High level review of transmission connection point forecasts: SA

A REPORT PREPARED FOR THE AUSTRALIAN ENERGY MARKET OPERATOR

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Executive summary

In 2012, the Council of Australian Governments (COAG) gave AEMO responsibility for developing independent maximum demand forecasts as an independent reference for the Australian Energy Regulator's (AER's) revenue reset determinations.

AEMO commissioned ACIL Allen (ACIL) to develop the original methodologies for forecasting maximum demand (MD) and energy consumption at the transmission connection point (CP) level.

AEMO engaged Frontier Economics (Frontier) to review AEMO's implementation of the methodology for NSW and Tasmanian (Tas) forecasts in 2014.

In 2014/15 AEMO will apply the methodology developed to date to forecast maximum demand for QLD, VIC and SA. AEMO engaged Frontier to act as peer reviewer and advisor in this forecast process, including:

- peer review of the models, assumptions, methodology and forecasts developed by AEMO's Connection Point Forecasting team
- provide expert advice and guidance on the data, methodology, models and forecasts, as required
- identification of any issues and recommendations to address these.

Part of this role includes assistance to AEMO to further develop and improve the forecasting methodology, where possible. This report reflects Frontier's review of revisions to the original methodology and AEMO's application of the revised methodology to produce maximum demand forecasts for 41 South Australian (SA) transmission CPs. The review and advice process included:

- a Red Flag review in which we identified key issues with proposed revisions to the methodology and its implementation for the SA CPs
- ongoing advice and interaction with AEMO regarding the methodology and its implementation
- this report, which reflects a review of AEMO's SA forecasts

The scope of Frontier's role is to provide advice to AEMO on methodology (and improvements) and to review AEMO's implementation of the methodology and the resulting forecasts. Frontier was not required to produce an alternative set of forecasts. The review did not involve an audit-type exercise which would include a detailed review of computer code in the R statistical package and spreadsheet formulas.

Based on the scope of the review undertaken, in our opinion the maximum demand forecasting methodology that was applied for the SA CP forecasts is robust and reflects improvements on the original ACIL methodology. On the basis of our understanding of the steps in AEMO's implementation of the methodology for the SA CPs, AEMO has implemented the revised methodology correctly.

Frontier made a number of recommendations during prior rounds of CP forecasts (NSW and Tas, and VIC) and we have provided some additional recommendations for this round of SA CP forecasts. Some of these have been implemented for the current forecasts in SA. Other recommendations were tested further by AEMO but not implemented in the current forecasting process. We understand that recommendations not implemented are part of AEMO's action plan and will be considered for future forecasts.

On the basis of our review of AEMO's implementation of the maximum demand forecasting methodology for the SA CPs, Frontier confirms that (a) the revised methodology adapted for the CP forecasts is reasonable and appropriate and (b) AEMO has correctly implemented this revised methodology to the best of our knowledge.

Our overall assessment of the methodology and implementation is that it meets the standard of good industry practice. The methodology has been implemented in a professional manner, and where issues of concern have arisen during the implementation of the methodology, all reasonable steps have been taken, within the time and resource constraints, to ensure the statistical integrity of the forecasts.

1 Introduction

1.1 Background

In 2012, the Council of Australian Governments (COAG) gave AEMO responsibility for developing independent maximum demand forecasts as an independent reference for the Australian Energy Regulator's (AER's) revenue reset determinations.

AEMO commissioned ACIL Allen (ACIL) to develop the original methodologies for forecasting maximum demand (MD) and energy consumption at the transmission connection point (CP) level.

AEMO engaged Frontier Economics (Frontier) to review AEMO's implementation of the methodology for NSW and Tasmanian (Tas) forecasts in 2014.

In 2014/15 AEMO is applying the methodology developed to date to forecast maximum demand for QLD, VIC and SA. AEMO has engaged Frontier to act as peer reviewer and advisor in this forecasting process, which includes:

- a peer review of the models, assumptions, methodology and forecasts developed by AEMO's Connection Point Forecasting team
- expert advice and guidance on the data, methodology, models and forecasts, as required; and
- identification of any issues and recommendations to address these.

Part of this role includes assistance to AEMO to further develop and improve the forecasting methodology, where possible. This report reflects Frontier's review of revisions to the original methodology and AEMO's application of the revised methodology to produce maximum demand forecasts for 41 South Australian (SA) transmission CPs. The review and advice process included:

- a Red Flag review in which we identified key issues with proposed revisions to the methodology and its implementation for the SA CPs
- ongoing advice and interaction with AEMO regarding the methodology and its implementation
- this report, which reflects a review of AEMO's SA forecasts.

1.2 Scope of our review

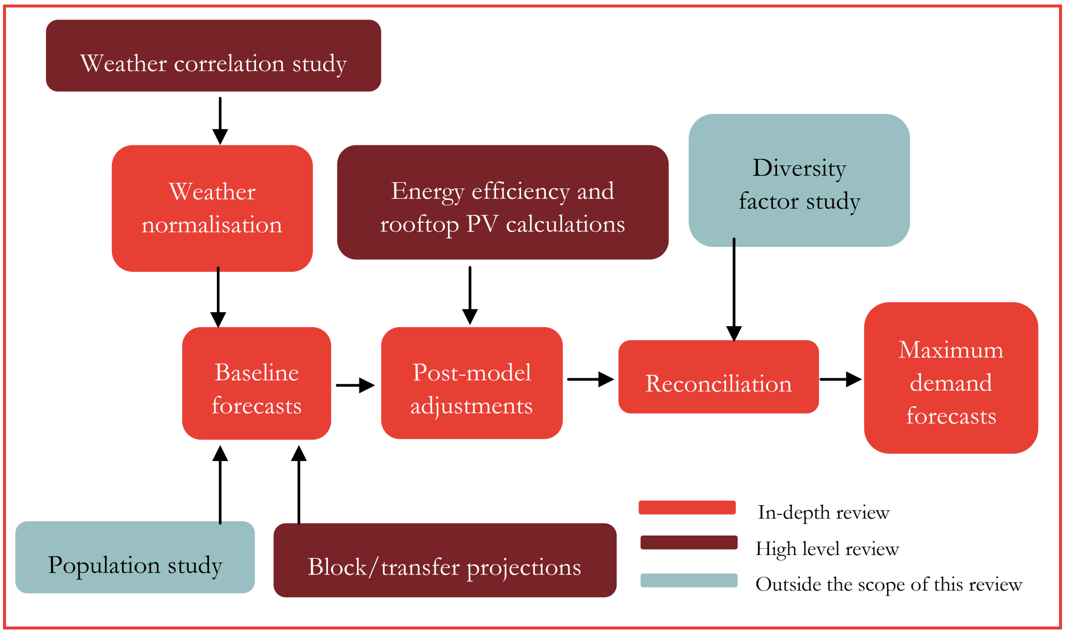
The scope of Frontier's role is to provide advice to AEMO on the maximum demand forecasting methodology (and potential improvements to the original methodology) and to review AEMO's implementation of the methodology and the resulting forecasts.

A simplified schematic representation of the steps involved in the forecasting methodology is presented in Figure 1. The scope of our engagement does not involve an in-depth review of all the steps involved in deriving the forecasts. Steps that have not been reviewed in any detail are shown as 'outside the scope of this review'.

Frontier was not required to produce an alternative set of forecasts. The review did not involve an audit-type exercise which would include a detailed review of computer code in the R statistical package and spreadsheet formulas.

In undertaking this review, we have assumed that appropriate investigations have been undertaken to select the required inputs, and that the preparation of the data used for the modelling has been performed to a professional standard. We have also assumed that the computer code has been checked carefully and does what it is intended to do (i.e. it is outside our scope to provide quality assurance or checks on the correctness of the computer code).

