

The market penetration of air conditioners in Victoria has increased dramatically in the last 10 years as is shown in Figure 9 below. In 1999, 43.5% of Victorian households had an air conditioner. By 2008, this had increased to 69.5% of households.

Figure 9 **Victorian penetration of air conditioners 1994, 1999, 2002, 2005 and 2008**



Data source: ABS, 4602.0.55.001 Environmental Issues: Energy Use and Conservation, Mar 2008

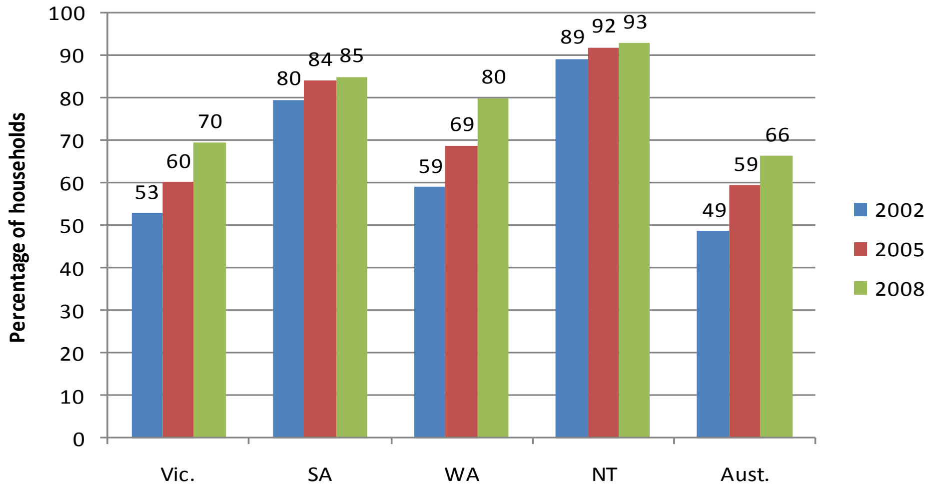
The data show that during the last regulatory period, growth in air conditioner sales continued to be a major factor in the growth in peak electricity demand. NIEIR has stated that for the next regulatory period it is forecasting a slowdown in air conditioner sales although these are expected to remain strong.[15] ACIL Tasman considers this to be a reasonable expectation. Growth

15 ACIL Tasman understands that NIEIR's forecast growth rate for air conditioners is 4.0% per annum over the regularly period, compared to observed growth of 7.2% over 2004-09.

in air conditioner sales should continue to be strong for a number of years before market saturation is reached.

This is supported by Figure 10, which compares Victoria's market penetration of air conditioners against other jurisdictions. In particular, market penetration rates of air conditioners in South Australia and Western Australia as at 2008 were 85% and 80% respectively suggesting that the Victorian market still has significant potential for further increases. In addition, while somewhat anecdotal, the market penetration data for South Australia and the Northern Territory indicates that the slowing in the rate of growth in market penetration commences after reaching around 80%.

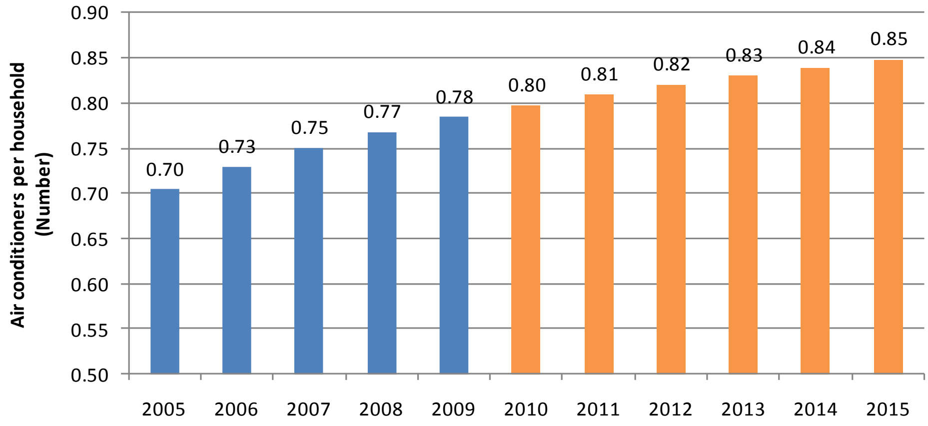
Figure 10 **Market penetration of air conditioners, Victoria versus other jurisdictions**



Data source: ABS, 4602.0.55.001 Environmental Issues: Energy Use and Conservation, Mar 2008

An alternative set of Victorian air conditioner forecasts published by the Department of the Environment, Water, Heritage and the Arts in 2008 shows that penetration of residential air conditioners is expected to continue to increase in the next 5 years, rising from 0.8 air conditioners per household in 2010 to 0.85 air conditioning units in 2015. It is also interesting to note that DEWHA projects growth to slow moderately compared to the previous 5 years. This is reasonably consistent with NIEIR's forecast scenario which has air conditioner sales also growing strongly but at a slower rate relative to the previous regulatory period.

Figure 11 **Number of residential Victorian air conditioners, 2005 to 2015**



Data source: Energy use in the Australian residential sector, 1986-2020, *Department of the Environment, Water, Heritage and the Arts, 2008.*

5 Policy interventions and the CPRS

The demand modelling processes described in the previous section does not take account of the fact that both the Australian and Victorian Governments are in the process of implementing a number of policies intended to reduce both maximum electricity demand and total electricity consumption. NIEIR has advised that it accounted for each of these policy interventions separately and made consequential adjustments to the above 'policy free' forecasts.

The policy measures that NIEIR took into account are:

1. Mandatory Energy Performance Standards – lighting
2. Standby Power
3. Insulation (residential only)
4. Photovoltaics (residential only)
5. Victorian Energy Efficiency Target (residential only)
6. Hot Water phase out of resistance style heaters
7. Mandatory Energy Performance Standards – air conditioning
8. 6 star building standards (residential only)
9. Advanced Metering Infrastructure (smart meters) (residential only)

5.1 Mandatory Energy Performance Standards - lighting

NIEIR and the distribution businesses forecast that the MEPS for lighting will have no impact on the level of maximum summer demand. This is on the basis that, in Victoria, summer demand tends to peak during the late afternoon while the sun is still up. On this basis, NIEIR has not attempted to calculate the impact that this MEPS will have on maximum summer demand in Victoria.

ACIL Tasman considers that this approach is logical and reasonable for the domestic sector. While we would expect that some lighting in the domestic sector would be on during daytime summer peaks (e.g. basements, poorly lit houses and houses that have closed drapes and curtains to insulate against the heat), we concur the proportion of overall domestic lighting would be expected to be small and hence any MEPS savings are likely to be trivial.

ACIL Tasman considers that the same approach cannot be applied to the commercial sector where a significant portion of commercial lighting (i.e. that in office buildings and shops) would be in use between 15:00 and 17:00 on weekday afternoons. NIEIR's own estimate is that there are more than one million incandescent light bulbs in the Victorian commercial sectors. The forecasting approach it has taken assumes that either none of these will be operating at (summer) peak time or any that are operating will not be replaced with more efficient lights during the regulatory period.

However if it is assumed that each incandescent light installed in the commercial sector averages 100 watts (probably conservatively high), then one million installations would add around 100 MW when all lights were operating (slightly more when system losses are included). ACIL Tasman accepts that only a fraction of the lights would be operating at summer peak. Hence after considering load diversity factors and the potential savings per installation of around 30% under the current MEPS program which commenced in late 2009, the savings across Victoria when all installations are replaced are likely to be significantly less than 30 MW. This implies that the savings per distribution business would be at most only a few MW.

Hence ACIL Tasman accepts that MEPS for lighting is likely to have a trivial impact on maximum demand over the regulatory period. While it is an oversimplification to state that the impact will be zero, ACIL Tasman considers that the true impact is likely to be small enough to fall well within the forecast error.

ACIL Tasman also notes that VENCorp (now AEMO) prepared the 2009 Annual Planning report on the basis that the impact of lighting MEPS on peak demand would be negligible because lighting use is not significant at the time when summer peaks occur.[16]

5.2 Standby power

NIEIR's maximum demand reports to the distribution businesses refer to a one watt standby target, the impacts of which are estimated using an approach based on the number of appliances, the average standby power of each appliance and a number of other parameters. The appliances that are considered, and therefore those to which the distribution businesses have applied this target, are:

- Television
- Video player
- DVD player
- Microwave
- Stereo system
- Surround sound system
- Desktop computer

[16] VENCorp "Victorian Annual Planning Report" 2009, p. 204, available online at http://www.aemo.com.au/planning/v400-0017.pdf.

- Laptop/notebook computer
- Printer/scanner/fax
- Games console
- Washing machine

The forecast impact of the one watt standby target put forward in the current set of forecasts is shown in Table 5:

Table 5 **annual incremental reductions in summer peak demand due to savings due to one watt standby target (MW)**

Incremental impact - Victoria	2011	2012	2013	2014	2015
Residential	24.9	49.7	49.7	31.2	12.2
Commercial	0.3	0.6	0.6	0.6	0.6

Data source: NIEIR reports to distribution businesses, tables 6.2 and 6.5 aggregated

ACIL Tasman is not aware of a single, comprehensive committed policy, of either the Commonwealth or Victorian Government, to introduce a mandatory requirement of this type.

ACIL Tasman is aware that there have been numerous attempts by various Governments to reduce the power used by domestic appliances operating in standby mode. A discussion of the history of a number of attempted and intended policies that contain one watt standby elements is set out on the energy rating website.[17] As is discussed on that website, there are MEPS either in place or under consideration for a number of the appliances listed above, some of which include standby power elements. For example:

- There is a MEPS for televisions in place at present. It has been foreshadowed that this will shift to 'tier 2' in 2012. Basically, televisions can now only be sold if they meet at least 1-star. This does not control the standby power use directly, although clearly this is part of the star rating process (and it must be measured to comply with the standard).[18]
- There is a MEPS for set top boxes in place already. These can meet either a 1 or 2 watt standby requirement. If standby power usage is between 1 and 2 watts then the on mode power usage restriction is more stringent than that which applies to units with standby power of less than 1 watt.[19]

17 See http://www.energyrating.gov.au/standby.html and http://www.energyrating.gov.au/standby-background.html, both accessed 6 March 2010

18 The process is described in "*Regulatory Impact Statement: Proposed Minimum Energy Performance Standards and Labelling for Televisions*" Energy Efficient Equipment, 2009 available at: http://www.energyrating.gov.au/library/pubs/200916-decision-ris-tvs.pdf.

19 See http://www.energyrating.gov.au/stb2.html

- There is a MEPS for external power supplies which requires that their standby mode power usage is below 0.75W (0.5W for supplies with lower power output)[20]

When this issue was discussed with the distribution businesses and NIEIR, they referred to a statement on the IEA's website that Australia has a one watt standby target [21], but were otherwise unable to refer ACIL Tasman to an Australian policy of this kind.

Given that it is unclear what policy is being modelled by NIEIR and the distribution businesses, ACIL Tasman recommends that the electricity demand reduction attributed to this target should be disregarded. This view is strengthened by the fact that a number of MEPS with one watt standby components are already in place and are thus already influencing the data that feeds NIEIR's model.

5.3 Insulation target

On 19 February 2010, several months after the distribution businesses submitted their regulatory proposals, the Commonwealth Government discontinued its insulation rebate scheme. Prior to this, the Government's objective had been to see insulation installed in up to 1.9 million homes by 2011. Retaining this objective, in March 2010 the Government had announced its intention to repackage the earlier insulation scheme as a new household renewable energy bonus scheme with an insulation component that would come into operation by 1 June 2010.

NIEIR's energy forecasts were prepared on the basis of a rebate of up to $1200 for home insulation. To estimate the energy savings that would result from this, NIEIR drew on ABS data showing that approximately three quarters of Victorian householders reported having insulation in their homes while another 19 per cent did not know whether or not their home was insulated. It estimated that insulating a home would reduce electricity use for heating and cooling by 35%. To take account of non-compliant installation and the rebound effect[22], NIEIR discounted this impact by approximately 30%.

Based on these parameters, NIEIR estimated that the Commonwealth insulation target would cause summer maximum demand to peak lower than it otherwise would have by the (incremental) amounts shown in Table 6 below.

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20 See http://www.energyrating.gov.au/eps2.html

21 See International Energy Agency, "Summary of Standby Power Regulatory Policies", available at https://www.iea.org/subjectqueries/standby.asp, accessed 11 March 2010.

22 Rebound occurs when, having installed insulation, the householder chooses to increase comfort levels rather than take all of the saving in the form of reduced energy bills.

Table 6 **estimated impact on energy sales of Commonwealth insulation target (annual, incremental MW)**

Year	2010	2011	2012	2013	2014	2015
CitiPower	0.95	0.95	0.48	0	0	0
SP AusNet	2.01	2.01	1	0	0	0
Powercor	2.2	2.2	1.1	0	0	0
Jemena	1	1	0.5	0	0	0
United	2.08	2.08	1.04	0	0	0
Total	8.24	8.24	4.12	0	0	0

Data source: NIEIR, energy reports, table 6.2

ACIL Tasman considers that the uncertainty surrounding this policy is such that there is a very real possibility either that it will not go ahead or that the Government's desire to improve the energy efficiency of Australian homes will manifest itself in different ways, excluding insulation.

ACIL Tasman regards this as distinct from the issue of a broader carbon emissions reduction policy, which is supported in concept by the federal opposition, although the particular means of achieving it (i.e. the CPRS) is not. In considering this issue, ACIL Tasman is not aware that the opposition parties have made any commitment that they will support an amended insulation rebate scheme or that they would choose this path to improving the energy efficiency of Australian homes (either in opposition or in government). Further, ACIL Tasman notes that the widespread reporting of the injuries and loss of property linked with this policy may cause people to be more reluctant to install insulation in their homes than they were to begin with. In ACIL Tasman's view, the high degree of uncertainty around the future of subsidised insulation suggests that it should be excluded from the forecasts.

5.4 Photovoltaics

The recent rise of climate change policies at both the State and Commonwealth level has led a large number of Victorians to install solar panels on their homes. Between 1999/00 and 2006/07, there was only one month when more than 50 photovoltaic systems were installed in Victoria. Since July 2007, the number has rarely dropped below 100 per month, with the average between July 2007 and February 2010 being more than 500 system installations per month.[2324]

[23] Department of the Environment, Water, Heritage and the Arts, Solar Homes and Communities plan data, available at http://www.environment.gov.au/sustainability/renewable/pv/history.html, accessed 27 March 2010.

This rise was observed nationally and can be attributed to a number of policy interventions including:

- a doubling of the available government rebate
- variations in the way solar panels earned renewable energy certificates under the renewable energy target and its predecessors.

In Victoria, the relevant policy measures included the Victorian renewable energy target and a premium feed-in tariff scheme.

Many of these policies will continue into the regulatory period although, as with other climate change policies, there is some uncertainty as to the precise form they will take. For example, during the course of this review, the Government announced substantial changes to the way that solar panels would be treated for the purposes of the renewable energy target scheme. However, it appears that the effect of these changes will mainly be on other forms of renewable generation and that residential based solar panels will continue to receive the same level of support that has been available.[25]

Given that the rise in the number of solar panels installed has been recent and rapid, it is not unreasonable to modify the forecasts from the base model to account for the impact of the ongoing take up of solar panels.

The contribution that a single solar panel will make to summer peak demand depends on the nominal capacity of the panel and the extent to which it operates below its nominal capacity at the time the peak occurs. There are a number of reasons why a solar panel might be expected to be operating below its nominal capacity when a summer peak occurs. These include the orientation of the solar panel, the orientation of the sun to the panel at the time of summer peak, ingress of dirt or other material on the panel which blocks some of the incident light, cloud cover at times of the summer peak and the fact that photovoltaic panels tend to operate with reduced efficiency when ambient temperature is high.[26]

Taking these factors into account it is reasonable to assume an average capacity factor across all photovoltaic cells and construct a simple mathematical

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24 Note that, strictly speaking, this data refers to solar panels for which rebates were provided. It is possible that some panels were installed without rebates, but ACI Tasman expects that the number would be trivial.

25 Australian Government, Ministers Wong and Combet, "Enhanced renewable energy target scheme", Media release PW 46/10, 26 February 2010.

26 For discussion of this, see Passey, R., Watt, M., Snow, M., Outhred, H. and Spooner, T. 'Study of Grid-connect Photovoltaic Systems: Benefits, Opportunities and Strategies', Progress in Photovoltaics (accepted for publication). See also a study that was conducted by a group of students at University of South Australia for the Electricity Supply Industry Planning Council.

relationship between the number of solar panels installed at a given time and the contribution they make to reducing peak demand.

There is insufficient information in the businesses' regulatory proposals to fully assess the methodology for estimating the demand offsetting effect of solar panels. However, it is notable that the total contribution to peak demand made by all solar panels in Victoria (i.e. the sum of the contributions in each business's proposal) does not appear to be consistent with NIEIR's forecast of the number of panels to be installed in Victoria over the regulatory period. This is highlighted by the declining ratios of contribution to installed capacity in Table 7 below.

Table 7 **Analysis of forecast contribution to peak demand resulting from solar panel support policies**

	2010/11	2011/12	2012/13	2013/14	2014/15
Annual panels installed (a)	5000	5000	5000	4000	3000
Total incremental contribution to peak demand (b)	3000	3000	2700	2090	1500
Ratio of peak contribution to installed capacity - (a)/(b)	0.6	0.6	0.54	0.52	0.5
Ratio in cumulative terms	0.6	0.6	0.58	0.57	0.56

Note: (a) NIEIR's report to each business, table 6.14 (b) this is the sum of the contribution in each businesses' distribution area

It should be noted that the variation in the ratios set out in Table 7 above is not large in absolute terms. The forecast values are consistent with an average solar panel size of 1.2kW, which NIEIR describes as a typical Victorian installation, generating at approximately 46% of its nominal capacity at peak time.

NIEIR has advised that "as the policy becomes 'business as usual' the energy impacts of the policy decline resulting in a declining ratio."[27] In other words, NIEIR is assuming that some of the panels represented by the take up scenario would be installed regardless of policy solar panels.

Generally speaking, the above approach of reverting to BAU is used in cases where a policy is designed to accelerate the impact of a phenomenon that is expected to occur anyway.[28] In this case, though, ACIL Tasman is concerned that, without government support of some form, solar panels would be so expensive that they would not be taken up at all. For this reason, ACIL Tasman would be inclined not to reduce the above ratio. The impact of this

27 Citipower, M Serpell email to L. Irlam (AER) and others entitled "RE: further questions arising from NIEIR meeting 10 March" received 8:58pm 22 March 2010.

28 BAU is also used to measure the impact of a policy by attempting to describe the 'business as usual world', namely one without the effect of the policy. This is analogous to using a control group in an experimental trial.

adjustment is small in the current context, though, and does not warrant amendment.

5.5 Victorian Energy Efficiency Target (residential only)

The Victorian Energy Efficiency Target, or VEET, is a 'white certificate' scheme which places an obligation on energy retailers, both electricity and gas, to create and acquit Victorian Energy Efficiency Certificates equal to a target that, in aggregate, amounts to 2.7 Mt of carbon dioxide equivalent greenhouse gas emissions per year in 2009, 2010 and 2011.

Certificates can be created by upgrading water heaters, space heaters, lights, shower heads or refrigerators and by installing various products that improve the energy efficiency of houses such as insulation. In some cases, VEET provides an incentive to switch from electric appliances to gas appliances.

It is clear from inspecting the list of VEET activities that there is potential for significant overlap between VEET and other policy measures such as the Commonwealth insulation policy. To account for this overlap in terms of energy sales, the businesses weighted the VEET impacts down by 90%, which implied a very small impact from VEET itself.

In terms of maximum demand, the businesses have assumed that VEET will have no impact but have given no basis for this assumption. This is almost certainly an underestimate of the impact VEET will have on maximum demand (i.e. VEET is likely to have some impact). However, as with a number of the other policy measures, it is not unreasonable to expect that the impact will be very small, especially in the first few years of the regulatory period.

Offsetting this is the fact that the Commonwealth Government's insulation rebate was suspended while this review was underway (see section 5.3 above). NIEIR's demand projections include an estimate of the impact of this rebate, which, given that it was cancelled after those projections were made, will turn out to be an overestimate of its effect.

Had the insulation rebate not been cancelled it would have interacted with the VEET. i.e. people who insulated their homes would have received benefit from both policies. Given that the rebate has been cancelled, it may be reasonable to remove this adjustment from the demand forecasts. However, if this was done, there would also be the need to reduce the weight applied to VEET (i.e. reduce the 90% discount).

ACIL Tasman notes that VENCorp prepared the 2009 APR on the basis that VEET would have a negligible impact on peak demand.[29]

5.6 Hot water initiatives

The maximum demand forecasting reports include a description of the impact that a number of initiatives affecting the use of electric resistance water heaters will have on energy sales. To summarise, electric resistance water heaters will more or less disappear from the range of available new hot water system options during the coming regulatory period. However as the average life of resistance hot water systems is between 10 and 15 years, and as systems are only likely to be replaced when they breakdown, the phase out of resistance hot water systems will have a considerable tail.

The businesses have asserted that this initiative will have no impact on the maximum demand for electricity in their regions, although no explanation has been offered for this. ACIL Tasman notes that electric resistance water heaters would generally be used at off peak times and, while the mechanisms for ensuring this may not be perfect[30], it is probably reasonable to assume that the removal of electric resistance water heaters from the system will have a negligible impact on maximum demand over the next regulatory period. However where the replacement systems are solar systems with a backup boost or heat pump based systems, they may be used during the summer peak, this policy may inadvertently add to maximum demand. Again, however this is likely to be negligible over the next regulatory period.

5.7 Mandatory Energy Performance Standards - air conditioning

NIEIR's forecast of the impact that the air conditioner MEPS will have on maximum demand is as follows.

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29 VENCorp "Victorian Annual Planning Report" 2009, p. 206, available online at http://www.aemo.com.au/planning/v400-0017.pdf

30 ACIL Tasman understands, anecdotally, that it is not at all uncommon for electric resistance water heaters to operate during the day notwithstanding that they are intended to operate overnight. Most of the off peak heaters operate on local time clocks in Victoria which are not regularly recalibrated and which ACIL Tasman understands may lose accuracy over time.

Table 8 **Estimated impact of air-conditioning MEPS on summer maximum demand**

Impact (MW)	2011	2012	2013	2014	2015
Residential sector	5.3	6.17	7.03	6.05	5.38
Commercial sector	2.96	3.98	4.93	5.19	5.65
Incremental total	8.26	10.15	11.96	11.24	11.03
Cumulative total	8.26	18.41	30.37	41.61	52.64

Data source: NIEIR maximum demand reports to the businesses

ACIL Tasman notes that VENCorp prepared the 2009 Annual Planning Report based on estimates of the impact that this MEPS would have on maximum demand that were similar, growing from 8 MW in 2011 to 80 MW in 2019/20, which is approximately consistent with the forecasts presented here.[31]

ACIL Tasman notes that the policy applies to new air conditioners, so it will not improve the efficiency of the stock of appliances already installed. In the context of increasing penetration of air-conditioners in Victoria, this policy would be expected to slow the rate of growth in air conditioning demand, but not to cause that demand to decline.

The distribution businesses have provided no information as to how this estimate was prepared. The information that is available to ACIL Tasman is insufficient to reach a conclusion as to whether the forecast is reasonable or otherwise.

5.8 Residential building standards – 5 and 6 star

New homes built in Victoria are required to meet a 5 star energy efficiency standard and there is some suggestion that COAG may move to increase this to a 6 star minimum performance standard. For the purposes of forecasting maximum demand, the businesses have assumed that this change will happen in 2012 and have estimated a modest reduction in peak demand as a result.

This measure would only be relevant for newly constructed homes and is thus limited to a very small portion of overall maximum demand. It also needs to be considered in the context trends for larger homes which, while more energy efficient, may nonetheless be large enough to have increasing, rather than decreasing, maximum demands.

[31] VENCorp "Victorian Annual Planning Report" 2009, p. 204, available online at http://www.aemo.com.au/planning/v400-0017.pdf

5.9 Advanced Metering Infrastructure (smart meters)

To date, the majority of electricity customers, including all residential customers, have had accumulation meters to underpin their electricity billing. These meters simply accumulate the amount of electricity used between reads, with no information captured as to when that electricity is used.[32] Over the course of the coming regulatory period, Victorian residential customers will be issued with smart meters and may be transferred to time varying tariffs.

However, on Monday 22 March 2010, very late in the course of this review, the Victorian Premier announced a moratorium on the introduction of time of use tariffs. ACIL Tasman understands that the effect of the moratorium is to prevent small customers from being charged either time of use or critical peak pricing tariffs. No indication has been given as to how long the moratorium will remain in place.

5.9.1 Advanced metering infrastructure and peak demand

While there may be some impact on electricity consumption behaviour due to the information provided by a smart meter, the main driver is likely to be the tariff. The key difference between an accumulation meter and a smart meter is that they allow time varying tariffs to be employed, where the price users pay for electricity depends on when it is consumed. The time varying tariffs that have been studied and trialled can be broken into two groups, namely critical peak price (CPP) trials and time of use tariff (TOU) trials.

A typical TOU tariff structure would apply every day, at least during peak season (i.e. all summer in Australia). The price of electricity would typically be higher during the afternoon and early evening, when peaks in demand occur, and lower at other times.

In case of a CPP tariff, the electricity supplier is permitted to call critical peak events in advance and, by doing so, apply critical peak prices during those events. The prices themselves would be much higher than the price that prevailed at other times with the intention of providing strong incentives to minimise electricity use during the critical peak events. In the studies that have been conducted, no more than about ten critical peak events could be called each year.

Generally speaking, a time of use or CPP tariff structure would be expected to induce two effects, namely load reduction and load shifting. Load reduction

[32] In the case of off peak tariffs a second meter is typically used to give a limited amount of appliance specific time of use information.

would be driven by the price elasticity of demand (for MW) at peak times, whereas load shifting is driven by the cross price elasticity of demand between peak and off peak times.

As is evident from NIEIR's maximum demand reports to the distribution businesses, the research work that has been done on forecasting the impact of time varying tariffs has focussed on the impact on energy sales, not on peak demand. In some cases, studies analyse the impact on energy sold at times of high demand, or at peak times, but ACIL Tasman is not aware of a study that measures the reduction in simultaneous peak demand.[33][34] ACIL Tasman notes that in choosing to pursue the AMI rollout, the MCE considered that smart meters would lead to a reduction in peak demand, and thus a deferral of network augmentation. However, ACIL Tasman acknowledges that estimating the extent to which this is likely to happen in the first few years of the rollout is a difficult task.

To understand this difficulty, consider the mechanism by which AMI would reduce maximum demand. Unlike a MEPS or other energy efficiency policy, which makes a physical change to technology, AMI enables time of use tariffs to be charged. The incentive to reduce electricity demand comes not from the meter itself but from the price (tariff) that can be charged once the meter is installed.

It follows from this that any change in consumption behaviour is driven by the change in relative prices between electricity consumption and other consumption for the electricity user, in other words, from the elasticity of demand. It is important to note that there are two distinct elasticities to consider. The first is the price elasticity of demand for energy, i.e. the relationship between the price of energy and the quantity, in watt-hours, of energy demanded at certain times. The second elasticity could be referred to as the price elasticity of demand for MW. This is the relationship between the price of electricity and the quantity that the customer will demand when their demand is at its maximum. These elasticities are not conceptually the same and would take different values. As NIEIR put it in discussion of this issue, "many studies found varying degrees of load shifting associated with AMI, however here we are concerned with the overall peak."[35]

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33 In other words, the studies tend to focus on a reduction in watt hours, not watts.

34 Note that Fan and Hyndman analyse the impact of (lagged) price on maximum demand, but this is without a time of use tariff or AMI meter. Fan, S and Hyndman, J. "The price elasticity of electricity demand in South Australia and Victoria", 2008, available at http://www.esipc.sa.gov.au/webdata/resources/files/Price_Elasticity.pdf, accessed 22 March 2010.

35 NIEIR, "Response to ACIL Questions (demand policy questions 1b.doc)", received by email from Citipower, M.Serpell, 23/2/2010 9:13 pm.

NIEIR and the distribution businesses did not attempt to model the impact that AMI would have on maximum demand using elasticities. In discussions with NIEIR, they questioned the relevance of using elasticities, tariffs and enabling technologies in terms of modelling the impact of the AMI rollout (or various other policies).[36] Rather, NIEIR made an assumption based on its review of literature that, for relevant customers, demand would peak at 2% below the level at which it would have peaked without the AMI rollout. This assumption is reflected in its reports to the distribution businesses.

ACIL Tasman notes that this assumption was based on "extreme weather conditions"[37] but that the forecasts that result from it are presented as 50 POE forecasts. As discussed above, 50 POE temperatures are high, but would not reasonably be described as extreme. Further, there is no distinction between the forecast impact of the AMI rollout on the 10 and 50 POE forecasts although the 'extremity' of the weather represented by these two conditions varies significantly. It would seem reasonable to expect, and consistent with NIEIR's views, that the impact on 10 POE demand would be smaller than the impact on 50 POE demand.

These factors suggest that the estimated impact of the AMI rollout on peak demand are 'on the low side' of what might be expected.

5.9.2 Advanced metering infrastructure – timing of impacts

The time dimension is significant in estimating the impact attributable to the AMI rollout. A number of competing issues are relevant.

Broadly, there are two ways that electricity consumers are able to respond to tariff changes such as those made possible by smart meters. Firstly, consumers could respond by making behavioural changes such as adjusting heating and cooling thermostats etc. Secondly, they could respond by changing their electric appliances for more efficient alternatives.

Behavioural changes

The first category of changes could potentially be made immediately as the new TOU or CPP tariffs are applied and theoretically, they could last indefinitely. There are both theoretical and empirical reasons to expect, though, that this may not happen. From a theoretical point of view, behavioural economists have recently been considering the concept of 'relativity'. In simple terms, the argument states that whether a product is 'cheap' or 'expensive' depends more on reference points than on the absolute cost of the product. It is possible

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36 *ibid.*

37 *ibid.*

that initially, while comparing TOU or CPP prices to anytime prices, consumers will alter their behaviour to reduce consumption. However, as time passes, the comparison of current prices to recent prices amounts to comparing TOU or CPP prices to themselves. As the new prices become 'normal' and therefore not relatively more expensive than the reference point provided by recent prices, consumption might be expected to return to higher levels.

There is some support for this possibility in the empirical work that has been done. For example, Faruqui and Sergici note that in the California statewide pricing trial, a TOU tariff caused peak period energy use (not maximum demand) to fall by about six per cent in the first year of a trial, but that "this impact completely disappeared in 2004" (the second year of the trial).[38] This suggests that, once the initial novelty of the TOU tariff has worn off, or once the new prices have become 'normal' and the concept of relativity takes effect, trial participants' interest in reducing energy during higher price periods wanes.

