ElectraNet Transmission Network Revised Revenue Proposal

Appendix F Oakley Greenwood, *Review of ElectraNet's Revised Demand Forecasts*, January 2013

Review of ElectraNet's Revised Demand Forecasts

ACKNOWLEDGEMENT

This report has been prepared in accordance with the Practice Note CM 7 of the Federal Court of Australia. OGW and the individual authors of this report acknowledge that we have read, understood and complied with the Practice Note. In addition, we note that:

- The opinions expressed in this report are wholly or substantially based on the specialised knowledge of the authors, and
- The authors have made all the inquiries that we believe are desirable and appropriate, and no matters of significance that we regard as relevant have to our knowledge been omitted from this report.

DOCUMENT INFORMATION

Project	Review of ElectraNet's Revised Demand Forecasts
Client	ElectraNet
Status	Final Report
Report prepared by	Rohan Harris (rharris@oakleygreenwood.com.au) Lance Hoch (lhoch@oakleygreenwood.com.au)
Date	14 January 2013

Signed by

Rohan Harris

Rohan Harris
Principal Consultant

Lance Hoch

Lance Hoch
Director

Table of CONTENTS

Table of FIGURES

1. Background to and purpose of this report

1.1. Background

The peak demand forecast that ElectraNet filed with its Revenue Proposal in May 2012 was based on (a) a peak demand forecast produced by South Australia Power Networks in April 2012, and (b) the forecast demand of ElectraNet's directly connected end-use customers.

The Australian Energy Regulator (AER) commissioned a review of the ElectraNet forecast from a consulting team comprising of Energy Market Consulting associates (EMCa) and the New Zealand Institute of Economic Research (NZIER). In addition, AEMO had reviewed the SA Power Networks forecast (referred to at the time as ETSA Utilities) on which ElectraNet's forecast had been based.

In response to the comments received, ElectraNet decided to change the basis of its demand forecast from that used by SA Power Networks in its April 2012 forecast, which was based on the 2008-09 year which represented an all-time peak demand due to heat wave conditions, to one based on a level of demand that is likely to be exceeded only once in every ten years (generally referred to as the 10% probability of exceedance, or 10% POE demand). In November 2012, at ElectraNet's request, SA Power Networks prepared a revised forecast of demand at the 10% POE level.

1.2. Purpose of the report and approach taken

At about the same time, ElectraNet commissioned Oakley Greenwood Pty Ltd (OGW) to:

- undertake an independent critical review of the methodology used by EMCa/NZIER in its report, *Review of Demand Forecast Proposed by ElectraNet*,
- provide an independent opinion on the reasonableness of the analysis undertaken and the conclusions drawn in the EMCa/NZIER report, and
- provide an independent review of and advice regarding the reasonableness of the approach taken by ElectraNet in conjunction with SA Power Networks in determining the revised set of connection point demand forecasts that serve as the basis for ElectraNet's revised Revenue Proposal which is to be submitted in January 2013.

It should be noted that in these directions ElectraNet sought a review of the reasonableness of only the methodologies and approaches employed. The Terms of Reference did not include re-calculation of specific outcomes or an audit of data or analyses.

In addressing these issues we reviewed the following documents and other information:

- Energy Market Consulting associates / NZIER, *Review of Demand Forecast Proposed by ElectraNet - Report to Australian Energy Regulator*", 30 October 2012.
- AEMO; *2012 South Australian Electricity Report*, August 2012.
- AEMO; *Rooftop PV Information Paper*, July 2012.

- Letter dated 30th November 2012, from David Pritchard, Manager Network Planning at SA Power Networks, to Hugo Klingenberg, Senior Manager Network Development at ElectraNet, outlining the methodology utilised by SA Power Networks to derive their revised forecasts.

- Letter dated 11th January 2013, from Hugo Klingenberg, Senior Manager Network Development at ElectraNet, to David Pritchard, Manager Network Planning at SA Power Networks, outlining ElectraNet's understanding of the agreed position reached between SA Power Networks and ElectraNet on adjustments made to the 10% POE load forecasts provided on the 30th November 2012 to arrive at the connection point, regional and transmission system load forecasts to be used for connection point and regional transmission network planning.

- Teleconference between OGW and SA Power Networks on the 4th of December to discuss SA Power Network's revised methodology.

These sources were augmented by various follow-up up email correspondences and conversations with ElectraNet and SA Power Networks personnel (via ElectraNet).

2. Key issues, findings and recommendations for further improvement in ElectraNet's approach to demand forecasting

2.1. Key issues

From the review of those documents and discussions with ElectraNet and SA Power Networks personnel, the following key issues were identified:

- What planning standard should underpin the demand forecast?
- How should the 'launch point' be derived?
- How should the forecast (baseline) growth rate in demand be derived?
- Should the effects of 'load curtailment' be included, and if so, how?
- How should the impact of 'embedded generation' be calculated?
- How should the impact of the deployment of solar PV be addressed and included in the forecast?
- What diversity factor across ElectraNet's connection points should be assumed?

2.2. Key findings

Our findings with regard to each of the seven key issues that were identified are presented below.

2.2.1. The planning standard that should be used to underpin the forecast

ElectraNet has lodged a proposal with ESCOSA to change the South Australia Electricity Transmission Code (ETC) to formally apply 10% POE forecasts for non-radial connection points in South Australia, and has adopted that planning standard for use in its revised Revenue Proposal. As such, ElectraNet did not ask us to review the underlying basis for the proposed planning standard, and we have taken 'as given' the need to plan the system to a 10% POE level.

2.2.2. How the 'launch point' for the forecast should be derived

The launch point refers to the peak demand that is used to establish the peak demand at the commencement of the forecast period.

To establish the 10% POE launch point, it is our understanding that EMCa/NZEIR derived:

- their own 50% POE forecast for 2012/13; and
- the relationship between AEMO's 50% POE and 10% POE 2012 demand forecasts (the "planning margin"), which they have then in turn used to adjust their 2012/13 50% POE forecast to a 10% POE forecast.

We do not believe this is an appropriate approach. Our primary concern with the approach used by EMCa/NZIER pertains to its reliance on the AEMO planning margins. It is our view that the approach used by AEMO to derive the 'planning margin' – deriving peak demand from an energy forecast rather than through a direct forecast – is unlikely to accurately account for how the specific conditions pertaining at different POE levels affect load factor.

We also note that EMCa/NZIER based their 50% POE forecast for 2012/13 based on actual historical demand since 2000/01. However, no formal weather correction was undertaken to the annual demands within the period. We consider that, in the absence of a formal weather correction of each year of the historical period, it is difficult to say with any certainty whether or not EMCa/NZIER's proposed 50% POE is in fact a 50% POE demand.

By contrast, a key input to SA Power Networks' November 2012 10% POE demand forecast methodology is the development of a temperature demand index to identify the demand associated with specific POE levels. SA Power Networks assessed long-term historical temperature sequences (heatwave events over a period of slightly over 100 years) to derive the temperature threshold that provides *the potential* for a 10% POE event to occur. SA Power Networks' analysis determined that a weighted average of 38^{o}C – comprised of the maximum temperature on the day in question (67% weighting), the minimum temperature of that morning (18% weighting) and the prior day's average temperature (15% weighting) – provides the temperature at which 10% POE demand levels may result.

For 10% POE demand levels to actually occur, however, other factors also need to be in place. The most important of these were found to be that the temperature threshold occurs on a weekday during a period in which most commercial and industrial facilities could be assumed to be in operation (i.e., not on a public holiday or during the holiday period starting just before Christmas through approximately mid-January).

Using this method, SA Power Networks identified 2009/10 as the appropriate 'base year' for the majority of connection points (over 70%), and 2010/11 as the appropriate 'base year' for around 23% of the connection points (with other years making up the remaining connection points).

We believe that this approach is suitably robust in that it takes account of the temperature over a period beyond a single day, and other factors in identifying the conditions under which 10% POE conditions are likely to occur. We also note that the 38 temperature demand index was reached 19 times over the course of the past 100 years. All of these events occurred in the 10 week period from 20th December and the end of February. Given that weekends and the Christmas / New Year holiday period account for 35 (i.e., 50%) of those days, those 19 events on average could be expected to result in 9.5 10% POE demand levels, which is very close to the 10 events that would be expected over a 100 year period.

We further note that the use of 2009/10 as the 'base year' – which occurs for over 70% of connection points – will, *ceteris paribus*, be more likely to under-estimate rather than overestimate 10% POE demands in that year, given that this occurred on a Monday at the start of January (11 January), which, as observed by SA Power Networks, is before some businesses may have returned from the holiday period.

Based on these considerations we believe that the launch points used in the revised ElectraNet demand forecast are reasonable.

2.2.3. How the forecast underlying growth rate in demand should be derived

The underlying growth rate is the percentage increase in demand, prior to post model adjustments (such as solar PV), which are assumed to occur over the forecast period.

EMCa/NZIER has based its forecast underlying growth rate on its own estimate of historical growth in 50% POE demands from 2000/01 to 2011/12. Even disregarding the extent to which their forecast represents a reasonable approximation of 50% POE demand (as discussed above) we consider that there are issues in applying a growth rate in 50% POE demands to derive the forecast growth at 10% POE levels. In particular, this trend will not reflect the change in temperature dependency of load during 10% POE events relative to 50% POE events, which is likely to have occurred over the intervening period between the first year (2000/01) and the last year (2011/12) of the ten-year evaluation period. In particular, the increased penetration of air-conditioners in the residential sector that has occurred over that period is likely to affect usage on a 10% POE day to a much greater extent than it will affect usage on a 50% POE day.

By contrast, SA Power Networks derived the underlying demand forecast for its revised November 2012 10% POE forecast based on the linear growth rate associated with the actual peak demand experienced in 2000/01 and the base year, which for the majority of connection points, was 2009/10. SA Power Networks stated that the peak demands of those two years were 'very close to 10% POE levels'. However, neither of them was formally weather corrected to 10% POE.

Despite the lack of weather correction we consider that SA Power Network's approach is likely to be preferable to the approach taken by EMCa/NZIER. While SA Power Network's approach would have been more robust had it included weather correction, we note that in the case of the years used by SA Power Networks, such weather correction would have been likely to increase the forecast underlying growth rate used in the forecast, in particular, because the 2009/10 maximum demand occurred in early January, which means that it is highly unlikely to represent a true 10% POE figure for that year. We further note from other information provided by SA Power Networks, which broadly cross-checks against figures derived by NIEIR, that (a) the actual 2000/01 demand was approximately 2.3% below the 10% POE figure for that year however (b) the actual 2009/10 demand was 3.3% lower than the 10% POE figure for that year.

Prima facie, this presents further support to the view that formal weather correction is likely to increase the slope between these two points, resulting in a higher underlying growth rate for the period than has been used.

A weakness in the SA Power Networks approach, however, is that it implicitly assumes that the increasing temperature dependency of load (at 10% POE levels) will continue at the same rate into the future, implying a continuing and constant deterioration in load factor. We do not think this is a warranted assumption. The approach could be improved by using 10% POE demands for each year in the historical period calculated by using weather-correction algorithms applicable to each of the years. This would allow the derivation of not only the point-to-point growth rate over the entire period, but also how the growth rate has changed over the evaluation period. Specifically, this would allow an assessment as to whether placing the same weight on older historical growth rates as is placed on more recent historical growth rates – which is what the linear growth rate implicitly does, is reasonable, or whether there is a disconnect between the two which needs to be considered in the selection of the underlying growth rate to be used for the forecast period. We also consider that this methodology should be sanity checked against one which is based on a more granular, bottom up build. This would involve estimating (a) the number of new customers that are expected to connect to the network, given the expected macro-economic conditions over the forecast period; (b) the demand that each of the additional new customers is expected to place on the system; (c) the estimated diversity of their demand; and (d) the impact of increased penetration of temperature dependent appliances within existing premises on total demand. Other required bottom up calculations include the estimated impact of solar PV and price on future demands on different POE levels, and the level of expected industrial (and commercial) demand as an explicit function of a range of broader macro-economic factors.

2.2.4. Whether and how the effects of 'load curtailment' by large customers should be incorporated into the forecast

EMCa/NZIER's states that[1] *"in our view the credibility of the ETSA "peak to peak" forecasting approach is challenged by the material adjustments that it made to recent historical actuals and especially the large upward adjustment that was made to create an apparent 2009 "alltime peak". This adjustment critically compromises both the growth rate (which was measured between the 2001 and 2009 "adjusted" peaks) and the choice of the 2009 adjusted peak as base year for the forecast."*

Broadly, we agree with EMCa/NZIER's critique; the manner in which these adjustments have been made is likely to over-state likely underlying peak demand. In short, in its original Revenue Proposal, ElectraNet removed the actual coincident peak demand of its directly connected customers and SA Power Network's major customers, and then added back in the anytime maximum demand of these customers over the evaluation period.

This essentially constitutes a deterministic, 'worst case' approach. We do not feel that this is consistent with the use of a 10% POE planning standard, and recommended an alternative methodology that is based on the probabilistic assessment of each customer's 10% POE demand level, given the time of day that their connection point generally peaks. More specifically, it involves:

- Obtaining demand data for the last five summer periods (plus March) for each customer;

1 Energy Market Consulting associates / NZIER – "Review of Demand Forecast Proposed by ElectraNet - Report to Australian Energy Regulator", p 23.