Figure 1: Scope of Frontier's maximum demand methodology review



Source: Frontier Economics

2 AEMO's maximum demand forecasting methodology

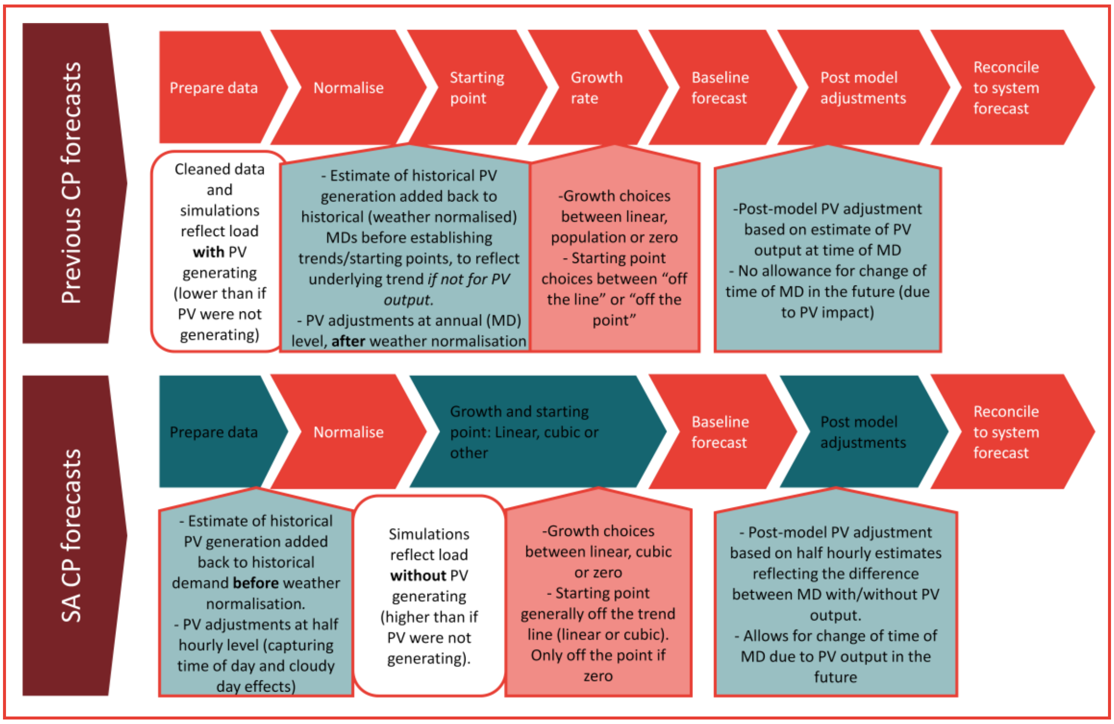
2.1 Overview

The methodology adopted by AEMO for the SA CP forecasts is an improvement on the original methodology proposed by ACIL for forecasting maximum demand at the CP level and implemented in previous rounds of forecasts in other states.

A high level summary of the previous methodology for forecasting maximum demand at the CP level is shown in the upper half of Figure 2. The lower half of Figure 2 shows the revised methodology adopted for the SA CP forecasts, highlighting the key changes from the previous methodology.

The steps involved in the previous approach are described in detail in the ACIL report. For the SA forecasts some modifications were made to ACIL's proposed methodology in response to issues arising during its implementation in the previous rounds of forecasts (NSW, Tas and Vic). These steps and changes are discussed in more detail in the following paragraphs. In all cases, any changes to the methodology and implementation were discussed in detail between AEMO and Frontier Economics.

Figure 2: Summary of original/revised methodology and key changes



Source: Frontier Economics

AEMO's current methodology consists of the following main steps:

1. **Data collection and manipulation**

- This step consists of the collection of load and temperature data, adjustments of load data for large industrial loads and embedded generation, and the treatment of influential and missing observations.
  - Under the previous methodology, no adjustment was made for historical PV at this stage. A single PV adjustment was applied for each year/season after weather normalisation/simulation based on an estimate of PV output at the time of system MD.
  - Under the updated methodology, estimates of historical PV output are added back to the historical half hourly level demand, prior to weather normalisation. If the PV adjustments can be estimated accurately, this would better reflect the underlying trend in customer demand for each half hour (in the absence of PV).

2. **Weather normalisation**

- This step involves specification and estimation of temperature sensitivity models for daily maximum demand, followed by a simulation exercise to determine the P50 (POE50) and P90 (POE10)[1] levels of maximum demand for each historical year.
  - Under the previous methodology, the weather normalised POE50 and POE 10 MD levels reflected estimates of MD when PV was generating. To estimate the underlying trend for MD at the consumer level, it was necessary to add back estimates of historical PV output to the annual historical non-coincident MDs;
  - Under the revised methodology the simulations reflect MD in the absence of solar PV generation (i.e. as if PV were not generating). Adjusting for estimates of historical PV for each half hour ideally should improve estimates of the underlying MD trends.
- AEMO also tested "pooling" of data across years at this stage, though without dummy variables allowing for different levels of MD in individual years.
  - AEMO considers that further evaluation with dummy year variables and different window sizes is required and did not adopt pooling for the final SA CP forecasts.

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1 Throughout this report the 90th percentile (P90) corresponds to the 10% probability of exceedence (POE10).

- We recommend further development of the pooling approach in future forecasts, with the inclusion of dummy variables for each year. We understand that AEMO plans to further test and develop this approach in line with this recommendation.

3. Selection of a starting point for the demand forecasts &
4. Determination of a growth rate

- Under the previous methodology:
  - the **starting point** is a choice between the last point on the trend line through the POE50 and POE10 historical demands ("off the line"), or the last actual observation for the POE historical demands ("off the point"). The choice depended on how well the trend line fits the data.
  - The **growth rate** is determined from either the trend line through the historical POE demands or anticipated population growth in the local area. In some cases a zero growth rate is assumed.
- Under the revised methodology for the SA forecasts, AEMO still starts with a linear trend as the default model and, in the same way as before, tests the fitted model for linearity and whether the last point is an outlier. But the outcome of these tests has different implications for the growth/starting point decisions:
  - If the statistical tests reject **both** non-linearity **and** find that the last point is not an outlier then the default position is to adopt a linear trend, starting from the last point on the linear trend line.
  - If **either** the hypothesis of linearity is rejected (accepting non-linearity) **and/or** the last point is deemed to be an outlier then the fallback position is to adopt a cubic trend, starting from the last point on the cubic trend line.
  - In some cases AEMO exercised judgement to override the test results.

This approach is summarised in Table 3. In some instances, the linear trend was manually replaced by a cubic or zero trend based on judgement. In two cases this was because there was insufficient data to apply the statistical tests. In other cases this was generally because the linear trend was deemed too low (negative) or too high (relative to population growth).

Table 1: Default trend applied given test results

Test for linearity	Test for outlier (last point)	
	Outlier	Non-outlier
Linear	Cubic	Linear
Non-linear	Cubic	Cubic

For the cubic trend, a 'horizon year' MD value was added to the estimation dataset as recommended by Willis (2002).[2] The horizon year was chosen to be 2030, and the MD value in the horizon year was set equal to the maximum of the historical weather normalised MDs at the relevant POE level. According to Willis, introducing horizon year MDs into the dataset improves forecast accuracy considerably, even if the horizon MDs are not very accurate.

5. **Calculation of baseline forecasts**

- This is done by applying the growth rate to the starting point on either the linear or cubic trend line. In cases where a zero growth rate was selected, this growth rate was applied to the last weather normalised point. In all these cases, the weather normalised point was quite close to the fitted line.

6. **Post-modelling adjustments for photovoltaic solar generation (PV), energy efficiency improvements (EE) and block loads and transfers**

- Under the previous methodology, AEMO determined the PV forecast at the CP level as a pro-rata allocation of the NEFR system level PV estimate based on the residential customers per CP. A limitation of this approach is that it implicitly assumes that all CPs have the same time of MD as the system (coincident) MD.
- Under the revised methodology, AEMO estimates the change in MD at the half hourly level with/without PV output for each CP. This requires pairing half hourly demand with half hourly PV traces. It is a more data intensive approach to accurately estimate PV output at the half hourly level, but the approach captures the effect of PV output on possibly changing the time of MD for each CP, and it also allows for different times of MD for each CP.