Another factor that should be borne in mind when considering the impact of AMI meters, whether on energy or peak demand, is the so called 'rebound effect'. There is the possibility that the rollout of AMI meters, accompanied with a significant information campaign to ensure that consumers 'know what they are in for' will induce a significant change in behaviour. This would be observed as a reduction in either or both of peak demand and energy consumed at peak times. However, as time passes, consumers may become less responsive to time of use tariffs. A number of reasons have been advanced for why this might happen, including that:

- energy bills are a relatively small amount of disposable income so not worth as much effort to reduce as other things,
- there is a principal agent problem in households with multiple occupants[39]
- the message will simply be lost over time.

Changes to appliances

The second category of change that could lead to reduced electricity demand following the AMI rollout of smart meters is changes to electrical appliances. In terms of simultaneous maximum demand, the change that would make the most significant difference would be changes to air conditioning.

38 Faruqui, A. and Sergici, S. "Household response to the dynamic pricing of electricity – a survey of the empirical evidence", 10 January 2009, p15.

39 This is the extent to which the people whose behavior must change are not the bill payer. Consider a family with parents (the principal) responsible for the bill and children (the agent) among the electricity users. The principal agent exists to the extent that the incentive (and behavior change0 on the children differs from that on the parent.

Air conditioners are quite expensive relative to the cost of the electricity they use and have long lives.[40] It seems unlikely that the AMI rollout will cause householders to replace these appliances before they fail. Rather, it is more likely that the cost of operating an air-conditioner would be taken into account when it needed replacing anyway, leading to the choice of a more energy efficient unit.

For the above reasons, it seems reasonable to expect that the AMI rollout will have a lagged effect on electricity demand, i.e. price changes 'now' may lead to changes in maximum demand 'in the future'. This is consistent with the work of Fan and Hyndman who analysed the data concerning price and electricity demand in South Australia and found that the best model of electricity demand included a lagged price variable.[41]

5.9.3 Advanced metering infrastructure – assessment and recommendation

ACIL Tasman has significant concerns with the way that the impact AMI meters would have on electricity sales was estimated by each distribution business other than SP AusNet[42] and with the way that those businesses interpreted the relevant literature. This is discussed in further detail in ACIL Tasman's report on its review of the distribution business's energy sales forecasts. In summary, it appears that, while the businesses have indicated that it is unlikely that they would introduce a CPP tariff during the coming regulatory period, these four businesses have forecast energy sales by assuming that they would experience the same reduction in energy sales throughout the year that Energy Australia observed in response to a CPP tariff. In ACIL Tasman's view, the literature does not support this conclusion.

In terms of maximum demand, the businesses have not provided a reasonable basis for their assumption that the AMI rollout will cause demand from

[40] The regulatory impact statement for proposed amendments to the MEPS for airconditioners modeled that policy on the basis of a ten year life for non-ducted systems and a fourteen year life for ducted systems. Average prices were around $2500~$3000 for ducted systems and around $750 to $1500 for various types of non-ducted (split system) air conditioners. See Equipment Energy Efficiency Committee, "Regulatory Impact Statement, Consultation Draft Revision to the Energy Labelling Algorithms and Revised MEPS levels and Other Requirements for Air Conditioners" September 2008, available at http://www.energyrating.gov.au/library/details200809-ris-ac.html, accessed 12 April 2010 pp. 99 (useful lives) and 103 (cost).

[41] Fan, S. and Hyndman R. op Cit p16. Note that this was not a time of use tariff study, but an empirical analysis of demands and prices observed in South Australia between 1997 and 2008.

[42] SP AusNet took a fundamentally different approach than the other businesses to estimating the impact of the AMI rollout.

affected customers to peak at two per cent below the level at which it would have peaked without the AMI rollout. This having been said, the literature, insofar as ACIL Tasman has reviewed it, makes if difficult if not impossible to draw any firm conclusion as to what impact the AMI rollout will have on simultaneous peak demand. In most of the literature, the impact on simultaneous peak demand is not distinguished from the impact on demand for energy at peak times, although these are clearly not the same.

In any event, ACIL Tasman notes that the moratorium will cause the adoption of time of use tariffs to be delayed. As a result, the AMI rollout's impact on maximum demand will also be delayed. Prior to the moratorium being called, the rollout schedule was such that there was only one full year in the coming regulatory period following rollout completion (assuming that it ran to schedule). Taking this into account, along with the likelihood that response to the AMI rollout will lag the introduction of the tariffs themselves, and the difficulty in estimating what that impact will be, ACIL Tasman considers that the most reasonable course of action would be to disregard the estimated impacts of AMI rollout for the coming regulatory period. This could perhaps be done with a view to making any necessary adjustments as the uncertainty is resolved, which may most reasonably be done on an ex post basis.[43]

ACIL Tasman notes that VENCorp prepared the 2009 APR on the basis that AMI would reduce summer peak demand by 5MW in 2010/11, increasing to 70 MW in 2015/16.[44]

5.10 Carbon Pollution Reduction Scheme

This review of electricity distribution prices comes at a time of significant uncertainty in terms of climate change policy. In particular, it is currently unclear whether an emissions trading scheme will be put in place in Australia or, if so, when it will commence.

The Carbon Pollution Reduction Scheme (CPRS) would, if implemented, bring about significant change in Australia's electricity industry. It would induce a shift towards generation technologies that emit less greenhouse gas but which are more costly in the absence of the CPRS than their conventional alternatives. As the higher cost of generation flows through to electricity prices, all users will face an increased incentive to take steps, both physical and behavioural, to limit their use of electricity. This is partially additional to the

43 Note that ACIL Tasman is not in a position to provide legal advice or to comment on the appropriateness of this approach in light of the National Electricity Rules or other relevant legal matters.

44 VENCorp "Victorian Annual Planning Report" 2009, p. 205, available online at http://www.aemo.com.au/planning/v400-0017.pdf

incentives provided by various other policy measures that are already in place to achieve the same results. These are discussed below.

The CPRS has implications for forecasts of energy sales and maximum demand. Both of these would be expected to be reduced by the increased price of electricity that the CPRS would cause, although in both cases the size of reductions, which are driven by the price elasticity of demand, would reasonably be expected to be small in the early stages of the CPRS. As is reflected in the studies that have been done into this question it takes time for users to adjust to higher electricity prices, either by substituting existing equipment for energy efficient equipment or by making behavioural changes.

At the time the distribution businesses produced their regulatory proposals, which were submitted in November 2009, it was reasonable to expect that the CPRS would commence on 1 July 2011 and follow something approximating the CPRS 5 path modelled by Commonwealth Treasury. This is the assumption upon which the energy and maximum demand modelling was based.

The CPRS legislation has not passed Parliament at the time of writing this report and its future is uncertain. Accordingly, Government policy notwithstanding, there is at least some chance that the CPRS will:

- be delayed beyond a mid 2011 start date,
- be introduced in a modified form
- not be introduced at all

For this reason, it seems unlikely that the existing CPRS will commence on 1 July 2011. However, it is also unlikely in the current environment that no greenhouse emissions reduction policy will be put in place in Australia during the coming regulatory period. In other words, it seems more likely than not that, by 2015, either the CPRS or an alternative policy aimed at reducing greenhouse emissions will be in place. Further, it would appear likely that any greenhouse emissions reduction policy that will be introduced will, assuming it has comparable emissions reduction targets to the CPRS, cause the price of electricity to increase to at least some extent towards the levels expected under the CPRS and even possibly higher.

It is not possible to be certain about what will happen in terms of greenhouse emissions reduction policy during the coming regulatory period. Accordingly, notwithstanding that the businesses have probably forecast maximum demand based on an incorrect assumption concerning the carbon price to 2015, ACIL Tasman does not consider it possible to provide a more accurate assumption. Given this uncertainty, ACIL Tasman has accepted the assumption made by each of the businesses that, in line with Government policy, the CPRS will commence on 1 July 2011 and follow the CPRS-5 trajectory.

If this assumption turns out to be incorrect there will be implications for the maximum demand forecasts. For example, if the CPRS is delayed beyond 1 July 2011 then it would be reasonable to expect that electricity prices will be lower at any given time than those used in producing the maximum demand forecasts. Given, though, that the impact the CPRS will have on maximum demand is by way of price elasticity and that the changes that underpin that elasticity take time to implement, ACIL Tasman does not expect that the impact of a one year delay in the commencement of the CPRS would have a material impact on maximum demand forecasts. For this reason, ACIL Tasman does not consider the uncertainty surrounding greenhouse emissions policy likely to have a substantial effect on maximum demand levels to 2015.

5.11 Conclusion – policy impacts

For the reasons set out above and consistent with its recommendations in relation to the electricity sales forecasts, ACIL Tasman recommends that the maximum forecasts be adjusted to disregard the impact of the:

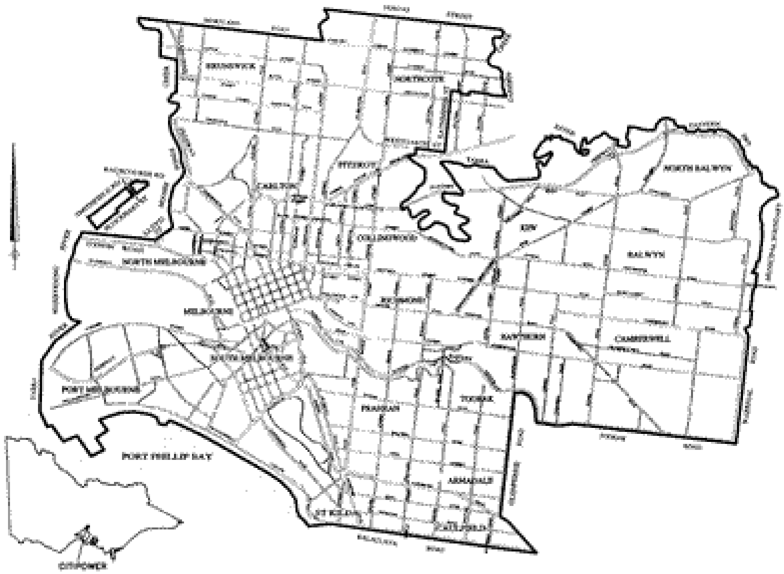
1. AMI rollout
2. insulation rebate beyond early 2010
3. one watt standby ‘target’

In terms of the electricity sales forecasts, ACIL Tasman has also recommended that the forecast impact of the MEPS for lighting be reduced. Given that the impact on maximum demand is very low already, no further adjustment is recommended in relation to the MEPS lighting policy.

6 CitiPower

6.1 Description of CitiPower network

Figure 12 **Map of the CitiPower region**



CitiPower's network is approximately 157 square kilometres in size and covers central Melbourne and inner suburbs. It accounts for approximately 12% of Victoria's population and dwelling stock, with a slightly lower occupancy rate (persons per household) than average.[45]

CitiPower's area accounts for almost 30% of Victoria's total gross state product including a dominant share of 'white collar' industries such as finance, property and business services, communication and public administration. Manufacturing, on the other hand, is relatively small in CitiPower's area.

NIEIR forecasts that population growth in CitiPower's area will be 0.9% per annum over the next regulatory period. This is 0.3 percentage points below the Victorian average. NIEIR's population growth forecast for CitiPower's area includes a forecast of 2.2% annual growth in Melbourne, with all other regions in CitiPower's area growing at less than 1.0% per annum.

Gross Regional Product in CitiPower's area will grow, according to NIEIR's forecast, at 1.4% per annum over the forecast period. By contrast to the

[45] NIEIR states that CitiPower's area includes 11.8% of the Victorian population and 12.3% of dwelling stock.

population growth estimates where Melbourne is forecast to outperform CitiPower's area, Melbourne's GRP is forecast to grow at 0.5%, lagging the rest of CitiPower's area where forecasts range from 0.9 to 3.1% per annum.

NIEIR's forecast growth in dwelling stock is consistent with its estimate of population growth for CitiPower's area. In Melbourne, NIEIR forecasts annual growth in the dwelling stock of 4.5% per annum. This is more than double the rate of growth in CitiPower's next fastest growing region. It also notes that the "current over-supply will postpone" many of the apartment projects currently planned, although ACIL Tasman understands that NIEIR's forecasting methodology, which is based on historical data, does not take this factor into account explicitly. ACIL Tasman has not been provided with sufficient specific information to reach a view as to whether CitiPower has taken this effect into account sufficiently (see the discussion of new known loads below).

6.2 Summary of methodology – CitiPower

CitiPower's approach to maximum demand forecasting is 'bottom up' from the zone substation level. Broadly, it:

1. prepares an individual forecast for each zone substation
2. aggregates these together, taking account of diversity, to the terminal station level
3. compares its terminal station forecasts to a set of terminal station forecasts prepared independently by NIEIR by the process described in the earlier sections.

In preparing its forecasts, CitiPower gives consideration to a number of factors including:

- the impact of temperature on the maximum demand
- historical growth in maximum demand
- CitiPower's expectations of future growth in maximum demand
- the anticipated impact of significant single discrete loads.

These factors are considered independently for each zone substation. The methodology by which each factor is considered is discussed in further detail below.

CitiPower's chosen methodology does not take account of a number of other factors relevant to forecasting maximum demand. These factors include economic conditions in the forecast period and the impact of government policies that would be expected to influence electricity demand, such as the rollout of advanced metering infrastructure and policies designed to encourage take up of small scale embedded generation and to improve energy efficiency. These factors are taken into account by NIEIR's methodology, so to the extent that the two forecasts are reconciled with one another, they would be accounted for in CitiPower's approach. However, it appears that CitiPower does not reconcile its forecasts with those prepared by NIEIR, with the result that these factors are not reflected in the forecasts CitiPower has put forward. This is discussed in more detail in section 6.2.3 below.

6.2.1 CitiPower's demand forecasting methodology[46]

The maximum demand forecasts CitiPower has put forward to the AER in its regulatory proposal were prepared using a bottom up methodology that begins at the zone substation.[47]

Starting points

The first step in preparing these forecasts was to adjust the most recent, observed, daily maximum demand to the 50 POE level. In most cases, the maximum observed demand occurred on or about 29 January 2009, when the daily average temperature was significantly above the 50 POE level, so the demand observed was significantly higher than 50 POE demand.

CitiPower applies a temperature correction methodology that uses a ratio based approach taking account of the average daily ambient temperature. The method implicitly assumes a one for one relationship between demand on a given day and the average of the minimum and maximum temperature prevailing on that day.

CitiPower uses a relationship derived from long run temperature data to determine the corresponding POE maximum demand that corresponds to a given average temperature on the day of the maximum. The relationship was determined by AEMO and is shown in Figure 13 below.

From the figure we can see that the 10 POE demand corresponds to an average temperature of 32.9 degrees Celsius. The 50 POE maximum demand corresponds to an average temperature of 29.6 degrees Celsius.

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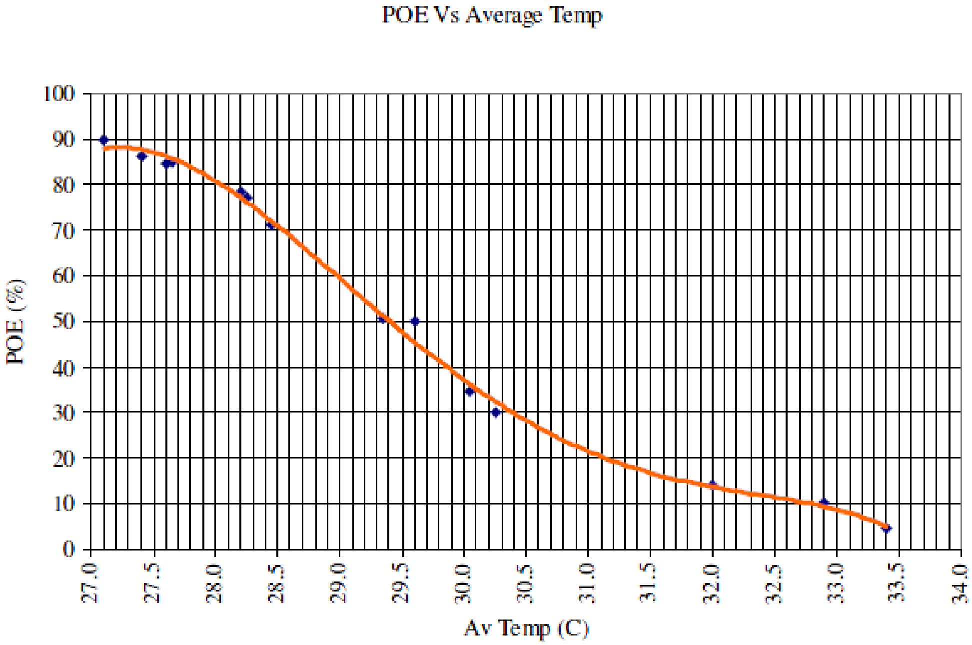
46 ACIL Tasman notes that the majority of the information with which it was provided concerning CitiPower's forecasting methodology was variously described as being 'example' forecasts and 'for information purposes only'. This should be borne in mind in interpreting the discussion and conclusions set out in this section.

47 Note that while the forecasting process is presented sequentially here, this is for ease of description. In practice, many of the steps may be performed simultaneously or in another sequence than that described here.

Figure 13 **Long run relationship between POE and average temperature in the CitiPower network**

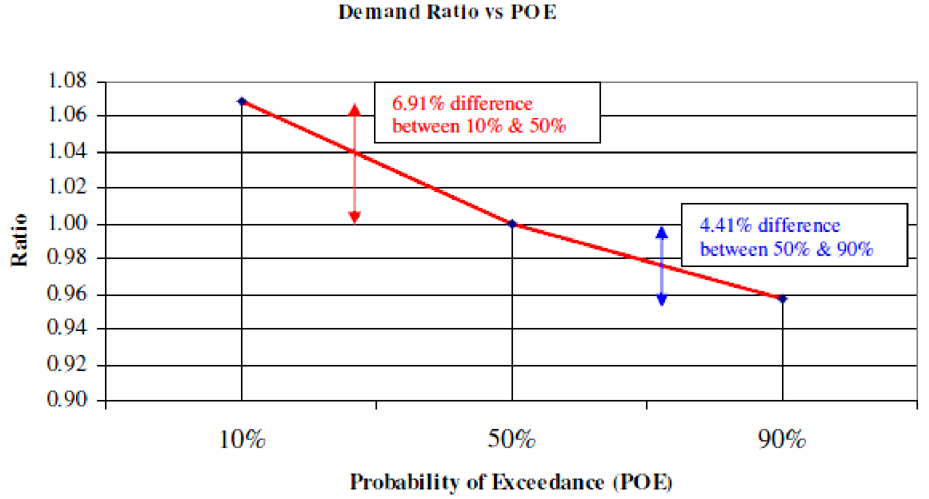


Data source: CitiPower correspondence to AER, 22 December 2009

Once CitiPower knows what the average temperature that applies to a given POE demand is, temperature correction becomes a matter of shifting along a function to the level of demand that corresponds to the desired POE. The temperature sensitivity of demand to changes in average temperature will determine the slope of the function used in the process.

Internal analysis by CitiPower of the historical relationship between demand and average temperature produced the relationship shown in Figure 14. Weather correction is then a simple matter of shifting along this curve. According to CitiPower, there is a 6.91% difference between the 50 POE and 10 POE level of demand.

Figure 14 **Relationship between maximum demand and POE in the CitiPower network**



Data source: CitiPower correspondence to AER, 22 December 2009

The next step is to account for load transfers, such as load transferred between zone substations, that have occurred since the most recent maximum demand was observed. CitiPower has advised that where a particular feeder is transferred from one zone substation to another, the corresponding maximum demand observations are adjusted by the load on that feeder at the time it was transferred, which is then scaled to account for weather correction. When part of the load supplied by a feeder is transferred the adjustment is based on an estimate of 50 POE demand for the load that was transferred.

Growth

Once CitiPower has established a series of starting points that have been adjusted for the impact of weather and load transfers, one for each substation, these form the basis of the forecasts going forwards.

CitiPower's approach treats growth as comprising of two basic components, being 'new known loads' and annual growth. These two components are handled separately.

CitiPower's process for accounting for new known loads is to 'record' every anticipated connection with demand >100kVa. These are generally based on CitiPower's understanding of likely future development in its area, drawn from local Government, or from connection inquiries made directly with CitiPower.

All jobs that are recorded are given a probability weighting of 0.5 to account for the fact that some will not proceed and others will not be as large as initially anticipated. This step appears to be a simplified approach to estimating the expected value of each 'new known load'.

The expected value of each new known load is then diversified to the zone substation level. The diversity factors that are applied depend on whether the new load is commercial, residential or industrial. The factors that are used are set out in Table 9.

Table 9 **CitiPower new load diversity factors**

Load type	Diversity to ZSS	Power Factor	Overall factor to MW
Commercial	0.9	0.8	0.72 (≈0.7)
Residential	0.7	0.8	0.56 (≈0.55)
Commercial/ Residential in CBD			0.65
Shipyards (Docks or terminals – not docklands)			0.5 (only operates when ships come in) (occupation rate CI)
Stadium (MCG, Telstra Dome)			0.1 (off peak) (Occupation rate CI)

Data source: CitiPower letter to AER, 22 December 2009

Some loads will, once installed, be taken up over time, for example the infrastructure necessary to connect a multi lot residential development may be put in place, and thus connected from CitiPower's perspective, before the homes themselves are actually built. The demand would then follow over a number of years. A series of occupation rates are used to account for this delay.

By way of example, consider the connection for a proposed new 145kVa office building:

- As a commercial project, it is assumed that this office will be operating at 70% of maximum load at coincident peak, so its contribution to the system peak is 101.5 kVa (0.7*145)
- As an active proposal, the probability that this project will go ahead is assumed to be 0.5 so the maximum demand is multiplied by 0.5 for 'probability weighting'
- To diversify the demand to the feeder level, it is multiplied by 0.7 again
- The contribution that this project makes to peak demand is 0.36 MW.

The sum of all 'new known loads' as calculated by this process is added to the forecast each year. Simultaneously, CitiPower projects growth in existing load by multiplying the starting point by a growth rate that is chosen by CitiPower staff based on their expectations for future growth in the relevant area.

At this stage in the process, CitiPower has a forecast of non-coincident maximum demand for each of the zone substations in its area. The final step in the process is to aggregate these forecasts to the terminal station and system level, by taking diversity and load factor into account. Each zone substation forecast is multiplied by a diversity factor. The diversity factors are determined by comparing the actual ZSS MD measure from the TS with the measurement at the ZSS. An average is taken over the last 5 years of historical data to forecast the diversity.

6.2.2 Reconciliation with top down forecast

CitiPower does not compare its forecasts to those prepared by NIEIR. No adjustments were made to CitiPower's forecasts to account for differences between them and those prepared by NIEIR. As is discussed elsewhere in this report, this raises a number of issues, including the fact that CitiPower's forecasts take no account of relevant changes in Government policy.

6.2.3 Assessment of demand forecasting methodology

Spatial forecasting methodology

The methodology that CitiPower employs in preparing its spatial forecasts addresses each of the relevant issues and appears to be a reasonable, bottom up methodology. It is noteworthy, though, that it makes substantial use of personal judgement which is partially guided by historical data. This raises significant questions over the transparency and repeatability of the process. This is not assisted by the fact that the process is not documented.

The process for incorporating block/spot loads makes a reasonable attempt to avoid double counting. It does this by:

1. Employing a minimum threshold for including loads
2. Treating loads probabilistically
3. Assigning them to the years they are expected to be built, taking account of delays in occupation

Weather correction appears to be applied appropriately for a spatial level forecast. In ACIL Tasman's experience, the unweighted average of daily minimum and maximum temperatures is less accurate in weather correction than an average which places greater weight on the maximum than the minimum. This is because daily maximum temperature is a more important driver of demand than the overnight minimum. This is an issue that CitiPower may wish to pursue as a possible avenue to improve its spatial level weather correction. This also highlights the benefit of the more sophisticated approach to weather correction taken in the system level forecast prepared by NIEIR, where the relative importance of maximum and minimum temperatures, as well as the previous day's maximum, are estimated from the data rather than being imposed by the analyst.

Further, as discussed above, while the weather correction approach here is appropriate for spatial level forecasts, this does not alter the fact that the methodology applied in NIEIR's system level approach is superior to that used by CitiPower. ACIL Tasman acknowledges that it would be impractical to perform this type of weather correction at the spatial level, which highlights the importance of reconciling to a system level forecast where this approach is taken.

The forecasts are diversified as they are aggregated to higher levels in the system as is appropriate

Overall methodology

Citipower has advised ACIL Tasman and the AER that it does not reconcile its forecasts with those prepared by NIEIR. In other words, the forecasts Citipower has put forward in this process are prepared entirely from 'bottom up'. ACIL Tasman considers that Citipower's forecasting methodology falls short of best practice because it is not reconciled to an independently prepared system level forecast. This reconciliation is something that ACIL Tasman regards as a critical component of best practice forecasting.

The bottom up only methodology by which Citipower has prepared its forecasts is not capable of taking account of several key drivers of electricity demand at the macro level other than in a very subjective manner by allowing it to influence the relevant person's choice of growth rate. The drivers of particular concern in this case are the various changes in government policy that NIEIR estimates will influence electricity demand and future economic and demographic conditions. It should also be noted that these factors are considered in the forecasts of electricity sales and that the two forecasts diverge significantly from one another. In ACIL Tasman's view, the two forecasts Citipower has put forward are not prepared on a consistent basis.

Finally, ACIL Tasman has been provided with no information concerning model testing or validation, nor is there any reason to believe that this has been done. This is a second significant shortcoming in the methodology.

As is discussed below, Citipower's methodology has produced forecasts that rise to higher levels than are forecast at the system level by NIEIR, where regard is had to these factors. ACIL Tasman recommends that Citipower's bottom up forecasts should be amended so that, with an appropriate allowance for diversity, they do not exceed the system level forecasts.

6.3 System level forecasts

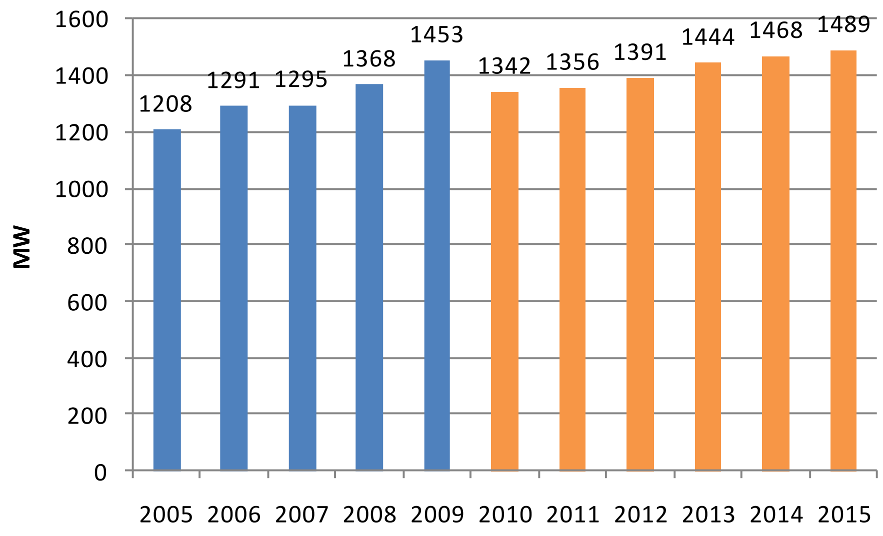
The system level forecasts CitiPower has presented are the sum of the non-coincident terminal station forecasts. As is noted above, CitiPower has not compared its forecasts with NIEIR's forecasts for CitiPower's region. This section shows the comparison between these two sets of forecasts.

Figure 15 below shows NIEIR's forecasts for CitiPower's system level maximum (50 POE) demand. NIEIR projects CitiPower's summer system maximum demand to reach 1489 MW by 2015.

In growth terms, the NIEIR projects a growth rate in CitiPower's 50 POE demand of 2.1% per annum in the 5 years between 2010 and 2015. This is compared to an annualised historical growth rate of 4.2% in the 3 years between 2005 and 2008.

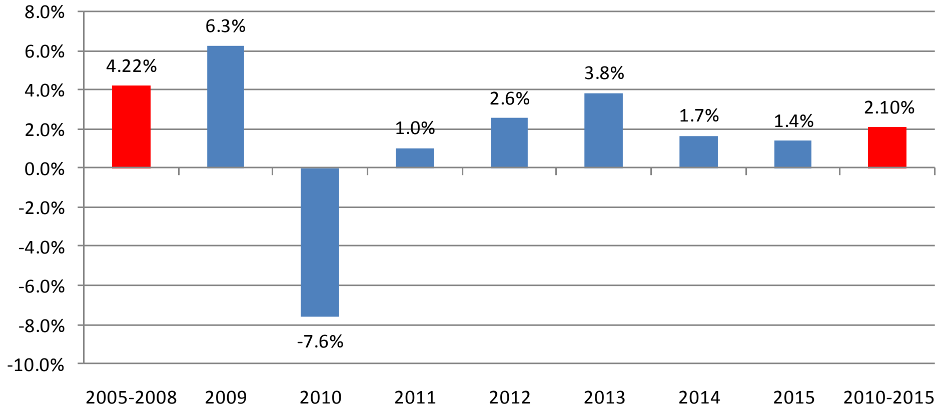
For comparison, the figure also shows (in blue) the historical actual demand in CitiPower's region. It needs to be remembered however that the historical values are not temperature corrected so that a direct comparison between the future and the past is not possible, either in terms of growth rate or levels. This is particularly important in the context that the last two years in Victoria have shown maximum demand significantly above the 50 POE level. The 2008 summer in Victoria produced a hotter than average extreme weather day. In 2009, the peak demand was driven by record breaking hot conditions, which were significantly above the 10 POE level for Victoria.

Figure 15 **CitiPower: NIEIR forecasts of CitiPower 50 POE system maximum demand**



Data source: NIEIR report prepared for CitiPower, Maximum demand for CitiPower terminal stations to 2019.