- Identifying the time at which the connection point that each of these customers is connected to generally peaked;
- Creating a distribution of the actual demands of each customer, during the summer months (plus March) in each year at the relevant peaking time identified above;
- Determining the 10% POE demand threshold for each year (i.e., the level of demand above which 10% of actual demands occurred); and
- Taking an average of the five annual 10% POE demand thresholds, and using this as the basis for the 10% POE forecast.

We consider that this approach represents a more robust statistical approach to generating the baseline 10% POE forecasts for these large customers. It also (a) puts these forecasts more on the basis of the mass market load forecasts, which are based on 10% POE conditions, and (b) provides a transparent, repeatable basis for deriving these demands.

This approach was accepted by both ElectraNet and SA Power Networks, and has been used in the demand forecasts included in ElectraNet's January 2013 revised Revenue Proposal.

To further improve the demand forecast in the future, we have also recommended that ElectraNet and SA Power Networks:

- undertake more detailed statistical analysis as to the relationship between market price and demand;
- assess the statistical relationship between the temperature demand index for the region most closely associated with the connection points in question and the demands of these customers; and
- undertake direct discussions with their major customers regarding the potential drivers of usage and curtailment on peak demand days. Specifically, we suggest that these customers be asked whether they have (or are likely to) put in place any measures or agreements to reduce load in response to market prices or a notification from a retailer, demand aggregator or other third party[2].

2.2.5. How the impact of 'embedded generation' on peak demand should be calculated

There are a number of different types of embedded generators connected to ElectraNet's system, including traditional power stations, wind farms, and land fill dump waste gas generators. Some of these generators appear to generate only during certain defined periods of the day (e.g., they stop generating at 6pm), whilst, for others this is not the case. Similarly, for some, there appears to be a relationship between generation and market price, whilst for others, this relationship is less pronounced.

2 We note that the AEMC, as part of its *Power of choice* review, has proposed that large customers be allowed to provide demand response into the wholesale market on settlement terms similar to those available to non-scheduled generators. If this proposal is put into practice it is reasonable to assume that more demand response will be provided on the part of these customers, and the nature of the non-scheduled arrangement under which it will be provided will make a probabilistic approach to it estimation for forecasting purposes increasingly important.

As a result, the expected level of coincidence of the generation output with the time of peak demand at its connection point is likely to vary across different embedded generators. As a result, their impact on the remaining connection point peak demand, regional and system maximum demands will differ.

In commenting on ElectraNet's original demand forecasts, EMCa/NZIER state that:

- *"The forecast effectively discounts (by adding back) the positive contribution to peak demand reduction of consumer demand response and embedded generation*[3] *"*…and
- *"in our view the credibility of the ETSA "peak to peak" forecasting approach is challenged by the material adjustments that it made to recent historical actuals and especially the large upward adjustment that was made to create an apparent 2009 "alltime peak". This adjustment critically compromises both the growth rate (which was measured between the 2001 and 2009 "adjusted" peaks) and the choice of the 2009 adjusted peak as base year for the forecast*[4]*."*

We agree with EMCa/NZIER that the large upward adjustments contained in ElectraNet's original Revenue Proposal are unlikely to be warranted. Rather, we consider that a detailed analysis of the components and drivers of those adjustments should be undertaken before any adjustments are made.

It is our understanding that as part of its revised Revenue Proposal, ElectraNet has examined the historical contribution of embedded generation within the distribution system in each of its regions. From that historical assessment an estimate has been made of the level of embedded generation that can be expected to occur at times of:

- regional and connection point maximum demand; and
- total system maximum demand.

We consider this approach to be a reasonable starting approach for developing the demand forecast. However, we recommend that this approach be augmented in the future with greater explicit regard for the relationship between market price, connection point peak demands and the dispatch of individual embedded generators. This is analogous to the approach that we recommended be adopted with regard to load curtailment by major customers.

2.2.6. How the impact of the deployment of rooftop solar PV systems on peak demand should be calculated and included in the forecast

The impact of rooftop solar PV systems on peak demand is a function of the number of PV installations that take place, the average generating capacity of the systems installed, and the operating efficiency of the panels and overall systems at the times of day at which peak demands occur in each of ElectraNet's connection points.

---

3 Energy Market Consulting associates / NZIER - "Review of Demand Forecast Proposed by ElectraNet - Report to Australian Energy Regulator", p 6.

4 Ibid, p 23.

EMCa/NZIER suggest that the estimated impact of solar be added back into the historical demand, and then the forecast impact of solar over the Regulatory Period be removed from the underlying growth in peak demand they have calculated, inclusive of the historical solar impact that was added back. EMCA/NZIER's forecast impact of solar of the Regulatory Period is based on AEMO forecasts.

We consider that EMCa/NZIER's use of the AEMO forecasts is reasonable, in the absence of any more granular information.

By contrast SA Power Networks has calculated the impact of solar PV on peak demand at each connection point, as:

- the total PV inverter capacity committed as at February 2012 at each connection point
- *times* a factor derived from a sample of three 1 kW PV systems that expresses the percentage of the system's rated capacity that was generated by half hour on sunny days
- *times* an 80% factor to correct for the actual connected panel capacity (relative to the installed inverter capacity), as well as to allow for wiring/orientation/vegetation issues.

The AEMO approach results in the solar PV systems having a 38% generation contribution at time of system peak (assumed to be 4.30pm), which, is slightly lower than SA Power Network's method which results in a forecast of 42% generation contribution at 4:30pm. While the two estimates are broadly similar, we have reservations about both.

Our concerns regarding the SA Power Networks approach centre on the overall statistical validity of the use of only the three 1 kW PV units to underpin its output factors. We also have some concern with the 80% factor as it was developed from information provided by other distribution businesses, and the transferability of their information to SA conditions cannot be taken for granted.

Our concerns regarding the AEMO generation estimate relates to the fact that it was based on a sample of system data obtained from a public website where people upload their own solar PV information. This raises the potential for the sample to suffer from self-selection bias, in that customers with better results may be more likely to report them. In addition, we note that AEMO develops its estimate from an "average" of system output on high-demand days. Solar PV output factors are likely to be lower as a result of the higher temperatures that are likely to characterise 10% POE conditions. Therefore, averaging data over multiple days – even though they are "high demand" days – may inflate the percentage output, when compared against a day that exhibits temperatures entirely consistent with 10% POE conditions.

Overall, we consider that the AEMO output percentages are likely to provide a more reasonable basis for deriving demand forecasts for ElectraNet. However, based on the information that we have been able to obtain in the public domain, we consider that even these forecasts may be overly optimistic. As a result, ElectraNet's use of SA Power Network's output percentages is likely to represent a conservative position.

With regards to penetration rates, SA Power Networks has assumed a 6% per annum increase as its core assumption based on internal information on connection applications over time. AEMO, in its 2012 state-wide forecasts (in the NPFR), has used 8%. These two estimates are not dissimilar but as we do not have detailed information on the underlying basis for either of these forecasts of take-up, we are not in a position to express a definitive preference for one or the other.

2.2.7. What diversity factor across ElectraNet's connection points should be used in the forecast

The 'Diversity Factor'[5] represents the difference between the aggregated demand forecasts of lower levels of the network (e.g., connection points), and the expected demand forecast at higher network levels (e.g., regions). As such a diversity factor must be determined to ensure that the demand forecasts at connection point level, when combined, are a reasonable reflection of the demand forecasts that will underpin any augmentation of the regional transmission network that is required to service those connection points.

We agree with EMCa/NZIER's position that for regional augmentation planning purposes, it is reasonable that a diversity factor be applied to the undiversified connection point demands. However, it is our understanding that EMCa/NZIER calculated the diversity factor used in their demand forecast based only on data from 2012. In this regard we note that the use of a single year for the development of the diversity factor is not optimal, particularly given that 2012 was not a 10% POE year, and diversity (particularly where a significant proportion of peak demand is temperature-sensitive), is likely to be materially different at different POE levels. Specifically, we would expect the correlation between decreases in diversity and decreases on POE level to be higher in areas with a higher proportion of temperature sensitive loads.

We also note that for practical purposes, it is the diversity factor of those regions in which augmentation may be required within a regulatory period (rather than the diversity factor that applies to the entire service area) that really matter.

In light of the 10% POE basis of the demand forecast to be included in its revised Revenue Proposal, ElectraNet has reviewed its historical diversity factors. It has done so:

- only for the connection points within those regions in which augmentation projects are contemplated over the coming regulatory period, and
- using data for the past four years; but selected the final diversity factors to be used based on observed diversity in 2009/10 and 2010/11, which we note are characterised by close to 10% POE conditions.

We consider that ElectraNet's revised approach is a reasonable basis for modelling regional demand forecasts.

5 Also known as a co-incidence factor.

2.2.8. Additional high level comments on the AEMO forecasts

We were also asked to provide a high-level review of AEMO's forecast of maximum demand in South Australia. Certain aspects of the AEMO forecast have been considered as part of one or another of the issues discussed above (for example the use of the AEMO planning margin and solar PV impact on maximum demand).

The other most relevant part of the AEMO forecast is its calculation of the forecast underlying growth rate.

The most recent AEMO forecasts (2012) assume a growth rate of only 1% in 10% POE maximum demand (or ~34 MW) over the period[6]. This compares to ElectraNet's revised growth rate of 1.8% (or ~60 MW per annum)[7].

This appears to be at the very low end of what a very high level check would indicate as being reasonable.

For example, air-conditioner sales alone are around 180 MW per annum at present (and have been at that level for at least the past five years). Some of these sales will replace old units, and therefore will not add to overall installed capacity. In fact, to the extent that the new units are more efficient than those they replace (which is almost certainly the case), their use may actually reduce maximum demand. However, even if we assume that say, 20% of these air-conditioners[8] are replacements[9], and that the new units are 30% more efficient than those they replace, and their coincidence factor is 75%, additional air-conditioning capacity being installed annually would still be approximately 100 MW.

While this increase will be offset by a number of factors, including the impact of increased solar penetration and possible demand response among larger customers, relatively material contributions would be required to achieve the net growth rate put forward by AEMO. In this regard, we note that the amount of solar PV forecast by AEMO would reduce the annual growth in maximum demand by 10 MW at the most. Further, while demand response may increase if the AEMC's proposed demand response mechanism is implemented, we note that (a) this mechanism had not been proposed at the time the AEMO forecast was made, and (b) even if it is implemented, it will not be in effect for at least a year and will require some time to create an impact.

In sum, therefore, we believe that a high-level assessment of the two most important drivers of changes in maximum demand over the forecast period appears to lead to outcomes that are more consistent with the outcomes presented by ElectraNet as compared to those presented by AEMO.

---

6 AEMO, "2012 South Australian Electricity Report", p 13.

7 This includes a one off reduction associated with the SA Water desalination plant mothballing, which, if excluded, would increase the growth rate by around 10 MW per annum.

8 20% in theory equates to a 5 year appliance life, which is incredibly conservative.

9 Noting that this ignores the previously mentioned possibility that some of the 'replaced' machines are in fact moved to another room.

2.3. Recommendations for further improvement in ElectraNet's approach to demand forecasting

2.3.1. Launch point

There are two components of the overall analysis that relate to the derivation of the launch point that we consider should be done in the future. These are:

- A thorough review of the rationale for the weightings that underpin the temperature demand index should be undertaken (e.g., that day's maximum, which has a 67% weighting, plus the minimum earlier that morning, which has an 18% weighting, plus the prior day's average temperature, which has a 15% weighting).

- A probabilistic assessment of the extent to which 10 *% POE temperature events* are more or less likely to occur during sub-periods within the December through end of February period (i.e., is a 38 temperature demand index event more or less likely to occur in early January – where other factors limit the likelihood of that event causing an overall 10% POE condition to occur – relative to say February).

2.3.2. Underlying growth rate

Despite the fact that the two data points used to calculate the linear growth rate are "close to 10% POE figures", ideally, these figures should in fact be formally weather corrected, before the growth rate is in fact calculated using this methodology.

We would also recommend that an approach that weather corrects all historical years to 10% POE levels, based on the weather-correction algorithms applicable in that year, should be used if possible. This would allow the derivation of not only the point-to-point growth rate over the entire period, but also how the growth rate has changed over the evaluation period. Specifically, this would allow an assessment as to whether placing the same weight on older historical growth rates as is placed on more recent historical growth rates – which is what the linear growth rate implicitly does - is reasonable, or whether there is a disconnect between the two which needs to be considered in the selection of the underlying growth rate to be used for the forecast period.

Additionally, we would recommend that an approach that relies upon historical growth rates be sanity checked against one which is based on a more granular, bottom up build. This would involve estimating (a) the number of new customers that are expected to connect to the network, given the expected macro-economic conditions over the forecast period; (b) the demands that each additional new customer is expected to place on the system; (c) the estimated diversity of their demand; and (d) impact of increased penetration of temperature dependent appliances within existing premises on total demand. Other required bottom up calculations would include the estimated impact of solar PV and price on future demands on different POE levels, and the level of expected industrial (and commercial) demand as an explicit function of a range of broader macro-economic factors.

2.3.3. Inclusion of load curtailment for major customers

We believe that the following additional work would allow ElectraNet to establish more robust forecasts of major customer in South Australia:

- Undertaking more detailed statistical analysis into the relationship between market price and the demand of major customers. This would allow a more robust assessment of the extent to which high market prices, which are likely to be highly correlated with a high temperature-demand index at the State-wide level, affect the demand of these major customers, which would in turn allow for a more accurate demand distribution to be determined upon which 10% POE levels could be calculated;
- Assessing the statistical relationship between the temperature-demand index for the region within which that major customer is located, and the demands of those customers. This would allow an assessment of the extent to which these customers' loads may in fact be temperature driven, which in turn would allow for a more accurate demand distribution to be determined upon which 10% POE levels could be calculated; and
- Undertaking direct discussions with major customers regarding the potential drivers of usage and curtailment on peak demand days. Specifically, we suggest that these customers be asked whether they have (or are likely to) put in place any measures or have entered (or are likely to) into any agreements to reduce load in response to market prices or a notification from a retailer, demand aggregator or other third party.