7. **Reconciliation of CP maximum demand forecasts to system maximum demand forecasts**

- This methodology is unchanged from before.
- Firstly, AEMO estimates a diversity factor for each CP, which reflects the ratio of the coincident demand (at the time of system level MD) to the non-coincident CP MD (at the time of the CP MD). This is based on an historical average over five years, so does not capture possible changes to the time of MD (coincident or non-coincident) or changes in the ratio. Despite this limitation, this is in line with the original methodology and is within the bounds of good industry practice. Since the non-coincident MD should always be equal to or greater than the coincident MD, the diversity factors

2 Willis, H.L.(2002), *Spatial Electric Load Forecasting* , CRC Press (available on Google books), Section 9.3.

should never be greater than 100%. The review confirmed that this was the case for the SA forecasts.

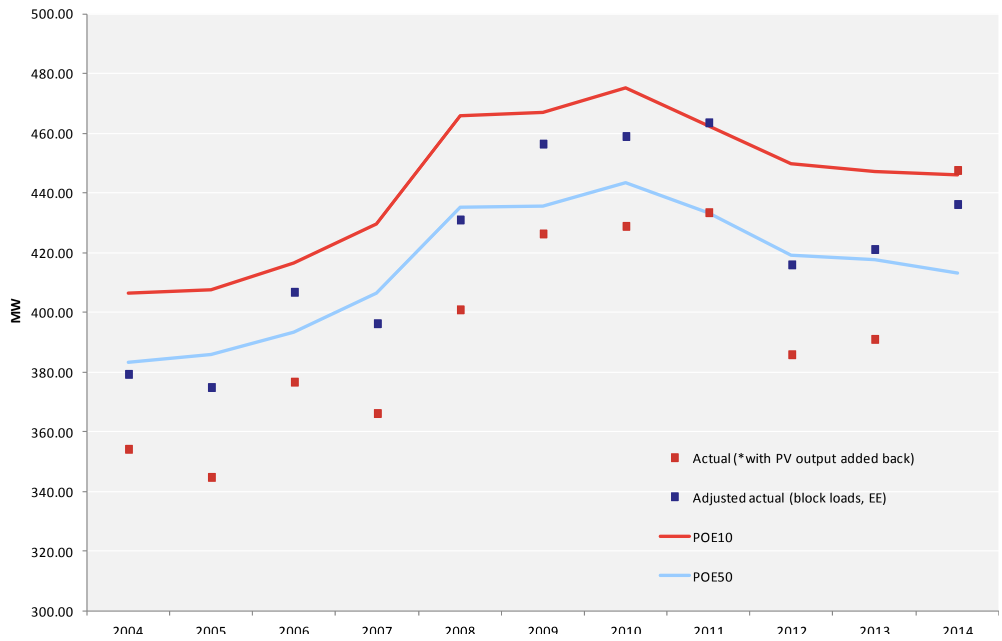
- Secondly, AEMO estimates a scaling factor to reconcile the sum of the CP coincident MDs to match the system level (regional) forecasts.

2.2 Worked example of a connection point forecast (revised methodology)

This section shows a worked example of the steps in the revised methodology, using the SPSISGSXWEST summer forecasts for illustration.

Steps 1 and 2: Data preparation, weather normalisation and simulation

Figure 3: Example: SPSISGSXWEST summer



Step 1. Data preparation. Red dots reflect historical actuals, with estimates of historical PV added back. Actual observed MDs from 2009 onwards, would be lower than this since PV generation supplies some of the demand. This adjustment is made at the half hour level prior to determining MD, which is a revision to the original methodology.

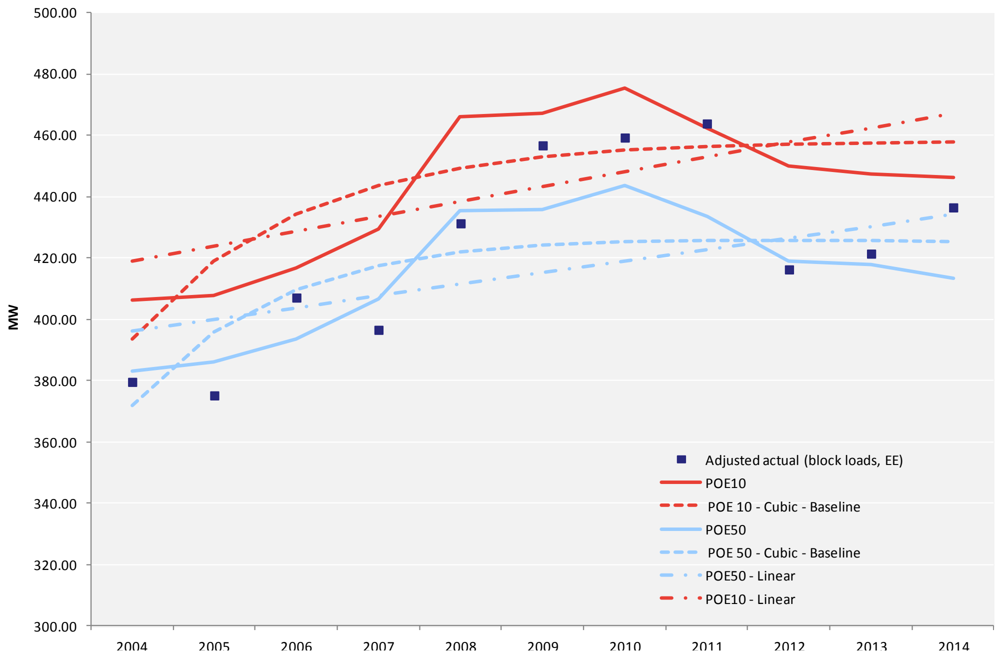
Navy blue dots incorporate an additional adjustment to historical MDs to reflect differences between the historical years and the latest year (2014) with respect to block loads and load transfers. In this case, this results in an upward adjustment.

Step 2. Weather normalisation and simulations. The red line reflects the POE10 MDs and the light blue line reflects the POE50 MDs obtained from the simulation. Around half of the navy blue dots should be above the light blue line, and around 10% should be above the red line (on average).

Source: Frontier Economics analysis of data provided by AEMO

Steps 3 & 4: Growth rate and starting point

Figure 4: Example: SPSISGSXWEST summer, Growth rate and starting point (trend selection)

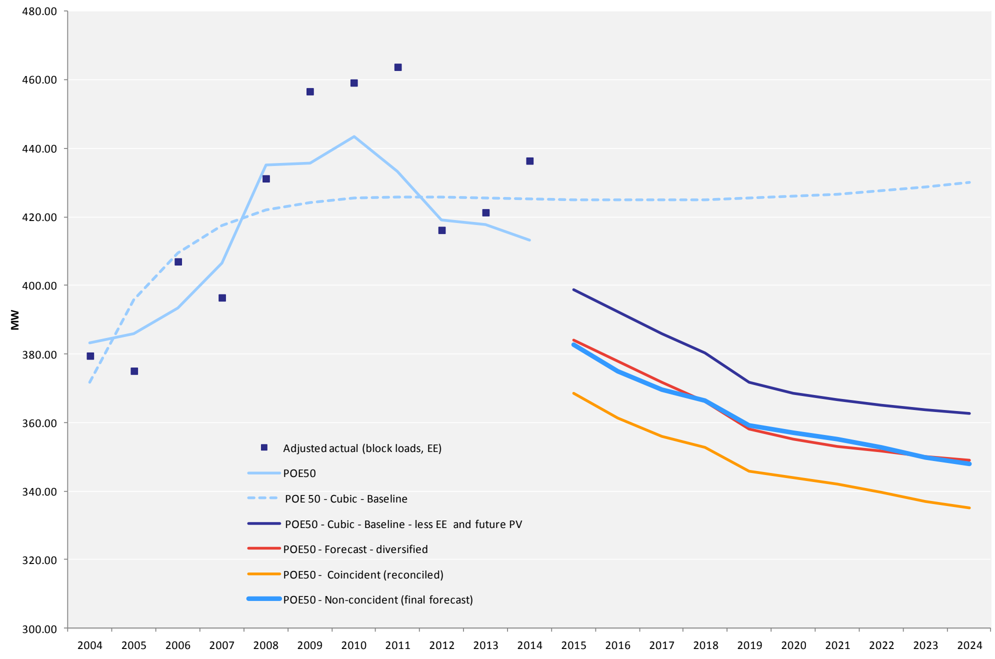


Steps 3 & 4. Cubic and linear trends estimated and statistical tests applied. For SPSISGSXWEST summer, the test found that the linear trend should be rejected and a non-linear trend should apply. Hence the cubic (dashed line) was chosen for the growth rate for each of the POE50 and POE10 demands. The starting point in this case is the last point on the cubic trend line.