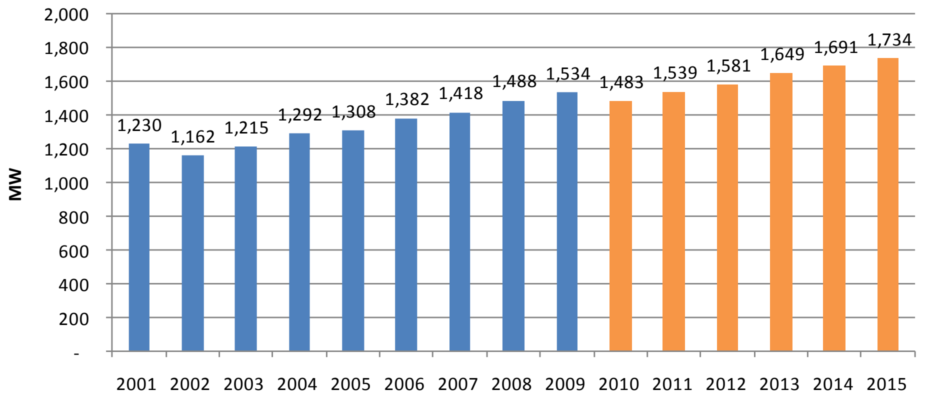
Figure 16 **CitiPower: Growth in NIEIR 50 POE forecasts**



Data source: ACIL Tasman calculations based on NIEIR report, Maximum demand for CitiPower terminal stations to 2019

CitiPower presents its system level forecasts as the sum of its non-coincident zone substation maximum demands. These are the result of the methodology described in 6.2 above. These forecasts are shown in Figure 17. According to CitiPower's data submitted in Table 11 of the RIN, the 50 POE demand for the non-coincident zone substations is expected to reach 1,734 MW by 2015. This is from a starting point of 1,534 MW in 2009.[48]

Figure 17 **CitiPower: Sum of non-coincident 50 POE zone substation maximum demands, historical and forecast**



Data source: CitiPower RIN Table 11

Between 2010 and 2015, the sum of the non-coincident 50 POE zone substations is forecast to grow at an annualised rate of 3.2%. This is significantly faster than the growth rate projected by NIEIR over the whole period at the system level of 2.1% per annum. As a result, the bottom up

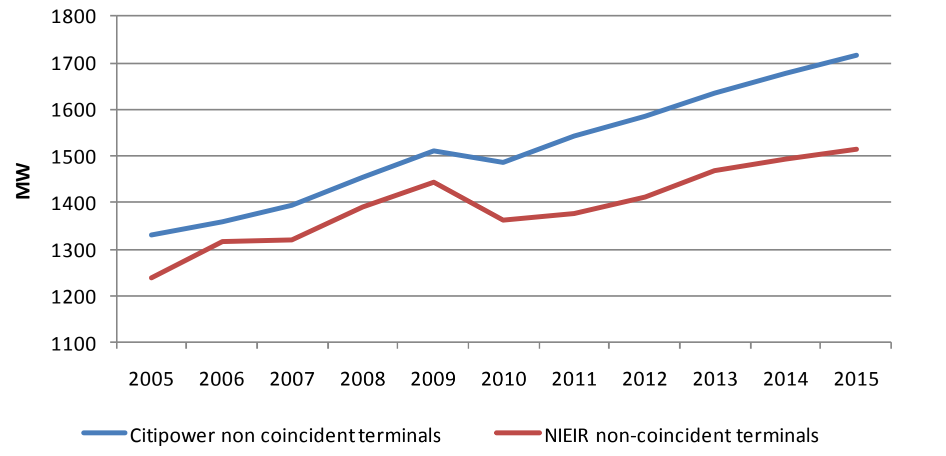
[48] Note that as the NIEIR forecasts are *co*incident while the CitiPower forecasts are *non*coincident they cannot be compared in terms of levels. Comparison of growth rates remains valid.

forecasts produced by CitiPower diverge over time from NIEIR's forecasts. This indicates that CitiPower's forecasts are not consistent with the economic and policy environment expected for Victoria over the coming regulatory period.

6.4 Comparison at terminal station level

As is to be expected, a comparison of the non-coincident terminal stations provided by both NIEIR and CitiPower shows similar results (see Figure 18). This comparison has the advantage over the system level forecast that it is on a like for like basis in that both series are non-coincident.

Figure 18 **CitiPower: NIEIR non coincident terminal station versus CitiPower non coincident terminal station forecasts**



Data source: CitiPower RIN Table 10 and NIEIR report, Maximum demand for CitiPower terminal stations to 2019

Figure 18 shows that the two series diverge during the forecast period reflecting the fundamental difference in the way the forecasts are prepared. The figure also shows a slowdown in the NIEIR growth rate in 2014 and 2015 due to a slowdown in their economic growth assumptions. The CitiPower series however, does not appear to reflect this change, with the slope of the line remaining unchanged in 2014 and 2015. Again, this indicates that CitiPower's spatial forecasts are not consistent with the economic and policy environment projected by NIEIR for Victoria over the coming regulatory period.

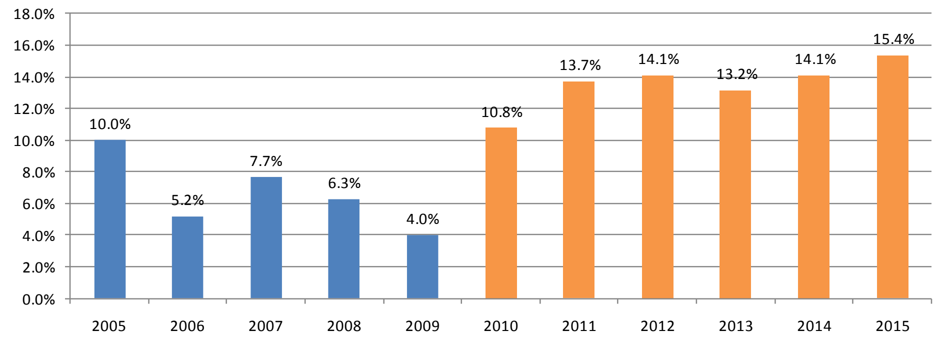
Figure 18 also shows a larger decline in NIEIR's system level forecast in 2010 compared to that estimated by CitiPower at its terminal stations. This is driven by the different approaches taken to weather correction in the two methodologies. The gap highlights the shortcoming inherent in spatial level weather correction. This is not surprising, given the methods employed by CitiPower in applying temperature correction. Generally, the temperature correction of a single observation (i.e. the peak) to a 50 POE level is likely to result in a poor estimate of the 50 POE demand. NIEIR's approach to temperature correction at the system level is more statistically robust because it uses all the available data in deriving a distribution of maximum demands from which the 50 POE is obtained (see 2.2.1 above for a more detailed discussion). As a result, we consider NIEIR's adjustment between 2009 and 2010 to be more reliable.

The comparison is complicated by a number of issues. The first is that the historical series between 2005 and 2009 are not identical. ACIL Tasman cannot fully explain this discrepancy. It appears that NIEIR includes power from two additional terminal stations at Springvale and Templestowe. These two terminal stations are not explicitly included in CitiPower's forecasts. Despite this, the sum of the non-coincident terminal station forecasts provided by CitiPower still exceeds NIEIR's measures. This is an issue that the AER may wish to pursue with CitiPower.

Despite this inconsistency in measurement, the difference between the two measures was relatively constant during the historical period shown and begins to expand during the forecast period. This implies that the historical discrepancy is due to a difference in measurement (it may be the impact of a single, fixed load that is excluded from NIEIR's forecasts for example). However, the fact that the forecasts diverge from one another while the historical numbers does not, indicates that CitiPower's forecasts are not consistent with those produced by NIEIR.

The difference between the two sets of forecasts is shown in Figure 19. The figure shows a large jump in the diversity in the first year of the forecast period to over 10%. The diversity then jumps to 13.7% in 2011 and then again to 15.4% in 2015.

Figure 19 **Diversity between NIEIR system level and CitiPower non-coincident terminal stations**

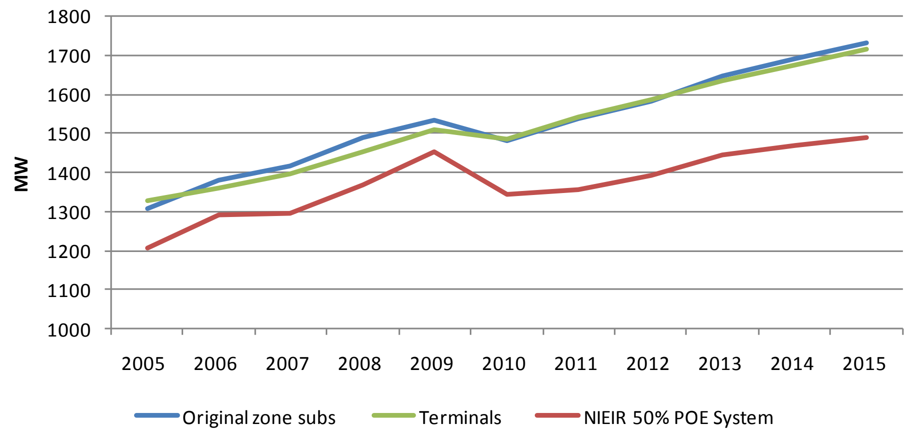


Data source: CitiPower RIN Table 10 and NIEIR, Maximum demand for CitiPower terminal stations to 2019

6.5 Zone substation forecasts

A comparison is also provided at the zone substation level. Figure 20 shows that CitiPowers's zone substation forecasts are consistent with their non-coincident terminal station numbers.

Figure 20 **Comparison of non-coincident terminal station, zone substation and NIEIR system peak, actual and forecasts, (50 POE)**

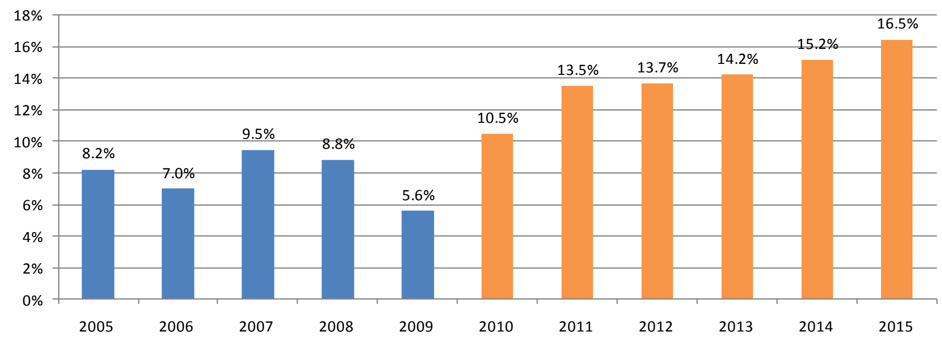


Data source: CitiPower RIN Table 10 and Table 11, NIEIR report, Maximum demand for CitiPower terminal stations to 2019

As is the case with CitiPower's terminal station forecast, CitiPower's zone substation forecasts are diverging from NIEIR's forecasts both in terms of the weather corrected starting point and the growth over time.

If NIEIR's system level forecast is taken as given, the divergence shown in the previous figures can only be attributed to increasing diversity on CitiPower's network. This is shown in Figure 21 below.

Figure 21 **Diversity between CitiPower non-coincident zone substation forecasts and NIEIR system maximum demand**



Data source: CitiPower RIN Table 11 and NIEIR, Maximum demand for CitiPower terminal stations to 2019

The jump in diversity in 2010 (from 5.6% to 10.5%) is due partly to the different approaches to temperature correction as between CitiPower and

NIEIR's methodologies and partly to the fact that CitiPower's methodology does not take into account the impact of slower economic growth to establish the starting point. Beyond that, the increasing diversity suggests a higher growth rate at the spatial level compared to NIEIR's system level forecasts.

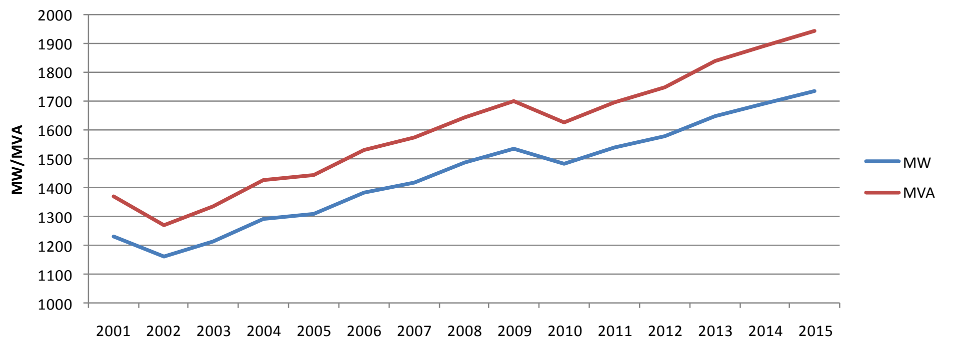
6.6 Analysis of power factor

In this section, we analyse Citpowers's zone substation forecasts as submitted in table 11 of the RIN and compare its MW forecasts to its MVA forecasts as a way of identifying any divergence between the two measures.

The MVA forecasts are linked to the MW forecasts by the power factor, which is simply the ratio of the forecast in MW to MVA. It can take any value between 0 and 1, and a declining power factor implies faster growth in the load in MVA relative to the load as measured in MW.

Figure 84 shows the historical and forecast maximum demand for the CitiPower network for both the historical period from 2001 to 2009 and for the next regulatory period. The figure shows that the two series appear to be diverging slightly over time in the forecast period, with the MVA forecasts growing slightly faster than the demand forecasts measured in MW.

Figure 22 **Sum of zone substation forecasts in MW and MVA, historical and forecast**

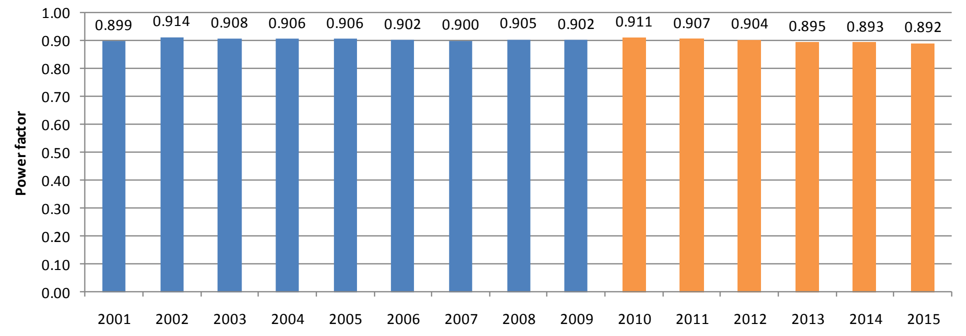


Data source: CitiPower RIN Table 11

Figure 85 presents the ratio of the historical and forecast maximum demand measured in MW and MVA as a ratio, also known as the power factor.

The figure shows that the average power factor across the CitiPower network is forecast to decline slightly from 0.911 to 0.892 between 2010 and 2015.

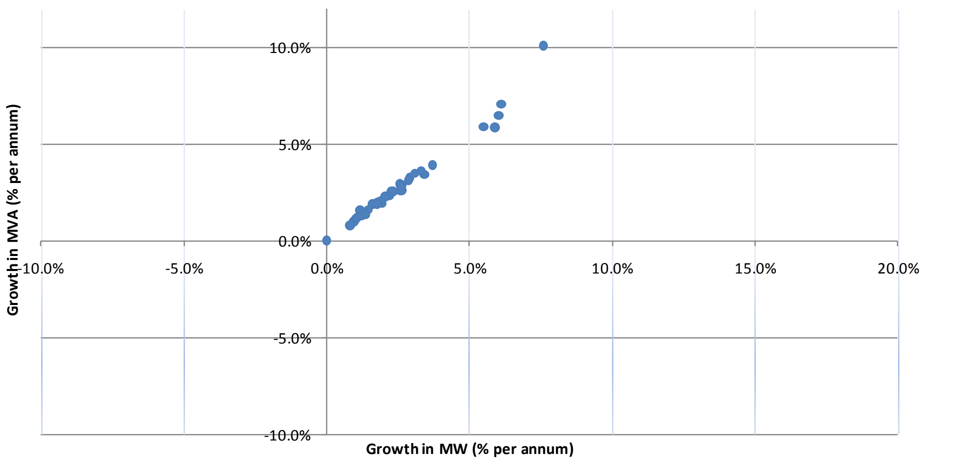
Figure 23 **CitiPower average power factors, historical and forecast**



Data source: ACIL Tasman calculations based on CitiPower RIN Table 11

Figure 86 shows a scatter plot of the annualised growth rates for each zone substation as measured in MVA and MW. The figure shows that most of zone substations lie close to an imaginary 45 degree diagonal (with a few exceptions) which indicates that the MVA forecasts are growing at about the same rate as the forecasts measured in MW.

Figure 24 **Zone substation MVA versus MW 2010 to 2015 forecast growth rates (% per annum)**

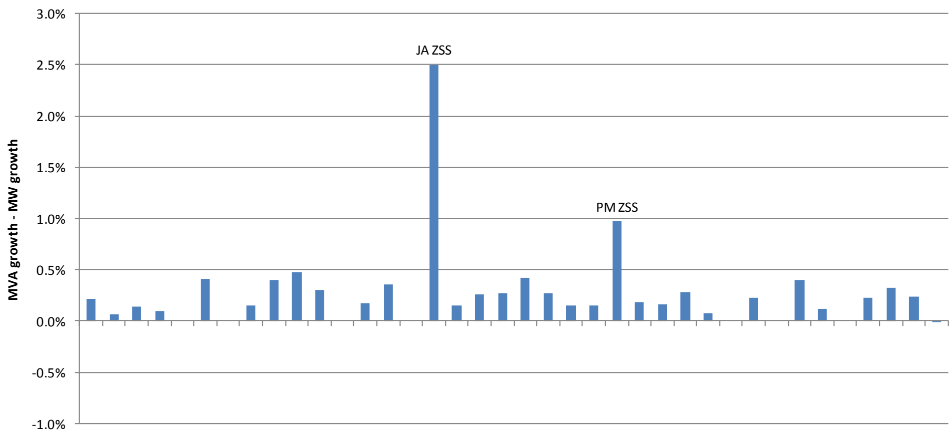


Data source: ACIL Tasman calculations based on CitiPower RIN Table 11

Figure 87 presents data on a zone substation by zone substation basis, but instead simply plots the difference in the annualised 5 year growth rate between the MVA forecasts and the MW forecasts.

The figure shows that for the majority of zone substations, the 5 year annualised MVA growth rate is slightly above the MW growth rate. Two zone substations where this differential is quite large are zone substations JA and PM. In the case of JA, the MVA forecasts are growing at an annualised rate that is about 2.5 percentage points per annum higher than that for the MW forecasts. In the case of PM, the growth differential is about 1 percentage point per annum.

Figure 25 **Zone substation differential between forecast demand growth measured in MVA versus MW, (2010 to 2015, % per annum)**



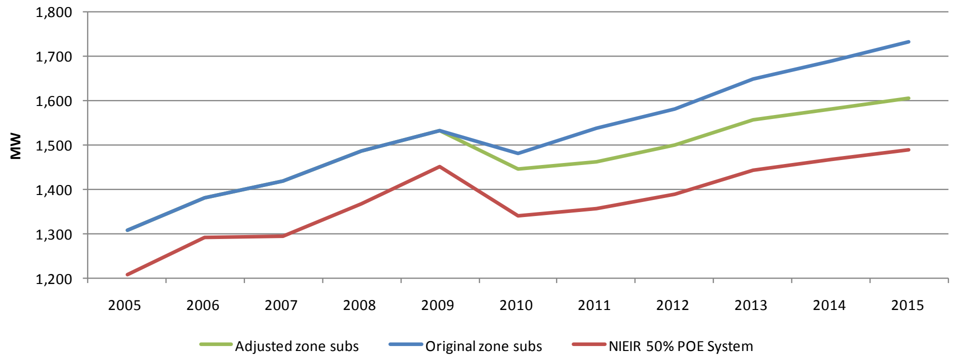
Data source: ACIL Tasman calculations based on CitiPower RIN Table 11

6.7 Conclusion – forecast maximum demand in CitiPower's region

ACIL Tasman considers that there is little justification for the CitiPower spatial forecasts and the NIEIR system level forecast to be diverging over time. As a general proposition, and for the reasons set out in section 1 above, we regard the general approach applied by NIEIR as a superior approach to forecasting macro drivers and policy impacts. ACIL Tasman considers best practice load forecasting requires that bottom up forecasts prepared by methodologies such as CitiPower's should be reconciled to system level forecasts that take account of economic growth projections and policy impacts.

For this reason, ACIL Tasman recommends that NIEIR's forecasts of maximum demand should be applied to CitiPower's region. Given the unaccounted for discrepancy between the historical actuals, we recommend that the difference between the two series be reduced to the historical average observed between 2005 and 2008, which was 7.8%. If we apply this level of diversity to the existing system level forecasts for Citipower's region into the forecast period we obtain the following forecasts.

Figure 26 **Adjusted CitiPower 50 POE non-coincident zone substation forecasts versus NIEIR 50 POE system forecasts**



Data source: CitiPower RIN Table 10, NIEIR and ACIL Tasman calculations

The data in Figure 26 is also presented in Table 10. By maintaining the historical link between the NIEIR system series and the sum of the non-coincident zone substations, the zone substation forecasts would need to be reduced by 36MW in 2010, gradually increasing to 129 MW by 2015. In percentage terms, this amounts to a 2.4% reduction in 2010, rising to 7.4% in 2015.

Table 10 **Impact of adjustment on the sum of the non-coincident substation forecasts**

Year	2009	2010	2011	2012	2013	2014	2015
Original zone subs 50 POE	1,534	1,483	1,539	1,581	1,649	1,691	1,734
NIEIR 50 POE System	1453	1342.2	1356.2	1390.8	1444.3	1468.5	1489.0
Adjusted zone subs 50 POE	1,534.1	1,446.8	1,461.9	1,499.3	1,557.0	1,583.0	1,605.2
Reduction-MW		**35.8**	**77.3**	**81.5**	**92.4**	**108.0**	**128.9**
Reduction - %		**2.4%**	**5.0%**	**5.2%**	**5.6%**	**6.4%**	**7.4%**

Data source: ACIL Tasman calculations

ACIL Tasman considers there are two main reasons why CitiPower's original zone substation forecasts diverge from NIEIR's system level forecasts. These are:

- Insufficient temperature correction in first year of the forecast period
- Not sufficiently accounting for NIEIR's slower economic and population growth outlook compared to that observed historically.

ACIL Tasman considers that in the absence of additional information, the adjustment at the zone substation level be applied proportionally to CitiPower's existing non-coincident 50 POE zone substation forecasts.

ACIL Tasman also recommends that these forecasts be adjusted to account for:

1. Updated economic growth forecasts
2. A more reasonable population growth forecast
3. Adjustments to the policy impacts.

The information available to ACIL Tasman is insufficient for it to estimate the impact of the first two recommendations above. The third recommendation, if applied to the current forecast, would result in the following system level forecast for Citipower's region set out in Table 11 below.

Table 11 **Policy adjusted system summer 50 POE maximum demand – Citipower region**

Year	2011	2012	2013	2014	2015
NIEIR (original) 50 POE forecast	1356	1390	1444	1468	1489
'policy adjusted' proposed system maximum demand	1359	1400	1459	1487	1509
'policy adjusted' non-coincident zone subs	1465	1509	1573	1603	1627

Data source: ACIL Tasman analysis based on NIEIR, demand report to Citipower tables 6.3 and 10.4

7 Powercor

7.1 Description of Powercor network

Figure 27 **Map of Powercor region**

Powercor's region contains significant areas of agricultural land. It contains 54% of Victoria's agricultural sector. It also contains almost 30% of Victoria's population and dwelling stock and almost one quarter of the State's agricultural sector. The finance, business, communications and public administrations sectors are under represented in Powercor's area relative to the rest of Victoria.

NIEIR's forecast of population growth over the next regulatory period in Powercor's region varies significantly area by area. At one extreme, NIEIR forecasts annual growth of 2.2% in Western Melbourne, dominated by growth in the fringe areas. At the other extreme, the forecast growth rate in the Wimmera is 0.4% per annum. NIEIR forecasts population growth of 1.6% per annum for Powercor's area as a whole.

The forecast growth in dwelling stock is approximately the same as that for population. In each of Powercor's regions, dwelling stock is forecast to grow at a slightly lower rate than population. This is notably in contrast to the forecast prepared for CitiPower in Melbourne.

7.2 Summary of methodology – Powercor

Powercor's approach to maximum demand forecasting is bottom up from the feeder level. To do this, it:

- Prepares an individual forecast for each feeder
- Aggregates these, taking account of diversity to the zone substation level
- Aggregates them further, taking account of diversity again, to the terminal station level
- Compares its terminal station forecasts to those prepared by NIEIR by the process described in section 3 above.

While this general approach is similar to that employed by most of the businesses, a characteristic of Powercor's forecasting methodology is that it relies on the judgement of Powercor network planning staff more heavily than most of the other businesses.

7.2.1 Powercor's demand forecasting methodology

Starting point

The starting point for demand forecasts is the most recently measured summer and winter peak demand at the feeder level. This is adjusted for planned feeder load transfers, but is not weather corrected.[49]

Powercor does not apply a formal weather correction methodology. Instead, it uses what it describes as a 'normalised load growth' to produce forecasts that it regards as equivalent to 50 POE forecasts. As ACIL Tasman understands it, Powercor's view is that, because its growth forecasts are based on regressions that take five years of historical data into account, there is no need for weather correction. In effect, Powercor appears to assume that the regression line itself represents the 50 POE demand. This is discussed further in section 7.2.3 below.

Powercor's area is large and sparsely populated. As a result, there are typically very few spot loads. Powercor gave a general description of a process whereby it could allow for spot loads that are known in advance, but the materials provided to ACIL Tasman did not include any examples of these being incorporated into its forecasts.

[49] Powercor, Attachment C to 22 December 2009 letter to Australian Energy Regulator

Load growth

Powercor's feeder level forecasts are driven by growth rates that are selected by its regional network planning group.

According to Powercor's letter to the AER of 22 December, in choosing the growth rates (which it does on a feeder by feeder basis) the regional network planning group is guided by two linear regressions, one each through the last five peaks in winter and summer demand. The group also takes into account network factors that it considers relevant to historical figures and future factors, such as:

- step changes in customer loads (historical)
- load transfer between feeders (historical)
- abnormal weather (historical)
- Local Government development plans and zonings
- housing growth
- appliance development
- major customer activity.

Taking account of these factors, the regional network planning group uses its judgement to determine an underlying growth rate.

Having obtained starting points and selected growth rates, Powercor projects growth forward at the feeder level and then aggregates the relevant feeder forecasts together. In doing this, it weights the individual feeder forecasts down by the ratio of the previous year's maximum demand on the zone substation to the sum of the maximum demands at each feeder. This ratio is held constant through the forecast period.

By this stage in the process, Powercor has established a series of (70) coincident maximum demand forecasts at the zone substation level, which it uses in its business. For the purposes of responding to the regulatory information notice (table 10), Powercor also produced a series of coincident maximum demand forecasts at the terminal station level. These were produced by applying the terminal station maximum demand growth rate calculated by NIEIR to the most recent observation of maximum demand at each terminal station. This process is independent of the spatial forecasting process described above.

7.2.2 Reconciliation with top down forecast

There is no formal reconciliation procedure between the NIEIR and Powercor forecasts. Powercor has advised that it made no changes to its forecasts as it considered them to be within a reasonable range of those prepared by NIEIR.

As is discussed above, a number of implications flow from this, including that Powercor's forecasts have taken no account of forecast economic conditions or of the policy interventions expected to influence the growth in maximum demand over the coming regulatory period.

7.2.3 Assessment of spatial methodology

Spatial forecasting methodology

ACIL Tasman considers that Powercor's spatial forecasting methodology falls significantly short of best practice. There are a number of areas of concern, namely the lack of weather correction, the high degree of subjective and undocumented judgement used in the forecasts and the lack of testing and validation.

Powercor has asserted that peak demand in its area is generally driven by water pumping. This makes Powercor's area unique among the Victorian distribution businesses as each of the others faces peak demand that is driven by temperature sensitive load, mainly air-conditioners.

In the more rural areas of Powercor's network, it may be plausible that maximum demand is driven by water pumping load rather than temperature sensitive load. However, the materials provided to ACIL Tasman in conducting this review are not sufficient to substantiate this assertion. Further, as is discussed below, the data indicates that Powercor's region experienced a significant increase in maximum demand in 2008 and 2009, which were both hot summers. This is not consistent with the view that Powercor's load is not temperature sensitive.

Further, even if pumping load does dominate peak demand in Powercor's area it does not necessarily follow that correction is not necessary. At the heart of demand forecasting, and a key plank in the regulatory model applying to Powercor, is the notion that forecasts are based on a certain probability of exceedence, in this case 50%. The probability of exceedence concept allows for the fact that there is a random element to maximum demand. In most cases, this random element is dominated by temperature variation and thus by cooling (or occasionally heating) load, so correcting to 50 POE is usually a matter of adjusting for the difference between actual temperature and 50 POE temperature.

This gives rise to an area where Powercor's forecasting methodology might be able to be improved. ACIL Tasman is not aware of any studies conducted by Powercor to improve its understanding of the variability of pumping load and the factors that drive that variability. If appropriate studies were done, they may give rise to methods of adjusting observed demand in the base year for the variability in factors that derive water pumping (noting that these may include temperature and other weather factors). ACIL Tasman notes, however, that this may be a difficult task.

Another concern relating to Powercor's decision to not weather correct is that, while it may be the case that some portions of Powercor's network do not contain large amounts of temperature sensitive load, it seems unlikely that this would be the case across the entire network. As is shown in the map above, Powercor's region includes some of Melbourne's western suburbs as well as a number of major regional centres including Ballarat, Bendigo and Geelong and the towns along the Great Ocean Road. Intuitively, it seems unlikely that zone substations that supply these areas, either largely, or entirely, do not demonstrate significant temperature sensitivity in maximum demand.

ACIL Tasman also notes that the forecasts that Powercor has produced may, implicitly, already include adjustments for these factors. It seems reasonable to assume that the regional network planning group would take the actual pumping loads into account when it makes its forecasts for individual feeders. The concern that this presents is the lack of transparency, repeatability and objectivity in the process.

The issue, then, is whether more formal methods, based on actual data, could be expected to improve on the heavily judgement based approach that is employed at the moment.

Overall methodology

Powercor has advised ACIL Tasman and the AER that it uses the system level forecast prepared by NIEIR only to validate its internal forecasts. This assessment is limited to ensuring that the two forecasts are within a reasonable range of one another, although Powercor has been unable to say what range it considers reasonable. In this case, Powercor made no changes to the forecasts it prepared internally to align with the NIEIR prepared system level forecasts. In other words, the forecasts Powercor has put forward in this process are prepared entirely from 'bottom up'. ACIL Tasman's view is that Powercor's forecasting methodology falls short of best practice because it is not reconciled to an independently prepared system level forecast. This reconciliation is something that ACIL Tasman regards as a critical component of best practice forecasting.

The bottom up only methodology by which Powercor has prepared its forecasts is not capable of taking account of several key drivers of electricity demand at the macro level other than in a very subjective manner. The drivers of particular concern in this case are the various changes in government policy that NIEIR estimates will influence electricity demand and future economic and demographic conditions. It should also be noted that these factors are considered in the forecasts of electricity sales and that the two forecasts diverge significantly from one another. ACIL Tasman considers that the two forecasts Powercor has put forward are not prepared on a consistent basis.

As is discussed below, Powercor's methodology has produced forecasts that are significantly higher than NIEIR's forecasts in the earlier years of the regulatory period, although the two forecasts converge by the end of the period. In large part this is due to the fact that NIEIR's forecasts take account of weather variability in demand while Powercor's do not. It should be noted that the fact that NIEIR's model predicts a drop in demand due in 2010 gives reason to believe that Powercor's region is more weather sensitive than Powercor considers it to be. This conclusion is also supported by the fact that, in NIEIR's forecasts, the difference between 10 and 50 POE summer maximum demand is in the order of 7 ~ 8% and the temperature sensitivity estimates set out in table 5.4 of NIEIR's maximum demand report to Powercor.