We would also recommend that ElectraNet apply a similar methodology to its own direct connect customers.

2.3.4. Inclusion of embedded generation

We recommend that ElectraNet adopt an approach that has more explicit regard for the relationship between market price, connection point peak demands, and the dispatch of individual embedded generators. This is analogous to the approach that we recommended be adopted with regard to load curtailment by Major Customers. More specifically, such an approach would involve, amongst other things:

- Obtaining generation data for previous summer periods (plus March) for each embedded generator;
- Identifying the time at which the connection point that each embedded generator is connected to has generally peaked;
- Creating a distribution of the actual generation amounts of each generator customer in each year during the summer months (plus March), at the relevant peaking time identified above;
- Augmenting this with an analysis of the statistical relationship between:

- Market price and that connection point peaking to determine the likely coincidence of that connection point peaking at times of high market prices. This is important as the latter is driven by state-wide demands, as opposed to connection point demands. This should also be done for different POE levels, as the level of coincidence may differ depending on the underlying temperature conditions on those peak demand days and the temperature-sensitivity of demand in the area served by the relevant connection point; and
- The relationship between embedded generator output and market price at times when the relevant connection point is assumed to peak.

Individualising an algorithm for each embedded generator which has regard for each of the aforementioned factors, which in turn will allow forecasts of future 10% POE generation amounts to be derived based on:

- 10% POE market price forecasts;
- the time at which the connection point that they are connected to peaks;
- the probability of that connection point peaking at times of high market prices during 10% POE conditions;
- the likely response of that embedded generator to high market prices during 10% POE conditions; and
- the underlying pattern of generation of those embedded generators, in particular, the extent to which they are able to (or have historically) generated at times when the connection point has peaked.

This approach could be further augmented by ElectraNet interviewing at least the larger embedded generators regarding the reasonableness of the results they obtain from the aforementioned analyses. As part of this, ElectraNet would seek information (on a strictly confidential basis) of the nature of the generator’s forward commercial arrangements, in particular, with a view to assessing whether similar or different generation operation could be expected over the forecast period. This would also assist ElectraNet in its operational planning, and more broadly, assist it in providing a reliable and safe transmission service.

2.3.5. Impact of Solar PV

We would recommend that the underlying factors that are likely to impact on the economics of solar PV, should, ideally, be explicitly considered when estimating future penetration rates. These include, but are not limited to:

- The expected output of PV systems, given location, sunlight intensity etc.;
- The price of installing PV systems;
- The amount and timing of solar subsidies and feed-in-tariffs;
- Retail electricity prices – and price structures – faced by consumers; and
- The rate of return (or payback period) required by consumers to install PV systems.

If not already done, we would recommend that further detailed investigation as to the factors contributing to the “80% factor” applied by SA Power Networks should be undertaken, before the use of data from other distribution businesses is deemed to provide an accurate reflection of the likely values attributable to customers in SA Power Network’s area.

More generally, we would recommend that where feasible, SA Power Networks increase the size of the sample upon which it is basing its assessment of the output from solar panels in South Australia. Obtaining a statistically significant sample of customers from across its region would allow it to obtain more granular output factors – e.g., at a regional/connection point level, and moreover, overcome the potential self-selection bias of the PVOutput.org sample used by AEMO.

2.3.6. Diversity factor

Whilst ElectraNet has adopted the pragmatic approach of calculating the diversity in the region where the potential timing of regional augmentation projects is affected is reasonable, we consider that in future, diversity factors for each region should be derived, and used as the basis for regional planning in that area. This would also form the basis for a more accurate reconciliation with State-wide forecasts of demand.

3. Structure of this Report

We have structured this report around what we consider to be the seven key components common across each of the above mentioned forecasts. These are:

- What planning standard should underpin the demand forecast?
- How should the ‘launch point’ be derived?
- How should the forecast (baseline) growth rate in demand be derived?
- Should the effects of ‘load curtailment’ be included, and if so, how?
- How should the impact of ‘embedded generation’ be calculated?
- How should the impact of the deployment of solar PV be addressed and included in the forecast?
- What diversity factor across CP’s should be assumed?

Each component is discussed separately.

In addition, we have provided some high-level comments on AEMO’s 2012 forecast for South Australia.

4. Planning standard

4.1. Background

- This refers to the level of service that is to be assumed to be maintained by ElectraNet, and that act as the criterion for assessing when augmentation (and what level of augmentation) is needed to its transmission network.
- In the context of electricity network reliability, the level of service is generally defined in terms of service level maintenance under specified load conditions, which are generally expressed in terms of the probability of that load being exceeded (probability of exceedance, or POE).
- Whilst the POE is primarily related to the probability of certain temperature events occurring – as demand is predominately driven by temperature related electricity consumption – there are other factors that also affect whether the specified POE load condition will occur. These include:
  - The time of year that that temperature event occurs, and in particular, whether this coincides with holidays in which businesses are down and / or population effects may be less centralised in capital cities (e.g., early January versus early February);
  - The day of week that the temperature event occurs (weekday versus weekend); and
  - Individual businesses' production processes, which in turn drive their demand for electricity, which may be unrelated to temperature.

4.2. Observations

- In its original Revenue Proposal, ElectraNet did not explicitly consider temperature related POE, or for that matter, any of the other factors mentioned above that affect the POE. Rather, the forecasts were based on the 2008/09 demand. This was consistent with their previous practice and understanding of the interplay between the SA Electricity Transmission Code (ETC), which requires ElectraNet to design the transmission network such that there is no requirement to shed load under normal and reasonably foreseeable circumstances and the excess demand charge in the Transmission Connection Agreement with SA Power Networks.
- EMCa/NZIER noted that the demand used by ElectraNet as the basis of its starting point "*appears to be well in excess of that required to meet a POE10% standard*[10]".
- It is our understanding that ElectraNet has lodged a proposal with ESCOSA to change the ETC to formally apply 10% POE forecasts for non-radial connection points in South Australia.

10 Energy Market Consulting associates / NZIER - "Review of Demand Forecast Proposed by ElectraNet - Report to Australian Energy Regulator", p 15.

4.3. Conclusion

- Based on the request to ESCOSA noted above, ElectraNet's revised Revenue Proposal will be based on a 10% POE planning standard, and as a result, ElectraNet did not ask us to review the underlying basis for the proposed planning standard.
- As such, we have taken 'as given' the need to plan the system to a 10% POE level – noting again that this requires more than just the consideration of temperature related POE.

5. Launch point

5.1. Background

- The launch point refers to the starting year 10% POE demand, to which growth rates, solar PV penetration rates, diversity factors etc., are applied.

5.2. EMCa/NZIER proposed methodology

- Our interpretation of EMCa/NZEIR's proposed approach is that to develop their 10% POE launch point, they have derived:
  - their own 50% POE forecast for 2012/13; and
  - the relationship between AEMO's 50% POE and 10% POE 2012 demand forecasts (the "planning margin"), which they have then in turn used to adjust their 2012/13 50% POE forecast to a 10% POE forecast.
- We base the above comment, on amongst other things, EMCa/NZIER statements that:

  "*we have developed the trend forecast as described in the preceding sections, based on trending underlying historical demand, adding direct customer forecasts (from ElectraNet) and taking account of PV, <u>a temperature-related planning margin</u> and diversity to the regional level*[11]" and

  "*for check forecasting purposes, we have added the AEMO POE10% demand margin to the POE50% trend forecast derived above for the ETSA connection points, then added ElectraNet's forecasts for its direct connect customers*[12]".

- Our primary concern with the approach used by EMCa/NZIER pertains to its reliance on the AEMO planning margins. In particular, we note that EMCa/NZIER state that '*we have no reason to doubt AEMO's assessment*', yet this is despite the fact that they clearly do not consider the AEMO forecasts, in totality, to be reasonable. For example, EMCa state that:

11 Ibid, p 29.

12 Ibid, p 27.

> *'In our high-level review, we briefly considered the suitability of the AEMO 2011 demand forecast since ElectraNet presents this in its RP and in its reconciliation report. We consider that this forecast also suffers from weaknesses that we would regard as material to its use in the RP. The AEMO forecasts have been criticised by ElectraNet and by others for an unsatisfactory methodology that exhibits poor regression statistics and unreasonable coefficients and these are evident in its 2011 forecast. We also consider it preferable that a top-down check model forecasts peak demand directly, rather than forecasting energy and then converting it to a peak demand forecast. In this regard we note the significant differences in drivers between peak demand and energy use*[13]*'.*

and

> *For a number of reasons, we do not consider this* [the AEMO approach] *the preferred means for forecasting peak demand at the transmission level. For example, energy consumption is far less influenced by temperature than peak demand and therefore the base energy forecasting model would tend not to capture the effect of historical temperatures on peak demand. Further, there is evidence in the AEMO and ElectraNet reports of some significant and relatively recent changes in the relationship between peak demand at the connection point level and grid generation (as measured for the purposes of AEMO's modelling), for example through rooftop solar (PV), demand response and embedded generation, and this further complicates the use of a generated-energy model for transmission peak demand forecasting purposes*[14]*.*

- We particularly note the reference to it being "*preferable that a top-down check model forecasts peak demand directly, rather than forecasting energy and then converting it to a peak demand forecast*". We agree with EMCa/NZIER's assessment, and in our mind, it is particularly relevant to the 'planning margin' that is derived by AEMO. We note that the approach adopted by AEMO is unlikely to be able to take into account changes in load factor; in fact, it is our understanding that AEMO assume that the load factor remains constant. AEMO's approach is also unlikely to be able to take into account how different POE conditions affect load factor, which is fundamental to the derivation of the planning margin that is at the core of the EMCa/NZIER methodology.

- By way of example, we note that AEMO have made a number of changes to the input assumptions underpinning the 2012 National Electricity Forecasting Report (NEFR) forecasts, relative to the 2011 Electricity Statement of Opportunities (ESOO) forecasts, and as a result, not only did the overall demand forecast reduce at all POE levels (10%, 50% and 90% POE levels), but the 'planning margin' was also reduced (from 10.3% in 2012/13 in the 2011 ESOO, to 9.4% in the NEFR). To quote from the 2012 NEFR, the changes to the model that have led to the overall reduction in demand (which in turn flow through to the planning margin) are[15]:

---

13 Ibid, p 6.

14 Ibid, p 15.

15 AEMO; "*2012 South Australian Electricity Report*", p 14.

- *'Slower than expected forecast increase in large industrial electricity demand, including developments in the mining sector and desalination plant.*
- *Significant penetration of rooftop photovoltaics (PV), which is further explained in the following section.*
- *Reduced demand in the manufacturing sector in response to the high Australian dollar.*
- *Moderation in gross state product (GSP) growth projections leading to reduced annual energy forecasts, especially in the short term.*
- *Commercial and residential consumer response to rising electricity costs, including energy efficiency measures. In 2012-13, electricity prices are expected to continue to increase, and then, on average, are expected to be moderate from 2013-14 until the end of the 10-year outlook period.*'

- In summary, it is unclear why any of these factors would have led to a reduction in the 'planning margin' at all, nor, why, given these changes, the planning margin in 2012/13 would be virtually identical to that which is calculated for 2017/18 in the new forecasts. In particular, we would have thought that the planning margin would have in fact increased in both the short and longer term – potentially materially – as a result of these factors. For example:
  - Whilst we would fully expect the price elasticity effects to impact on energy consumption (which in turn underpins the AEMO forecasts), we consider that in the absence of critical peak demand based pricing being applied to temperature dependent load, the elasticity effects could be materially different during the more extreme heat events that characterise a 10% POE forecast relative to a 50% POE forecast. This is because whilst the price remains the same (because they are not demand based, or time variant), the value that a consumer drives from the use of air-conditioning increases as temperature increases. By contrast, the relative value the consumer derives from less energy intensive sources of cooling, such as fans and blinds diminishes, as temperature increases and the general amenity impacts of higher temperatures (e.g., discomfort levels) increase.
  - All PV semiconductor technologies incur increasing losses in performance as temperature rises. We note one study that suggests this can be as much as 0.5% per degree Celsius[16]. Obviously, during the more extreme heat events that characterise a 10% POE forecast relative to a 50% POE forecast, the output from PV panels will reduce proportionately, which again would have the effect of increasing the planning margin, rather than reducing the planning margin. Whilst the overall degradation of panel performance may be small when considered at the individual panel level, the overall impact is magnified when considered in the context of the aggregated large solar penetration rates assumed over the forecast period; and

16 Photovoltaics International Journal: "*Performance characterization and superior energy yield of First Solar PV power plants in high-temperature conditions*", August 2012.

- Slower than expected forecast increases in large industrial electricity demand, and reduced demand in the manufacturing sector in response to the high Australian dollar, would again go to increase the planning margin in the new forecasts, relative to the old forecasts. This is because these customers are likely to have much better (i.e., higher) annual load factors across all POE ranges (as they are primarily unrelated to temperature) when compared to the rest of the customer base. Therefore as the energy consumption of these customers decreases as a proportion of total load, the total system load factor will decline and the overall temperature sensitivity of the total load will increase.