Source: Frontier Economics analysis of data provided by AEMO

Steps 5, 6 & 7: Baseline forecasts, post-model adjustments, reconciliation

Figure 5: Example: SPSISGSXWEST summer, POE50: Baseline forecast, post-model adjustments and reconciliation (final forecasts)



Step 5. The light blue dashed line shows the Baseline forecasts, which reflect the starting point and trend (growth) for the cubic trend line (selected in the previous step).

Step 6. The **navy blue line** reflects the Baseline forecast, less post-model adjustments for future EE and PV (unreconciled, non-coincident MD). The adjustment for EE only reflects a deviation from the historical trend. The adjustment for PV reflects an estimate of the total contribution of PV to reducing future MD. The adjusted forecast will start lower than the historical actual MDs (simulated MDs), as the historical actual MDs have PV output added back (i.e. the forecast is not directly comparable to the historical given that under this methodology, adjustments for PV are now made **before** the simulations). This is illustrated in the stylised example in Figure 7.

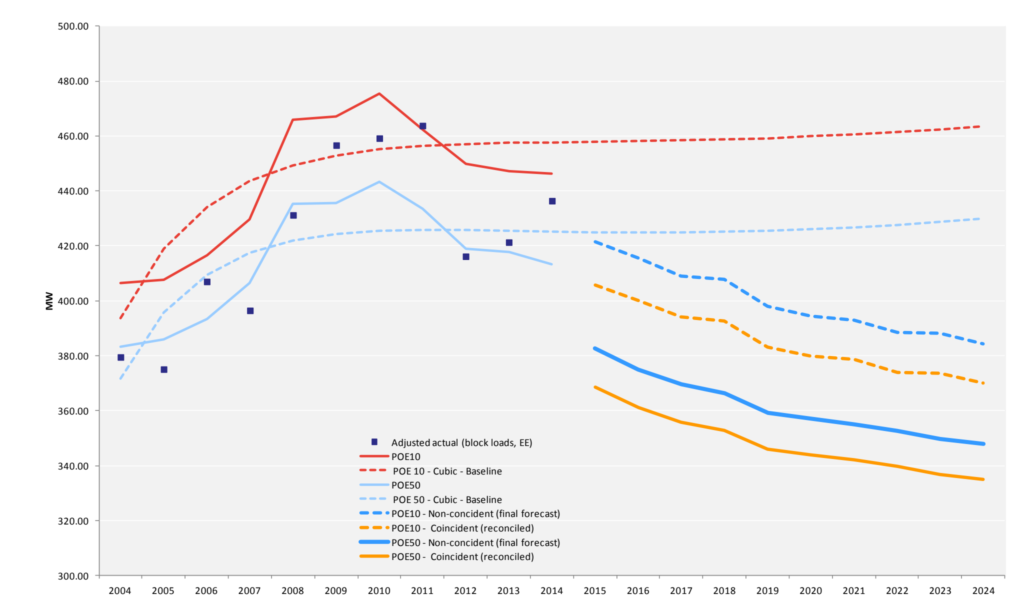
Step 7a. AEMO multiplies the Adjusted Baseline (navy blue) by the diversity factor at that CP. The diversity factor is the historical ratio of the average CP demand at the time of the system MD to the CP demand at the time of the CP MD (**red**: the **unreconciled coincident MD**). Diversity factors will differ by CP, but under this methodology are constant over time for each CP. Diversity factors should always be less than 100% (this shift should always be down).

Step 7b. AEMO scales the diversified MD of each CP so that the sum of the diversified MDs matches the regional (coincident) MD (**orange: reconciled coincident MD**). The same scaling factor is applied to all CPs, though a different scaling factor is applied by season and by POE. Scaling factors also differ over time, and can be greater or less than 100%, depending on whether the CP forecasts are higher/lower than the regional forecasts (ideally close to 100%). In the case of summer POE50, the scaling factors are around 96-97%.

Step 7c. AEMO divided the reconciled coincident MD (orange) by the diversity factor at each CP to obtain a reconciled **non-coincident final MD forecast** (**mid-blue**). This shift should always be up (non-coincident MD should always be greater than coincident MD).

Source: Frontier Economics analysis of data provided by AEMO

Figure 6: Example: SPSISGSXWEST summer, POE50 and POE10: Final reconciled forecasts, coincident and non-coincident



Source: Frontier Economics analysis of data provided by AEMO

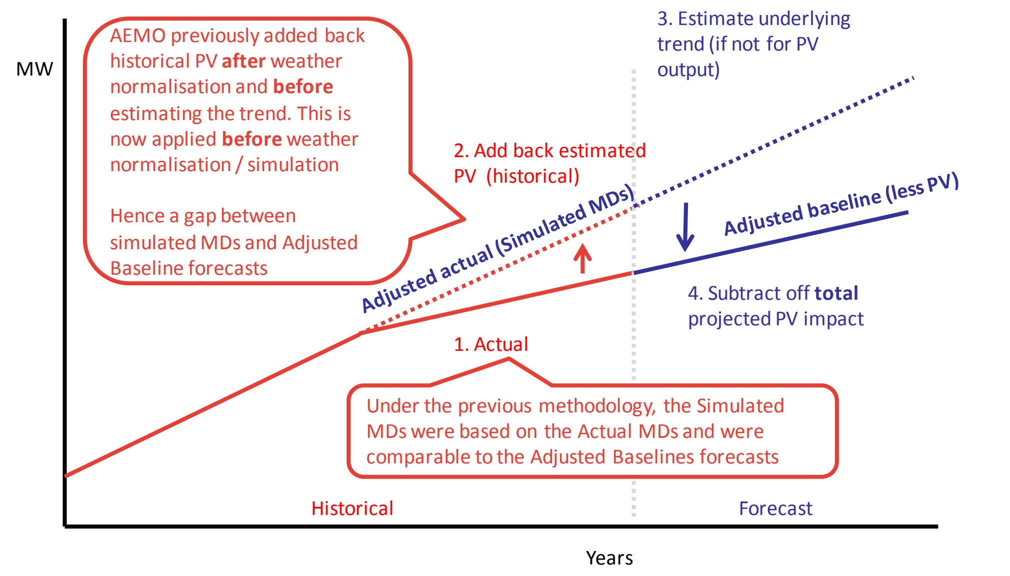
Stylised example of PV and EE adjustments

Figure 7 and Figure 8 show stylised examples of the difference in treatment of PV adjustments and energy efficiency (EE) adjustments. Figure 7 also illustrates the difference between the historical simulations (which reflect PV output of 0MW) and the baseline adjusted forecasts (which reflect a positive PV output and hence lower MD forecasts).

For PV, estimates of the total historical PV are added back to the historical MDs, the underlying trend is estimated and projected into the future (reflecting demand with PV not generating), and then estimates of the total PV impact in future are subtracted off the future forecasts. As discussed later, the PV "impact" on future MD is the estimated change in MD with/without PV in the future which, due to a possible change in the time of MD with/without PV, is not the same as estimated PV output at any given time.

EE is treated differently: historical EE is not added back to historical MD, hence the underlying trend that is estimated reflects the impact of EE. The methodology assumes that the impact of EE on MD is linear and continues to grow in the future at the same rate as in the past. Hence, the EE adjustment to future MD forecasts reflects only an estimate of the deviation from the historical, linear trend for EE impacts (which is less than the total EE impact).