Finally, ACIL Tasman has been provided with no information concerning model testing or validation, nor is there any reason to believe that this has been done. This is a significant shortcoming in the methodology.

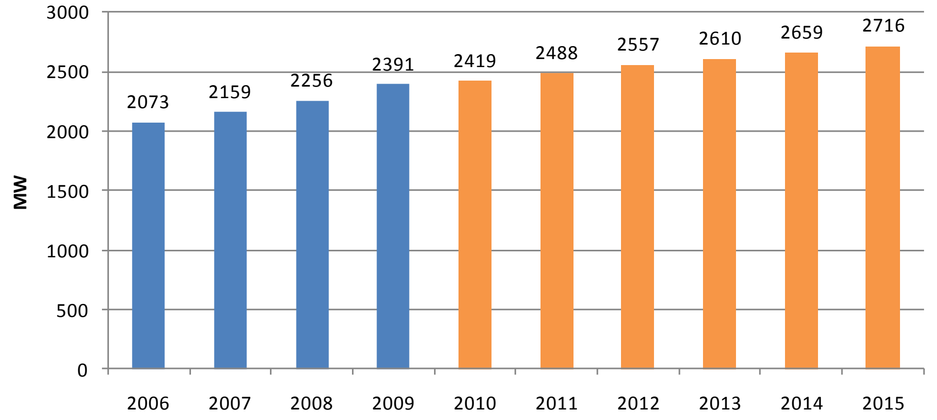
ACIL Tasman recommends that Powercor's bottom up forecasts should be amended so that, with an appropriate allowance for diversity, they do not exceed the system level forecasts.

7.3 System level forecasts

The system level forecasts Powercor has presented are the result of its own methodology as described above, not those prepared by NIEIR. Powercor has compared its forecasts with those prepared by NIEIR and has advised that it considers the two to be within a reasonable range of one another.

As is shown in Figure 28, Powercor projects the sum of the 50 POE coincident zone substation forecasts to reach 2716 MW by 2015.

Figure 28 **Powercor: Sum of coincident zone substations, 50 POE forecasts**

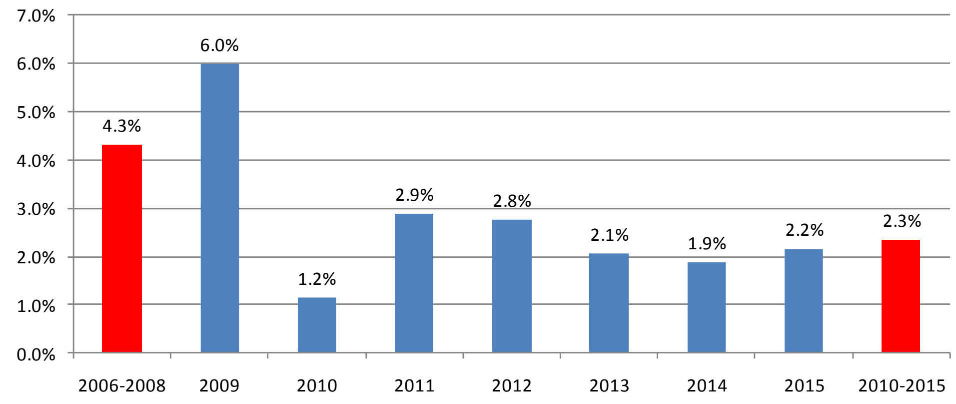


Data source: Powercor RIN Table 11

Powercor's zone substation forecasts amount to a growth rate of 2.3% p.a. between 2010 and 2015 (see Figure 31). This is compared to a higher growth rate of 4.3% p.a. between 2006 and 2008 in the actual maximum demands.

The slower growth rate masks the fact that the 2010 starting point for the forecasts could be overstated as a result of insufficient temperature correction. In the case of the other businesses, the 2010 forecast has tended to lie below the 2009 actual maximum, which was abnormally high due to an exceptionally hot summer season.

Figure 29 **Annualised growth rates in sum of Powercor's coincident zone substations over several time horizons, historical and forecast**

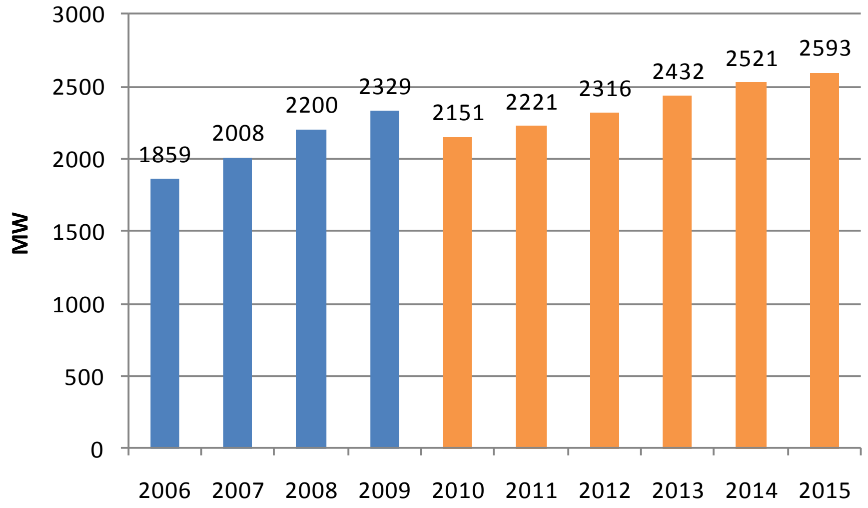


Data source: ACIL Tasman calculations based on Powercor RIN Table 11

7.3.1 Comparison with NIEIR system level forecasts

NIEIR forecasts the 50 POE maximum demand for the Powercor network to reach 2593 MW by 2015. For the period between 2010 and 2015 NIEIR's forecast implies a growth rate of 3.8% per annum (see Figure 31). This is somewhat faster than Powercor's own forecast growth of 2.3% over the same period. It should be noted, though, that the faster growth rate in NIEIR's forecasts is offset somewhat by a lower starting point in 2010 due mostly to temperature normalisation, i.e. NIEIR's forecast is for faster growth from a lower base.

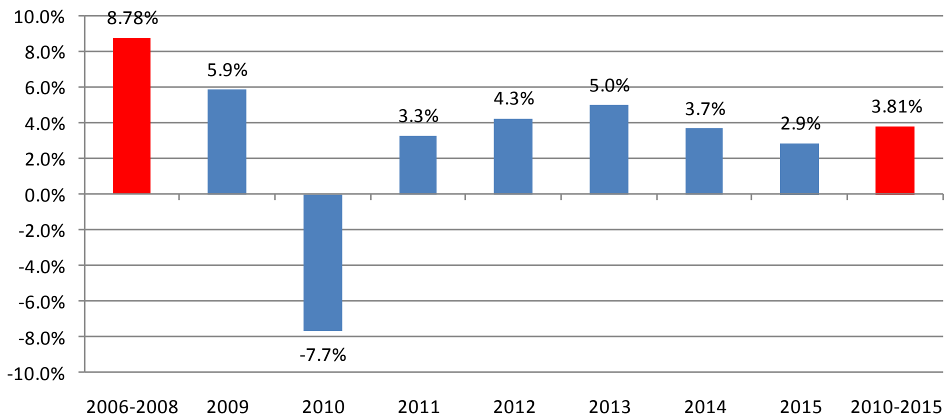
Figure 30 **Powercor: NIEIR 50 POE forecasts**



Data source: NIEIR, Maximum demand forecasts for Powercor Australia terminal stations to 2019.

Powercor's own forecasts therefore appear to be too high in the first year (2010) due to the absence of any form of temperature correction. They then grow at a slower rate to keep the two sets of forecasts from diverging substantially.

Figure 31 **Powercor system maximum demand growth, historical and forecast (NIEIR)**



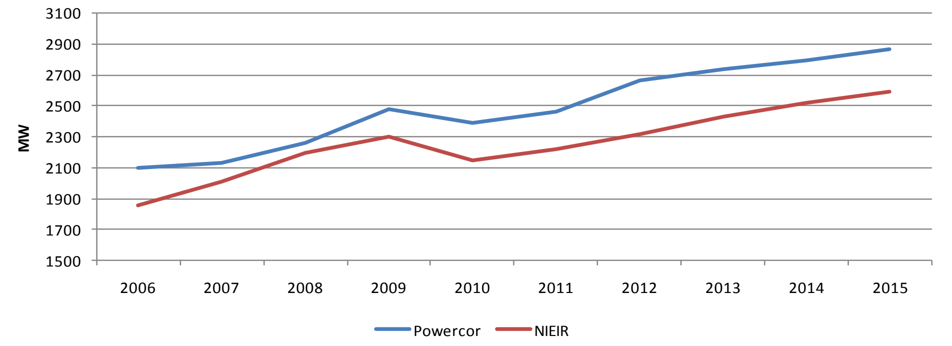
Data source: NIEIR, Maximum demand forecasts for Powercor Australia terminal stations to 2019.

7.4 Comparison at terminal station level

The sum of Powercor's coincident terminal stations are plotted in Figure 32 against the sum of NIEIR's coincident terminal stations. We note that the NIEIR forecasts exclude 3 terminal stations. For the purposes of the comparison we also exclude these from the Powercor series. These terminal stations are:

- Terminal Station 2 - ATS/BLTS
- Terminal Station 7 - BLTS – SCI
- Terminal Station 17 - WETS

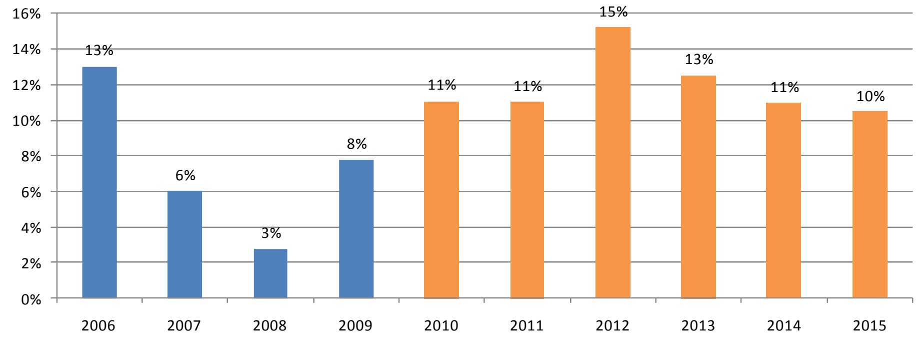
Figure 32 **Sum of Powercor coincident terminal stations versus NIEIR coincident terminal stations, historical and 50 POE forecasts**



Data source: Powercor RIN Table 10 and NIEIR, Maximum demand forecasts for Powercor Australia terminal stations to 2019.

The difference between the two series is shown in Figure 33 below.

Figure 33 **Difference between Powercor and NIEIR coincident terminal stations, historical and forecast**



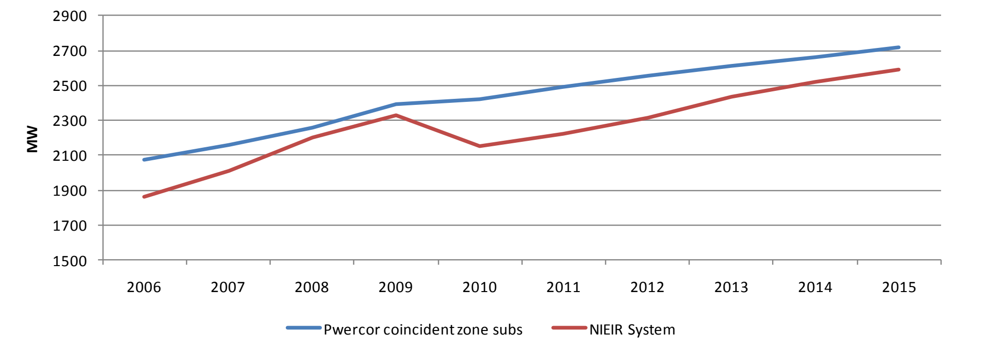
Data source: ACIL Tasman calculations based on Powercor RIN Table 10 and NIEIR, Maximum demand forecasts for Powercor Australia terminal stations to 2019.

7.5 Zone substation forecasts

A comparison of Powercor's zone substation forecasts against the total NIEIR system forecasts are shown in Figure 34.

As already mentioned, the Powercor forecasts appear to not adjust sufficiently in 2010 and then proceed to grow more slowly than NIEIR's overall system level forecasts.

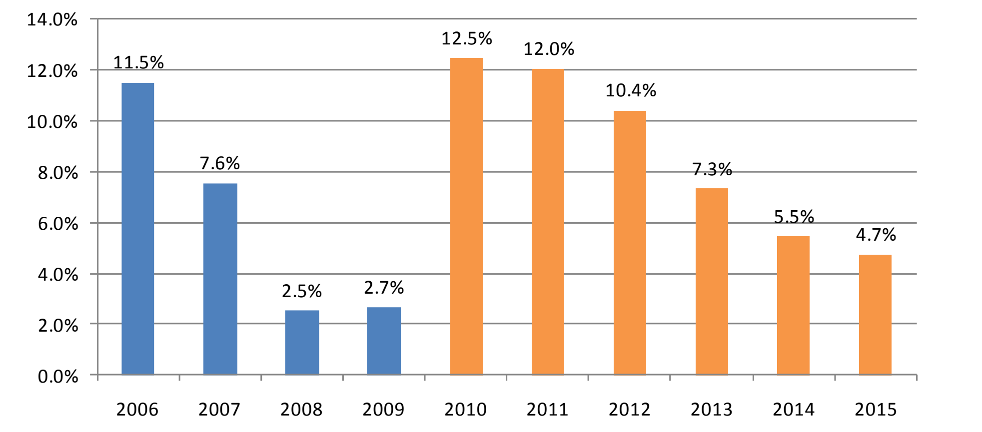
Figure 34 **Comparison of coincident zone substation and system maximum, actual and 50 POE forecasts**



Data source: Powercor RIN Table 11, NIEIR Maximum demand forecasts for Powercor Australia terminal stations to 2019.

The difference between the two series is presented in Figure 35. A large divergence is evident in 2010, which then proceeds to narrow over the rest of the forecast period.

Figure 35 **Difference between coincident zone substations and NIEIR system level 50 POE forecasts**



Data source: ACIL Tasman calculations based on Powercor RIN Table 11, NIEIR Maximum demand forecasts for Powercor Australia terminal stations to 2019.

ACIL Tasman's view is that the divergence in the difference which is evident in the first year of the forecast period is unreasonable. This is most likely due to the lack of temperature correction by Powercor of its spatial forecasts.

ACIL Tasman considers that the Powercor's zone substation forecasts should move in step with NIEIR's system level forecasts. By doing this, ACIL Tasman considers that Powercor's forecasts can be made to reflect NIEIR's macroeconomic and demographic assumptions into the forecast period, as well as ensuring appropriate temperature correction is incorporated.

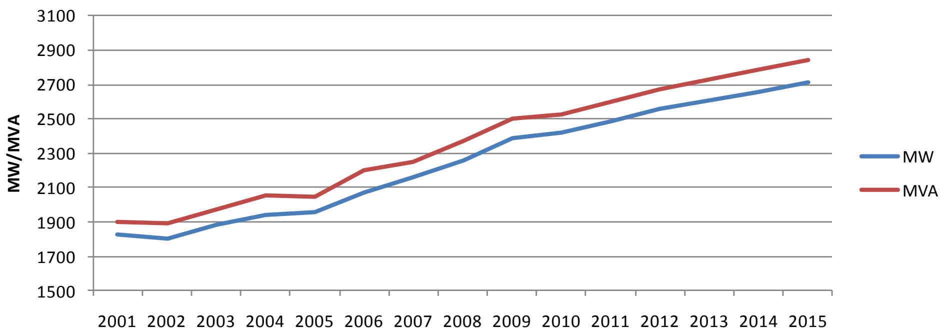
7.6 Analysis of power factor

In this section, we analyse Powercor's zone substation forecasts as submitted in table 11 of the RIN and compare their MW forecasts to their MVA forecasts as a way of identifying any divergence between the two measures.

The MVA forecasts are linked to the MW forecasts by the power factor, which is simply the ratio of the forecast in MW to MVA. It can take any value between 0 and 1, and a declining power factor implies faster growth in the load in MVA relative to the load as measured in MW.

Figure 84 shows the historical and forecast maximum demand for the Powercor network for both the historical period from 2001 to 2009 and for the next regulatory period. The figure shows that the two series are tied together over time in the forecast period, with the MVA forecasts moving in conjunction with the forecasts in MW.

Figure 36 **Sum of zone substation forecasts in MW and MVA, historical and forecast**

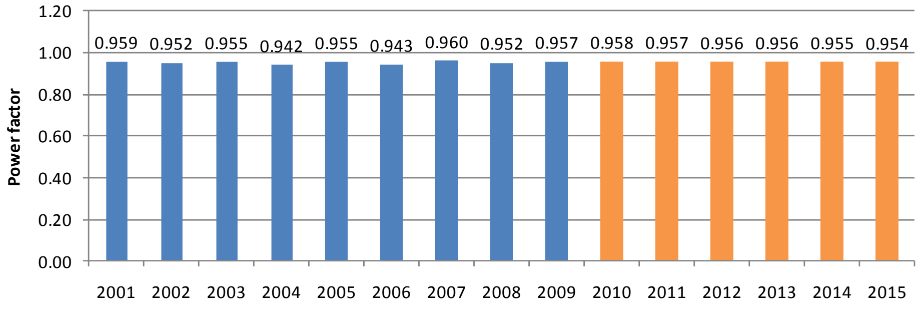


Data source: Powercor RIN Table 11

Figure 85 presents the ratio of the historical and forecast maximum demand measured in MW and MVA as a ratio, also known as the power factor. The measured power factors remain relatively stable both in the historical and forecast period.

The figure shows that the average power factor across the Powercor network is forecast to decline slightly from 0.958 to 0.954 between 2010 and 2015.

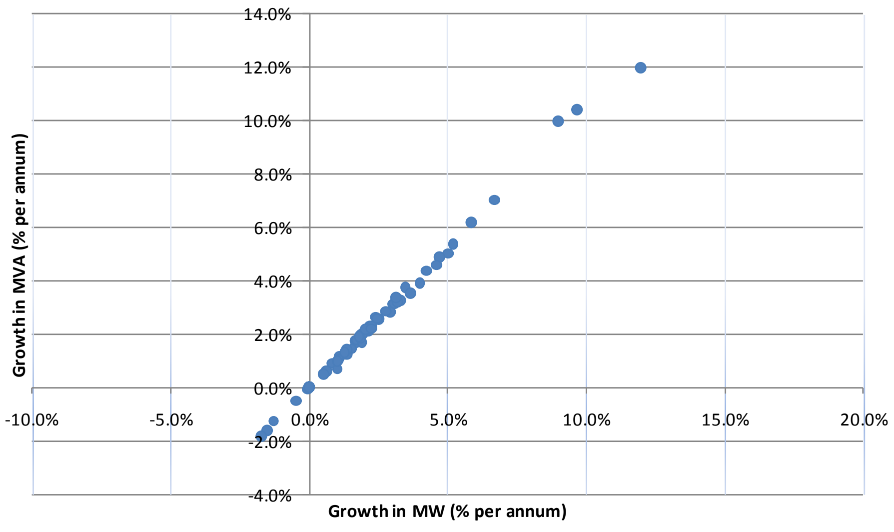
Figure 37 **Powercor average power factors, historical and forecast**



Data source: ACIL Tasman calculations based on Powercor RIN Table 11

Figure 86 shows a scatter plot of the annualised growth rates for each zone substation as measured in MVA and MW. The figure shows that most of zone substations lie close to an imaginary 45 degree diagonal, which is indicative of the MVA forecasts growing at the same rate as the forecasts measured in MW.

Figure 38 **Zone substation MVA versus MW 2010 to 2015 forecast growth rates (% per annum)**

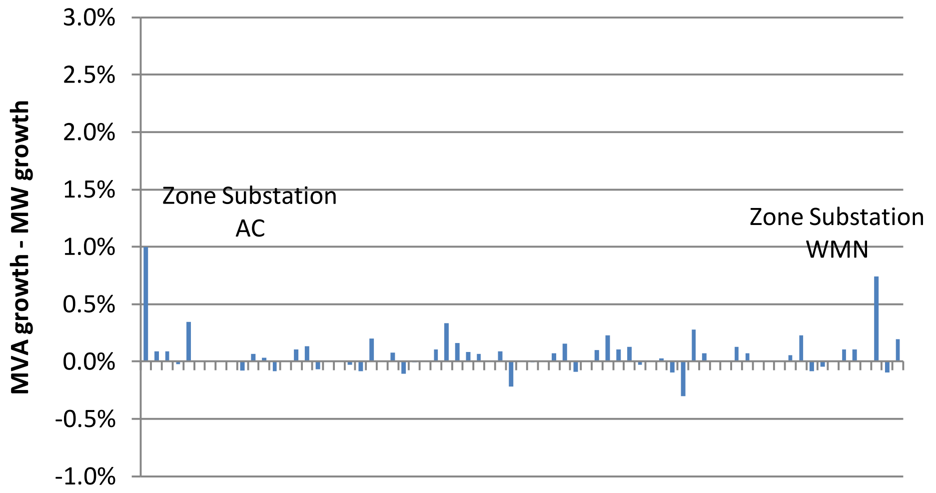


Data source: ACIL Tasman calculations based on Powercor RIN Table 11

Figure 87 presents data on a zone substation by zone substation basis, but instead simply plots the difference in the annualised 5 year growth rate between the MVA forecasts and the MW forecasts.

The figure shows that for the majority of zone substations, the 5 year annualised MVA growth rate lies very close to the MW growth rate. Two zone substations where this differential is quite large are AC and WMN. In these cases, the MVA growth forecasts exceed the MW growth forecasts by a substantial margin. For the zone substation denoted as AC, the growth differential between the MVA and MW growth rates is a full percentage. In the case of WMN, the growth differential is about 0.7 percentage points per annum.

Figure 39 **Zone substation differential between forecast demand growth measured in MVA versus MW, (2010 to 2015, % per annum)**



Data source: ACIL Tasman calculations based on Powercor RIN Table 11

7.7 Conclusion – maximum demand forecasts for Powercor's region

The sum of Powercor's zone substation forecasts can be linked to NIEIR's overall system level forecast through the application of an appropriate diversity factor. ACIL Tasman considers this diversity factor should remain constant over time, unless Powercor can provide a convincing rationale for why it should change.

The average diversity of the last 3 historical years in Figure 35 is 4.3%. In its report to Powercor, NIEIR apply a diversity factor of 4.5% between the non-coincident terminal stations and the system maximum demand. This diversity factor also remains constant over the entire forecast period.

ACIL Tasman considers that the same diversity factor should be maintained between Powercor's zone substation forecasts and the NIEIR system maximum demand forecasts. We apply 4.5% as an appropriate factor.

The impact of forcing Powercor's spatial forecast to be brought into line with the current system level forecast for its region is shown in Table 12.

To maintain a constant relationship between the sum of Powercor's coincident zone substation forecasts and NIEIR's system requires a total reduction of 171 MW from the sum of Powercor's forecasts in 2010. This declines gradually in every year following 2010, until it reaches a reduction of 6 MW by 2015. In percentage terms, this is equivalent to a 7.1% reduction in 2010, declining steadily to a 0.2% reduction in 2015.

According to this result, Powercor has chosen too high a starting point for its spatial forecasts and then subsequently applied a growth rate that is too low compared to the NIEIR forecast.

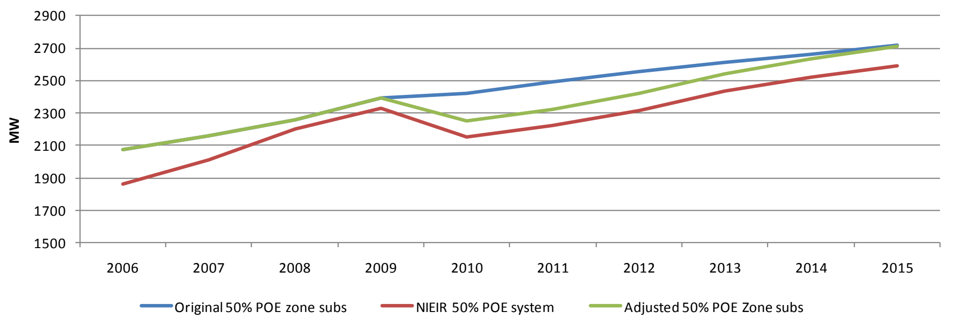
Table 12 **Impact of adjustment on the sum of the coincident zone substation forecasts**

	2009	2010	2011	2012	2013	2014	2015
Original 50 POE zone subs	2391.0	2418.6	2488.4	2557.0	2609.8	2658.8	2716.4
NIEIR 50 POE system	2328.9	2150.8	2221.2	2315.9	2431.7	2521.3	2593.5
Adjusted 50 POE Zone subs	2391.0	2247.6	2321.1	2420.2	2541.1	2634.7	2710.2
Reduction -MW	**0**	**171**	**167**	**137**	**69**	**24**	**6**
Reduction -%	**0.0%**	**7.1%**	**6.7%**	**5.4%**	**2.6%**	**0.9%**	**0.2%**

Data source: ACIL Tasman calculations

The impact of the adjustment is shown graphically in Figure 40 below.

Figure 40 **Adjusted Powercor 50 POE coincident zone substation forecasts versus NIEIR 50 POE system forecasts**



Data source: Powercor RIN Table 11, NIEIR and ACIL Tasman calculations

ACIL Tasman considers that in the absence of additional information, the adjustment proposed be applied proportionally to all of the zone substations in the Powercor network.

ACIL Tasman also recommends that these forecasts be adjusted to account for:

1. Updated economic growth forecasts
2. A more reasonable population growth forecast
3. Adjustments to the policy impacts

The information available to ACIL Tasman is insufficient for it to estimate the impact of the first two recommendations above. The third recommendation, if applied to the current forecast, would result in the following system level forecast for Powercor's region set out in Table 13 below.

Table 13 **Policy adjusted system summer 50 POE maximum demand**

Year	2011	2012	2013	2014	2015
NEIIR (original) 50 POE system forecast	2221	2316	2432	2521	2594
'policy adjusted' proposed system maximum demand	2227	2332	2458	2554	2629
'policy adjusted' non-coincident zone subs	2327	2437	2569	2669	2747

Data source: ACIL Tasman analysis based on NIEIR demand report to Powercor tables 6.3 and 10.4

8 Jemena

8.1 Description of Jemena network

Figure 41 **Map of Jemena network**

Jemena's distribution region covers approximately 950 square kilometres to the north of Melbourne. It incorporates industrial and residential areas as well as the Tullamarine Airport.

Jemena's region accounts for approximately 12% of Victoria's population and dwelling stock. It is characterised by a relatively large proportion of manufacturing activity, with nearly 13% of Victoria's manufacturing output coming from Jemena's area.[50]

On average, NIEIR forecasts that population growth in Jemena's area will be 1.0% per annum over the next regulatory period, which is 0.2 percentage points below the Victorian average. Similarly, gross regional product in Jemena's area is forecast to be 1.6% per annum, lagging the Victorian average growth rate by 0.5 percentage points. Also lagging the Victorian average is the rate of growth in the dwelling stock, which NIEIR forecasts will be 1.3% per annum in Jemena's area, 0.2 percentage pointes behind the Victorian average.

[50] This compares to only 9% of Victoria's GSP coming from this area.

8.2 Summary of methodology – Jemena

Jemena’s approach to maximum demand forecasting is ‘bottom up’ from the zone substation level. Broadly, it:

1. prepares an individual forecast for each zone substation
2. aggregates these together, taking account of diversity, to the terminal station level
3. compares its terminal station forecasts to a set of terminal station forecasts prepared independently by NIEIR by the process described in the earlier sections.

8.2.1 Jemena’s demand forecasting methodology

Starting point

Jemena's bottom up forecasting methodology starts by taking the daily maximum demands observed at each feeder, zone substation, terminal station and for the whole system and normalising them for temperature effects. The first step in doing this is to scatter plot all observations, including weekends and public holidays, against the average daily temperature (unweighted) and discard the observations ‘below the curve’ of a polynomial curve of best fit.

The remaining observations are plotted against daily average temperature and a polynomial curve of best fit taken (i.e. the above process is repeated with a ‘filtered’ data set containing only high demand days).

The best fit curve explains the relationship for the year in question, which is the most recent year for which data is available, between daily average temperature and daily maximum demand.

The next step is to identify the maximum demand observed in the most recent year and the temperature at the time it was observed. Typically, the temperature that was observed at that time will not be the 50 POE temperature.

The difference between the average temperature on the day when demand peaked and the 50POE is taken. This represents the extent to which the observed maximum demand differs from the 50 POE maximum demand.

To determine the current season’s 50POE demand, JEN adjusts the max demand as follows:

50POE demand = actual demand-(T-29.4)*k

Where:

T is the average temperature observed on the day

29.4C is the value JEN takes as the 50 POE temperature in its area

k is a scaling factor derived from the polynomial curves of best fit

This process provides a 'starting point' for each feeder.

Growth projection – known loads and organic growth

Jemena's approach is to treat growth as comprised of two components, namely known loads and 'organic' growth. These are treated separately and summed to produce a forward demand projection for each zone substation.

Known loads larger than 100kVA are added to the forecast individually. The process for doing this takes account of the fact that residential and commercial multi-lot projects are typically 'taken up' over a number of years.

The process that is used to add residential lots into the forecast assumes that the diversified load of residential lots is 3kVA. Commercial and industrial loads are diversified at a factor of 70%.

This process provides a set of 'step growth' values for each year that are added to the starting point.

The second component of the forward demand projection is 'organic' growth.

Organic growth rates are estimated based on the local knowledge and judgement of Jemena staff and on historical trends. Later in the process, these growth rates are altered as required to reconcile the bottom up forecast with NIEIR's system level forecast. Jemena takes the view that the initial growth rate estimates are relatively unimportant, as they are quite likely to be written over at the reconciliation stage.

8.2.2 Reconciliation with top down forecast

By this stage in the process, Jemena has two independent forecasts of maximum demand at the terminal station level, one it prepared itself and a second prepared by NIEIR. These two forecasts are compared at both the network and terminal station level and adjustments are made to remove any material differences. These adjustments are made to the organic growth rates applied to the zone substations.

The end result would be, typically, that Jemena's system level forecasts are equal to those prepared by NIEIR. In this particular case, though, JEN has chosen a different starting point than NIEIR used to account for the fact that, in January 2009 when the year's peak was observed, some of Jemena's customers were involuntarily off supply. Jemena's rationale for varying from NIEIR's forecast in this way is that the maximum demand that was observed in January 2009, when Jemena's system peak occurred, do not reflect the true demand as it existed at that time. Had the JEN network been stronger at that time, it would have been able to meet the needs of customers over and above what was actually observed and, accordingly, the observed peak in demand would have been higher. For this reason, Jemena chose to apply NIEIR's forecast growth rate to its own estimate of 2009/10 50 POE demand.