- In summary, whilst the scope of this project does not provide for us to undertake a thorough critique and review of the AEMO forecasts, nor the methodology underpinning those forecasts, we consider that:

  - Placing significant weight on the AEMO "planning margin" to derive ElectraNet's demand forecasts is inconsistent with the broader discussion and level of trust in the AEMO forecasts expressed by EMCa/NZIER in its report. This is particularly pertinent given that one of the reasons EMCa/NZIER questions the use of the AEMO forecasts is likely to directly impact on the robustness of the 'planning margins' that EMCa/NZIER heavily relies upon in its methodology; and

  - A number of the factors mentioned by AEMO in support of the significant change in their 2012 NEFR forecasts relative to their 2011 ESOO forecasts would actually have the effect of increasing rather than reducing the planning margin in 2012/13. Furthermore, the contribution of these factors over time would, ceteris paribus, be expected to increase the planning margin over the evaluation period (e.g., between 2012/13 and 2017/18), as things like solar penetration and differing elasticity effects at different POE levels become more pronounced etc., which again, is inconsistent with the AEMO outcomes.

- We consider that the above issues cast doubt on what is a fundamental aspect of EMCa/NZIER's approach to deriving the launch point.

- Over and above the aforementioned issue, we query EMCa/NZIER's assertion that its[17] *"trend forecast…. conceptually is a PoE50% forecast – that has an equal probability of actual demand exceeding or being less than this level)*", in particular, because EMCa/NZIER have not explicitly taken into account the temperature conditions that have occurred over the ten-year evaluation period. This is particularly pertinent as heatwave events appear to have historically tended to come in waves (i.e., once a heatwave event has occurred, there is a greater probability of heat events occurring in the following year) - see the figure below in section **Error! Reference source not found.** for more information. Therefore, just because a ten-year period was used as the basis of the assessment, we do not consider that it can be concluded that that period exhibited temperature conditions that would lead to outcomes that could be considered consistent with 50% POE conditions. We note that in saying this, we are not necessarily suggesting that explicit consideration of the temperature conditions within the period would automatically lead to a higher demand being derived using EMCa/NZIER's methodology; it could in fact lead to a lower starting demand. We simply make the point that in the absence of an assessment of the underlying conditions underpinning each peak demand data point over the evaluation period (temperature, time of year), it is impossible to state with any certainty that the methodology adopted by EMCa/NZIER will lead to 50% POE levels.

5.3. SA Power Network's revised methodology

- We understand that for each connection point, the 'base year' used to derive the 'launch point' is based on a number of different factors, including the particular characteristics of the customers connected to the network below that connection point. Further, based on information provided by SA Power Networks, we understand that for over 70% of connection points, the 'base year' was 2009/10, whilst a further 23% used 2010/11 as the 'base year' (with the remainder being based on other years).

- Furthermore, we understand from verbal discussions with SA Power Networks that a key part of their forecasting approach was to create a temperature demand index, based on that day's maximum temperature (which has a 67% weighting) plus the minimum temperature earlier that morning (18% weighting) plus the prior day's average temperature (15% weighting). SA Power Networks uses a 38 temperature demand index as a guide to a 10% POE.

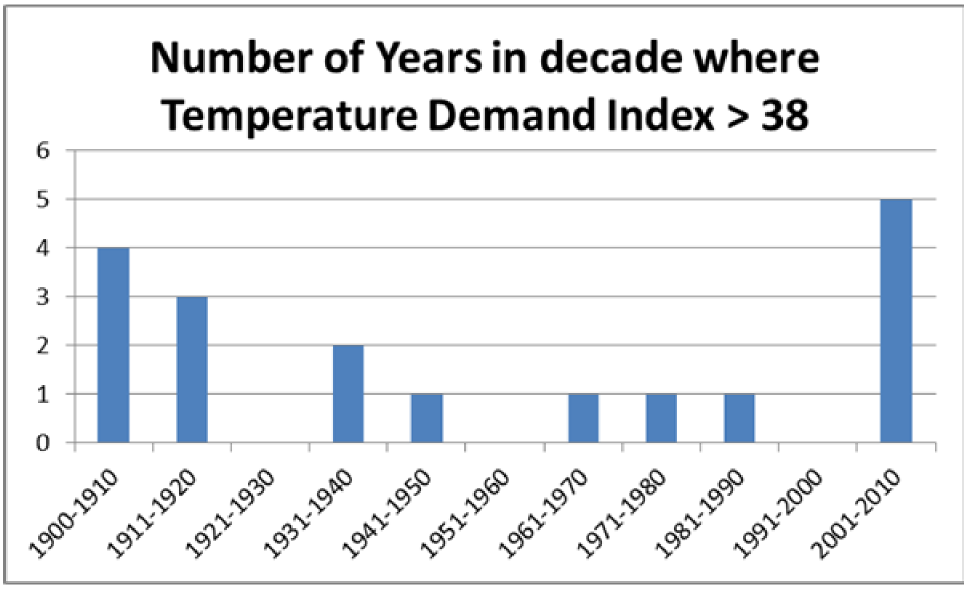
- In an email dated Wed 5/12/2012 2:10 PM from James Bennett – Manager Regulation at SA Power Networks, to Michael Heyer - Substation & Planning Officer at SA Power Networks, it was stated that "*over the last 13 years, there have been 6 years with such a day – more than would be expected by a 10% POE. However, many of these occurred outside of work-days or during holiday periods*". Essentially, this notes that the occurrence of the temperature that is associated with 10% POE conditions does not in and of itself mean that a 10% POE event will occur. Other conditions must also be met.

17 Energy Market Consulting associates / NZIER – "*Review of Demand Forecast Proposed by ElectraNet - Report to Australian Energy Regulator*" – p 27.

- We have reviewed the analysis undertaken by SA Power Networks with regards to the historical heatwave events that it has used to derive the probability of the underlying temperatures that are in turn used to determine that a 38 temperature demand index is consistent with a 10% POE outcome.

- Based on the information provided, the overarching methodology for determining the temperature related component of the POE appears reasonable, in that it utilises long-term historical temperature sequences (heatwave events) to determine the probability that a certain temperature demand index will occur. See Figure 1 below for the historical data series. It is this temperature demand index that is used to derive the 10% POE *temperature* threshold that provides the potential for a 10% POE event to occur.

Figure 1: Temperature Demand Index > 38 during heatwaves in South Australia



Source: SA Power Networks

- We note that Figure 1 notes that heatwaves often cluster. Four of the ten decades for which information is available experienced at least 2 heatwaves, while three had none.

- In addition, while the data in Figure 1indicate that five 10% POE temperature events have occurred in the last 10 years, we believe POE should be considered over a much longer time period. To this end, the data provided indicates that 13 other events have occurred between 1904/05 and 1997/98. Therefore, in total, 19 (13 plus 6) events have occurred broadly in what is a very long data series (≈100 years). This indicates that, from a purely *temperature perspective*, these temperature events are likely to occur twice every ten years rather than once. Hence, from a purely temperature perspective, a higher temperature demand index threshold would be required than what has been derived by SA Power Networks to establish a 10% POE condition on the basis of temperature alone.

- However, we note that to convert a *10% POE temperature outcome* to a *10% POE demand outcome*, the overall probability of that temperature event occurring on a day that does not coincide with certain other factors (e.g., weekends or holiday periods) also needs to be taken into account. Whilst SA Power Networks appears to have had regard for this in a qualitative sense, for the purposes of assessing whether SA Power Network's proposed launch point is consistent with 10% POE demand conditions, we consider that this should be done in a more formal, probabilistic manner.

- To do this, we consider it reasonable to first assume that a 38 temperature demand index could only occur on any day between the 20th December and the end of February. This range was chosen as it represents the range over which 38 temperature demand index days have occurred over the last ≈100 years based on the data provided by SA Power Networks. This equals 10 weeks. Therefore, to convert the *10% POE temperature events* to a *10% POE demand event*, the probability of a temperature event occurring needs to be further "discounted" by the probability of that event occurring:

  - On a weekend over that 10 week period (20 weekend days / 70 total days); or

  - During the Christmas / New year holiday period over that 10 week period (estimated to be 15 workdays between Christmas and mid-January / 70 total days).

- In total, this equates to 35 days out of 70 days, or 50%. Therefore, the probability of the 10% POE temperature event occurring on a day which coincides with other variables that are not barriers to a global peak demand event occurring is 19% (19 out of the last ≈100 years) x 50% = 9.5% which is consistent with a 10% POE demand event.

5.4. Summary of key points

- We consider that SA Power Networks' overall temperature threshold is likely to be reasonable, and consistent with broader 10% POE conditions, once both temperature and other factors are considered. We further note that the use of 2009/10 as the 'base year' – which occurs for over 70% of connection points – will, ceteris paribus, be more likely to under-estimate rather than overestimate 10% POE demands in that year, given that this occurred on a Monday at the start of January (11 January), which, as observed by SA Power Networks, is before some businesses may have returned from the holiday period. Counteracting this is that using historical years as 'launch points' means that other changes that are otherwise not captured in post model adjustments will not be factored into the forecasts. This is discussed further in later sections.

- As outlined above, we have concerns with regards to the use by EMCa/NZIER of the AEMO planning margins for converting their assumed 50% POE forecast into a 10% POE forecast. We also consider that in the absence of a formal weather correction of each year of the historical evaluation period, it is difficult to say with any certainty whether or not EMCa/NZIER's proposed 50% POE is in fact a 50% POE demand.

- Notwithstanding the above, there are two other components of the overall analysis that we consider should be done in the future, but which, due to the scope and timeframes associated with undertaking this project, we have been unable to undertake. These are:

- A thorough review of the rationale for the weightings that underpin the temperature demand index should be undertaken (e.g., that day's maximum, which has a 67% weighting, plus the minimum earlier that morning, which has an 18% weighting, plus the prior day's average temperature, which has a 15% weighting). That said, we note that the weightings – which heavily favour that days' maximum temperature – are intuitively reasonable, therefore we do not consider this a material risk to the use of a 38 temperature demand index, and therefore, the consistency of SA Power Network's launch points for each of its connection points.

- A probabilistic assessment of the extent to which 10*% POE temperature events* are more or less likely to occur during sub-periods within the December through end of February period (i.e., is a 38 temperature demand index event more or less likely to occur in early January – where other factors limit the likelihood of that event causing an overall 10% POE condition to occur – relative to say February). Again, we do not consider this to be a material risk to the assessment as to whether the base years nominated for use by SA Power Network are consistent with 10% POE conditions.

6. Underlying growth rate

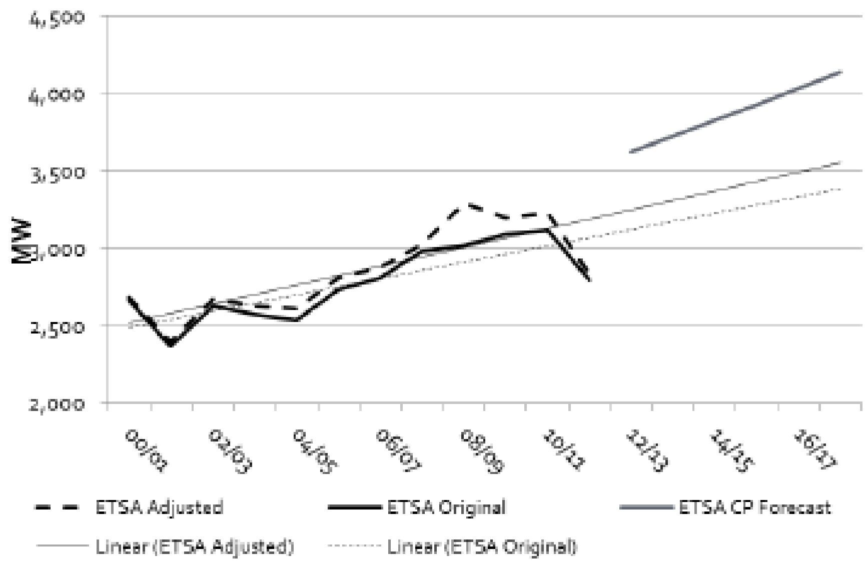
6.1. Background

- The underlying growth rate is the percentage increase in demand, prior to post model adjustments (such as solar PV), which are assumed to occur over the forecast period.
- The overall growth rate outlined in the Draft Decision is 1.89%, which equates to about 75 MW per annum (page 24-25 of Draft Decision). This compares to ElectraNet's original proposal of 2.8% (or ~120 MW per annum).
- The most recent AEMO forecasts (2012) assume a growth rate of only 1% in POE10% peak demand (or 34 MW) over the period.

6.2. EMCa / NZIER report

- EMCa/NZIER has based its forecast underlying growth rate on its own estimate of historical growth in 50% POE demands.
- The key figure in their report that illustrates this is provided below.

Figure 5 : ETSA Connection Points - Peak Demand Trend Analysis



Source: EMCa/NZIER from data supplied by ElectraNet

69. The "point to point" growth rate from 2001 to 2012 in this ETSA data is only 1% p.a. However the graph shows that this is heavily influenced by "above trend" demand in 2001 and "below trend" demand in 2012. Using a log-log function to overcome this effect, we find that the trend underlying growth rate over the past 12 years averaged 2.1%.

Source: Review of ElectraNet 2013-2018 Electricity Demand Forecast - Report to AER, p 24.