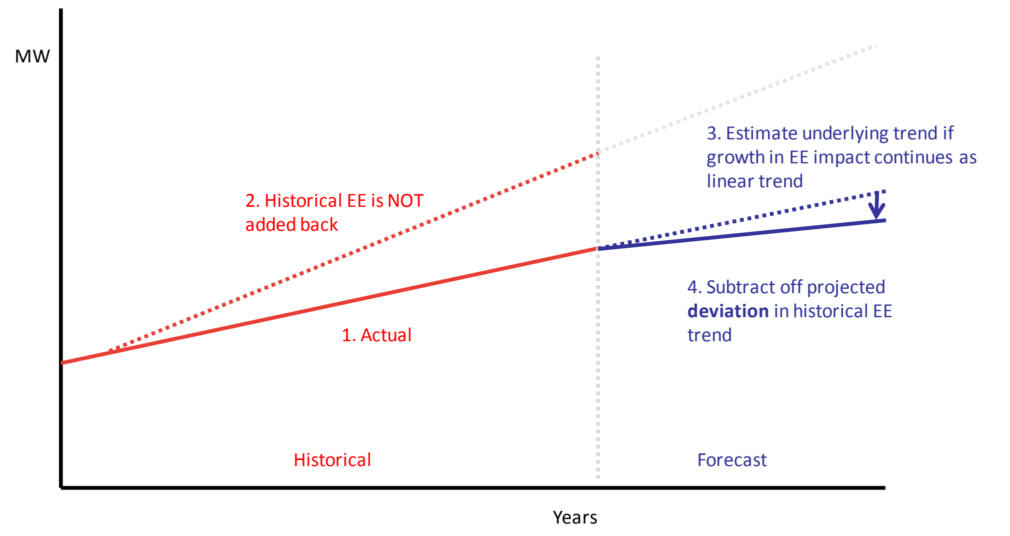
Figure 7: Methodology for PV adjustments



Note: *Previously, future PV adjustment was based on pro-rata of NEFR, assuming same time of MD for all CPs. For the SA forecasts, the PV estimates differ for each CP reflecting a different time of MD for each CP (and allowing for changes over time). Hence the sum of the CP PV adjustments can be larger than in the NEFR. The MW PV capacity installed by CP is as provided by SAPN; output is estimated by AEMO based on output traces*

Source: Frontier Economics

Figure 8: Methodology for EE adjustments



Source: Frontier Economics

3 Review of AEMO's implementation of forecasting methodology

In this section we review AEMO's implementation of the revised forecasting methodology compared with that outlined in the ACIL Report and implemented in previous forecasts for other states.

Table 2: Summary of methodology, changes and recommendations

Step	Methodology adopted previously	Implementation (and modifications adopted) for SA	Improvements to consider in future
Data preparation	Prior to undertaking regression modelling, daily maximum demand and weather data should be modified to: • remove known block load and transfers, as these are exogenous • remove weekends and public holidays • remove 'mild' days and potentially misclassified days (which appear as outliers). **No adjustments were made for historical PV at this stage in the original methodology.**	On Frontier's recommendation, for the SA forecasts AEMO adjusted historical data for block loads and load transfers and added PV load ***before*** weather normalisation and simulations. AEMO changed the "base year" for block loads/ transfers to reflect the last year of the data (as opposed to the first) This required AEMO to estimate historical PV output for each half hour, as opposed to a single estimate of historical PV output for each year/season. AEMO estimated historical PV based on a combination of: (a) installed PV capacity for each CP (provided by SAPN) (b) estimates of typical PV hourly output for an average day for an average month, to capture variation in PV output across time of day (c) historical weather data for daily solar radiation (at Adelaide Airport), to capture the effects of cloudy days (d) the PV adjustments were implemented before weather normalisation Frontier has not inspected the files or data where AEMO applied these historical PV adjustments, as this is highly data intensive. ***The methodology as described appears reasonable and appropriate and in theory provides a more robust estimate of the underlying MD trend (without solar PV output) than the previous approach. This is subject to the calculation of estimated PV output at the half hour level given that this is not measured. From our review, the PV output estimates appear reasonable at the half hour level.*** Frontier has not inspected the data showing removal of major industrial load or the addition of embedded generation. We understand that in some cases (non-permanent events) data was not available and AEMO has made judgment calls on appropriate block load/transfer adjustments.	***The revised methodology applied for historical PV adjustments (and applying these prior to weather normalisation) reflects an improvement in methodology. Frontier recommends that this should continue to be applied/ considered in future implementations.***

Step	Methodology adopted previously	Implementation (and modifications adopted) for SA	Improvements to consider in future
Weather normalis-ation	To weather normalise the maximum demand: • for each historical year, estimate a model of daily maximum demand as a function of temperatures • for each historical year, use this relationship to simulate a distribution of hypothetical historical annual peak demands under different weather scenarios and random influences • determine the POE50 and POE10 levels of peak demand for each year from these distributions	**No modifications to methodology were adopted for the final forecasts other than that adjustments to historical load were undertaken prior to weather normalisation.** **Weather normalisation:** Frontier has previously recommended pooling observations across years when estimating maximum demand-temperature models in order to more effectively use the available data. AEMO tested the pooling approach but judged that further investigation, in line with Frontier recommendations, is required before implementing this approach. **Weather simulations:** The distribution for maximum demand produced by AEMO's simulation procedure should be inspected to confirm that, on average, about 50% of the historical actual MDs do lie above the POE50 levels, and about 10% lie above the POE10 levels. ***Frontier recommends reviewing the weather simulation results against historical actual data and this review was undertaken for the SA CPs. In most cases the simulation results appear within the bounds of reasonableness, but during the review we identified some CPs where the simulations appeared higher/lower than expected. AEMO corrected for this by manually overriding the temperature model where appropriate.*** For example, the test for SPSKNC accepted a minmax temperature model for summer and winter (though it was borderline accepted). The resulting simulations resulted in POE50 and POE10 values that appeared to be too high in winter (the POE50 points were all above historical actual). AEMO corrected for this by changing to a constant temperature model for the final forecasts.	***Frontier recommends that AEMO consider data pooling for weather normalisation in future forecasts.*** ***We recommend that this be based on 3 years of pooled data. For "boundary years" (the first and last in an available sample) this should still include 3 years. For example, year 1 can be pooled with year 2 and year 3.*** ***We recommend that this should include dummy variables for each of the years.***

Step	Methodology adopted previously	Implementation (and modifications adopted) for SA	Improvements to consider in future
Estimate historical trends	Prior to estimating the trends, AEMO adjusted historical POE values for block loads and load transfers, and adds PV load to identify the underlying MD trend (if not for the impact of solar PV). Regression is used to fit linear trends through the historical POE50 and POE10 values.	In the modified methodology, adjustments for historical PV are made prior to weather normalisation/simulation rather than after, so no further PV adjustment is required at this stage. AEMO fitted linear and cubic trends through the historical POE50 and POE10 values. For the cubic trend, a 'horizon year' MD value was added to the estimation dataset as recommended by Willis (2002).[3] The horizon year was chosen to be 2030, and MD value in the horizon year was set equal to the maximum of the historical weather normalised MDs at the relevant POE level. According to Willis, introducing horizon year MDs into the dataset improves forecast accuracy considerably, even if the horizon MDs are not very accurate. ***This approach appears reasonable and has been appropriately applied for the SA forecasts, though there is scope to further consider the appropriate horizon for estimating cubic trends in future forecasts.***	**Alternative horizon values** Presently, AEMO's default horizon value is set equal to the historical maximum demand. This could be inappropriate, for example, for a CP where demand seems to be decreasing. In that case AEMO could consider using the historical minimum demand as the horizon demand, or some other lower value**,** in future forecasts. **Double horizon values** Willis recommends that "where the overall system load growth rate is high (above 3% annually) or the small area size is quite small, dual horizon year loads - loads of the same value, separated by one year in between them (e.g. years +25 and +27) - can make a slightly greater improvement." We recommend that AEMO investigate this option for CPs where the default procedure does not produce plausible projections**.**

3 Willis, H.L.(2002), *Spatial Electric Load Forecasting* , CRC Press (available on Google books), Section 9.3.

Step	Methodology adopted previously	Implementation (and modifications adopted) for SA	Improvements to consider in future
Select starting point for projecting forecasts	The starting point for forecasting is based in the last year for which actual data are available. ACIL recommends that, depending on how far the last observed point deviates from the trend line, the forecasts should start either: • "off the point": taking the most recent weather normalised observation, or • "off the line": taking the corresponding point on the fitted time trend line through the weather normalised data. During previous CP forecasts for other regions, Frontier recommended a statistical test to determine whether the trend model is "well specified", in which case "off the line" should be used as the starting point.	When the linear trend was applied for a forecasts, the starting point applied was "off the line", consistent with the previous methodology. This methodology was revised to include an appropriate alternative when the cubic trend was applied. In this case, the starting point applied was "off the cubic line". Where a zero trend was applied, the starting point was "off the point". ***This approach appears reasonable and appropriate and was implemented by AEMO in the final forecasts.***	***Frontier can assist AEMO to develop a statistical test to help determine whether to apply a linear or cubic trend (and hence starting point) in future forecasts.***