8.2.3 Assessment of forecasting methodology

Spatial forecasting methodology

Jemena's spatial forecasting methodology addresses each of the relevant issues and appears to be a reasonable bottom up methodology.

There are a number of elements of Jemena's methodology that could potentially be improved. In particular, the approach that is taken to incorporating block/spot loads still leaves room for double counting between these and the organic growth rate

A related issue is that the choice of the initial growth rates is heavily subject to the individual judgement of Jemena's system planners. While reliance on judgement to some extent is unavoidable in bottom up load forecasting, it reduces the transparency and repeatability of the process and creates room for bias. This can be addressed by ensuring that regard is given to historical growth rates and other objective data related to the growth of demand in the relevant area.

Overall forecasting methodology

In preparing the forecasts it submitted for this process, Jemena took its internal, spatial forecasts and adjusted the growth rates forecast for each zone substation so that the growth rate of its internal system level forecast was no greater than the growth rate of NIEIR's system level forecast. In effect, Jemena reconciled the growth rates of the two forecasts but not the starting points.

Starting point

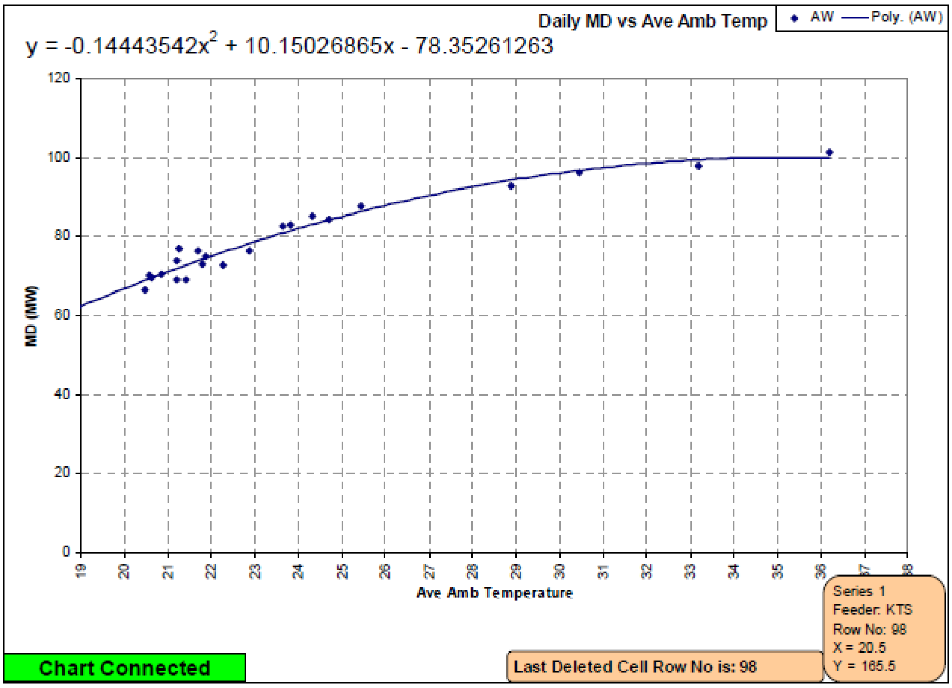
ACIL Tasman does not agree with Jemena's decision to adopt its own estimate of 2009 50 POE demand in preference to NIEIR's. ACIL Tasman acknowledges that the maximum 'quantity' of electricity (i.e. in MW) that was supplied to Jemena's customers when Jemena's system reached peak demand in January 2009 may have been less than the true demand for electricity at that time. However, there are two key reasons why this does not warrant disregarding NIEIR's estimate and giving preference to Jemena's.

First, as is discussed above, it is ACIL Tasman's view that NIEIR's approach to estimating 50 POE demand is far superior to what can practically be done in a bottom up methodology (of which Jemena's approach is an example). ACIL Tasman considers it far more likely that NIEIR's estimate of 50 POE demand for Jemena's system is accurate rather than Jemena's estimate. In simple terms, this is because Jemena's estimate is based on a single observation whereas NIEIR's is based on the entire sample of demands and temperatures observed over several years, which numbers in the thousands. The peak day in early 2009 is just one of many observations that contribute to NIEIR's estimate so whether the additional load on that day is included or excluded would be unlikely to change the estimates significantly.

Second, ACIL Tasman notes that the temperatures observed in January 2009 were unusually high, even for the time of year. From an econometric perspective this means that little is known about the way that electricity demand behaves at these temperatures, simply because they occur very infrequently. Jemena has used a particular approach to estimate the true level of underlying demand at the time. This involved fitting a second order polynomial curve to the observed data and extrapolating the underlying demand from that curve. In discussing its forecasting methodology with ACIL Tasman, Jemena indicated that it uses second order polynomials for weather correction because they perform well in goodness of fit tests (i.e. they achieve high R squared values).

While this approach has some logical appeal, the choice of the second order polynomial curve is simultaneously arbitrary and critical for the demand estimate. The issue here is that, while it may fit the data well 'inside' the sample, i.e. at temperatures and demand levels that are observed regularly, there is, by definition, no information as to how it performs at levels *outside* the sample (i.e. at temperatures that have not previously, or recently, been experienced). A point against the use of a second order polynomial is the way that the curve can behave. Jemena's load forecasting manual contains the following example, which illustrates the point.

Figure 42 **Weather normalisation example – AW zone substation**



Source: Jemena Electricity Networks, Load Demand Forecast Methodology, version 1.0, 4/2/2010, p 9.

Figure 35 shows the relationship between temperature and electricity demand for zone substation AW in Jemena's region. It shows the equation of the second order polynomial curve of best fit that Jemena used to weather correct this zone sub station. Table 14 shows the demand estimated by that curve at a selection of temperatures (on an average basis)

Table 14 **demand predictions at various temperatures – AW zone substation**

Average ambient temp (°C)	30	31	32	33	34	35	36	37	38	39	40
Demand (MW)	96.16	97.50	98.55	99.32	99.79	99.97	99.87	99.48	98.79	97.82	96.56

As can be seen in the chart in Figure 42 and Table 14, when the data moves out of sample, the sign of the relationship between temperature and demand is reversed. In other words, this model predicts that as temperature rises demand will rise, until daily average ambient temperature reaches approximately 36 C, which is the average ambient temperature Jemena recorded on 29 January 2009. This model implies that, had temperature continued to rise beyond that point, electricity demand would have declined. Such a decline would, of course, run contrary to the underlying theory that electricity demand rises as temperature rises (in summer). In this example a straight line, notwithstanding that it would not fit the data as neatly, would provide a result that is more consistent with the underlying theory and should thus be used in preference.

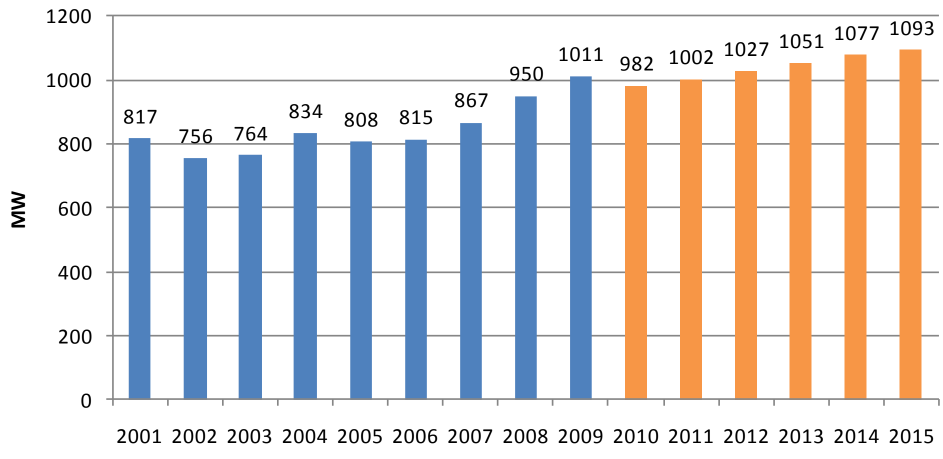
Finally, ACIL Tasman has been provided with no information concerning model testing or validation, nor is there any reason to believe that this has been done. This is a significant shortcoming in the methodology.

ACIL Tasman considers that Jemena's demand forecasts should be adjusted so that 2010 maximum demand forecast does not exceed NIEIR's forecast of demand in that year, with corresponding adjustments in later years.

8.3 System level forecasts

Jemena's historical summer maximum demand and 50 POE forecast system demands are shown in Figure 43. Jemena forecasts its 50 POE demand to reach 1093 MW by 2015. This is equivalent to a growth rate of 2.2% per annum between 2010 and 2015 (see Figure 44).

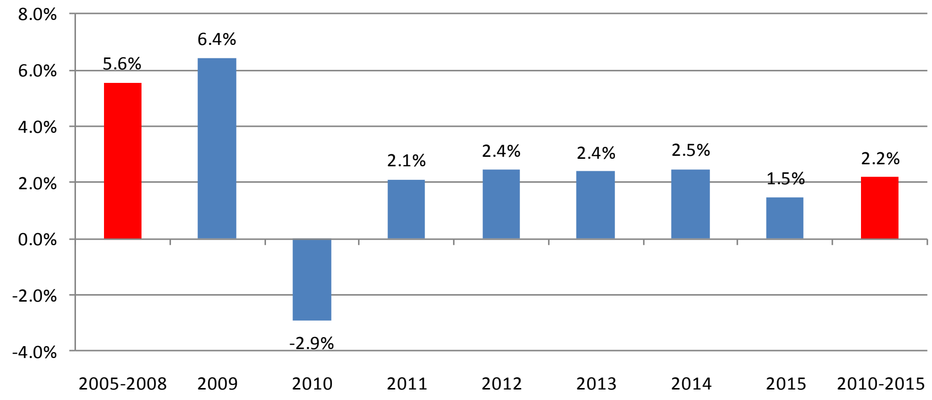
Figure 43 **Jemena system maximum demand historical and 50 POE forecasts**



Data source: Jemena RIN table 9

Jemena's historical numbers have not been weather corrected. As a result, the 2010 maximum demand declines relative to the extremely high demand observed in 2009, which proved to be an extreme weather year. This is simply the effect of shifting from an observation that is substantially influenced by weather to a forecast that is at the 50 POE level.

Figure 44 **Annualised growth in Jemena system demand over a number of time horizons**

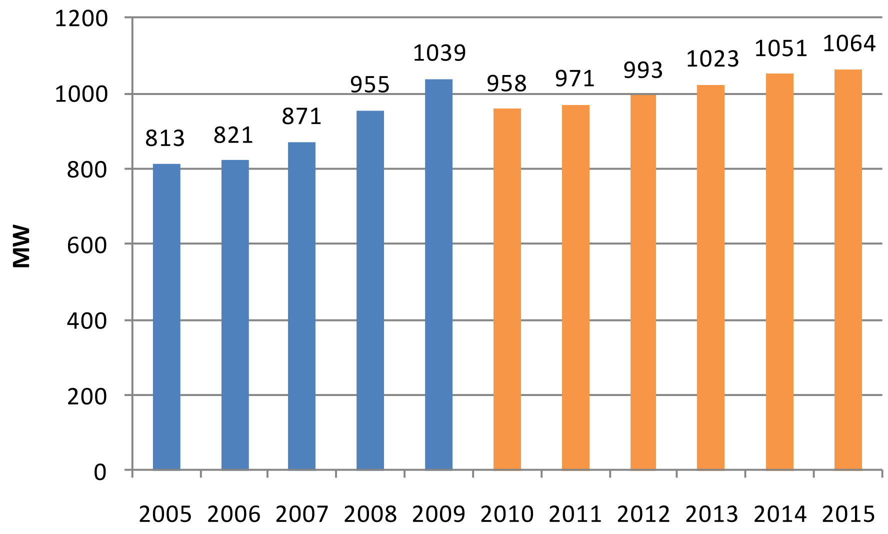


Data source: ACIL Tasman calculations based on Jemena RIN table 9

8.3.1 Comparison with NIEIR

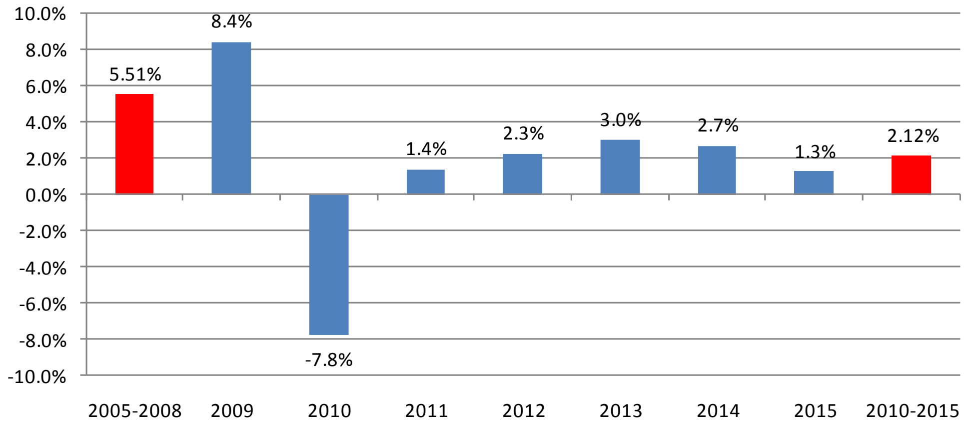
NIEIR's forecasts are presented in Figure 45. Jemena's 50 POE system demand forecasts follow a similar trajectory to those provided independently by NIEIR. NIEIR's projected growth rate of 2.1% per annum over the forecast period is comparable to Jemena's growth rate of 2.2% (see Figure 45).

Figure 45 **NIEIR system level 50 POE forecasts**



Data source: NIEIR, Maximum demand forecasts for Jemena electricity networks terminal stations to 2019

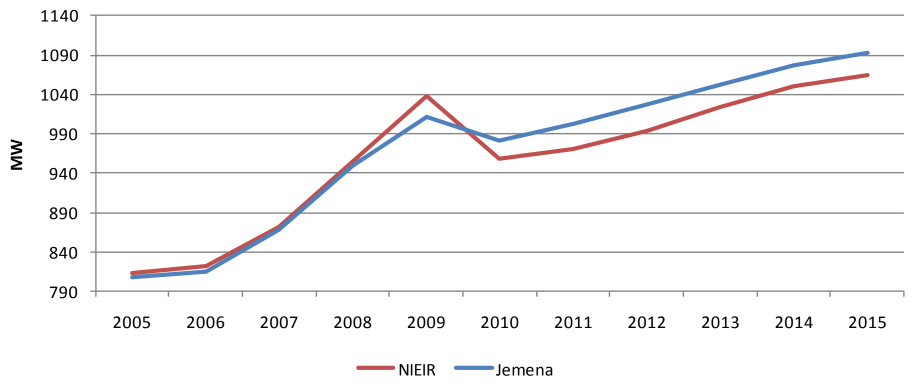
Figure 46 **NIEIR system maximum forecast - Comparison with JEN system level forecasts**



Data source: ACIL Tasman calculations based on data in Figure 37

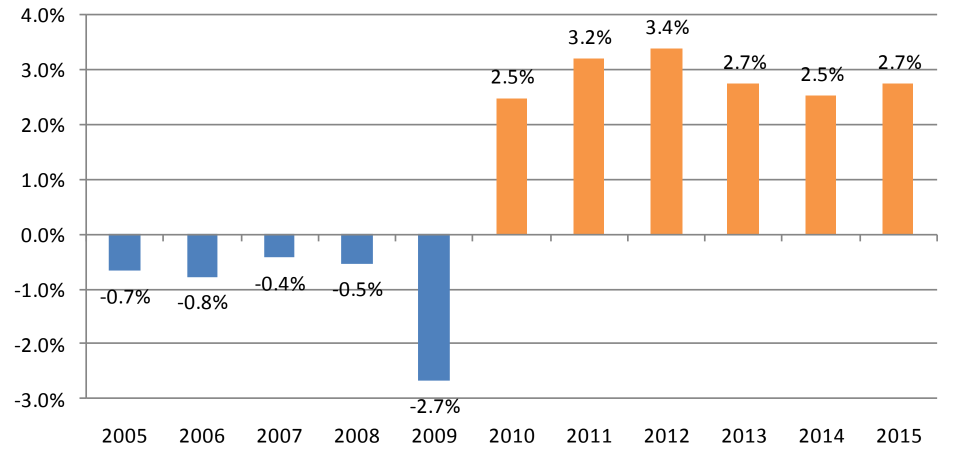
Figure 46 shows a comparison between the system level forecasts prepared by NIEIR and Jemena. The main difference between the two sets of forecasts is in the impact on 2010, where NIEIR applies a larger decline as a result of its temperature correction methodology (see section 8.2.2 above). This figure shows that Jemena's reconciliation has meant that the rates of growth of the two forecasts are aligned with one another although, as is set out in Figure 48 below, there is still a small amount of variation between the two series.

Figure 47 **Comparison of system level forecasts, NIEIR and Jemena 50 POE**



Data source: NIEIR, Maximum demand forecasts for Jemena electricity networks terminal stations to 2019, Jemena RIN Table 9

Figure 48 **Percentage difference between Jemena and NIEIR system maximum demand**



Data source: NIEIR, Maximum demand forecasts for Jemena electricity networks terminal stations to 2019, Jemena RIN Table 9

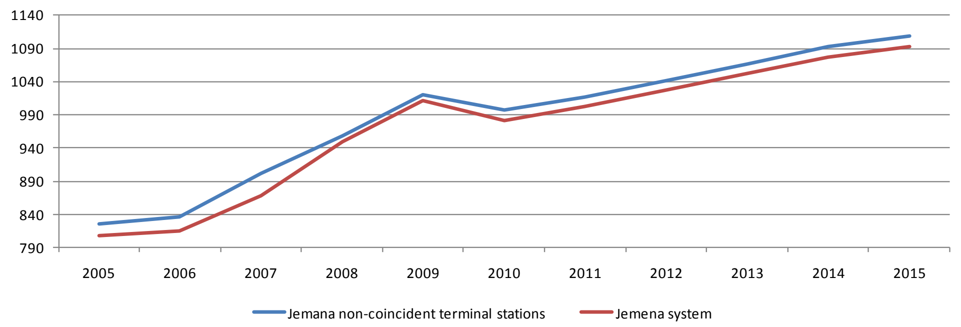
Figure 48 shows that Jemena's growth rate in the forecast period is not completely aligned with that projected by NIEIR. In particular, Jemena allow the forecasts to diverge in the first year where it is about 2.5% higher than the normal historical divergence.

While the impact in terms of MW is not large, ACIL Tasman considers that Jemena's system level forecasts should be in line with NIEIR's independent system forecasts.

8.4 Comparison at terminal station level

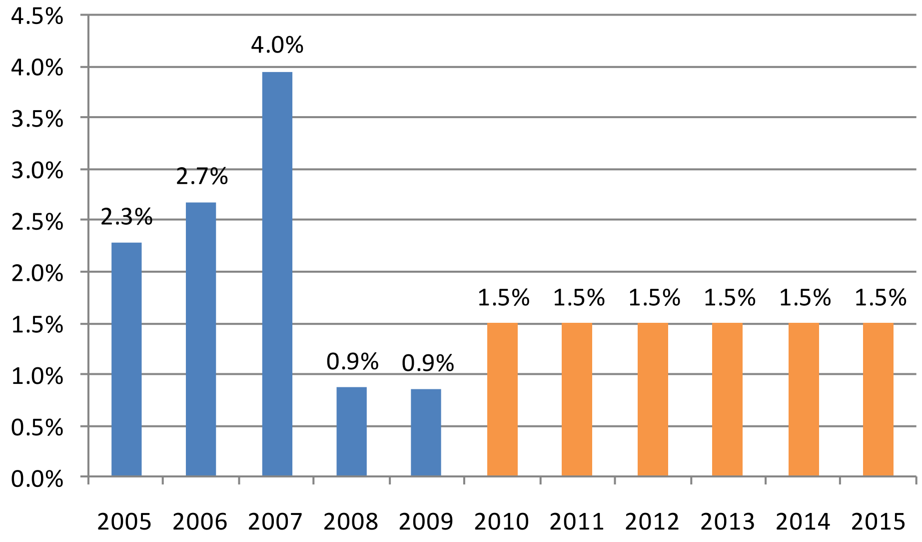
Analysis of terminal station historical data and 50 POE forecasts shows that the non-coincident terminal stations forecasts have a 1.5% diversity factor relative to the Jemena system level forecasts. This is reasonable given the observed historical diversity (see Figure 50).

Figure 49 **Jemena non-coincident terminal stations versus Jemena system**



Data source: Jemena RIN table 9 and table 10

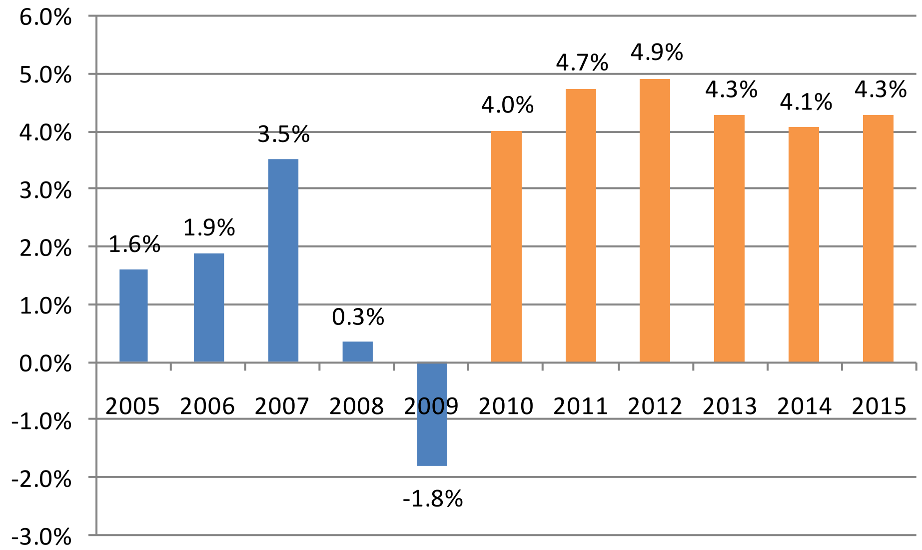
Figure 50 **Diversity between Jemena non-coincident terminal stations and Jemena system, actual historical and 50 POE forecasts**



Data source: ACIL Tasman calculations based on Jemena RIN table 9 and table 10

A comparison of Jemena's 50 POE non-coincident terminal station forecasts against NIEIR's system forecasts shows a divergence between the two. As was the case with Jemena's 50 POE system level forecasts, their terminal station forecasts jump in the first year relative to history. This is a result of the different temperature correction applied in the first year of the forecast period.

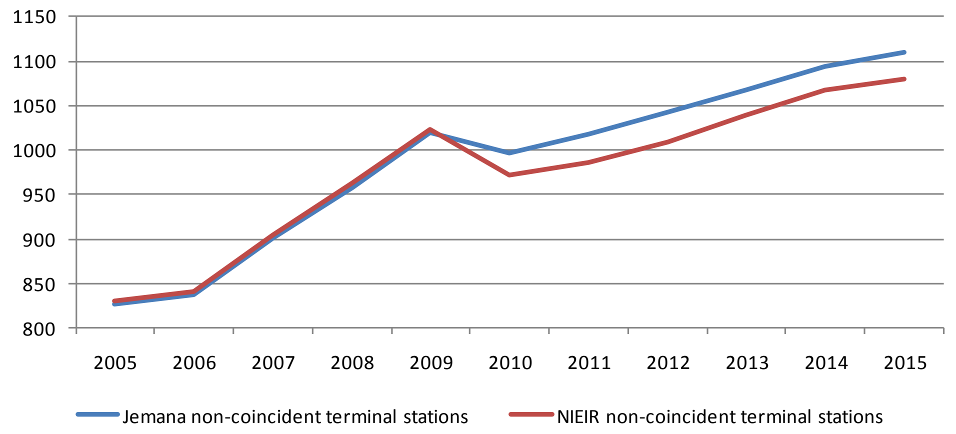
Figure 51 **Diversity between Jemena non-coincident terminal stations and NIEIR system**



Data source: ACIL Tasman calculations based on NIEIR, Maximum demand forecasts for Jemena electricity networks terminal stations to 2019 and Jemena RIN Table 10.

A similar divergence can be seen when comparing the non-coincident terminal station forecasts for both NIEIR and Jemena.

Figure 52 **Non-coincident terminal station forecasts, Jemena and NIEIR**

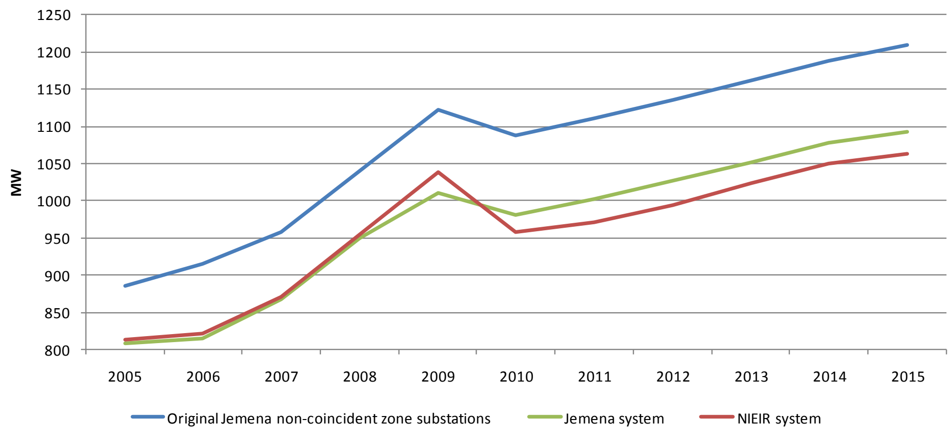


Data source: NIEIR, Maximum demand forecasts for Jemena electricity networks terminal stations to 2019 and Jemena RIN Table 10

8.5 Zone substation forecasts

Figure 53 presents Jemena's non-coincident zone substations, both historical and the 50 POE forecast against Jemena's and NIEIR's historical and forecast maximum demands for the Jemena network.

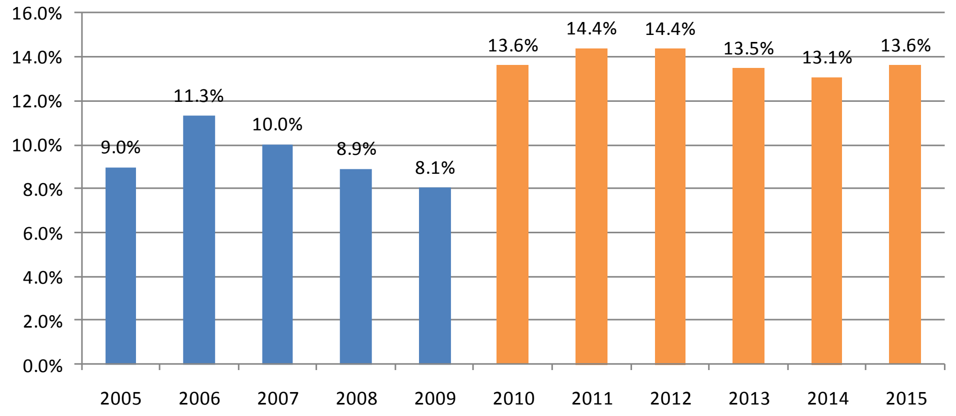
Figure 53 **Comparison of non-coincident zone substation, Jemena system maximum demand and NIEIR system maximum demand, actual and forecast (50 POE)**



Data source: Jemena RIN Table 9 and table 11, NIEIR, Maximum demand forecasts for Jemena electricity networks terminal stations to 2019

While Jemena's non-coincident zone substation forecasts are more closely tied to their system level forecasts, the diversity between Jemena's non-coincident zone substations and NIEIR's 50 POE forecasts has expanded in the forecast period relative to the historical period. Figure 54 illustrates this point.

Figure 54 **Diversity between zone substations and NIEIR 50 POE**



Data source: ACIL Tasman calculations based on Jemena RIN Table 9 and table 11, NIEIR, Maximum demand forecasts for Jemena electricity networks terminal stations to 2019

The average diversity between the zone substation and NIEIR system level demands is 9.5% over the last 5 years. This jumps to 13.8% over the forecast period. ACIL Tasman does not consider there is a valid reason for this to be the case. ACIL Tasman recommends a diversity of 9.5% over the NIEIR system level forecasts to bring Jemena's spatial forecasts into line with NIEIR.

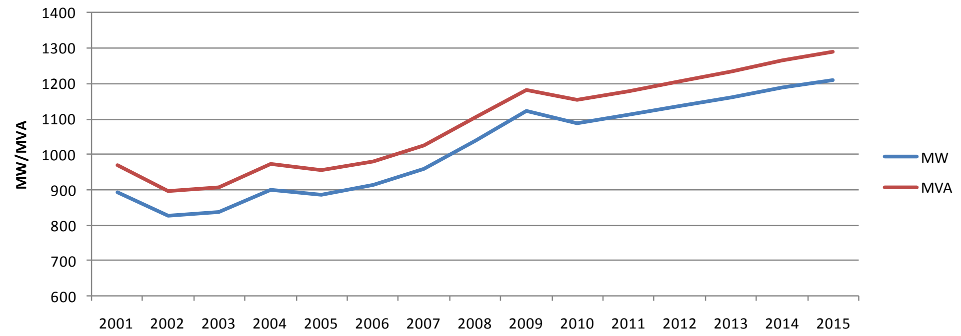
8.6 Analysis of power factor

In this section, we analyse Jemena's zone substation forecasts as submitted in table 11 of the RIN and compare their MW forecasts to their MVA forecasts as a way of identifying any divergence between the two measures.

The MVA forecasts are linked to the MW forecasts by the power factor, which is simply the ratio of the forecast in MW to MVA. It can take any value between 0 and 1, and a declining power factor implies faster growth in the load in MVA relative to the load as measured in MW.

Figure 84 shows the historical and forecast maximum demand for the Jemena network for both the historical period from 2001 to 2009 and for the next regulatory period. The figure shows that the two series are generally tied closely together, with the difference between the two series in the forecast period adhering quite closely to the historical relationship.

Figure 55 **Sum of zone substation forecasts in MW and MVA, historical and forecast**

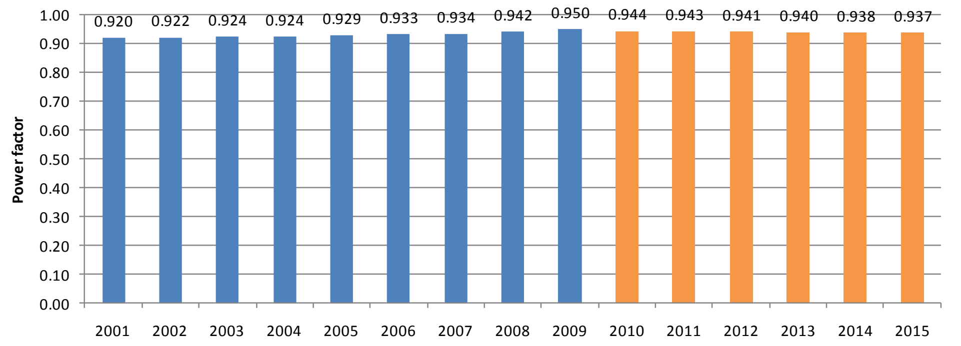


Data source: Jemena RIN Table 11

Figure 85 presents the ratio of the historical and forecast maximum demand measured in MW and MVA as a ratio, also known as the power factor.