- Two other pertinent statements in the report pertaining to this issue are:

> *'We consider the trend growth rate provides a better indication of the underlying growth rate than either the 2001 to 2012 "point to point" growth rate of 1% or the "peak to peak" growth rate of 2.9% p.a. that has been used for the ElectraNet RP forecast. The chart shows the widening difference in forecasts that arises from this assumed growth rate*[18]*.'*

and

> *'As a means of assessing the quantum of the proposed planning margin, we have assessed the difference at the "starting point" (i.e. in 2013) between ElectraNet's forecast and our trend forecast (which conceptually is a PoE50% forecast – that has an equal probability of actual demand exceeding or being less than this level). We have done this for the ETSA connection point loads, since it is these underlying loads (as opposed to directly-connected mining loads etc) that are temperature-dependent. In this way we find that ElectraNet's 2013 demand forecast is 14% greater than the trend line and, since differences in growth rate have little impact for this year, a reasonable interpretation of this difference is that the 14% approximately reflects the planning margin attributable to "heatwave peaks"*[19]*.*

- We note EMCa/NZIER's own reference to its forecast being a 50% forecast – that is, the growth rate that has been derived relates to the growth in 50% POE demands. Even disregarding the extent to which their forecast represents a reasonable approximation of 50% POE demand (which was discussed in the previous section), we consider that, conceptually, there are issues in applying a growth rate in 50% POE demands to derive the forecast growth at 10% POE levels.

- More specifically, this trend will not reflect the change in temperature dependency of load during 10% POE events relative to 50% POE events, which is likely to have occurred over the intervening period between the first year (2000/01) and the last year (2011/12) of the ten-year evaluation period. By way of example, increased penetration of air-conditioners over that period into existing households is unlikely to have impacted 50% POE usage at exactly the same rate as 10% POE usage. A countervailing factor may be the extent to which large customers may be more responsive to higher pool prices during periods that coincide with 10% POE events, relative to 50% POE events, and how this has changed over the period.

---

18 Energy Market Consulting associates / NZIER - "*Review of Demand Forecast Proposed by ElectraNet - Report to Australian Energy Regulator*",-p 25.

19 Ibid, p 27.

- In summary, the EMCa/NZIER approach could only be considered reasonable if either (a) it is reasonable to assume that 10% POE demands have exactly the same growth rate as 50% POE demands, which we consider highly doubtful, or (b) if the factors that lead to any historical difference between the 10% POE growth rate and the 50% POE growth rate could not be reasonably be assumed to continue into the future. Put another way, if the 'distribution' of demand outcomes has become more skewed to the right (i.e., the right hand tail is increasing), and it is considered that this increased temperature dependency of load at these POE levels will continue into the future, then deriving an average (trend) increase in 50% POE outcomes does not necessarily provide a picture of what is happening at 10% POE.

6.3. SA Power Network's revised methodology

- We understand that to derive the forecast growth rate in demand for the next regulatory period, SA Power Network's revised forecast (which underpins ElectraNet's revised Revenue Proposal) is broadly based on the linear growth rate between 2000/01 actual demand and 2009/10 actual demand. We understand that these two figures have not been formally weather corrected to a 10% POE standard to derive the growth rate, as both 2000/01 and 2009/10 are considered to be very close to 10% POE years.

- Our first observation is that despite them being "close to 10% POE figures", ideally, if this methodology is to be used, these figures should in fact be formally weather corrected. That said, we note from information provided by SA Power Network's, which broadly cross-checks against figures derived by NIEIR and also provided by SA Power Network's, that (a) the actual 2000/01 demand was approximately 2.3% below the 10% POE figure for that year and (b) the actual 2009/10 demand was 3.3% lower than the 10% POE figure for that year. This means that, ceteris paribus, SA Power Network's use of the actual demands will serve to reduce the linear growth rate that is derived from the point-to-point change between the two figures. (In other words, use of these actual demands fully corrected to relevant 10% POE levels is likely to result in a higher point-to-point growth rate over the evaluation period).

- Further, we note that SA Power Network's revised approach implicitly assumes that the increasing temperature dependency of load (at 10% POE levels) will continue at the same rate into the future. Broadly, this means that it assumes that the load factor, defined as the ratio of average demand for the year divided by maximum demand in any half-hour of the year, will continue to decrease at a similar rate over the forecast period with the installation of progressively larger or more numerous air-conditioning units (amongst other things).

- Whilst we agree that the data indicates that there has been an increase in the temperature dependency of load historically, and thus a decline in load factor over the evaluation period, we consider that the implicit assumption that this trend will continue into the future in a linear fashion may not in all likelihood be warranted. The reason being is that it could be argued that future air-conditioner penetration rates are unlikely to match historical levels over the evaluation period (which are in turn embedded into the trend analysis), nor are increases in the utilisation of those air-conditioners likely to match historical rates.

- The following figures outline the historical change in air-conditioner annual sales and penetration rates, as provided by SA Power Network.

Figure 2: Air conditioner sales in South Australia

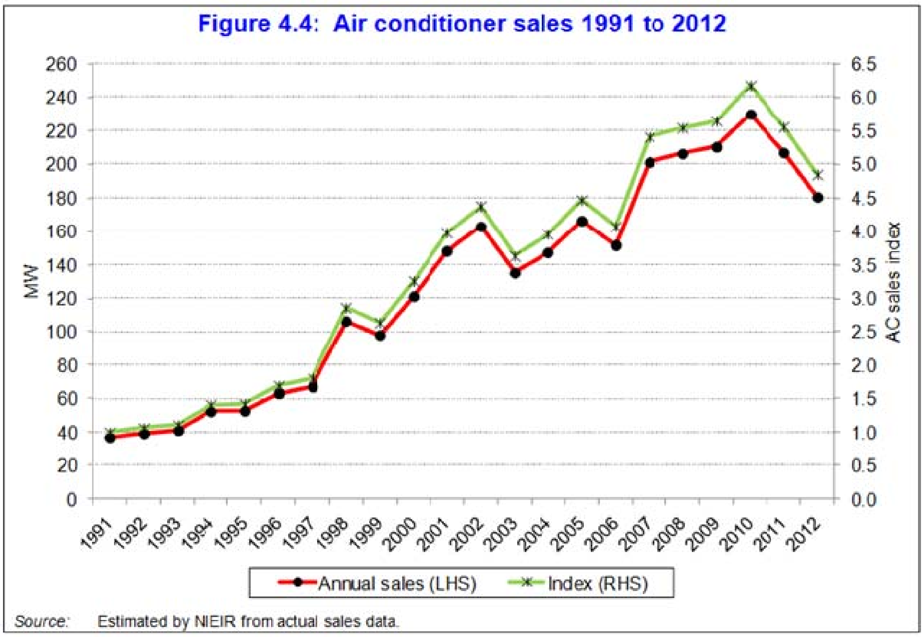


Figure 3: Air conditioner sales penetration rates in South Australia

	Mar 1999	Mar 2002	Oct 2004	Mar 2008	Mar 2011
Evaporative '000	119	143	159	144	140
Non-Evap '000	212	345	360	406	466
Total '000	332	488	519	550	606
% households '000	605	613	634	647	664
Evaporative	20%	23%	25%	22%	21%
Non-Evap	35%	56%	57%	63%	70%
Total	55%	80%	82%	85%	91%

- Whilst we have not undertaken any detailed analysis of this information, we make the following observations:

- We agree with a statement made by SA Power Networks which accompanied the above data that the proportion of air conditioning sales represented by replacement of existing units is likely to be more significant today than it was a decade ago[20]. This means that only a proportion of the annual air-conditioner capacity sold will translate into new demand at times of connection point or system peak[21]. We note that this also means that to maintain trend increases in temperature dependency at 10% POE levels into the future, the growth in annual sales (in MW of capacity) would need to increase at ever increasing rates (to compensate for the likely larger amount of sales that are devoted to replacement of existing systems). However, in actuality sales in each of the last five years except one (2010) have stayed at a relatively constant level. This tapering off in the growth in sales may point to a reduction in the rate of load factor decline in the future relative to historical levels – though it is difficult to be definitive in this regard prior to additional data collection and analysis.

- By contrast, for much of the historical period on which the point-to-point estimate is based, year-on-year sales (in MW terms) increased at ever increasing rates, and a larger proportion of this is likely to have been due to increased penetration of air-conditioners (and increased air-conditioning capacity per air-conditioned home), as opposed to the replacement of ageing units.

- Ideally, an approach that weather corrected all historical years to 10% POE levels, based on the weather-correction algorithms applicable in that year, should be used. This would allow the derivation of not only the point-to-point growth rate between any two years (including 2000/01 and 2009/10), but would also illustrate how the growth rate has changed over the evaluation period. Specifically, this would allow an assessment into whether the moving average (e.g., 2 year moving average) of this 10% POE growth rate is (and has been for a number of years) lower than the 'point-to-point' growth rate between 2000/01 and 2009/10 to be made. If this is the case, then prima facie, this indicates that the point-to-point estimate may over estimate demand if extrapolated into the future, as it places equal weight on older historical growth rates and more recent historical growth rates, despite there being a disconnect between the two. Obviously, if the moving average is higher than the point-to-point growth rate, it indicates that recent historical growth rates are in fact higher than the longer-term historical growth rate; in this case, the point-to-point estimate may therefore underestimate demand. Whilst it is clear that history is not a perfect predictor of the future (regardless of whether point-to-point estimates or some form of moving average are used) such a weather corrected approach can provide additional and useful information to support a decision concerning what is the likely to be the most reasonable growth rate to assume in the forecast.

---

20 While this is conceptually attractive, there is also the possibility that the old unit is moved to another room for occasional use – similar to what often happens when a second refrigerator is purchased. Based on the information available, we are not in a position to make any substantive statement with regards to the likelihood of this occurring, but we mention it purely to illustrate the fact that the currently available data is not sufficient for making fully documented conclusions.

21 Whether this increases or decreases total air-conditioning peak demand will depend on other factors including (among others) whether the capacity rating of the new air-conditioner is larger than the unit being replaced, and whether the efficiency of the new unit is greater than that of the unit being replaced.

- The other qualifying comment that we would make with regard to the use of trend growth rates – even after confirming their consistency with 10% POE conditions – is that there may be other factors (outside of the penetration rate of temperature dependent appliances) that may be related to the weather co-efficient but have not been identified in the trend analysis, and whose impacts cannot be accurately forecast for future years. For example, whilst SA Power Networks has made 'post-model' adjustments for factors such as the increased penetration of solar PV, it has not taken into account other factors that may have changed the relationship between weather and demand since 2009/10 or 2010/11 (the 'base years' used in most cases). A possible example of such a factor is the impact that price may have had on demand at 10% POE conditions. That said, it is difficult to quantify the impact of such factors in the absence of actually experiencing events consistent with 10% POE conditions, given that such factors may have different impacts at different POE levels.

- Additionally, we would recommend that an approach that relies upon historical growth rates be sanity checked against one which is based on a more granular, bottom up build. This would involve estimating (a) the number of new customers that are expected to connect to the network, given the expected macro-economic conditions over the forecast period; (b) the demands that each additional new customer is expected to place on the system; (c) the estimated diversity of their demand; and (d) impact of increased penetration of temperature dependent appliances within existing premises on total demand. Other required bottom up calculations would include the estimated impact of solar PV and price on future demands on different POE levels, and the level of expected industrial (and commercial) demand as an explicit function of a range of broader macro-economic factors.

6.4. Summary of key points

- Despite the fact that the two data points used to calculate the linear growth rate are "close to 10% POE figures", ideally, these figures should in fact be formally weather corrected, before the growth rate is in fact calculated using this methodology. That said, it would appear that SA Power Networks' approach, would, if anything, temper forecast growth rates, as the base year that is predominately used is 2009/10, which is likely to be actually lower than a true 10% POE forecast (because of the time of year that it occurred), and moreover, the 2000/01 year is closer to what is considered to be a 10% POE level;

- Conceptually, we have concerns about EMCa/NZIER's approach to calculating a trend growth rate based on what they consider to be 50% POE levels, and then applying this to a 10% POE launch point, to calculate a 10% POE forecast;

- We consider that deriving a baseline (ex-post-model adjustments) growth rate based on the point-to-point growth rate at the connection point level between what we understand to be two 'close to' 10% POE years is a reasonable approach, albeit not a perfect approach when it is done in isolation. Preferably, reliance on historical rates of growth would be sanity checked against a more granular, bottom-up calculation of changes in demand, given forecast macro-economic conditions/prices etc.

- In summary, based on the information provided to us by SA Power Networks, it appears that, if anything, their point-to-point methodology is likely to have under-estimated historical growth in 10% POE demands at the connection point level, as a result of using the 2009/10 'base year' in the majority of cases. However, a countervailing factor is that, in all likelihood, the increase in temperature-dependent load that has occurred over the evaluation period is unlikely to continue at the same rate over the forecast period.

7. Inclusion of load curtailment for major customers

7.1. Background

- This refers to the inclusion of demand reductions associated with the load curtailment of major customers during times of peak demand events.

7.2. EMCa / NZIER report

- EMCa/NZIER states that[22]:

  "in our view the credibility of the ETSA "peak to peak" forecasting approach is challenged by the material adjustments that it made to recent historical actuals and especially the large upward adjustment that was made to create an apparent 2009 "all-time peak". This adjustment critically compromises both the growth rate (which was measured between the 2001 and 2009 "adjusted" peaks) and the choice of the 2009 adjusted peak as base year for the forecast."

- Broadly, we agree with EMCa/NZIER's critique; the manner in which these adjustments have been made is likely to over-state likely underlying peak demand. However, we do not believe that it is incorrect to undertake any adjustment for the effect of customer demand response or embedded generation on likely peak demand.