Step	Methodology adopted previously	Implementation (and modifications adopted) for SA	Improvements to consider in future
Determine a growth rate	ACIL proposes that two approaches be investigated to determine the growth rate: (i) fitting a linear time trend regression model through the historical POE50 and POE10 series; and (ii) estimating a regression model with regional population as the driver. The approach with the better fit to the data is used to determine the future growth rate, provided that the estimated growth rate seems reasonable. If the growth rate does not seem reasonable, a zero growth rate is assumed. In previous CP forecasts for other regions, Frontier provided a statistical test to determine when use of the linear time trend model for producing forecasts was inappropriate due to nonlinearity. In cases where the statistical test rejected the use of the linear trend model for producing the forecasts, Frontier recommended using judgement to determine an appropriate alternative trend to use.	Some trends in the historical data are nonlinear. When this is the case, it is inappropriate to use a linear trend line to determine the growth rate. For the SA forecasts, AEMO also estimated and applied a cubic trend for some CPs where the last point was an outlier or the trend was non-linear. A trend of zero was applied in cases where there was insufficient data to apply the tests or because the linear trend was deemed too low (negative). The basis for choosing a linear or cubic trend was the result of the statistical tests, subject to judgement to potentially override. For example, If the tests accepted **both** linearity and found that the last point was not an outlier then the default position was to adopt a linear trend If **either** the hypothesis of linearity is rejected (accepting non-linearity) **and/or** the last point is deemed to be an outlier then the fallback position is to adopt a cubic trend ***This approach is reasonable and appropriate and was implemented by AEMO in the final forecasts.***	***Frontier can assist AEMO to develop the statistical test to help determine whether to apply a linear or cubic trend (and hence starting point) in future forecasts.***
Baseline forecasts	Apply the selected growth rate to the selected starting point to produce baseline forecasts	***The recommended approach was implemented by AEMO in the final forecasts. (This is an outcome of the starting point/growth rates).***	

Step	Methodology adopted previously	Implementation (and modifications adopted) for SA	Improvements to consider in future
Post-model adjust-ments	Make post model adjustments to take into account factors that are known but not yet incorporated into the trend forecasts. Factors include: • new large block loads, load transfers • energy efficiency and the uptake of solar PV **Energy efficiency**: AEMO adjusted CP forecasting for EE based on a pro-rata adjustment of the NEFR EE estimate for the state (based on customers per CP for building EE and residential customers per CP for appliance EE). **Solar PV:** AEMO adjusted CP forecast for PV based on a pro-rata adjustment of the NEFR statewide PV estimate at time of MD. This was adapted to reflect the same time of (state) MD for POE50 and POE10.	**Energy efficiency** ***This is unchanged from before, and the approach is reasonable and appropriate*** **Solar PV** The previous approach was consistent with the NEFR and relatively simple to apply given data availability and time constraints. However, one limitation of the previous PV approach is that it implied that all CPs have the same time of MD (which was the same as the statewide MD). This implied a "coincident PV" output. For the SA forecasts, AEMO tested two revised approaches to better capture the different time of MD for each CP (non-coincident). The first attempt was to identify the time of MD for each CP and pro-rate the state-wide PV output at that time based on the forecast installed capacity in the CP in a given year. This allowed for a difference in time of MD between CP and the state, but it didn't allow for a change in time of MD across years. As such, it appeared to overestimate the impact of PV in the future given that in many cases, the forecast MD would be shifting later in the day when PV output would be lower. This approach was not applied for the final forecasts. The second approach combined a half hourly trace of demand without PV with a half hourly trace of PV output (scaled to installed capacity) to estimate half hourly profiles with/without PV for each CP. This provided estimates of (a) the change in time of MD with/without PV for each CP for each year, (b) the level of MD for each CP with/without PV, and (c) the difference between the two, which reflects the contribution of PV to reducing the MD. This last term is not an estimate of the actual PV output at either time of MD (with/without PV), but it is a better estimate of the impact of PV on MD where PV is causing a change in the time of MD. For example, if PV output was causing the MD to shift from midday to evening: - PV output at midday would likely overestimate the impact of PV on MD; - PV output at night would likely underestimate the impact of PV on MD; - the net impact of PV on MD would lie between the two. ***The revised approach adopted by AEMO is reasonable and appropriate and an improvement on the previous methodology.***	***The revised methodology applied for future (post model) PV adjustments is an improvement in methodology. Frontier recommends that this should continue to be applied/considered in future implementations.***

Step	Methodology adopted previously	Implementation (and modifications adopted) for SA	Improvements to consider in future
Recon-ciliation with system forecasts	Scale the individual connection point forecasts so that the totals of the CP forecasts match the system level (regional) forecasts. AEMO estimates the diversity factor for each CP by averaging the annual diversity factors for the latest five years.	***No change in methodology was adopted for this implementation*** The switch from day peak to night peak due to increasing PV is likely to affect the relationship between maximum demand and coincident maximum demand, and hence the diversity factor. ***Frontier will work with AEMO to address this issue in future implementations*** The scaling factors for the SA CPs appear to be reasonable. In summer, the scaling factors appear quite stable over time and close to 100%, suggesting consistency between the NEFR and the CP forecasts. In winter, the scaling starts near 100% but increases over time to around 110% by the end of the forecast period. The source of this discrepancy should be investigated in future implementations. ***Frontier will work with AEMO to address this issue in future implementations*** The scaling factor for POE10 is consistently larger than for POE50 for summer and winter. There is no theoretical reason why this should be the case. It suggests that the simulated spread of MDs due to weather conditions is larger in the system level forecasts than in the CP forecasts. The reason for this most likely lies in the different approaches used to develop the weather simulations. The reconciliation exercise overcomes the discrepancy between the approaches to some extent, but the source of the discrepancy should be investigated. ***Frontier will work with AEMO to address this issue in future implementations***	***Frontier will work with AEMO to*** ***(a) consider the potential for estimating changes to diversity factors over time (to reflect future changes to the time of MD) and*** ***(b) understand why scaling factors are increasing over time, and higher in POE10 cases than POE50***

3.1 Weather normalisation

3.1.1 Methodology

ACIL's approach to weather normalising maximum demand consists of two main steps:

- estimating a regression model to determine the temperature sensitivity of the daily maximum demands in a season
- using this model to simulate the annual maximum demands under many different weather scenarios. The simulations also incorporate a random term that varies from simulation to simulation. The random term encapsulates unobserved idiosyncratic factors that impact maximum demand.

The simulation step results in a distribution of hypothetical annual maximum demands for each historical year. The maximum demand for each year at any level of POE can be obtained from the corresponding percentile of this distribution.

Frontier has previously recommended pooling the data across years when estimating the temperature sensitivity models.[4] Using a sample that covers several years has the following benefits:

- it increases the range of temperatures included in the estimation which leads to more precise estimates of the coefficients. The increased spread of temperatures also overcomes the problem that in mild years it is difficult to obtain statistically significant coefficients because the weather was too mild to evoke much demand response. Both of these factors will result in less instances of a CP being deemed to be not temperature sensitive.
- it increases the sample size, which further improves the precision of the estimates.
- it smoothes the estimated temperature sensitivity coefficients over time, which will result in less volatile weather normalised demands. This should also benefit the step where a trend line is fitted through the POE50 and POE10 historical maximum demands.

AEMO investigated the pooling of data in a previous round of forecasts for NSW and Tas. In earlier forecasting processes, it was not applied to the final forecasts, partly due to time constraints and partly to adhere to the published methodology for this round of forecasts.