The graph indicates that the average power factor across the Jemena network is relatively constant over time, declining slightly from 0.944 to 0.937 between 2010 and 2015.

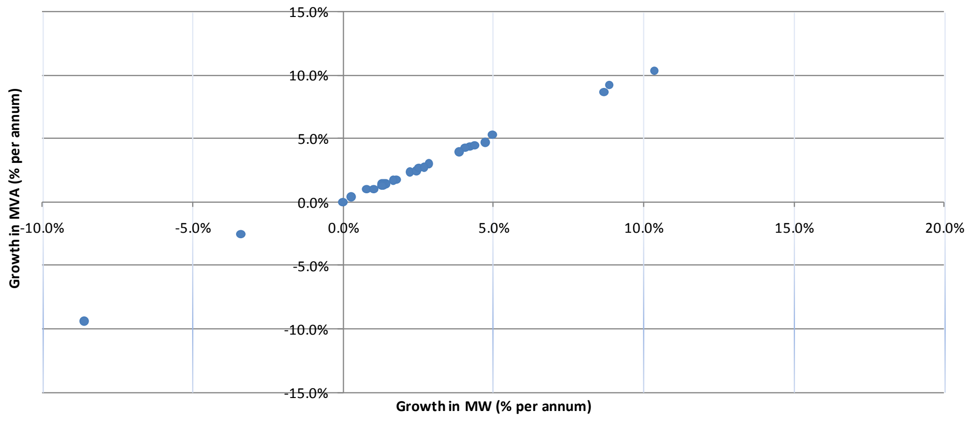
Figure 56 **Jemena average power factors, historical and forecast**



Data source: ACIL Tasman calculations based on Jemena RIN Table 11

Figure 86 shows a scatter plot of the annualised growth rates for each zone substation as measured in MVA and MW. The figure shows that most of zone substations lie close to an imaginary 45 degree diagonal, which indicates that the MVA forecasts are growing at about the same rate as the forecasts measured in MW.

Figure 57 **Zone substation MVA versus MW 2010 to 2015 forecast growth rates (% per annum)**

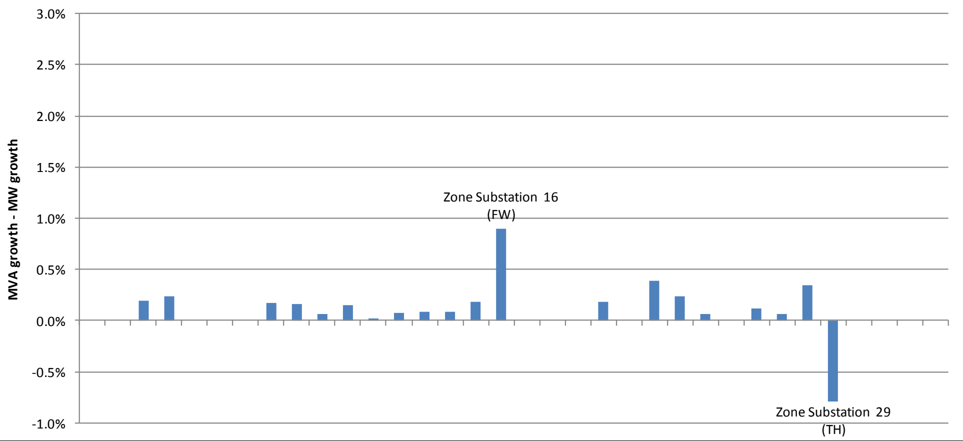


Data source: ACIL Tasman calculations based on Jemena RIN Table 11

Figure 87 presents data on a zone substation by zone substation basis, but instead simply plots the difference in the annualised 5 year growth rate between the MVA forecasts and the MW forecasts.

The figure shows that for the majority of zone substations, the 5 year annualised MVA growth rate is either the same as or slightly above the MW growth rate. The two exceptions are zone substation number 29 (TH) which is forecast to grow in MVA at a rate of about 0.8% per annum less than its forecast in MW and Zone substation 16 (FW) whose MVA forecasts are shrinking at a considerably slower rate than their MW forecasts (leading to a large positive differential).

Figure 58 **Zone substation differential between forecast demand growth measured in MVA versus MW, (2010 to 2015, % per annum)**

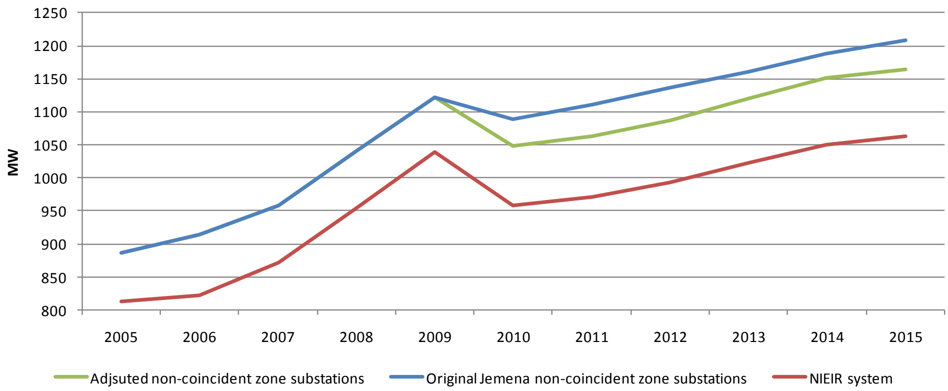


Data source: ACIL Tasman calculations based on Jemena RIN Table 11

8.7 Conclusion – forecast maximum demand for Jemena's region

As is discussed in sections 2.2 and 8.2.3 above, ACIL Tasman considers a system based temperature correction methodology using a simulation approach superior to the bottom up temperature correction applied by Jemena. For this reason, we consider that the adjustment that takes place in the first year is not warranted. Rather, ACIL Tasman considers that Jemena's system level forecasts should be no greater than those prepared by NIEIR. ACIL Tasman has calculated the adjustment required to Jemena's non-coincident substation forecasts to reflect the current 50 POE system maximum demand forecasts produced by NIEIR. By maintaining a diversity between Jemena's zone substation forecasts and NIEIR's system level forecasts of 9.5%, which is consistent with the historical relationship between the two series, we produced an adjusted sum of the non-coincident zone substation demands. The impact of this adjustment is shown in Figure 59.

Figure 59 **Adjusted Jemena non-coincident zone substation forecasts**



Data source: ACIL Tasman calculations, Jemena RIN Table 11, NIEIR, Maximum demand forecasts for Jemena electricity networks terminal stations to 2019

Table 15 presents the impacts both in terms of MW and percentage changes.

Table 15 **Impact of adjustment on the sum of the non-coincident zone substation forecasts**

	2009	2010	2011	2012	2013	2014	2015
Original 50 POE non-coincident zone substations	1122.2	1088.2	1110.9	1135.9	1161.0	1188.1	1208.6
NIEIR 50 POE system	1038.6	957.9	971.2	993.3	1023.3	1050.8	1063.9
Adjusted 50 POE non-coincident zone substations	1122.2	1048.9	1063.5	1087.7	1120.5	1150.6	1165.0
Reduction-MW	**0**	**39**	**47**	**48**	**41**	**37**	**44**
Reduction -%	**0.0%**	**3.6%**	**4.3%**	**4.2%**	**3.5%**	**3.2%**	**3.6%**

Data source: ACIL Tasman calculations

The table shows that our adjustment to bring the zone substation forecasts in line with those produced independently by NIEIR, requires a 39 MW reduction in Jemena's total non-coincident substation forecasts in 2010. This increases to a maximum reduction of 48 MW in 2012 before declining slightly thereafter. In percentage terms, this is equivalent to reducing Jemena's zone substation forecasts by 3.6% in 2010 and 4.3% in 2011. Jemena's zone substation forecasts are reduced by 3.2% and 3.6% in 2014 and 2015 respectively.

ACIL Tasman considers that in the absence of information to the contrary that these adjustments be applied proportionally at the zone substation level.

ACIL Tasman also recommends that these forecasts be adjusted to account for:

1. Updated economic growth forecasts
2. A more reasonable population growth forecast
3. Adjustments to the policy impacts

The information available to ACIL Tasman is insufficient for it to estimate the impact of the first two recommendations above. The third recommendation, if applied to the current forecast, would result in the following system level forecast for Jemena's region set out in Table 16 below.

Table 16 **Policy adjusted system summer 50 POE maximum demand**

Year	2011	2012	2013	2014	2015
NIEIR (original) 50 POE forecast	1111	1136	1161	1188	1209
'policy adjusted' proposed system maximum demand	971	993	1023	1051	1064
'policy adjusted' non-coincident zone subs	1067	1096	1134	1168	1184

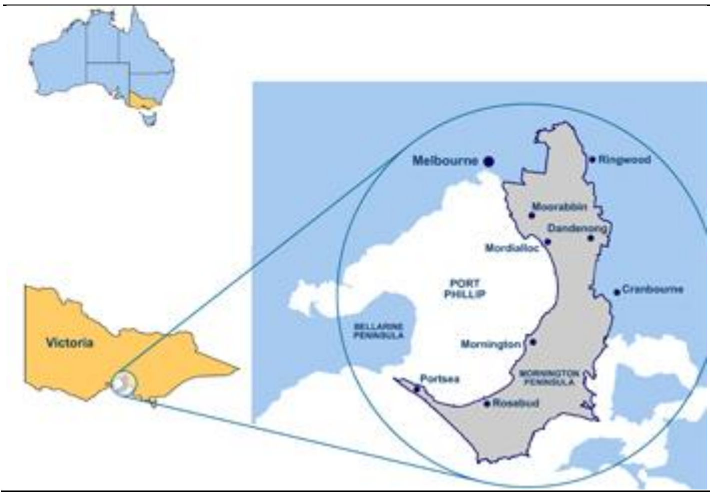
Data source: ACIL Tasman analysis based on NIEIR, demand report to Jemena tables 6.3 and 10.4

9 United Energy

9.1 Description of United Energy network

United's distribution region services the south-eastern suburbs of Melbourne and the Mornington Peninsula. It is largely urban in nature.

Figure 60 **Map of United area**



United's region accounts for approximately 23% of Victoria's population and dwelling stock. It is characterised by a large proportion of manufacturing activity, with slightly more than 29% of Victoria's manufacturing output coming from United's region.[51]

On average, NIEIR forecasts that population growth in United's area will be 0.8% per annum over the next regulatory period, which is 0.4 percentage points below the Victorian average. Also lagging behind the Victorian average is the forecast rate of growth in dwelling stock in United's region, which NIEIR forecasts will be 0.7% per annum, less than half the Victorian average of 1.6%. By contrast, gross regional product in United's area is forecast to be 2.2% per annum, ahead of Victorian average growth rate by 0.1 percentage points.

[51] This compares to 22.7% of Victoria's GSP coming from this area (in 2001) (NIEIR, "Maximum demand forecasts for United Energy terminal stations to 2019", November 2009)

9.2 Summary of methodology – United

9.2.1 United's demand forecasting methodology

United's demand forecasting differs from the other businesses in that it is done on a 10 POE level.

United's approach to maximum demand forecasting is 'bottom up' from the zone substation level. Broadly, it:

1. prepares an individual forecast for each zone substation
2. aggregates these together, taking account of diversity, to the terminal station level
3. compares its terminal station forecasts to a set of terminal station forecasts prepared independently by NIEIR by the process described above.

In preparing its forecasts, United gives consideration to a number of factors including:

- the impact of temperature on the maximum demand
- historical growth in maximum demand
- United staff's expectations of future growth in maximum demand
- the anticipated impact of significant single loads.

These factors are considered independently for each zone substation. The methodology by which each factor is considered is discussed in further detail below.

United's chosen methodology does not take account, explicitly, of a number of other factors relevant to forecasting maximum demand, such as economic conditions in the forecast period or the impact of government policies. These are taken into account by NIEIR's methodology, though, so to the extent that the two forecasts are reconciled with one another, they are also accounted for in United's approach.

The maximum demand forecasts United has put forward to the AER in its regulatory proposal were prepared using a bottom up methodology that begins at the zone substation.[52]

The first step in preparing these forecasts was to adjust the most recent, actual, summer daily maximum demand to the 50 POE level.[53] In most cases, the

[52] Note that while the forecasting process is presented sequentially here, this is for ease of description. In practice, many of the steps may be performed simultaneously or in another sequence than that described here.

[53] United has only one zone substation, Elwood, that is winter peaking.

maximum observed demand occurred on or about 29 January 2009, when the daily average temperature was significantly above the 50 POE level, so the demand observed was significantly higher than 50 POE demand.

The amount by which observed maximum demand needed to be reduced to estimate the 50 POE maximum demand was estimated using a two stage process. United uses a weighted average approach to temperature correction. It plots daily observed maximum demand against daily weighted temperature and takes the slope of the line of best fit to that plot. This slope is then multiplied by the difference between the actual maximum daily weighted temperature and the 10 POE daily weighted average temperatures for each of United's two sub regions, namely 36.34C for the Glen Waverley region and 36.74 C for Mornington.

The next step is to account for load transfers, such as load transferred between zone substations, that have occurred since the most recent maximum demand was observed. Where a particular load has been transferred from one zone substation to another, the corresponding maximum demand observations are adjusted accordingly.

By this stage in the process, United has established a series of starting points, one for each substation, that have been adjusted for the impact of weather and load transfers. These form the basis of the forecasts going forwards.

United's approach treats growth as comprising of two basic components, being 'new known loads' and annual growth. These two components are handled separately.

United's process for accounting for new known loads is to 'record' every anticipated connection with demand >0.5 MW. These are generally based on United's understanding of likely future development in its area, drawn from local Government, or from connection inquiries made directly with United.

The sum of all 'new known loads' as calculated by this process is added to the forecast each year. Simultaneously, United projects growth in existing load by multiplying the starting point by a growth rate that is chosen by United staff based on their expectations for future growth and observations of recent energy consumption in the relevant area.

This results in a forecast of non-coincident maximum demand for each of the zone substations in its area. The final step in the process is to aggregate these forecasts to the terminal station and system level, using diversity factors. Each zone substation forecast is multiplied by a diversity factor that is determined by taking the ratio of demand at each zone substation to the observed system maximum demand to produce a set of terminal station forecasts. The diversity factors that were used were based on demand observed in January 2009.

9.2.2 Reconciliation with top down forecast

The result of the process described above is a system level, bottom up forecast. As is the nature of bottom up forecasts, it does not explicitly incorporate economic and policy factors that are relevant to maximum demand.

As is described above, these economic and policy factors underpin the system level forecast prepared by NIEIR. Reconciling the two forecasts ensures that the final forecast that is taken forward is 'informed by' these factors as well as the detailed information concerning local area growth that underpins the bottom up forecasts.

United's approach to reconciling its forecasts is limited to ensuring that the two growth rates (at the system level) are consistent with one another. United takes its own forecast value for the first forecast year and forecasts that, at the system level, maximum demand will grow in accordance with NIEIR's forecasts. To adjust its own forecasts to be consistent with NIEIR's growth rates, United removes load from each zone substation in proportion to its contribution to system peak. Following this United then perform a judgement based check of each zone substation level forecast and make adjustments where considered necessary based on this judgement.

9.2.3 Assessment of forecasting methodology

Spatial forecasting methodology

The spatial forecasting approach employed by United appears to be a reasonable bottom up methodology that addresses the relevant issues. It is noteworthy that United uses a weighted average approach to weather normalisation. ACIL Tasman's experience is that the unweighted average of daily maximum and overnight minimum temperatures is not the best explanatory variable in adjusting for the impact of weather. Rather, we have found that the daily maximum has a stronger influence on electricity demand than the overnight minimum, which is consistent with United's approach.

It is also noteworthy that a threshold is used to minimise the extent of double counting between spot loads and organic growth in demand. However, forecast spot loads are not probability weighted, which would improve the forecasting methodology further.

Overall methodology

ACIL Tasman's concern with United's forecasting methodology is the limited reconciliation between its own bottom up forecasts and NIEIR's system forecasts. While the reconciliation of growth rates is undoubtedly preferable compared with no reconciliation at all, ACIL Tasman is concerned that

United's approach does not take sufficient account of the impact of the very high temperatures observed in the last few years.

Finally, ACIL Tasman has been provided with no information concerning model testing or validation, nor is there any reason to believe that this has been done. This is a significant shortcoming in the methodology.

ACIL Tasman recommends that United's bottom up forecasts should be amended so that, with an appropriate allowance for diversity, they do not exceed the system level forecasts.

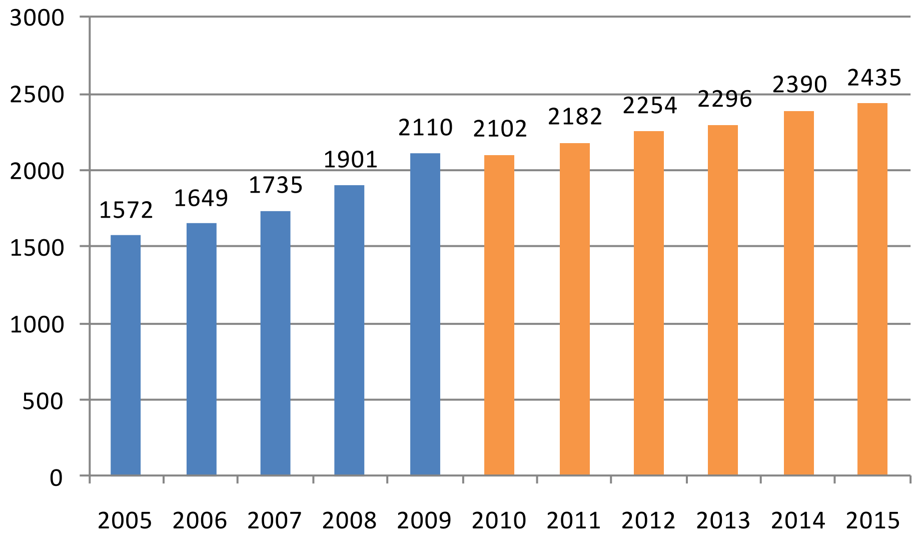
9.3 System level forecasts

The forecasts submitted by United Energy in its RIN template are at odds with its description of its forecasting process. The system level forecasts contained in table 9 of the RIN appear to have been taken from NIEIR's report. However, the zone substation level forecasts, which would be expected to be linked to the system level forecasts through a well established diversity factor, appear to have growth rates aligned with NIEIR's forecasts but are taken from a different starting point (as described by United). Accordingly, the zone substation forecasts appear to be disconnected from the system level forecasts.[54]

Figure 61 shows actual summer system level peaks for United Energy from 2005 to 2009 as well as 10 POE forecasts from 2010 onwards. The system is characterised by moderate growth between 2005 and 2009, although it is important to note that these figures are actual peak demands and have not been temperature normalised in any way. This means that the growth rate in the historical data, which is not used in the forecast, is likely to be biased upwards by the recent unusually hot summers.

[54] See United Energy, "UED A-3A RIN template 6.3_revised.xls" table 9 and NIEIR, "Maximum demand forecasts for United Energy terminal stations to 2019", table 10.3

Figure 61 **United Energy system actual and forecasts, 2005 to 2015**



Data source: United Energy RIN Table 9

This is particularly true for the 2008-09 summer which, as discussed above, peaked at a temperature significantly above the 10 POE temperature for Melbourne.[55] As is mentioned earlier, the Bureau of Meteorology described these conditions as exceptional. The temperatures observed at the time were the highest ever recorded in Melbourne.[56] For this reason, growth in the peaks between 2008 and 2009 was 11.0% (see Figure 62). In the absence of weather corrected actual peaks, ACIL Tasman considers that the growth in the 2009 year should be excluded from any comparisons to prevent significant upward bias in the growth comparisons.

Between 2005 and 2008, system maximum demand has grown at a rate of 6.5% per annum. From 2010 to 2015 the 10 POE of United Energy's system maximum demand is forecast by NIEIR to grow at a rate of 2.98% p.a. This slowdown reflects NIEIR's lower economic and population growth assumptions compared to conditions experienced in the previous regulatory period.

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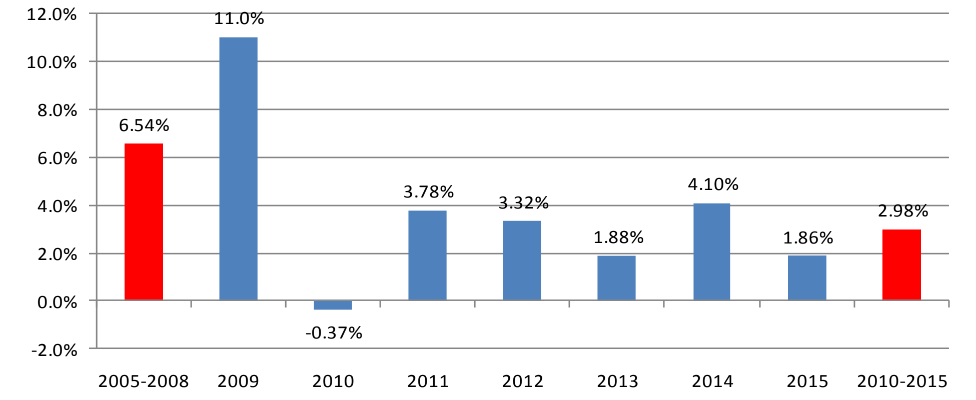
[55] The temperature on 29/1/2009 (at Melbourne) was max 43.4 min 25.7 (http://www.bom.gov.au/climate/dwo/200901/html/IDCJDW3050.200901.shtml). That gives an unweighted average of 35C or an 80:20 weighted average of 39.86. The 80:20 average is significantly above the 10POE 80:20 temperature of 36.47C

[56] 2009, Bureau of Meteorology, *Special Climate Statement 17*, p. 3, retrieved from www.bom.gov.au on 24 September 2009

Figure 62 **United Energy system maximum demand growth**

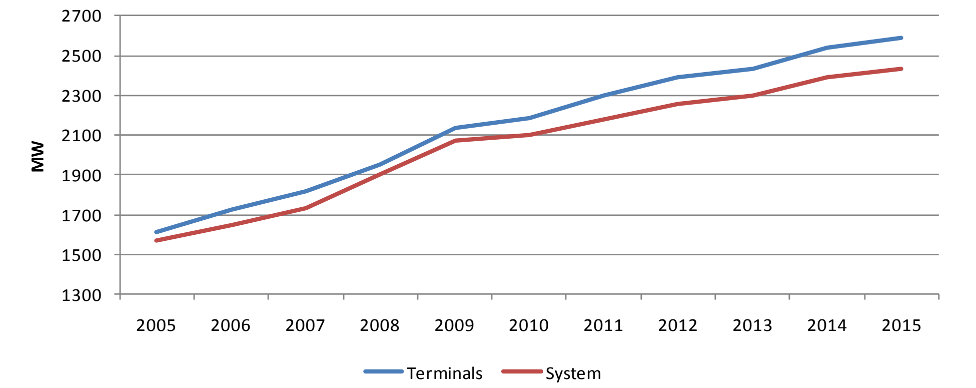


Source: United Energy RIN Table 9

9.4 Comparison at terminal station level

Another way of assessing the forecasts is to consider the sum of United Energy's non-coincident terminal station forecasts against the growth of the system in total. Although the non-coincident terminal station forecasts will not add up to the system level forecasts they can be used to assess any divergence in growth. This can provide some indication of the reasonableness of the lower level spatial forecasts. In particular, changing diversity between the sum of the non-coincident terminal stations and the system overall is an indication of spatial forecasts not being consistent with the system level forecasts.

Figure 63 **United energy: Non coincident terminal stations versus System, 10 POE**



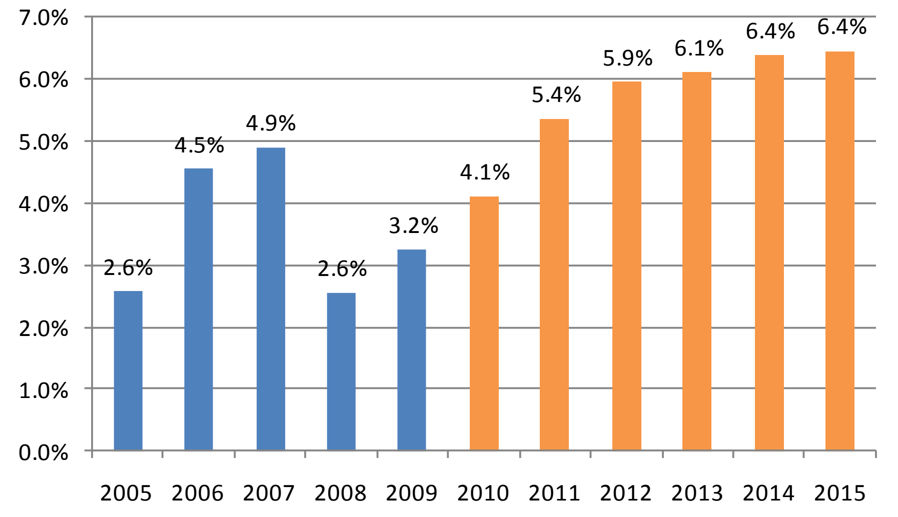
Data source: United Energy RIN Table 9 and Table 10

Figure 63 shows the sum of the non-coincident maximum demands at United Energy's terminal stations compared with their system level forecasts. The figure shows that between 2005 and 2009, the difference between the two was relatively narrow.

It is to be expected that the non-coincident terminal station demands add up to a number that exceeds the system peak in any given season because of the fact that the terminal stations do not all peak at the same time as the system. However, the fact that the diversity or the percentage difference between the two is expanding in the forecast period over time suggests that the spatial level forecasts are decoupled from the overall NIEIR system forecast.

This is also highlighted in Figure 64, which shows that between 2005 and 2009 the diversity between the terminal station peaks, and the United Energy system averaged 3.6%. This rises to an average diversity of 5.7% in the forecast period between 2010 and 2015.

Figure 64 **Diversity between terminal stations and system level, Actual and forecast**



Data source: United Energy Table 9 and Table 10

This is another clear indication that the spatial level forecasts are growing at a faster rate than the system overall and that these forecasts are out of line with the independent system forecast.

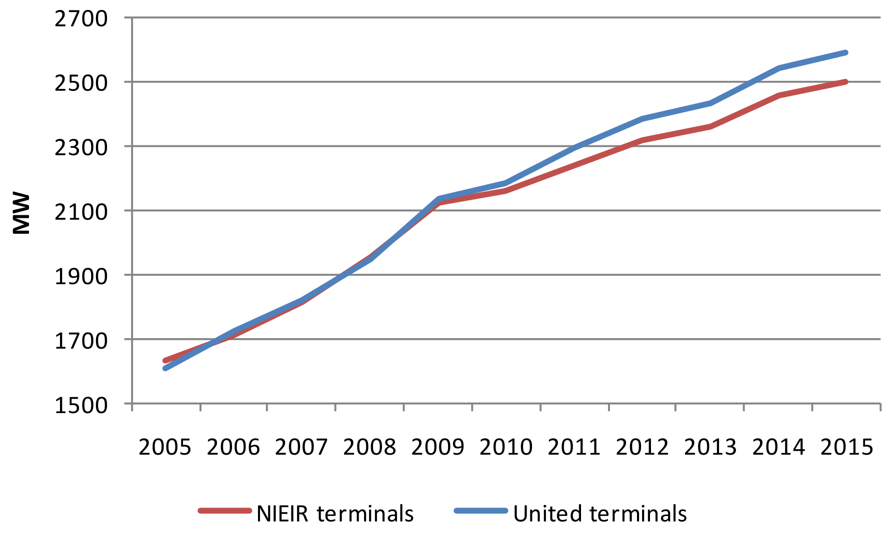
9.4.1 Comparison with NIEIR terminal station forecasts

NIEIR's terminal station forecasts are tied to their system level forecasts through a constant diversity factor of 2.8%. In other words, NIEIR maintain a constant percentage difference between the sum of their non-coincident 10 POE forecasts and their system level forecasts. ACIL Tasman considers that this is likely to be a more reasonable assumption than allowing the terminal station forecasts to diverge from the system, especially in the absence of a plausible reason why diversity is expected to increase. This suggests that United Energy's spatial level forecasts are overstated.

This is illustrated by Figure 65, which compares NIEIR's 10 POE non-coincident forecasts of United Energy's terminal stations compared with United Energy's own 10 POE terminal station forecasts.

The figure shows a clear divergence of the two sets of forecasts with United Energy's forecasts accelerating faster than those of NIEIR.

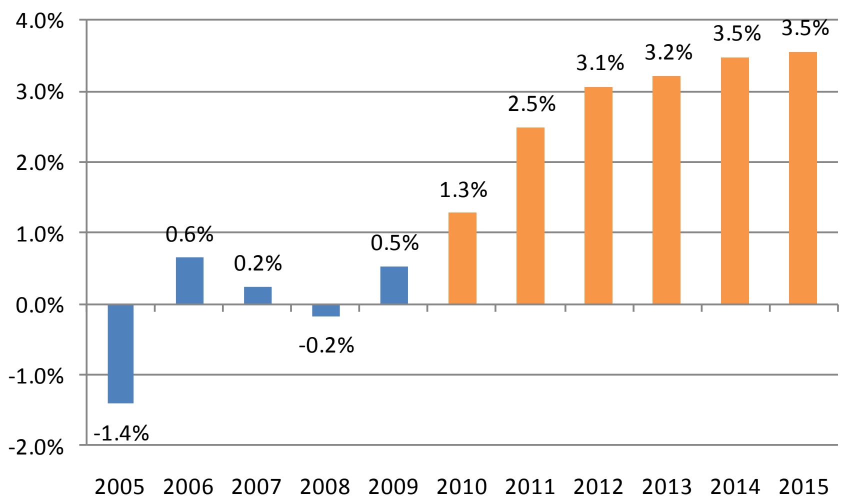
Figure 65 **United and NIEIR forecasts of non-coincident terminal stations, 2010 to 2015 10 POE.**



Data source: United energy RIN Table 10 and NIEIR report, Maximum demand forecasts for United Energy terminal stations to 2019.

The percentage differences between the two are shown in Figure 66.