- In the first instance, adjustments for involuntary load curtailment (i.e., load shedding) in the evaluation period are entirely warranted. We are aware that such an event coinciding with system peak demand did take place in 2008/09.

- In addition, from a statistical perspective, we consider that a formal, probabilistic assessment should be undertaken on the demand of large customers (and the output of embedded generators, which is discussed in the next section) to determine their expected response under 10% POE conditions. We are less inclined to adopt an approach that simply embeds outturn levels of demand response and embedded generation into historic demand levels and then projects their continuance into the future, as it appears EMCa/NZIER have done.

- Our above position is further reinforced by looking at the underlying volatility in the adjustments that were made (e.g., Figure 4 on page 23 of EMCa/NZIER's report indicates that the range of adjustments is from less than 1% up to 8.5% in any one year, which, prima facie, indicates that there is volatility (and quite likely risk) around embedding a point estimate of historical levels into underlying demands, without an understanding of the underling drivers for load curtailment (or dispatch of embedded generation), and the extent to which that dispatch will occur during times of peak demand in the future).

22 Energy Market Consulting associates / NZIER - "Review of Demand Forecast Proposed by ElectraNet - Report to Australian Energy Regulator", p 23.

7.3. SA Power Networks' revised methodology

- Originally, ElectraNet's forecasts assumed that major customers would revert back to their recorded anytime peak demands. That is, they implicitly assumed that any recorded level of demand below anytime peak demand was in fact load curtailment, and could not be assumed to be relied upon when developing demand forecasts. This assumption is consistent with the way in which ElectraNet has historically addressed the reliability requirements of the ETC in its planning, and the fact that those plans have historically been accepted by the State regulator, ESCOSA. Clause 2.1.1 of the ETC states that *"a transmission entity must use its best endeavours to plan, develop, and operate the transmission network to meet the standards imposed by the National Electricity Rules in relation to the quality of transmission services such that there will be no requirements to shed load to achieve these standards under normal and reasonably foreseeable operating conditions*". Given that these loads had been experienced it was not necessarily unreasonable to consider that they could be experienced at times of peak demand. In essence, assuming that the anytime maximum demand of major customers could occur at time of system peak demand is analogous to assuming extreme heatwave conditions when forecasting mass market demand.

- The mechanics of this meant that the actual recorded coincident peak demands of five major customers connected to the distribution network were deducted from the recorded peak demand for each relevant connection point, and then their anytime maximum demands added back in to inform the peak demand forecast for each connection point.

- We expressed concern to both SA Power Networks and ElectraNet in relation to this proposed approach. Our concern was based on both theoretical and empirical foundations:

  - The theoretical issue was that SA Power Networks' original approach disregarded the distribution of demands by each of these major customers. In particular, we asked whether it would be reasonable to assume that under a 10% POE assumption, the historical anytime peak demand would occur at the same time the connection point is peaking. As stated above, in a sense, SA Power Networks' approach was a deterministic, 'worst case' assumption, as it assumed reversion to the highest demand recorded by these customers, which may have been consistent with the previous interpretation of the ETC.

  - By contrast, the empirical concern was that investigation of the load data of these customers showed that, in the main, they had not historically drawn their peak demand during the months that coincide with peak demand, nor even at the time of day which their relevant connection point peaked. In particular, the evidence from the last five years' for each of these customers showed that their daily load profile almost always dipped during the afternoon / early evening period, which is when their respective connection points peaked.

- Following on from this, we developed an alternate methodology which was accepted by both SA Power Networks and ElectraNet, and which forms the basis for the Major Customer component of the demand forecasts outlined in ElectraNet's 16 January 2013 revised Revenue Proposal.

- This methodology involves undertaking a probabilistic assessment of each major customer's 10% POE demand level, given the time of day that their connection point generally peaks. More specifically, it involves:
  - Obtaining demand data for the last five summer periods (plus March)[23] for each customer;
  - Identifying the time at which the connection point that each of these customers is connected to generally peaked;
  - Creating a distribution of the actual demands of each customer, during the summer months (plus March) in each year at the relevant peaking time identified above;
  - Determining the 10% POE demand threshold for each year (i.e., the level of demand above which 10% of actual demands occurred); and
  - Taking an average of the five annual 10% POE demand thresholds, and using this as the basis for the 10% POE forecast.
- We also, for completeness, downloaded price information from the AEMO website for SA for the five-year evaluation period, and assessed the extent to which there was likely to be a relationship between market price and the demands of these customers. In particular, we were keen to assess the extent to which there were other explanatory variables, over and above the underlying distribution of demand that resulted from the underlying production processes of these customers, which could help explain the levels of demand that could be expected on days that were consistent with 10% POE conditions. Due to the time constraints, we were unable to undertake any detailed statistical analysis to test the strength of this relationship. However, for at least two of the five customers, there appeared to be a relationship between price and demand (e.g., low demands corresponded with high prices) at least in the early years of the evaluation period. However, that relationship was not clearly apparent in latter years' data (although we note that this may be due to lower maximum prices in that period[24]). Overall, at this stage, it is our understanding that ElectraNet has not made any specific adjustment for this relationship; however, as is discussed below, this would seem to warrant further investigation and analysis.
- This further work should involve, amongst other things:
  - Undertaking more detailed statistical analysis into the relationship between market price and the demand of major customers. This would allow a more robust assessment of the extent to which high market prices, which are likely to be highly correlated with a high temperature-demand index at the state-wide level, affect the demand of these major customers, which would in turn allow for a more accurate demand distribution to be determined upon which 10% POE levels could be calculated;

---

23 It is noted that the period which has been analysed could potentially be further refined by removing public holidays, weekends, and periods which are assumed to be inconsistent with when overall 10% POE temperature conditions could occur (e.g., early January).

24 For example, our analysis indicates that the average maximum price in the top 20 days of each year reduced from $5140/MWh in 2007/08 to around $62/MWh in 2011/12.

- Assessing the statistical relationship between the temperature-demand index for the region within which that major customer is located, and the demands of those customers. This would allow an assessment of the extent to which these customers' loads may in fact be temperature driven, which in turn would allow for a more accurate demand distribution to be determined upon which 10% POE levels could be calculated; and
- Undertaking direct discussions with major customers regarding the potential drivers of usage and curtailment on peak demand days. Specifically, we suggest that these customers be asked whether they have (or are likely to) put in place any measures or have entered (or are likely to) into any agreements to reduce load in response to market prices or a notification from a retailer, demand aggregator or other third party[25].

- We would also recommend that ElectraNet apply a similar methodology to its own direct connect customers.

7.4. Summary of key points

- Whilst we consider EMCa/NZIER's approach, which in effect utilises the actual co-incident demand of major customers at the time of system peak, to be a reasonable starting point for deriving major customer load forecasts (and moreover, probably the only approach that could have been adopted given the data available to them at the time), we do not consider this to be the optimal approach.
- We consider that the approach described above, and which has now been adopted by SA Power Networks and ElectraNet for SA Power Networks' major customers, represents a more robust statistical approach to generating the baseline 10% POE forecasts for these large customers. It also puts these forecasts more on the same basis as the mass market load forecasts, which are based on 10% POE conditions. We say this because the method adopted explicitly assesses each individual major customer's distribution of demands at the time the connection point they are connected to peaks. It also provides a transparent and repeatable basis for deriving these demands.
- However, we reiterate that over time, ElectraNet should seek to incorporate a number of other improvements into these forecasts, which would assist them in obtaining an even more accurate baseline 10% POE forecast for these major customers. This would involve, amongst other things, assessing the explanatory power of variables such as market price, and a location-specific temperature-demand index on the demands of these customers, which in turn would allow the demand distribution to be more reflective of actual 10% POE conditions.
- We would also recommend that ElectraNet apply a similar methodology to its own direct connect customers.

25 We note that the AEMC, as part of its *Power of choice* review, has proposed that large customers be allowed to provide demand response into the wholesale market on settlement terms similar to those available to non-scheduled generators. If this proposal is put into practice it is reasonable to assume that more demand response will be provided by these customers, and the nature of the non-scheduled arrangement under which it will be provided will make a probabilistic approach to it estimation for forecasting purposes increasingly important.

8. Inclusion of embedded generation

8.1. Background

- The expected level of coincidence (or MW outputs) between the outputs of Embedded Generators, and the time of the maximum demand at the Connection Point that they are connected to will differ depending on the embedded generator. As a result, their overall contribution to meeting connection point peak demand, regional and system maximum demands will differ.

- There are a number of different types of embedded generators connected to ElectraNet's system, for example, power stations, wind farms, and waste generators. Based on historical figures, their generation patterns are quite different. For example, some of these generators appear to generate only during certain defined periods of the day (e.g., they stop generating at 6pm), whilst, for others this is not the case. Further, for some, there appears to be a relationship between generation and market price, whilst for others, this relationship is less pronounced.

8.2. EMCa / NZIER report

- In commenting on ElectraNet's original demand forecasts, EMCa/NZIER state that:

  - *"The forecast effectively discounts (by adding back) the positive contribution to peak demand reduction of consumer demand response and embedded generation*[26]*"*…and

  - *"in our view the credibility of the ETSA "peak to peak" forecasting approach is challenged by the material adjustments that it made to recent historical actuals and especially the large upward adjustment that was made to create an apparent 2009 "alltime peak". This adjustment critically compromises both the growth rate (which was measured between the 2001 and 2009 "adjusted" peaks) and the choice of the 2009 adjusted peak as base year for the forecast*[27]."

- We agree with EMCa/NZIER that the large upward adjustments contained in ElectraNet's original Revenue Proposal are unlikely to be warranted. Rather, we consider that a detailed analysis of the components and drivers of those adjustments should be undertaken before any adjustments are made.

- Further, we agree with the general thrust of the EMCa/NZIER report that the impact of embedded generation should be incorporated into the forecasts.

---

26 Energy Market Consulting associates / NZIER - "Review of Demand Forecast Proposed by ElectraNet - Report to Australian Energy Regulator", p 6.

27 Ibid, p 23.

- We also consider that a reasonable starting point for assessing the contribution of embedded generation to mitigating overall peak demand is to assess the magnitude of its contribution historically (which, in effect, is what EMCa/NZIER did by removing any adjustments from the historical data).

- However, analogous to our previous discussion in relation to Major Customer Load Curtailment, we consider that a more granular assessment of the relationship between Embedded Generators, market price and individual connection point peak demand should be undertaken in order to derive sufficiently robust assessments of embedded generation outputs at different POE levels upon which forecasts can be based.

8.3. ElectraNet's revised methodology

- It is our understanding that as part of its revised Revenue Proposal, ElectraNet has examined the historical contribution of embedded generation within the distribution system in each of its regions. From that historical assessment an estimate has been made of the level of embedded generation that can be expected to occur at times of:

  - Regional and Connection Point maximum demand; and

  - Total system maximum demand.

- Furthermore, based on information provided by ElectraNet to SA Power Networks[28]:

  - *"these contributions were based on the type of generation and the perceived probability of dispatch during maximum demand conditions, based on limited observations of previous behaviour under various system conditions and market outcomes. In most cases the assumed contribution at times of total system maximum demand is higher because the system maximum demand usually correlates with high spot prices, resulting in more generation"*.

- Having regard to the above, we consider the methodology utilised by ElectraNet to be a reasonable starting approach for developing its Revised Demand Forecasts, given the current information readily available. However, we would recommend that this approach be augmented in the longer term by the adoption of an approach that has more explicit regard for the relationship between market price, connection point peak demands, and the dispatch of individual embedded generators. This is analogous to the approach that we recommended be adopted with regard to load curtailment by Major Customers. More specifically, such an approach would involve, amongst other things:

  - Obtaining generation data for previous summer periods (plus March) for each embedded generator;

  - Identifying the time at which the connection point that each embedded generator is connected to has generally peaked;

28 Letter from Hugo Klingenberg, Senior Manager Network Development at ElectraNet to David Pritchard, Manager Network Planning at SA Power Networks, on 11 January, 2013

- Creating a distribution of the actual generation amounts of each generator customer in each year during the summer months (plus March), at the relevant peaking time identified above;

- Augmenting this with an analysis of the statistical relationship between:

    - Market price and that connection point peaking to determine the likely coincidence of that connection point peaking at times of high market prices. This is important as the latter is driven by state-wide demands, as opposed to connection point demands. This should also be done for different POE levels, as the level of coincidence may differ depending on the underlying temperature conditions on those peak demand days and the temperature-sensitivity of demand in the area served by the relevant connection point; and

    - The relationship between embedded generator output and market price at times when the relevant connection point is assumed to peak.

- Individualising an algorithm for each embedded generator which has regard for each of the aforementioned factors, which in turn will allow forecasts of future 10% POE generation amounts to be derived.

- This approach could be further augmented by ElectraNet interviewing at least the larger embedded generators regarding the reasonableness of the results they obtain from the aforementioned analyses. As part of this, ElectraNet would seek information (on a strictly confidential basis) of the nature of the generator's forward commercial arrangements, in particular, with a view to assessing whether similar or different generation operation could be expected over the forecast period. This would also assist ElectraNet in its operational planning, and more broadly, assist it in providing a reliable and safe transmission service.

8.4. Summary of key points

- We consider that a reasonable starting point for assessing the contribution of embedded generation to meeting overall peak demand is to assess the magnitude of its contribution historically.