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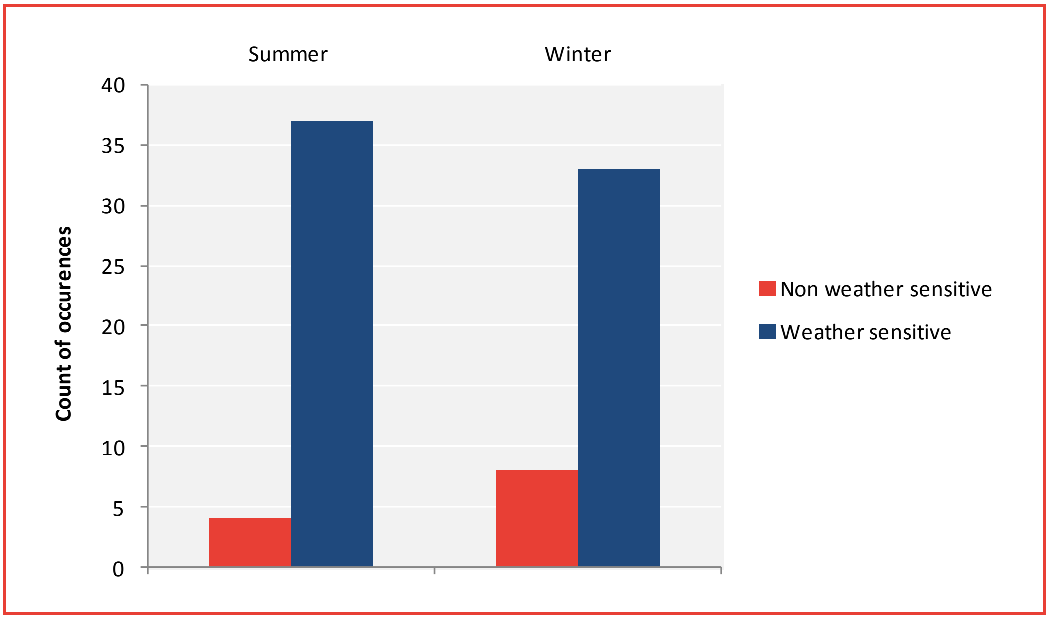
4 The pooled model recommended by Frontier includes yearly dummy variables to capture differences in the average level of demand from year to year. But determining the best approach to pooling the data across years requires further investigation.

In this round of forecasting for SA CPs there were fewer temperature insensitive connection points, so obtaining an acceptable weather normalisation equation was less of an issue (see Figure 9). AEMO tested the pooling approach in the present round of forecasting and judged that further investigation is required before implementing it. We understand that AEMO is committed to this in future forecasts.

Figure 9: Temperature sensitivity of SA CPs



Source: Frontier Economics analysis of data provided by AEMO

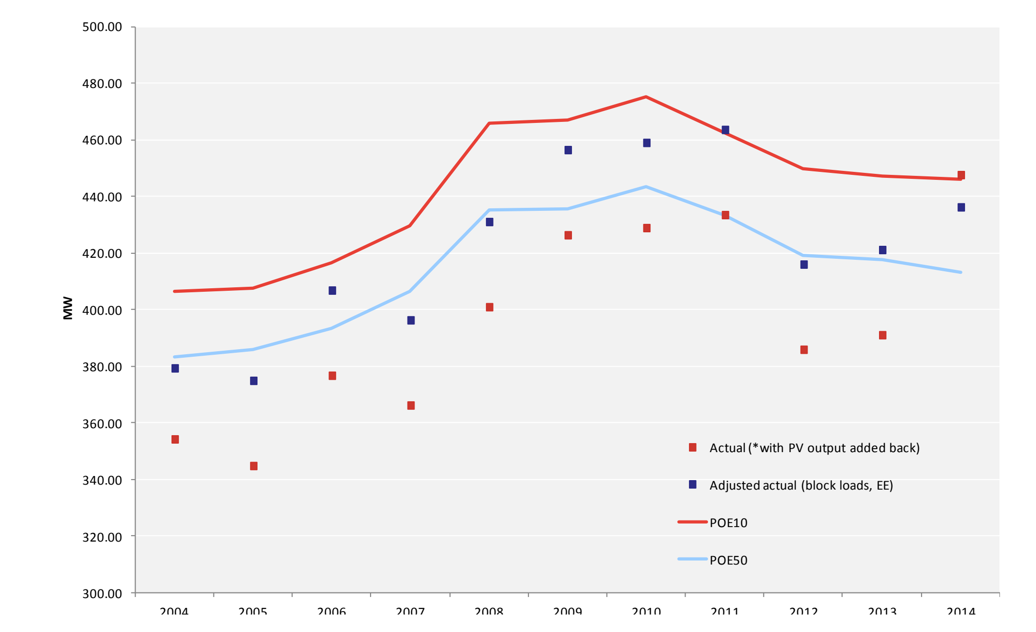
3.1.2 Review of temperature model / simulation results

The distribution for maximum demand produced by AEMO's simulation procedure should result in, on average, about 50% of the historical actual MDs above the POE50 levels, and about 10% lie above the POE10 levels.

As an example, the results for SPSISGSXWEST summer are shown in Figure 10. Comparing the "adjusted actuals" (navy blue dots) against the simulations, 55% (6/11) are above the POE50 line (light blue) and 9% (1/11) are above the POE10 line (red).

In general the simulations were reasonable when compared with historical actual MDs across the CPs. Where the results did not seem reasonable, AEMO refined the temperature model and/or the mild-days definition to improve the alignment of POE values with actual MDs.

Figure 10: Example: SPSISGSXWEST summer



Source: Frontier Economics analysis of data provided by AEMO

3.2 Historical trends in MDs and starting points for the forecasts

3.2.1 Previous methodology

ACIL's methodology to determine growth rates includes fitting a linear trend line through the historical weather normalised MD data. For a number of CPs it appears that the time trend is non-linear or that there is a structural break in the series. In previous forecast rounds, Frontier recommended two simple statistical tests to assist in deciding between starting point options:

- **Test for linear trend.** Include a quadratic term in the time trend model and test whether the coefficient on the quadratic term is statistically significant.
- **Test for outlier**. Test whether the last weather normalised observation is an outlier for the linear trend model by testing the significance of the 'external' or 'jacknifed' studentised residual.

Frontier recommended that the 'off the line' starting point be used only in cases where the above tests accepted linear trend and rejected the outlier. If either the trend was found to be non-linear or the last point to be an outlier, then the forecasts should be started 'off the point'.

This has been developed further for the SA CP forecasts to consider non-linear (cubic) trends, discussed below.

3.2.2 New developments in the methodology (SA forecasts)

AEMO has adapted the methodology for the SA forecasts to consider a non-linear trend rather than starting off the point and using a linear trend. This is applied as follows:

- If the statistical tests accept both a linear trend **and** that the last point is not an outlier, a linear trend is applied as the default (starting "off the line", never "off the point")
- If **either** the test for a linear trend is rejected or the last point is an outlier, then a cubic trend is applied (by default). In this instance, the starting point chosen is the cubic trend line, not the last actual point.

This approach is summarised in Table 3. In some instances, this was manually overridden based on judgement, and a linear trend was replaced by a cubic/zero trend. In two cases this was because there was insufficient data to apply the tests. In other cases this was generally because the linear trend was deemed too low (negative) or too high (relative to population growth).

Table 3: Default trend applied given test results

Test for linearity	Test for outlier (last point)	
	Outlier	Non-outlier
Linear	Cubic	Linear
Non-linear	Cubic	Cubic

Table 4 summarises the number of instances when the tests determined that a linear or non-linear trend should be applied in SA, including where manual adjustments were applied to the final trend.

Table 4: Trends applied to SA CPs: Summer

Trend	Trend based on tests	Modified trend		
		Linear	Cubic	Zero
Linear	24	16	7	1
NA (insufficient data)	2	0	0	2
Cubic	15	0	15	0
Zero	0	0	0	0

Total number of CPs	41	16	22	3

Source: Frontier Economics analysis of data provided by AEMO

Table 5: Trends applied to SA CPs: Winter

Trend	Trend based on tests	Modified trend		
		Linear	Cubic	Zero
Linear	26	24	0	2
NA (insufficient data)	2	0	0	2
Cubic	13	0	13	0
Zero	0	0	0	0
Total number of CPs	**41**	**24**	**13**	**4**

Source: Frontier Economics analysis of data provided by AEMO

We agree with the enhancement to the methodology of including cubic trends, and with AEMO's application of these modifications in the SA CP forecasts.