Figure 66 **Difference between United Energy and NIEIR terminal station forecasts, (Percent)**

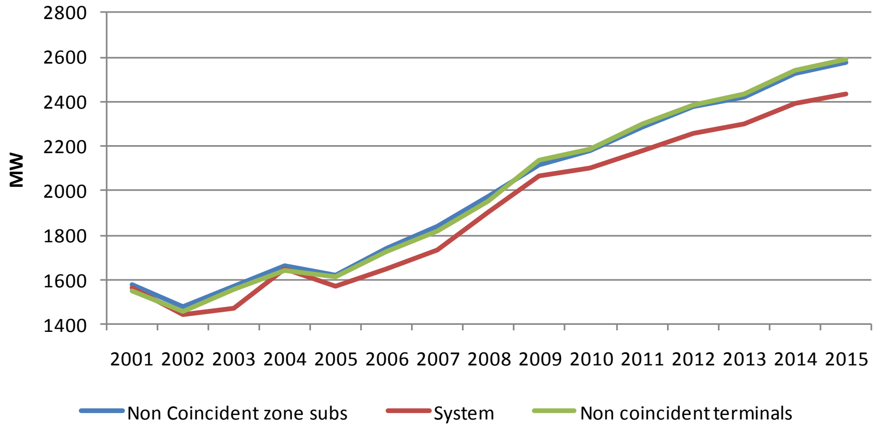


Data source: United Energy, NIEIR report, Maximum demand forecasts for United Energy terminal stations to 2019.

9.5 Zone substation forecasts

A similar comparison can be undertaken between the zone substation forecasts and the system level forecast. Figure 67 shows that the overall non-coincident zone substation forecasts are consistent with the terminal station forecasts. However, as in the case of the terminal stations, the sum of the non-coincident zone substation demands are growing at a rate that is not consistent with the overall system (albeit that United described a methodology whereby the sum of zone substations growth rates in its forecasts and NIEIR's forecasts were aligned with one another).

Figure 67 **Comparison of non-coincident terminal station, zone substation and system peak demand, actuals and forecasts**



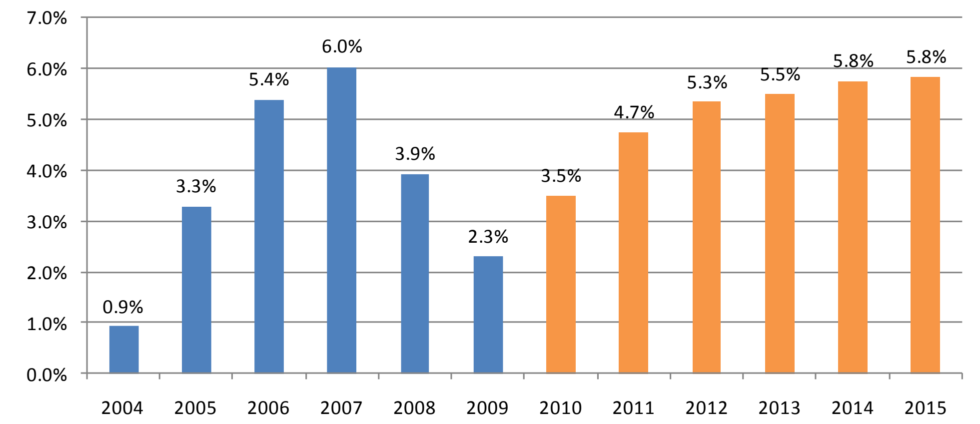
Data source: United Energy RIN Table 9, 10 and 11

Figure 68 shows the degree of diversity between United's (non coincident) zone substation and system demand forecasts.[57]

The average diversity of United Energy's non-coincident zone substations measured against the system maximum demand over the last 6 years was 3.6%. This is consistent with United Energy's zone substation forecasts in the first year. However, based on the forecasts provided by United Energy, the zone substation forecasts are diverging over time from the system level forecasts. ACIL Tasman considers that there is no valid reason for this to occur and recommends that forecasts be adjusted to maintain a consistent link between the non-coincident zone substation forecasts and the system maximum demand forecasts.

[57] Note that the zone substation forecasts are non-coincident so they would not be expected to equal the system forecast.

Figure 68 **Diversity between non-coincident United Energy zone substations and system level forecasts**



Data source: ACIL Tasman calculations based on United Energy RIN Table 9 and 11

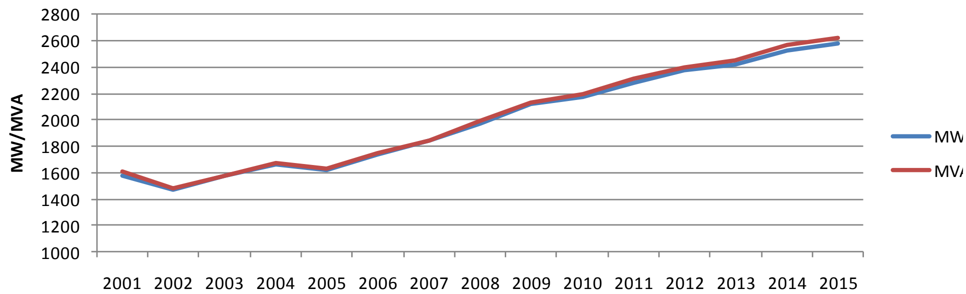
9.6 Analysis of power factor

In this section we analyse United Energy's zone substation forecasts as submitted in table 11 of the RIN and compare their MW forecasts to their MVA forecasts, e linked together through the power factor.

The MVA forecasts are linked to the MW forecasts by the power factor, which is simply the ratio of the forecast in MW to MVA. It can take any value between 0 and 1, and a declining power factor implies faster growth in the load in MVA relative to the load as measured in MW.

Figure 69 shows the historical and forecast maximum demand for the United Energy network for both the historical period from 2001 to 2009 and for the next regulatory period. The figure shows that the two series are closely tied together over time in the forecast period, with the MVA forecasts moving in conjunction with the forecasts in MW, although they do diverge slightly by the latter part of the next regulatory period.

Figure 69 **Sum of zone substation forecasts in MW and MVA, historical and forecast**

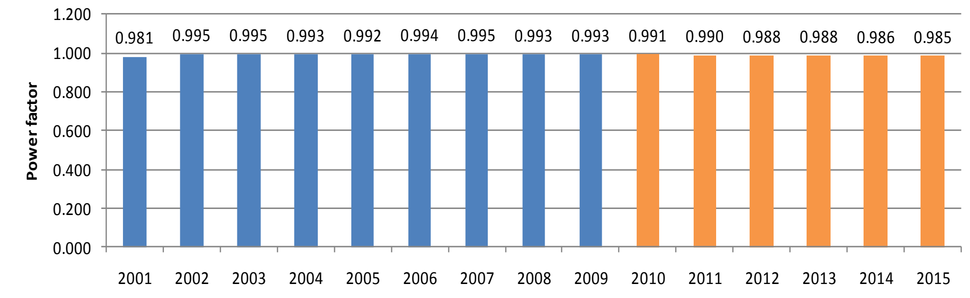


Data source: United Energy RIN Table 11

Figure 70 presents the ratio of the historical and forecast maximum demand measured in MW and MVA as a ratio, also known as the power factor. The measured power factors remain relatively stable both in the historical and forecast period.

The figure shows that the average power factor across the United Energy network is forecast to decline slightly from 0.991 to 0.985 between 2010 and 2015.

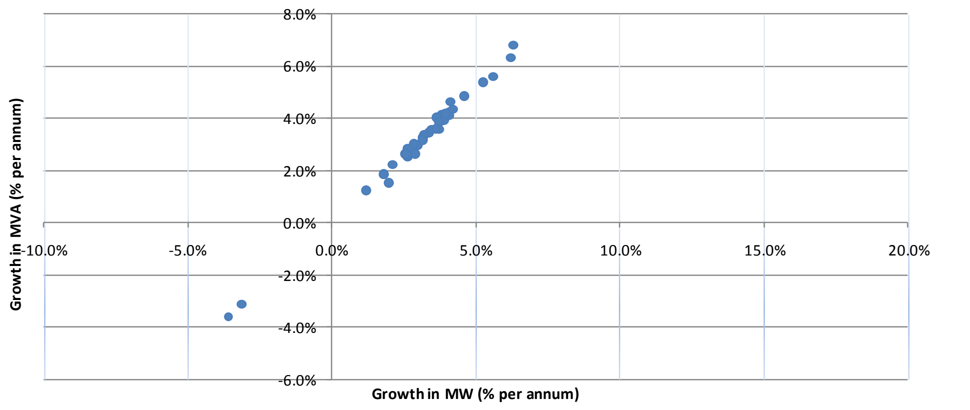
Figure 70 **United Energy average power factors, historical and forecast**



Data source: ACIL Tasman calculations based on United Energy RIN Table 11

Figure 71 shows a scatter plot of the annualised growth rates for each zone substation as measured in MVA and MW. The figure shows that most of zone substations lie close to an imaginary 45 degree diagonal, which is indicative of the MVA forecasts growing at the same rate as the forecasts measured in MW.

Figure 71 **Zone substation MVA versus MW 2010 to 2015 forecast growth rates (% per annum)**

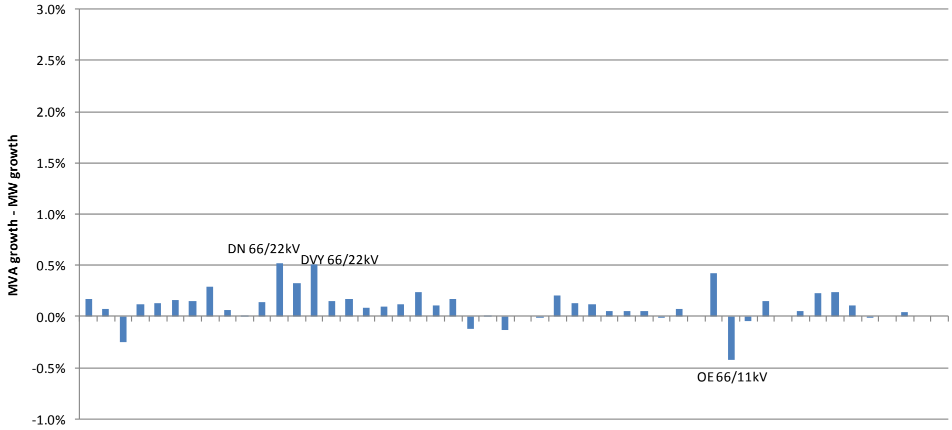


Data source: ACIL Tasman calculations based on United Energy RIN Table 11

Figure 72 presents data on a zone substation by zone substation basis, but instead simply plots the difference in the annualised 5 year growth rate between the MVA forecasts and the MW forecasts.

The figure shows that for the majority of zone substations, the 5 year annualised MVA growth rate lies very close to the MW growth rate. ACIL Tasman identifies three zone substations where this differential is relatively wide in comparison to other zone substation within the United Energy network. In the case of the zone substations identified as DN 66/22 kV and DVY 66/22 kV, the MVA growth forecasts exceed the MW growth forecasts by 0.5 percentage points per annum. For the zone identified as OE 66/11 kV, the growth differential between the MVA and MW growth rates is about -0.4 percentage points per annum.

Figure 72 **Zone substation differential between forecast demand growth measured in MVA versus MW, (2010 to 2015, % per annum)**



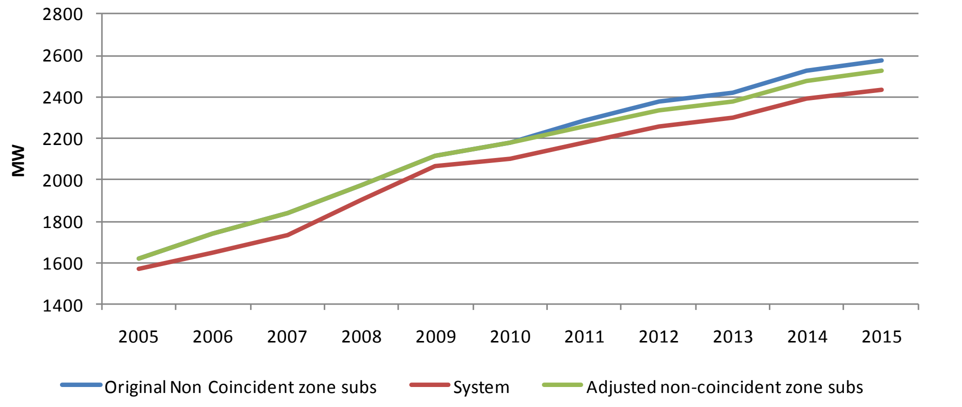
Data source: ACIL Tasman calculations based on United Energy RIN Table 11

9.7 Conclusion – forecast maximum demand in United's region

By maintaining a constant diversity factor over time for United Energy's non-coincident zone substation forecasts of 3.6%, the spatial zone substation forecasts are brought into line with the system maximum demand forecasts.

The impact of applying constant diversity is shown in Figure 73 below.

Figure 73 **Adjusted United Energy non-coincident zone substation forecasts, 10 POE**



Data source: United Energy RIN Table 9 and 11, ACIL Tasman calculations

The chart shows a relatively small impact on United Energy's non-coincident zone substation forecasts. Table 17 presents the reduction in the sum of the non-coincident zone substation demand in MW and percentage terms.

In order to align the spatial forecasts to the system maximum demand forecasts, the non-coincident zone substation demand forecasts need to be reduced by 54MW by 2015, or by 2.1%. It is interesting to note that our assumed diversity factor leads to a very small increase in the first forecast year of 2 MW.

Table 17 **Impact of adjustment on the sum of United Energy's non-coincident zone substation 10 POE forecasts**

Year	2009	2010	2011	2012	2013	2014	2015
Original Non Coincident zone substations	2117	2176	2285	2374	2422	2528	2577
System Maximum demand	2070	2102	2182	2254	2296	2390	2435
Adjusted non-coincident zone substations	2117	2178	2260	2335	2379	2477	2523
Reduction- MW	**0**	**-2**	**25**	**39**	**43**	**52**	**54**
Reduction-%	**0.0%**	**-0.1%**	**1.1%**	**1.6%**	**1.8%**	**2.0%**	**2.1%**

Data source: United Energy RIN table 9 and 11, ACIL Tasman calculations

ACIL Tasman recommends that these reductions be applied proportionally to all the non-coincident zone substation forecasts in the absence of additional information.

ACIL Tasman also recommends that these forecasts be adjusted to account for:

1. Updated economic growth forecasts
2. A more reasonable population growth forecast
3. Adjustments to the policy impacts

The information available to ACIL Tasman is insufficient for it to estimate the impact of the first two recommendations above. The third recommendation, if applied to the current forecast, would result in the following system level forecast for United's region set out in Table 18 below.

Table 18 **Policy adjusted system summer 10 POE maximum demand**

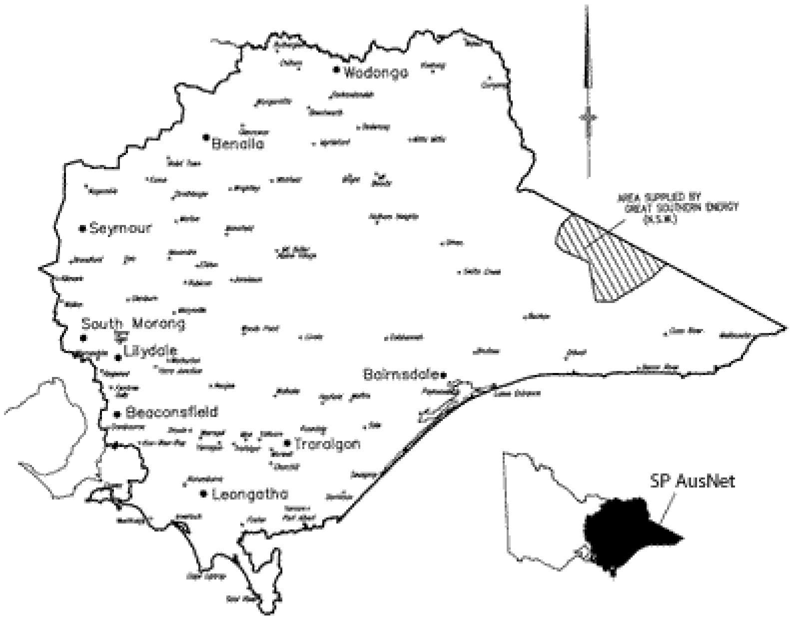
Year	2011	2012	2013	2014	2015
NIEIR (original) 10 POE forecast	2182	2254	2296	2390	2435
'policy adjusted' proposed system maximum demand	2187	2270	2322	2422	2469
'policy adjusted' non-coincident zone subs	2266	2352	2406	2509	2558

Data source: ACIL Tasman analysis based on NIEIR, demand report to United tables 6.3 and 10.3

10 SP AusNet

10.1 Description of SP AusNet network

Figure 74 **Map of SP AusNet area**



SP AusNet's distribution region includes over 600,000 customers across eastern Victoria. This network spans approximately 46,000 kilometres across an area of 80,000 square kilometres.

SP AusNet's region accounts for approximately 24% of Victoria's population and 23% of its dwelling stock. It is characterised by a relatively large proportion of mining activity, with more than half of Victoria's mining activity in SP AusNet's area. It is also home to 35% of Victoria's agriculture industry.

On average, NIEIR forecasts that population growth in SP AusNet's area will be 1.4% per annum, 0.2 percentage points above the Victorian average. Similarly, gross regional product in SP AusNet's area is forecast to be 2.6% per annum, outperforming the Victorian average growth rate by 0.4 percentage points. Also outperforming the Victorian average is the rate of growth in the dwelling stock, which NIEIR forecasts will be 1.6% per annum reflecting rapid growth in Melbourne's south eastern and north eastern growth corridors.

10.2 Summary of methodology – SP AusNet

At the time of writing this report, SP AusNet had not provided any evidence that its spatial forecasting approach was formally defined by way of a process manual or similar document. SP AusNet did not describe its bottom up forecasting process in the written materials it provided the AER.[58] The following description is based on a largely verbal summary of that process given to the AER and ACIL Tasman at a meeting (27 January 2010). At that meeting, SP AusNet explained that the ZSS forecasts set out in table 11 of its response to the AER were prepared as follows:

10.2.1 SP AusNet forecasting methodology

SP AusNet has three local planners, one each responsible for the Northern, Eastern and Central regions of SP AusNet's area. The forecasting process is largely conducted by these planners and relies heavily on their judgement and local knowledge of 'their' area.

Starting points and weather correction

SP AusNet does not apply a weather correction methodology. As a general rule, the starting points for its zone substation forecasts are the most recent observation of maximum demand. In some cases, though, SP AusNet revised the starting point down from this level to account for the unusually high temperatures in January 2009.

SP AusNet did ensure that the sum of the starting points in its forecast was equal to the system level forecast received from NIEIR.

Growth rates

On a zone substation by zone substation basis, the planners review scatter plots of historical maximum observed demand. These are usually taken over the past five or six years, although the length of the time series is at the discretion of the individual planner on a case by case basis.

The scatter plots are of actual observed annual maximum demand, with no weather correction applied. As mentioned above, SP AusNet does not use a formal weather correction methodology in preparing its forecasts, although there are cases where forecast 'starting points' are derived through manual adjustments to account for the impact of unusually high temperatures.

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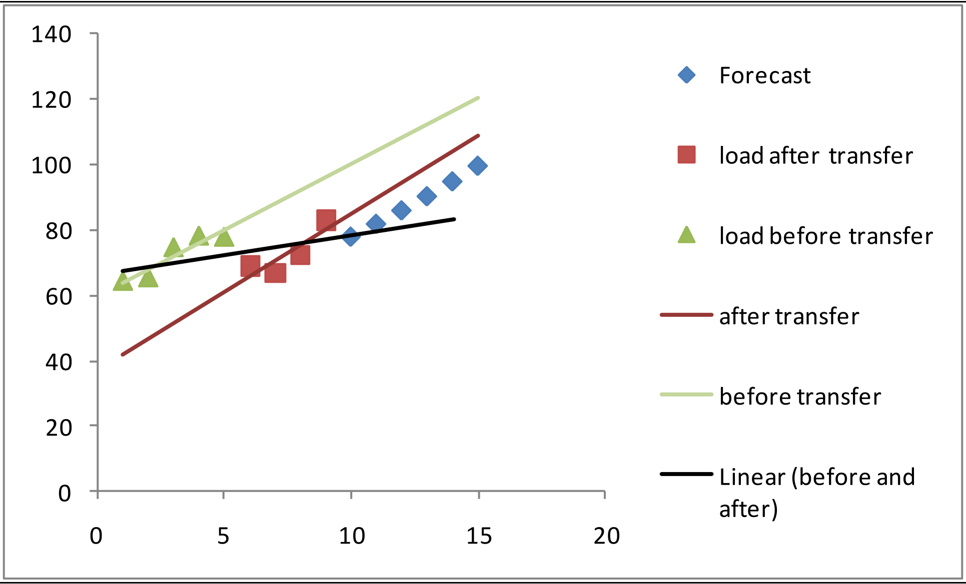
58 On Tuesday, 2 March 2010, three days before the draft of this report was submitted to the AER for its review, SP AusNet provided a document that contains an *ex post* summary of the process that it used to produce its demand forecasts. Given the timing, ACIL Tasman was only able to take this document into account to a limited extent. However, the document cannot be described as a formal documentation of the process SP AusNet requires its planners to use in preparing forecasts.

The planners determine what they considered to be reasonable historical growth rates from the scatter plots. In doing this, they would typically fit lines of best fit to the scatter plots over a time period they would choose to best reflect the circumstances at the individual zone substation being analysed.

These growth rates are intended to capture all growth in this area so, unlike other businesses, SP AusNet does not add individual known spot or block loads to its forecasts. Similarly, in cases where load had been transferred to or from the ZSS in question the historical data was not adjusted, although SP AusNet stated that the planner 'bore it in mind'

The SP AusNet forecasting process is illustrated in the following example, which is based on the Hampton Park zone substation.

Figure 75 **load growth forecasting example, Hampton Park**



Source: SP AusNet

Figure 75 is a scatter plot of actual maximum demand as observed at the Hampton Park substation. The series is characterised by steady growth in the first five years followed by a strong dip around 2005. Growth resumes from around 2005. It is noteworthy that the nearby Clyde North substation was commissioned in 2005, and that a portion of load from Hampton Park was transferred to it around that time.

The data depicted in green shows the actual (non-weather adjusted) maximum demand observed annually until 2005 with a linear trend line projected into the future. The data in red shows the situation after the establishment of the Clyde North zone substation while the trend line in black takes all of the data into account, before and after the transfer.

Taking a simple trend analysis across the whole time series (i.e. the black trend line) would indicate that load growth in this zone has been at approximately 1.2 MW per year (1.8%) since 2000. By contrast, the 'before transfer' and 'after transfer' trend lines indicate that growth was approximately 4.0 (6.6%) and 4.8 MW (6.9%) per year respectively.

The 'before' and 'after' growth rates are similar to one another, and obviously different to the growth rate when measured across the whole data series which highlights the importance of accounting for load transfers in preparing load forecasts.

In SP AusNet's approach, load transfers are stated to be accounted for when the planners 'bear in mind' transfers that have affected the different zone substations. Accordingly, the accuracy of the process relies heavily on the subjective judgement and experience of the planners and as such is not easily reproducible. In this example, SP AusNet has forecast annual growth of 5%, as depicted in blue in the figure. This appears to be approximately consistent with historical growth in the area as determined by the trend analysis discussed above.

10.2.2 Reconciliation with system level forecasts

SP AusNet provided details of the relationship between its forecasts and those prepared by NIEIR.

The first step in its reconciliation was to remove the forecast load from a number of high voltage customers located at the Wodonga and Ringwood terminal stations as well as the Morwell mine supplies at Loy Yang and Yallourn. Second, NIEIR's forecasts were adjusted upwards to account for SP AusNet's assumption that embedded generation would not operate at times of peak demand and also to remove the load from 66kV customers.

Having made these revisions to bring the two forecasts onto a common base, SP AusNet took NIEIR's forecasts into account and says that it revised many of its own forecasts to bring them closer to NIEIR's. However, at the time of writing this report, ACIL Tasman has not seen documentation of these adjustments.

As is discussed further below, SP AusNet's adjustments to its forecasts consider the NIEIR forecasts but fall short of using the NIEIR forecast to constrain the substation forecasts (adjusted for coincident factors). In some cases, such as the terminal stations at Thomastown and South Morang, SP AusNet rejects NIEIR's growth forecasts on the basis of its own local knowledge of the area. In other cases SP AusNet forecasts lower growth than NIEIR and has retained its own forecast.

Seven of SP AusNet's 12 terminal station forecasts were lower than or very close to NIEIR's forecasts for the same terminal station. In two cases, SP AusNet did not make a forecast based on its assumption/ expectation that the load for those substations would be flat over the next regulatory period. In the remaining three cases, SP AusNet reject's NIEIR's forecast growth. In short

- SP AusNet considers that NIEIR's growth estimates at South Morang terminal stations are too low
- At Wodonga terminal station, where NIEIR has forecast a slight decline in demand over the regulatory period, SP AusNet expects an increase of slightly more than 10% leading to SP AusNet rejecting the NIEIR's forecast
- In the last case, Morwell Terminal station, SP AusNet forecasts growth of 1.5 percentage points higher than NIEIR which, bearing in mind NIEIR's growth forecast of 2.1% per annum, is a significant discrepancy. The result is that, over the regulatory period, SP AusNet expects demand to grow by 8.7 MW more than NIEIR.

10.2.3 Assessment of forecasting methodology

Spatial forecasting methodology

ACIL Tasman does not regard SP AusNet's approach to load forecasting as methodologically sound. At its heart, this methodology relies entirely on the judgement of the three people who prepare the forecasts. There is no systematic adjustment for the influence of temperature on demand and only a general relationship between other objective data and the forecasts that are prepared. While ACIL Tasman acknowledges that spatial forecasting will always involve an element of judgement of the forecaster, SP AusNet's methodology appears to be unduly reliant on them.

It is also concerning that, while SP AusNet has provided a general description of the factors it takes into account in preparing the forecasts, at the time of writing this report, it has not provided the details of which factors influenced which growth rates at which zone substations. ACIL Tasman is concerned that this process lacks transparency to the point that if it were to be repeated by another group of planners with comparable skills and experience, it is possible that a different set of forecasts could be developed.

Overall methodology

In addition to the above concerns with the spatial forecasting methodology employed by SP AusNet, ACIL Tasman is also concerned that SP AusNet does not reconcile its forecasts with an independent system level forecast in any formal way. However, it is notable that, as is shown below, the levels of the two forecasts are not dramatically different. Nevertheless, the system level forecast is capable of taking account of a number of factors that cannot be incorporated into bottom up forecasts, such as changing policy and economic conditions.

In this context, where SP AusNet's energy sales forecasts did take account of these factors explicitly, the lack of reconciliation gives rise to possible inconsistency between the demand and energy forecasts.

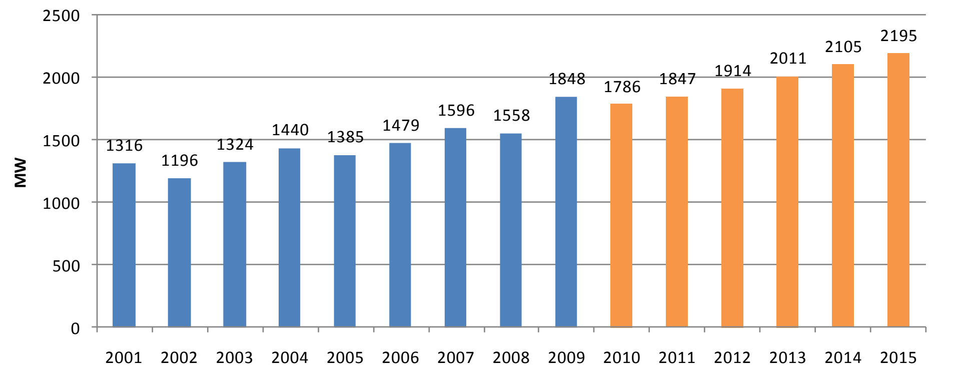
Finally, ACIL Tasman has been provided with no information concerning model testing or validation, nor is there any reason to believe that this has been done. This is a significant shortcoming in the methodology.

ACIL Tasman recommends that SP AusNet's bottom up forecasts should be amended so that, with an appropriate allowance for diversity, they do not exceed the system level forecasts.

10.3 System level forecast

SP AusNet's 50 POE system maximum demand forecasts are shown in Figure 76.

Figure 76 **SP AusNet: System maximum demand, historical and 50 POE forecast**

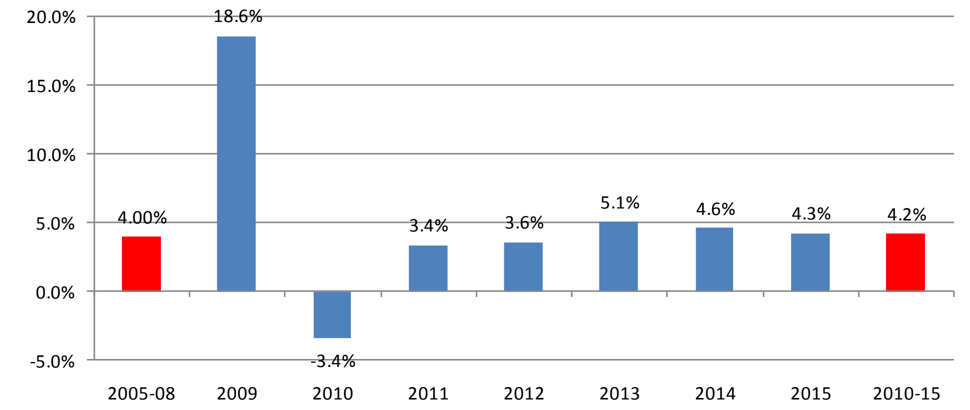


Data source: SP AusNet RIN Table 9

According to the chart, SP AusNet projects its 50 POE system maximum demand to reach 2195 MW by 2015.

This is equivalent to a growth rate of 4.2% per annum between 2010 and 2015 (see Figure 77).

Figure 77 **Annualised growth rates in SP AusNet system maximum demand over several time horizons, historical and forecast**

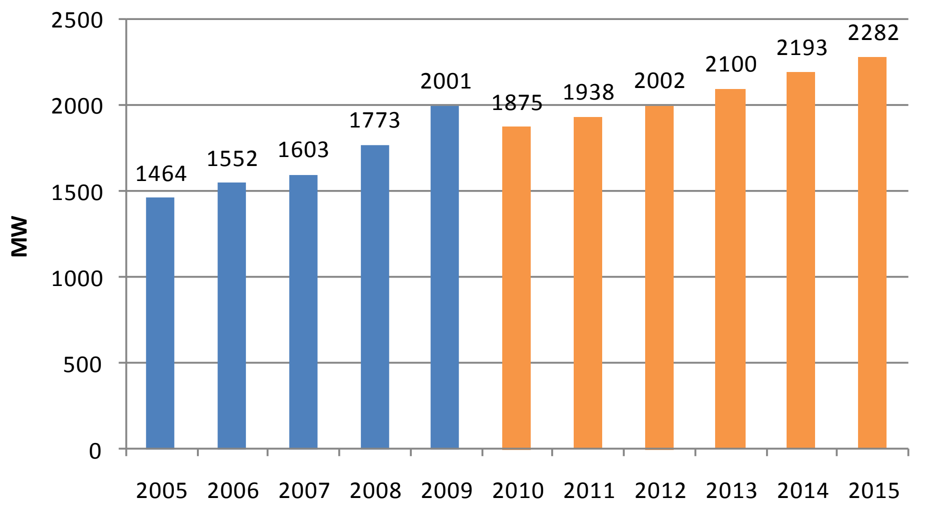


Data source: ACIL Tasman calculations based on SP AusNet RIN Table 9

10.3.1 Comparison with NIEIR system demand forecasts

SP AusNet commissioned NIEIR to produce an independent set of forecasts at the terminal station level. The sum of the coincident terminal station forecasts, which is equivalent to the system maximum demand, is presented in Figure 78. NIEIR projects system maximum demand to reach 2282 MW by 2015.