- We consider that both EMCa/NZIER's approach - which, in effect, relies on actual historical demand data - and ElectraNet's approach - which undertakes a bottom up build, based on an estimate of the historical coincidence of generation at times of connection point peak demands - are a reasonable starting basis for assessing the contribution of embedded generation to mitigating overall peak demand.

- As outlined above, we consider that, in the longer term, ElectraNet should undertake more robust analysis to derive the outputs of embedded generators at the time of connection point and state-wide peak demand. This should seek to derive a specific algorithm for each embedded generator, which in turn will allow forecasts of future 10% POE generation amounts to be derived based on:

    - 10% POE market price forecasts;

    - the time at which the connection point that they are connected to peaks;

  - the probability of that connection point peaking at times of high market prices during 10% POE conditions;

  - the likely response of that embedded generator to high market prices during 10% POE conditions; and

  - the underlying pattern of generation of those embedded generators, in particular, the extent to which they are able to (or have historically) generated at times when the connection point has peaked.

- We would also recommend that ElectraNet consider interviewing at least the larger embedded generators regarding the reasonableness of the results it obtains from the aforementioned analyses.

9. Impact of Solar PV

9.1. Background

- This refers to the impact increasing penetration of solar PV will have on peak demand. This is a function of the number of PV installations that occur, the average generating capacity of the systems installed, and the operating efficiency of the panels and overall systems at the times of day at which peak demands occur in each of ElectraNet's connection points.

9.2. EMCa / NZIER report

- EMCa/NZIER proposed to add back the estimated impact of solar PV into the historical demand, and then to remove the forecast impact of solar generation over the Regulatory Control Period from the underlying trend increase they have calculated, inclusive of the historical solar impact that was added back. The forecast impact of solar of the Regulatory Control Period is based on AEMO forecasts.
- We agree with EMCa/NZIER that the impact of solar PV should be explicitly taken into account when forecasts of peak demand are developed.
- We consider that EMCa/NZIER's use of the AEMO forecasts was reasonable, in the absence of any more granular information.

9.3. SA Power Network's revised methodology

- We understand from email correspondence[29] that SA Power Networks has calculated the impact of solar PV on peak demand at each connection point, as the total PV inverter capacity committed as at February 2012 at each connection point x the time of day % output (see Figure below for these) x 80%.

Figure 4: SA Power Network's PV output percentages

Time of Day	1200	1230	1300	1330	1400	1430	1500	1530	1600	1630	1700	1730	1800	1830	1900	1930	2000
% of PV Inverter output	77%	80%	82%	82%	80%	77%	73%	67%	61%	53%	46%	37%	29%	22%	15%	9%	4%

Notes:
1) Additional 80% factor applied to allow for variables (i.e. solar panel installation orientation, panel output vrs inverter capacity etc.)
2) Inverter Capacity x time of day factor x 80% = PV adjustment value

Source: SA Power Networks

- As an example, the above formula, in combination with the output percentages contained in Figure 4 **Error! Reference source not found.**above, result in a solar PV generation contribution of 42% of installed panel capacity at 4.30pm.

29 Email from David Pritchard - Manager Network Planning at SA Power Networks, to Josh Smith - Senior Network Strategy Engineer at ElectraNet, on Wed 12/12/2012 8:14 AM.

- Based on information provided by SA Power Networks[30], we understand that the 80% factor was applied to correct for the actual connected panel capacity (relative to the installed inverter capacity), as well as to allow for wiring/orientation/vegetation issues. We further understand that the output factor is taken from the gross metered output of three 1kW PV systems to which SA Power Networks has access, and the growth (in solar PV penetration) is assumed to be 6% per annum.

- For completeness, it is noted that in correspondence that SA Power Networks removed their previous assumption that a 50% factor be applied to arrays being '*dirty, misaligned, of poor quality, not working*', because, to paraphrase[31], its removal was consistent with adopting a 10% POE planning standard (which assumes that the forecast will be exceeded from time to time), relative to a forecast that had no chance of being exceeded (extreme heatwaves). We agree with the removal of this factor.

- Whilst we consider the overall methodology to be reasonable, we provide commentary on a number of the key assumptions that underpin that methodology:

  - <u>80% factor:</u> As part of this review process, we sought more information with regard to the rationale and basis for applying the 80% factor. SA Power Networks indicated[32] that they developed the nominal 80% PV moderator to convert connected PV inverter sizes to likely PV output (before consideration of time of day), based on discussions with AEMO (which took place in or around September 2010) and other distribution businesses who had gross interval metering in place. SA Power Networks further stated that whilst the values used varied, they considered it reasonable to allow for a 10% reduction due to panels having a lower capacity than the associated and approved inverter size, and to allow a further 10% reduction for wiring/orientation/vegetation issues. Our observation is that whilst the broad approach of leveraging off information from other electricity businesses that may have a richer source of data on this issue appears reasonable, the reference to 'numbers varying' may point to certain discrete factors driving the overall 'output factor' of different businesses. Ideally, detailed investigation as to those contributing factors should be undertaken before the use of data from other distribution businesses can be deemed to provide an accurate reflection of the likely values attributable to customers in SA Power Networks' area. It is unclear to us whether such an analysis has been undertaken not;

30 Email from David Pritchard of SA Power Networks to Joshua Smith of ElectraNet on Monday the 7th of January, 2013

31 Email from David Pritchard - Manager Network Planning at SA Power Networks, to Josh Smith - Senior Network Strategy Engineer at ElectraNet, on Wed 12/12/2012 8:14 AM.

32 Ibid.

- <u>% of capacity generated at times of peak demand</u>: In our initial discussions with SA Power Networks and ElectraNet, we stated that we had concerns as to the statistical validity of using a sample of only three gross metered 1 kW units located in Adelaide to derive the output percentages that are applied to all PV units State-wide. We considered that the sample size is entirely inadequate to provide any statistical confidence regarding the representativeness of the output or these three systems to that of all PV systems installed across the state. However, we note that the risk of error in this regard is more likely to impact the overall magnitude of the output at each half hourly interval, due to the impact that locational and panel issues may have (shade, age of panel, orientation, tilt, etc.), as compared to the profile over the day (i.e. the relative output in any half-hour period relative to any other half hour period).

- We also note that AEMO uses 38% generation contribution at time of system peak, which, is slightly lower than SA Power Network's forecast of 42%. While the two estimates broadly support one another, it is difficult for us to identify which represents the more robust estimate. In particular, whilst we have expressed concerns as to the overall statistical validity of SA Power Network's use of only three 1 kW PV units to underpin its output factors, we understand that AEMO's estimate is based on a sample of systems obtained from a public website where people upload their own solar PV information. More specifically, AEMO state that "*to estimate the output of rooftop PV systems at the time of the maximum demand, sample data for maximum system days was obtained on a regional basis from the website PVOutput.org for the last summer.*" Two other pertinent comments are reproduced below:

  "*It is possible that the sample systems obtained from PVOutput.org are not representative of rooftop PV systems across the NEM. It seems likely that people who log their system generation and upload it to a website will also ensure that their system is configured, installed and maintained to above-average standards. There is an opportunity for future work to analyse whether these energy generation results are over-estimated*[33]*.*"

  and

  "*Detailed generation data for high-demand days during the summer of 2010/11 was obtained from PVOutput for a range of sample systems in each of the regions. Each system's generation was recorded as a percentage of its rated installed capacity. Records were filtered according to 30-minute intervals, with a time lag applied in order to align the data to Australian Eastern Standard Time (AEST). Readings were averaged for each 30-minute interval of the day, to derive a generation curve. The value on this curve was noted for a typical time of maximum demand in each region, for example 16:00 AEST. To produce a forecast of rooftop PV generation at the time of maximum demand, this value was multiplied by the region's installed capacity*[34]"

33 AEMO, Rooftop PV Information Paper; July 2012; Appendix B-5

34 Ibid, Appendix B-6

- In relation to the first quote, we agree with the AEMO's concern regarding the self-selection bias that is likely to characterise the PVOutput.org sample. However, we further note that if the AEMO outputs are likely to be over-estimates (because of the types of customers who upload data onto the website utilised) ***and*** they are still lower than SA Power Network's revised forecasts, then it could be that there are even greater risks to using the SA Power Network's forecast. We also consider that the risk is magnified when consideration is given to the fact that AEMO references its sample data to the "average" of high-demand days to derive a generation curve. As stated earlier on in this report, output factors are likely to be lower as a result of the higher temperatures that are likely to characterise 10% POE conditions. Averaging data over multiple days – albeit "high demand" days – may inflate the percentage output, when compared against a day that exhibits temperatures consistent with 10% POE conditions.

- Overall, we do not consider ourselves to be in a position to definitively state whether either of these estimates is likely to lead to demand forecasts that are more reasonable and robust than the other. This is particularly compounded by the fact that we are not privy to the sample size utilised by AEMO. That said, assuming the sample size used by AEMO is reasonable – both in size, and its spatial distribution across South Australia - we would err on the side of using their outputs factors.

- **Penetration rates:** With regards to penetration rates, SA Power Networks has assumed a 6% per annum increase as its core assumption. AEMO, in its 2012 state-wide forecasts (in the NPFR), has used 8%. Obviously, this cross-check indicates that the SA Power Networks' forecasts are likely to be in the reasonable range. However, we are not privy to the underlying basis for either of the forecast take-up rates. This is particularly important, because there are a number of factors that are likely to impact on the economics of solar PV, which should, ideally, be explicitly considered when determining penetration rates. These include, but are not limited to:

  - The expected output of PV systems, given location, sunlight intensity etc.;
  - The price of installing PV systems;
  - The amount and timing of solar subsidies and feed-in-tariffs;
  - Retail electricity prices – and price structures – faced by consumers; and
  - The rate of return (or payback period) required by consumers to install PV systems.

- In the absence of a detailed model, or outline of modelling methodology, pertaining to the above, we do not consider ourselves to be in a position at this stage to make a definitive statement as to which of the forecasts presented (6% per annum, as proposed by SA Power Networks, or 8% per annum, as used by AEMO), is most likely to lead to robust and accurate demand forecasts.

9.4. Summary of key points

- Overall, we consider that the AEMO output percentages are likely to provide a more reasonable basis for deriving demand forecasts for ElectraNet.

- Overall, we consider that the AEMO output percentages are likely to provide a more reasonable basis for deriving demand forecasts for ElectraNet. To be clear, we consider that the AEMO output percentages that coincide with the timing of peak demand at each connection point should be used to derive the impact of solar at that connection point. We are not suggesting that AEMO's 38% output factor (at 4.30pm) be simply applied to all connection points.

- However, based on the information that we have been able to obtain in the public domain, we consider that even these forecasts may possibly be overly optimistic for the following reasons:

  - the use of an average output on high demand days may overestimate output to the extent that all days included in the sample do not reflect the temperatures that would pertain on a 10% POE day; and

  - the potential self-selection bias of the PVOutput.org sample, which may, if anything, lead to an over-estimate of the average output of PV cells.

- Considering the above, ElectraNet's use of SA Power Networks' output percentages is likely to represent a conservative position.

- In the absence of a detailed model, or outline of modelling methodology pertaining to assumed penetration rates, we do not consider ourselves to be in a position at this stage to make a definitive statement as to which of the forecasts presented (6% per annum, as proposed by SA Power Networks, or 8% per annum as used by AEMO), is most likely to lead to robust and accurate demand forecasts.

10. Diversity factor

10.1. Background

- The 'Diversity Factor'[35] represents the difference between the aggregated demand forecasts of lower levels of the network (e.g., connection points), and the expected demand forecast at higher network levels (e.g., regions). A diversity factor less than 100% means that not all lower network components in a region - in this case, connection points - are expected to reach maximum demand levels at the same time that the regional system peaks (i.e., they are not perfectly co-incident). This means that the regional demand forecast, which underpins the augmentation plans of assets servicing the connection points in that region[36], must be lower than the summated connection point forecasts.

- Therefore, in ElectraNet's case, a 'diversity factor' must be determined to ensure that the demand forecasts at connection point level, are, when combined, a reasonable reflection of the demand forecasts that will underpin any augmentation of the regional transmission network that is required to service those connection points.

10.2. EMCa / NZIER report

- In their report, EMCa/NZIER quote ElectraNet as saying[37]:

> "*Peak demand forecasts at individual connection points are, by necessity, used for connection point planning and local regional planning. This is due to minimal diversity at a regional level during peak times; i.e. in most cases, heat wave conditions simultaneously affect the entire area in question.*"

- EMCa/NZIER also state that[38]:

> *"For regional augmentation planning purposes, we consider it reasonable that a diversity factor should be applied to the undiversified connection point demands. Rounding up conservatively from the metro area diversity factor derived above, we have applied a factor of 0.96 in comparing ElectraNet's demand forecast with the trend forecast, and with AEMO's state-diversified forecast".*

---

35 Also known as a coincidence factor.

36 This regional demand forecast will not underpin connection point augmentation plans, with augmentation plans at connection point level are driven by connection point forecasts.

37 Energy Market Consulting associates / NZIER - "Review of Demand Forecast Proposed by ElectraNet - Report to Australian Energy Regulator", p 28.

38 Ibid, p 29.

- Conceptually, we entirely agree with EMCa/NZIER's position that for regional augmentation planning purposes, it is reasonable that a diversity factor be applied to the undiversified connection point demands. However, to our mind, basing this on a single year's data (in this case the 2012 peak, which was not a 10% POE year), which appears to be what EMCa/NZIER has relied upon, is unlikely to give the most robust result, given that the diversity factor may vary across years, and moreover, is likely to be related in some way to the temperature conditions prevailing at the time.

- Given this, we would consider that diversity within the system is likely to differ at different POE levels, and in particular, at 10% POE levels, one would expect diversity to be different as compared to times of less extreme conditions (e.g., 50% POE)[39].

- In addition to the above, we also note that for practical purposes, it is the diversity factor of those regions in which augmentation may be required within a regulatory period (rather than the diversity factor that applies to the entire service area) that really matter.

10.3. ElectraNet's revised methodology

- ElectraNet has reviewed historical diversity factors under high demand conditions in light of the adoption of 10% POE connection point forecasts and determined a diversity factor of 97%, for application to the demand forecasts adopted in the revised revenue proposal.

- In determining this diversity factor, we understand that ElectraNet has:

  - Examined the potential for diversity between connection point maximum loads, only where it would potentially affect the timing of regional augmentation projects. Given this, the diversity factor was only calculated for the Mid-North region connection points affecting the projects related to Bungama and Hummocks connection points;

  - Calculated the loads at Mid-North connection points, and their level of coincidence, for the last 4 years (2008/09 through 2011/12);

  - Derived diversity factors ranging from 94% to 97% over that period; and

  - Adopted a 97% diversity factor, which we note is consistent with the levels of diversity that occurred in 2009/10 and 2010/11 for each region (and which, as previously noted, are both considered to be close to 10% POE conditions).

39 Whilst intuitively, we consider that at more extreme temperatures, diversity will reduce, as extreme temperature conditions occur broadly simultaneously across varying connection points within a broader region, we note that this may be counteracted by the response of large customers and embedded generators to the higher market price levels that are likely to occur during those periods. The approach that we have proposed for developing large customer and embedded generation 10% POE forecasts would assist in explaining the impact of their behaviour on diversity at a regional level.

10.4. Summary of key points

- Whilst we agree with EMCa/NZIER that there is a need to consider diversity, we consider that a more reasonable basis to derive this factor is to assess the level of diversity that has occurred in years that have exhibited 10% POE conditions, as opposed to basing this on a single year's diversity factor in a year that didn't represent those types of conditions. We also consider that tailoring this diversity calculation to regions where the potential timing of regional augmentation projects is affected is likely to provide more accurate demand forecasts, given how they are used for augmentation planning purposes.

- We consider that ElectraNet's revised approach, which utilises actual diversity factors prevailing in years when peak demands have occurred in conjunction with 10% POE conditions (2009/10 and 2010/11), is a reasonable basis for modelling regional demand forecasts, which in turn underpin regional augmentation plans. We also note that these two years represent the 'base years' that underpin SA Power Networks' proposed launch points.

- Notwithstanding the above, we note that in theory, the diversity factor may differ for every single connection point, which means that applying one diversity factor across ElectraNet's entire region to obtain regional demand forecasts is not theoretically correct. However, we note that since the two connection points chosen (both in the Mid-North region) are the only ones that require augmentation over the forecast period, for practical purposes, it is their diversity factor that is in fact the most relevant for the purpose of regional augmentation planning.

11. Additional high level comments on the AEMO forecasts

11.1. Topics already covered

- We have already outlined our concerns regarding:
  - the planning margin (see section 5.2), and
  - a number of the detailed assumptions utilised by AEMO, for example, around solar PV production at times of maximum demand (see sections 9.2 and 9.3).

11.2. Reasonableness of AEMO growth rates

- We note that the most recent AEMO forecasts (2012) assume a growth rate of only 1% in 10% POE maximum demand (or ~34 MW) over the period[40]. This compares to ElectraNet's revised growth rate of 1.8% (or ~60 MW per annum)[41].
- Whilst we acknowledge there are many factors that are incorporated within the AEMO forecasts (e.g., solar penetration and generation, price elasticity, industrial consumption, etc.), at a high level, it is our view that 1% growth (or ~34 MW[42]) appears at the very low end of what some high level checks indicate would be the reasonable range.

---

40 AEMO, *2012 South Australian Electricity Report*, p 13.

41 We note that this also includes a one off reduction associated with the SA Water desalination plant mothballing, which, if excluded, would increase this growth rate by around 10 MW per annum.

42 Less a small amount for things such as transmission losses, which affect generation, but not connection point forecasts.

- For example, if we believe the figures that underpin **Error! Reference source not found.** above, air-conditioner sales alone are around 180 MW per annum at present (and have been for at least the past five years). Clearly, some of these sales will be purely replacement air-conditioners, and therefore, they will not add to overall capacity, and moreover, may lead to reduced consumption, as the efficiency of the new units will undoubtedly be higher than that of the units they replace. However, even if we assume that say, 20% of these air-conditioners[43] were out-and-out replacements for an existing machine that is no longer utilised[44], and that new machines were 30% more efficient than those that were replaced, this would still mean that approximately 133 MW of effective air-conditioning capacity is likely to be installed in the coming years. We consider it reasonable to assume that a reasonable proportion of the overall nameplate capacity of this air-conditioning capacity will be used at the high temperatures that characterise 10% POE conditions. If that proportion was, say 75%, it would lead to an overall increase of 100 MW at the time of maximum demand. We further note that much of the “price elasticity” effect would in fact be embedded within historical sales statistics already, as opposed to the usage of the appliance. More specifically, we would posit that consumers that do not have an adequate willingness to pay to run an air-conditioner during temperature conditions consistent with 10% POE events, because of the price of the system or its operating costs, are unlikely to buy one in the first place. As a result, those systems that are installed can be assumed to have been installed by consumers that would predominately have a willingness to pay to use the air-conditioner during such events, despite the running costs[45]. Therefore, any further discounting applied to the forecast maximum demand associated with additional installed air conditioning capacity is almost certain to be unwarranted.

- Obviously, the above increase will be offset by a number of factors, the most prominent being the impact of increased solar penetration. Broadly, if AEMO assumes that there is an 8% increase in solar penetration per annum, and if we assume there are around 300 MW of installed capacity in South Australia (which is a particularly conservative assumption), and that, consistent with AEMO figures, they produce 38% of their capacity at time of system maximum demand, you get a 10 MW reduction in maximum demand each year from solar.

- Even just looking at the aforementioned two drivers of the maximum demand forecast, and excluding diversity (which we consider would be minimal, given that use of air-conditioners by residential customers is the overwhelming contributor to overall system maximum demand, and therefore their usage is likely to be very highly correlated with overall system maximum demand), the net increase would be 90 MW.

43 20% in theory equates to a 5 year appliance life, which is incredibly conservative.

44 Noting that this ignores the previously mentioned possibility that some of the ‘replaced’ machines are in fact moved to another room.

45 More generally, it is logical to assume that extreme temperatures represent those times at which air conditioning is likely to be used even by customers who may want to control/reduce their electricity bill – particularly in the absence of peak demand price signals.

- Obviously, there are other factors that will affect future maximum demand, for example increased take-up of energy efficiency measures by all customer segments, growth in large customer demand and the potential for additional demand response among larger customers in the event that AEMO's proposed demand response mechanism is enacted. Even assuming that these factors cancel each other out, and the only factor impacting maximum demand is residential air conditioning, relatively aggressive assumptions are needed in order to generate a forecast for these two key parameters that has an overall growth as low as 35 MW per annum. One set of assumptions that would achieve that result would be for the replacement rate to be assumed to be around 40%; an efficiency factor of 40%; and a fall in the coincident use of newly installed air-conditioners (relative to nameplate rating) to around 60%. Another set of assumptions that would work would be to retain the 20% replacement rate; 30% efficiency factor and the 75% coincident utilisation factor (relative to nameplate capacity), but reduce the overall capacity of air-conditioners installed by around a half – which would entail sales levels not seen since the 1990's.

- As stated in a previous section, we consider that there is a downside risk to future air-conditioner installation rates, relative to recent historical levels. However, reversion back to levels of over a decade ago is considered implausible.

- In summary, we acknowledge that there are numerous other drivers incorporated in the AEMO forecasts, some of which will increase and others of which will reduce the overall level of forecast maximum demand. We are not trying to replicate AEMO's forecasts, nor are we trying to represent the points we make above as being fully representative of all drivers of future demand. Rather, our point is simply to illustrate that a high-level assessment of the two most important drivers of changes in maximum demand over the forecast period appears to lead to outcomes that are more consistent with the outcomes presented by ElectraNet as compared to those presented by AEMO.

Appendix A: Authors

A.1 Rohan Harris

Rohan Harris is an economist who has worked in the energy, water and consulting industries for more than 14 years. Rohan's experience primarily relates to the areas of: energy and water demand forecasting; regulatory strategy and analysis; tariff design; cost benefit analysis; and risk management identification and quantification.

Prior to working at Oakley Greenwood, Rohan was the Principal Economist at SP AusNet, a large electricity and gas business. There, Rohan's primary role was to lead the development of numerous aspects of SP AusNet's 2011-2015 Electricity Distribution Pricing Submission.

Prior to joining SP AusNet, Rohan worked for three years at consulting firm SAHA International. At SAHA, Rohan provided regulatory, commercial, policy, strategic and risk management advice to a range of customers from the electricity, water, and gas industries.

Before joining SAHA, Rohan worked at South East Water for 7 years, including as Manager, Economic Regulation. Here, Rohan led both the strategic development, writing and modelling of South East Water's Pricing Submission ('Water Plan').

A selection of previous projects that Rohan has undertaken that relate to the requirements of this project include:

- Project managing and providing strategic advice in relation to the complete reconstruction of SP AusNet internal energy forecasting model.
- Leading a small Oakley Greenwood team that was tasked with undertaking a detailed review of the drivers of energy consumption for SP AusNet with the objective of understanding and quantifying the relative impacts of weather, solar penetration, roof insulation, macro-economic variables, and the price elasticity effects driving a material reduction in energy consumption 2011 relative to 2010.
- Developing South East Water's original demand forecasting model that was used in support of its 2005 Water Plan. This involved a detailed, bottom up assessment of the drivers of water and wastewater consumption, including: the penetration rate of different types of water efficient appliances; customer number forecasts by area; the impact of recycled water on potable water demand and wastewater flows; the impact of on-site storage (e.g., rainwater tanks) on potable water demand and wastewater flows; and the impact of South East Water's proposed tariff structure on water and wastewater consumption.
- Project managing the development of SP AusNet's Tariff Impact model, which allowed the energy and demand impacts of SP AusNet proposed Time of Use tariffs and Critical Peak Demand tariffs to be estimated and included in its pricing submission. More specifically, this included modelling the estimated own-price and cross price elasticity of demand impacts of its Time of Use tariff structure.

A.2 Lance Hoch

Lance Hoch has over 30 years of experience as a consultant to the electricity industry and the government and regulatory agencies that are involved with it. He specialises in the operation of electricity and gas distribution/retail utilities and has provided expert and innovative assistance to Australia's deregulated electricity utilities in a number of areas including regulatory strategy, tariff design, improving the commercial basis on which internal operations are undertaken, demand management and energy efficiency for improved financial and technical operation, business strategy development and implementation, and customer interactions.

Examples of project assignments he has undertaken that addressed issues and required expertise similar to that involved in this review for ElectraNet include the following:

- In separate assignments, critically reviewed the load forecasting approaches and documentation being used by EnergyAustralia and Integral Energy to support the tariff proposals in their submissions to the 2009 Regulatory Network Pricing Determination process. This included expert advice on and modelling of the relationship between their energy and demand forecasts and pricing options.

- Advised both Integral Energy and EnergyAustralia in NSW (in separate projects) on the development of their pricing strategies and methodologies for their current access undertaking negotiations with the AER. This included expert advice on (a) the development of new time-of-use and dynamic pricing options and (b) the design and analysis of the pricing trials that are being undertaken by both distribution entities using a range of more dynamic, interval-metered pricing options at the residential level. The impact of these tariffs on network capex requirements and system reliability was also assessed.

- Played a major role in an assignment to assist Ergon Energy, which at the time was an electricity distribution and /retail business owned by the Queensland (Australia) Government, develop the capabilities and databases required to meet regulatory requirements and develop and pursue a regulatory strategy.

- Assisted Ausgrid in developing a long-term pricing strategy that focuses on providing more cost-reflective prices to better signal the cost imposed by users on the network. The new pricing strategy was developed in light of (a) the availability and increasing deployment of interval metering and (b) the sale of the EnergyAustralia retail electricity and gas business with which the network business had formerly been associated. The work also involves developing a set of tariffs (both structure and price levels) that better reflect the revised pricing principles, and a transition plan that minimises price shocks in moving from the current to the new tariffs. It is expected that the new pricing principles and associated tariffs will provide significantly more cost-reflective prices, improved price signals for demand response, and greater certainty of recovery of required revenue.

- Led a major assignment for the Essential Services Commission of South Australia (ESCOSA), the state's independent electricity regulator, which demonstrated that demand-side management strategies – including technology promotions and pricing initiatives – could have a meaningful impact on the utility's need for capital. Based on the study's results, ESCOSA intends to provide approximately A$15 million over the next five years to enhance the utility's capabilities in demand management, including the conduct of load research to establish an information base for demand-side planning, and the design and implementation of up to a half dozen demand-side programs aimed at deferring the need for capital expenditures on low load factor system augmentations.

- For NEMMCO, led two projects that estimated the potential impacts of the simultaneous (even if not co-ordinated) deployment of large volumes of demand response and embedded generation (including renewables) on the stability of the power system. This included estimation of the quantity of these resources likely to emerge in the next 5 to 10 years in each NEM region.

Lance holds a Master's Degree in Energy Management and Policy from the University of Pennsylvania.