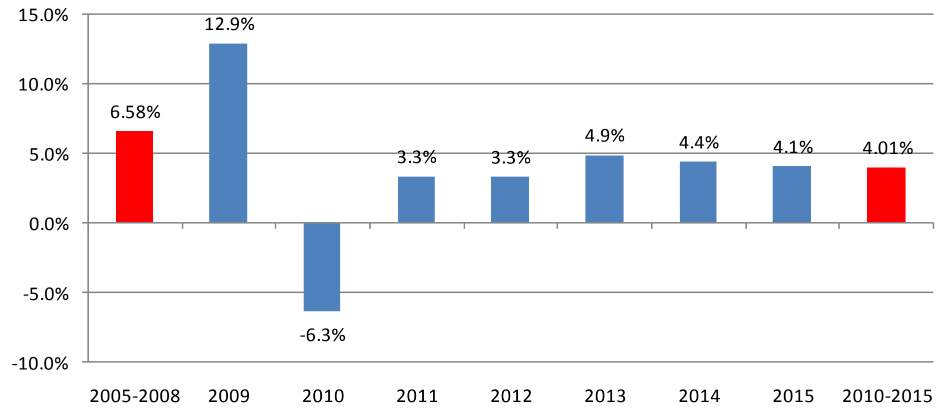
Figure 78 **SP AusNet: NIEIR historical and forecast 50 POE**



Data source: NIEIR, Maximum Demand forecasts for SP AusNet terminal stations to 2019.

The projected annualised growth rate for NIEIR's forecasts of the SP AusNet system is 4.0% between 2010 and 2015. This is slightly less than the growth rate applied in the forecasts produced by SP AusNet.

Figure 79 **Implied growth rates from NIEIR's SP AusNet system maximum demand 50 POE forecasts**

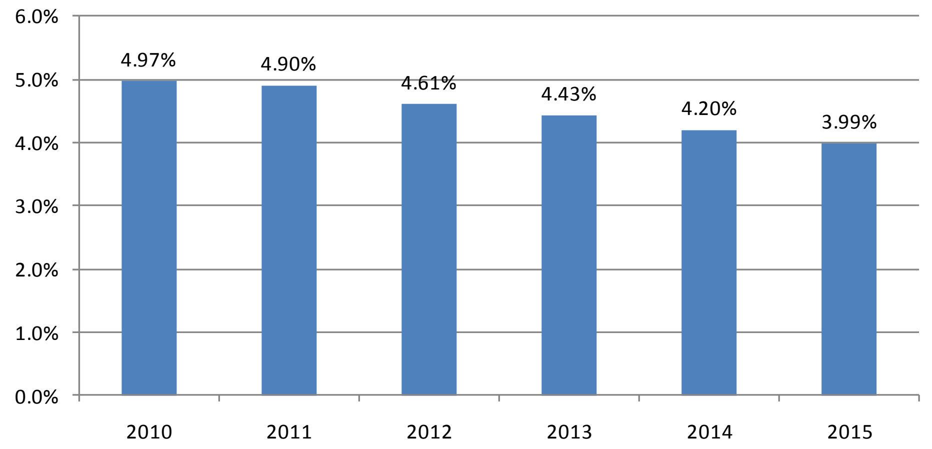


Data source: ACIL Tasman calculations based on data from NIEIR, Maximum Demand forecasts for SP AusNet terminal stations to 2019

Figure 80 shows the percentage difference between SP AusNet's system maximum demand forecasts and those produced independently by NIEIR.

The figure shows that SP AusNet's system maximum demand forecasts are consistently lower than NIEIR's, ranging from 4.97% in the first year of the forecast period, before declining steadily to 3.99% by 2015.

Figure 80 **Difference between system maximum demand forecasts, SP AusNet versus NIEIR, 50 POE**



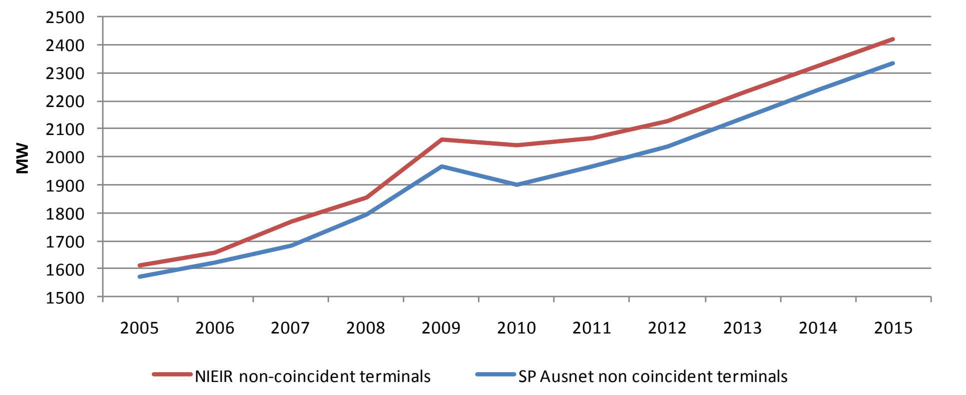
Data source: ACIL Tasman calculations based on NIEIR, Maximum Demand forecasts for SP AusNet terminal stations to 2019 and SP AusNet RIN Table 9

ACIL Tasman notes that the two sets of forecasts are not directly comparable because the NIEIR forecasts include 22kV supplies from the Wodonga and Ringwood terminal stations as well as mine supplies from Loy Yang and Yallourn. SP AusNet excludes these sources of demand from their forecasts. Before the full implications of the discrepancies between these two forecasts can be assessed, it would be necessary to obtain a system level forecast that was prepared on the same basis as the spatial forecast. ACIL Tasman notes that the sum of the 50 POE demand at Yallourn terminal station and Loy Yang switching station is approximately 30 MW in 2010. SP AusNet also remove a proportion (not provided) of the Ringwood and Wodonga terminal stations, which have 50 POE maximum demand of approximately 100 MW and 70 MW respectively in 2010. This may account for much of the discrepancy between the forecasts.

10.4 Comparison at terminal station level

The different basis on which the forecasts are constructed is evident again in Figure 81, which plots the sum of NIEIR's non-coincident terminal stations against SP AusNet's non coincident terminal station forecasts.

Figure 81 **SP AusNet non-coincident terminal stations versus NIEIR non-coincident terminal stations, historical and 50 POE forecasts**



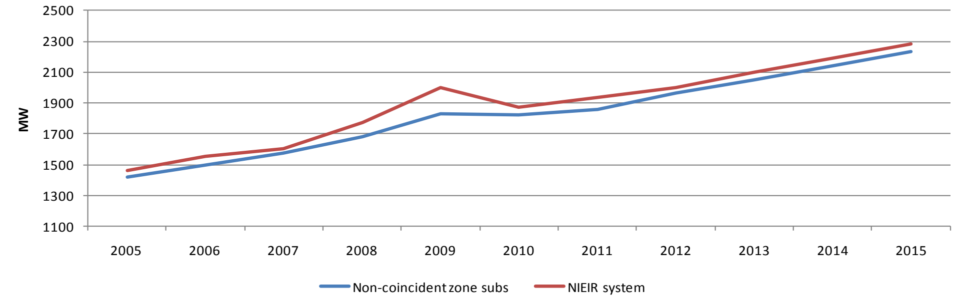
Data source: SP AusNet RIN Table 10 and NIEIR, Maximum Demand forecasts for SP AusNet terminal stations to 2019

The NIEIR forecasts include demand sources, which are excluded from the SP AusNet forecasts and are therefore consistently higher.

10.5 Zone substation forecasts

Figure 82 plots SP AusNet's historical and forecast non-coincident zone substations against NIEIR's forecast of SP AusNet's system maximum demand. As in the case of the terminal station plots, NIEIR's numbers are consistently higher reflecting the difference basis in the two sets of forecasts.

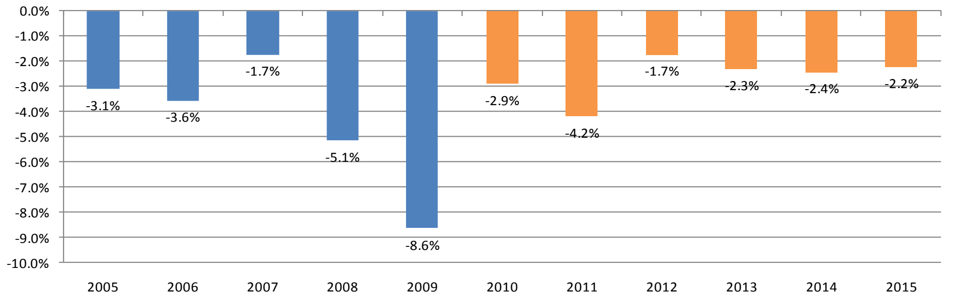
Figure 82 **Comparison of SP AusNet non-coincident zone substations and NIEIR's system maximum demand, actual and 50 POE forecast**



Data source: SP AusNet RIN Table 11 and NIEIR, Maximum Demand forecasts for SP AusNet terminal stations to 2019

Figure 83 presents the percentage difference between the two series, both historical and forecast. The figure shows that at the zone substation level over the forecast period, SP AusNet is growing demand at a slightly higher rate than that estimated by NIEIR's system demand forecasts, with the difference between the two sets of forecasts shrinking from 2.9% in 2010 to 2.2% in 2015.

Figure 83 **Difference between non-coincident SP AusNet zone substations and NIEIR system level forecasts, historical and 50 POE forecasts**



Data source: ACIL Tasman calculations based on SP AusNet RIN Table 11 and NIEIR, Maximum Demand forecasts for SP AusNet terminal stations to 2019

The average deviation between the two series between 2005 and 2009 was 4.4%. On the basis that any historical differences between the two series should remain constant over time, ACIL Tasman proposes to adjust SP AusNet's zone substation forecasts to maintain a constant percentage differential over time of 4.4%, reflecting the historical differences.[59]

Adjustments to the forecasts are presented in section 10.7 below.

59 Note that there is an argument that the adjustment should retain the gap in MW terms, due to the apparently flat nature of the loads that have been excluded. This would result in a slightly larger percentage adjustment.

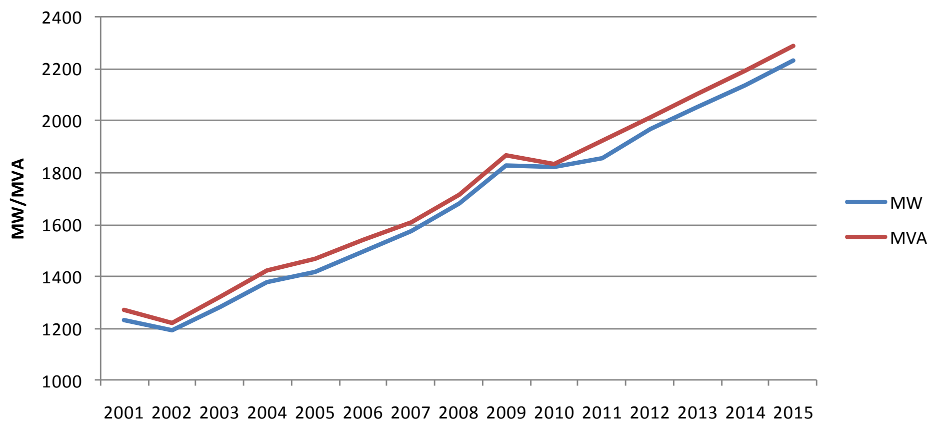
10.6 Analysis of power factor

In this section, we analyse SP AusNet's zone substation forecasts as submitted in table 11 of the RIN and compare their MW forecasts to their MVA forecasts as a way of identifying any divergence between the two measures.

The MVA forecasts are linked to the MW forecasts by the power factor, which is simply the ratio of the forecast in MW to MVA. It can take any value between 0 and 1, and a declining power factor implies faster growth in the load in MVA relative to the load as measured in MW.

Figure 84 shows the historical and forecast maximum demand for the SP AusNet network for both the historical period from 2001 to 2009 and for the next regulatory period. The chart shows that the two series are closely tied together.

Figure 84 **Sum of zone substation forecasts in MW and MVA, historical and forecast**

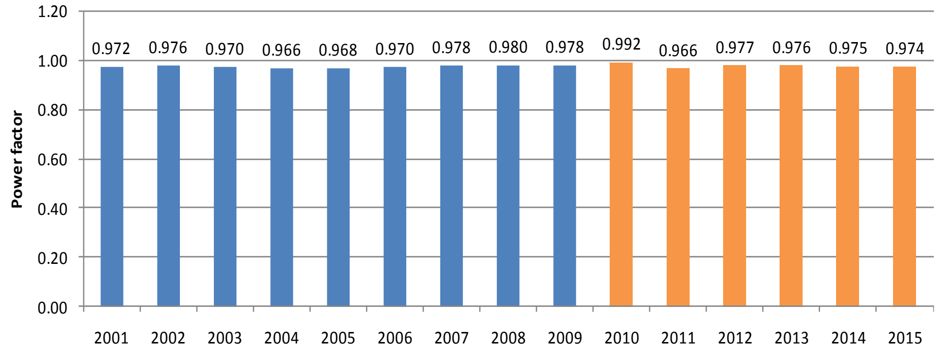


Data source: SP AusNet RIN Table 11

Figure 85 presents the ratio of the historical and forecast maximum demand measured in MW and MVA as a ratio, also known as the power factor.

The graph indicates that the average power factor across the SP AusNet network is relatively constant over time, declining slightly from 0.992 to 0.974 between 2010 and 2015.

Figure 85 **SP AusNet average power factors, historical and forecast**



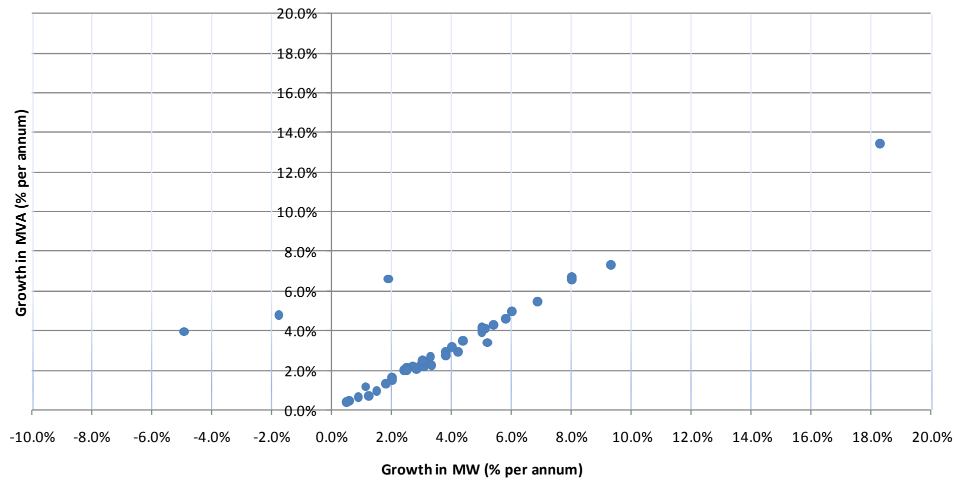
Data source: ACIL Tasman calculations based on SP AusNet RIN Table 11

While the sum of the zone substation forecasts remain closely tied together, at the zone substation by zone substation level considerable variation can be observed.

Figure 86 shows a scatter plot of the annualised growth rates for each zone substation as measured in MVA and MW. The graph shows that the vast majority of zone substations lie close to an imaginary 45 degree diagonal, which indicates that the MVA forecasts are growing at about the same rate as the forecasts measured in MW.

The figure does also highlight several outliers whose observations lie some distance away from the diagonal.

Figure 86 **Zone substation MVA versus MW 2010 to 2015 forecast growth rates (% per annum)**



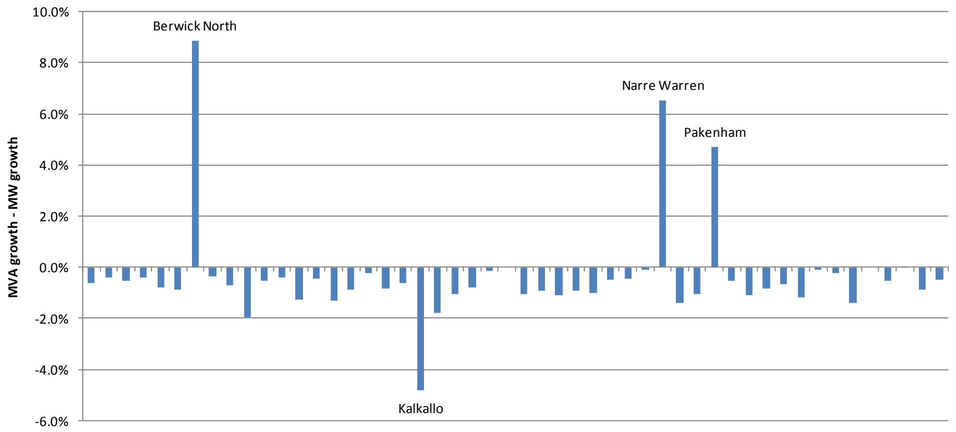
Data source: ACIL Tasman calculations based on SP AusNet RIN Table 11

Figure 87 presents data on a zone substation by zone substation basis, but instead simply plots the difference in the annualised 5 year growth rate between the MVA forecasts and the MW forecasts.

The figure shows that except for a small number of outliers, the MVA forecasts on a zone substation by zone substation basis are growing at a slower rate that the equivalent forecasts measured in MW. The three exceptions are the zone substations located at Berwick North, Narre Warren and Pakenham, which are forecast to experience strong declines in their power factors.

It is also important to note that the differences between the MW and MVA growth rates are significantly higher in the case of SP AusNet compared to the other distribution businesses. This becomes clearly apparent when the scale of Figure 87 for SP AusNet is compared with the equivalent figures for the other distribution businesses (-4% to +10% compared with -1% to +3%). This indicates that in the case of SP AusNet the differences between the MW and MVA zone substation forecasts diverge significantly more than for the other distribution businesses. ACIL Tasman considers that the AER should require SP AusNet to provide a reasonable explanation for this significant difference.

Figure 87 **Zone substation differential between forecast demand growth measured in MVA versus MW, (2010 to 2015, % per annum)**

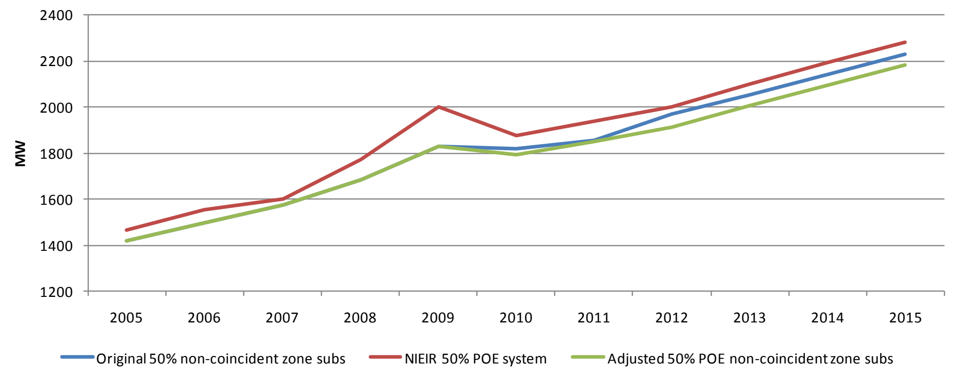


Data source: ACIL Tasman calculations based on SP AusNet RIN Table 11

10.7 Conclusion – maximum demand in SP AusNet's region.

By applying a constant differential of 4.4% into the forecast period, SP AusNet's zone substation forecasts are constrained to be consistent with NIEIR's system level forecasts. The forecasts are constrained to produce an equivalent growth rate over the forecast period, therefore incorporating NIEIR's macroeconomic, demographic, air conditioning and policy impacts at the system level into the substation forecasts.

Figure 88 **Adjusted SP AusNet 50 POE non coincident zone substation forecasts versus NIEIR 50 POE system forecasts**



Data source: SP AusNet RIN Table 11, NIEIR and ACIL Tasman calculations

The proposed adjustments are also presented in Table 19 below.

Table 19 **Impact of adjustment on the sum of SP AusNet's non-coincident substation forecasts**

	2009	2010	2011	2012	2013	2014	2015
Original 50% non-coincident zone subs	1828.7	1820.5	1856.4	1967.5	2051.8	2139.7	2231.3
NIEIR 50 POE system	2001.4	1874.8	1937.5	2002.2	2100.5	2193.0	2282.2
Adjusted 50 POE non-coincident zone subs	1828.7	1792.3	1852.3	1914.1	2008.0	2096.5	2181.7
Reduction-MW	**0.0**	**28.2**	**4.1**	**53.4**	**43.8**	**43.2**	**49.6**
Reduction-%	**0%**	**1.5%**	**0.2%**	**2.7%**	**2.1%**	**2.0%**	**2.2%**

Data source: ACIL Tasman calculations

Based on the adjustment, ACIL Tasman proposes SP AusNet reduce its zone substation forecasts in 2010 by 1.5% or 28 MW. The adjustment then declines to 4 MW in 2011 before expanding to a maximum reduction of 53 MW in 2012, equivalent to a 2.7% reduction to the forecasts.

ACIL Tasman considers that in the absence of additional information, these adjustments should be applied proportionally to all the zone substations comprising the SP AusNet network.

ACIL Tasman also recommends that these forecasts be adjusted to account for:

1. Updated economic growth forecasts
2. A more reasonable population growth forecast
3. Adjustments to the policy impacts

The information available to ACIL Tasman is insufficient for it to estimate the impact of the first two recommendations above. The third recommendation, if applied to the current forecast, would result in the following system level forecast for SP AusNet's region set out in Table 20below.

Table 20 **Policy adjusted system summer 50 POE maximum demand**

Year	2011	2012	2013	2014	2015
NIEIR (original) 50 POE forecast	1938	2002	2101	2193	2282
'policy adjusted' proposed system maximum demand	1943	2017	2125	2223	2314
'policy adjusted' non-coincident zone subs	1858	1928	2032	2125	2212

Data source: ACIL Tasman analysis based on NIEIR, demand report to SP AusNet tables 6.3 and 10.4

A Excerpt from ACIL Tasman's terms of reference

The demand forecasting consultant will be required to review the reasonableness and accuracy of the demand … forecasts that underlie the proposals submitted by each of the Victorian DNSPs for the forthcoming regulatory control period.

The demand forecasting consultant will be required to determine whether the forecast methods and data sources (using public information where possible[60]) used by each DNSP are robust, represent good electricity industry practice[61] and therefore produce realistic forecasts of maximum demand…for the forthcoming regulatory control period.

The demand forecasting consultant will be required to provide a full written assessment of the DNSPs' forecasts of demand…

The demand forecasting consultant must conduct an assessment of maximum demand … including advice on the reasonableness and/or appropriateness of:

(a) the DNSPs' methodologies;

[60] For example it may not be possible to refer to specific mechanisms within a DNSP's demand forecasting model where it refers to proprietary intellectual property. However, it is expected where this is the case, best endeavours are made to conduct a high level assessment of the model for the purposes of allowing the AER to form a view on the demand forecasts provided by the DNSPs.

[61] 'Good electricity industry practice' is defined (also in the NER) as the exercise of that degree of skill, diligence, prudence and foresight that reasonably would be expected from a significant proportion of operators of facilities forming part of the supply of electricity under conditions comparable to those applicable to the relevant facility consistent with applicable regulatory instruments, reliability, safety and environmental protection. The determination of comparable conditions is to take into account factors such as the relative size, duty, age and technological status of the relevant facility and the applicable regulatory instruments.

(b) key assumptions and inputs, and their use[62];

(c) any base year(s) selected for the demand forecasts;

(d) probabilities of exceedence used;

(e) global (or top-down) and general spatial (bottom-up) forecasting processes, and the reconciliation of the global and spatial forecasts;

(f) the weather normalisation methodology and how weather data has been used;

(g) the outline of the treatment of spot loads and load transfers within the forecasting process;

(h) any appliance models, where used, or assumptions relating to average customer energy usage (by customer type); and

(i) where scenarios are employed, the appropriateness of the scenarios developed and justifications for selecting one particular scenario over others in developing expenditure proposals.

The demand forecasting consultant will also be required to examine and provide advice on the explanations provided by each DNSP on:

(a) how the forecasting methodology used is consistent with and takes into account historical observations (where appropriate); and

(b) the resulting forecast data is consistent at different levels of aggregation.

The full assessment of the DNSPs' forecasts must include a comparison with other relevant measures of demand by other organisations (e.g. AEMO).

The demand forecasting consultant is also expected to undertake a brief comparison of each DNSP's demand forecasts for the next regulatory period with:

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62 Some examples of key assumptions include but are not limited to gross state product, energy efficiency requirements, embedded generation, advanced metering infrastructure and demand elasticities used.

(a) actual demand outcomes for the current and previous regulatory periods and

(b) forecasts provided in the current and previous regulatory periods.

Such a comparison should comment on any identified trends over the time period studied and consider any differences in the demand forecasts between the DNSPs. Any improvements or changes in forecasting methods over time should also be identified.

In the event that the demand forecasting consultant considers that a DNSP's forecast methods or data sources are materially deficient in any way, the consultant must identify and explain these deficiencies in its report, and recommend alternatives that the DNSP could reasonably adopt in its regulatory proposal. The alternatives could range from selecting a different scenario provided by the DNSPs' demand forecaster (e.g. using the alternative base scenario) to modifying inputs, assumptions and/or the methodology used to obtain demand forecasts. The alternative methods and data sources must be fully explained in the demand forecasting consultant's report and be compliant with the NER.

In the case of network maximum demand … the consultant will be expected to provide views on the impact of any material deficiencies in quantitative form…

In the case of spatial demand forecasts, the consultant will focus principally on the general methodology and assumptions applied in developing spatial forecasts. In the event the consultant finds any aspect of the methodology or assumptions used to be materially deficient, qualitative findings will be acceptable …

B Overview of spatial forecasting methodologies

Factor	CitiPower	Powercor	Jemena	UED	SP AusNet
Approach	Bottom up from zone substation	Bottom up from feeder level	Bottom up from zone substation	Bottom up from zone substation (10 POE)	Bottom up from zone substation
Reconciles to NIEIR	Does not reconcile. No process for reconciliation	Compares forecasts to ensure 'reasonable range'. No adjustments made to bottom up forecast in this case	Compared and reconciles at both network and terminal level. Jemena adjustment to NIEIR starting point	Reconciles growth rates but not levels (i.e. different starting point with the same growth)	Revised forecast to bring closer to NIEIR although not fully reconciled Main concern is whether growth (in MW) is similar
Weather correction	Ratio based approach using average daily temperature assuming a one for one relationship (VENCorp approach)	No Weather correction (demand driven by water pumping)	Daily observations of demand plotted against average daily temperature to developed polynomial best fit using filtered data (low demand days discarded). Formula developed to adjust max demand to 50 POE based on average temperature (VENCorp approach with non-linear fit)	Weighted average approach to temperature correction. Plots daily observed maximum demand against daily weighted temperature to get slope of best fit. slope is multiplied by the difference between the actual maximum daily weighted temperature and the 10 POE daily weighted average temperature for each of the two sub regions (i.e. VENCorp approach with 80:20 weighted average temperature)	No weather correction
Starting Point	Most recent daily maximum (28 January 2009)	Most recent summer and winter peak demand at feeder level	Daily max demand at feeder, zone and terminal and whole system and normalising for temperature 2009 adjusted for demand not supplied	most recent, actual, summer daily maximum demand (on or about 29 January 2009)	Most recent daily maximum (In some cases 2009) revised down (judgement based weather etc adjustment)

Growth Rates	Two Components Known loads >100kVa (using 50% probability and diversity factors) Growth rate based on staff expectations within a range of 0.3 to 1.0%p.a.	Judgement to determine underlying growth rate (based in part on linear regression last 5 years peaks) No block or spot loads, said to be an unusual occurrence	Two Components Known loads >100kVa added to forecast individually. Organic growth rates estimated based on local knowledge then adjusted to reconcile growth rate to system forecast	Two Components Know loads >500kVa added to forecast individually. Organic growth estimated based on staff expectations. No regard to history – considered unhelpful. Organic growth rates are then adjusted to reconcile growth rate to system forecast	Judgement to determine underlying growth rate (based in part best fit line over the last 5 years peaks) Block or spot loads not added explicitly, but judgement based growth might be influenced by known block or spot loads
Weakness in approach	Addresses relevant issues - reasonable bottom up approach Substantial use of judgment Weather correction using unweighted daily min and max Not reconciled at top level, incapable of accounting for changing economic conditions and policy Not validated/ tested	Substantial use of judgment No weather correction. No attempt to account for drivers of load variability. No investigation of variability of pumping load Not reconciled at top level, incapable of accounting for changing economic conditions and policy Not validated/ tested	Addresses relevant issues - reasonable bottom approach Double counting of block loads and organic growth Use of judgment in growth rates (impact reduced due to reconciliation)	Addresses relevant issues - reasonable bottom approach Spot load not weighted by probability Use of judgment in growth rates (impact reduced due to reconciliation)	Substantial use of judgment No weather correction Lack of transparency Not validated/ tested
System Level Forecast	Sum of non coincident zone substation max demand	Coincident zone substation forecast	System coincident forecast	System coincident forecast (as provided by NIEIR and therefore disconnected from bottom up	System coincident forecast
Proposed Adjustment	36 MW in 2010 to 129 MW in 2015 (2.4% to 7.4%	171 MW in 2010 to 6 MW in 2015 (7.1% to 0.2%)	39 MW in 2010 to 44 MW in 2015 (3.6% to 3.6%)	-2 MW in 2010 to 54 in 2015 (-0.1% to 2.1%)	28.2 MW in 2010 to 49.6 MW 2015 (1.5% to 2.2%
Basis for adjustment	Apply historical level of diversity (7.8%) between NIEIR's system forecast and Sum of non coincident zone substation max demand	Apply NIEIR's system to terminal diversity to Sum of coincident zone substation max demand	Removed Jemena's 2009 starting point adjustment. Done by Apply historical level of diversity (9.5%) between NIEIR's system forecast and Sum of non coincident zone substation max demand	Apply historical level of diversity (3.6%) between NIEIR's system forecast and Sum of non coincident zone substation max demand	Apply historical level of diversity (4.4%) between NIEIR's system forecast and Sum of non coincident zone substation max demand