3.3 Solar PV adjustments

The previous methodology applied for PV adjustment was a reasonable approach given time constraints and data availability, but some limitations were identified in both the pre-model adjustments and post-model adjustments for PV. The methodology was revised for the SA forecasts to attempt to improve the forecasts and address these limitations.

3.3.1 Pre-model adjustments for PV

Previous methodology

Under the previous methodology, a single PV adjustment was applied for each year/season *after* weather normalisation/simulation based on an estimate of PV output at the time of MD. This is a manageable and implementable approach (as estimated PV output can be derived from the NEFR) but it implicitly assumes that either the MD for each CP is at the same time as the MD for the region or that the PV contribution is the same (if the time of MD is different). Although PV only begins to affect MD after around 2010 (when installed capacity increases) this may have an effect on estimates of the underlying trends if the time of CP MD differs from the statewide MD (and PV output would be different for each).

Revised methodology

Under the updated methodology, estimates of historical PV output are added back to historical half-hourly demands *prior to* weather normalisation. If the PV adjustments can be estimated accurately then this would better reflect the underlying demand trend (in the absence of PV) for each half hour, capturing differences in time of day and the "cloudy day" effects (when solar radiation was lower on some days).

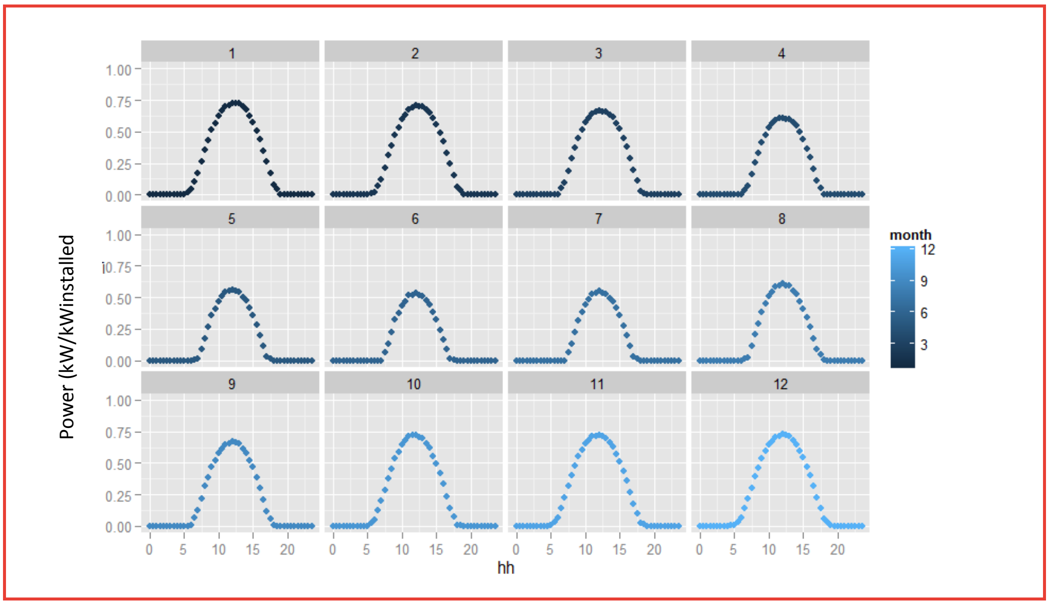
The methodology implemented in this round of forecasts reflects a combination of:

- Installed capacity by CP (based on data provided by SAPN). This is typically close to zero prior to 2009;
- Hourly traces of solar PV (interpolated to the half hour), to capture the typical variation of solar output across the day/seasons (see Figure 11; and
- historical (actual) daily solar radiation at Adelaide Airport weather station to capture the actual variation in historical radiation (eg to capture effects of cloudiness) as much as possible.

Frontier did not review the actual calculations (as this was beyond the scope of the review) but the methodology appears sound and reasonable and worth implementing in future forecasts.

One implication of this revision to the methodology is that the "Actual MDs" (historically) that form the basis of the simulations are after PV adjustment (i.e. reflect underlying demand, assuming 0MW PV output). This is not comparable to the actual MDs used for the simulations in prior forecasts (which reflect underlying demand less PV output). This also means that the historical actual MDs (which are now based on 0MW PV) should be compared with the final unreconciled forecasts *prior* to the post-model PV adjustments; previously, these would be compared against the final unreconciled forecasts *after* the post-model PV adjustments.

Figure 11: ROAM Solar PV traces



Source: AEMO

3.3.2 Post-model solar PV adjustments

Previous methodology

Under the previous methodology, AEMO determined the PV forecast at the CP level as a pro-rata allocation of the NEFR system level PV estimate based on the residential customers per CP. This is a reasonable approach given time and data constraints, but a limitation is that it implies that all CPs have the same time of MD as the system (coincident) MD, or otherwise that PV output is the same at both times. This is potentially a problem where there is a shift in the time of the regional MD from the middle of the day (high PV output) to the evening (low PV output).

Revised methodology

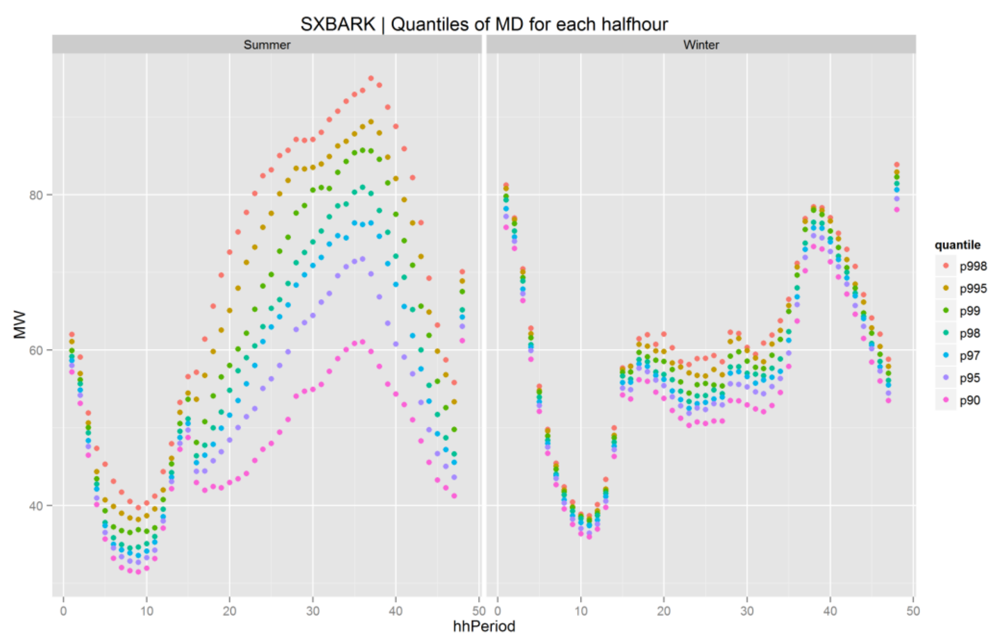
Under the revised methodology, AEMO estimates the change in MD at half hourly level with/without PV output for each CP. This requires pairing of half hourly demand with half hourly PV traces. This is a more data intensive approach to accurately estimate PV output at the half hourly level, but if this can be reasonably estimated given the available data, then the approach should better capture the effect of PV output on changing the time of MD for each CP, and allow for different times of MD for each CP.

As an example, Figure 12 shows a typical trace for demand across a day at SXBARK if PV output were zero. The 98th percentile of this demand trace (with zero PV) is combined with forecasts of PV output across the day (from the NEFR) and forecasts of installed capacity to estimate (a) forecast half hourly PV output and (b) forecast half hourly demand with PV generating: Figure 13. This is used to identify the changing time of MD with/without PV, and the difference caused by solar output. Figure 14 shows the difference in demand with/without PV, the different time of MD with/without PV and the difference in PV output at those times.

Note that an estimate of PV output at the time of MD without PV (afternoon) would likely result in too large an adjustment as PV output is higher in the afternoon. Similarly, an estimate of PV output at the time of MD with PV (evening) would likely result in too small an adjustment as PV output is lower in the evening. Neither approach would accurately capture the effect of pushing MD to later in the day (the changing time of MD). However, the blended approach applied by AEMO (looking at MD with/without PV) appears to reasonably reflect this.

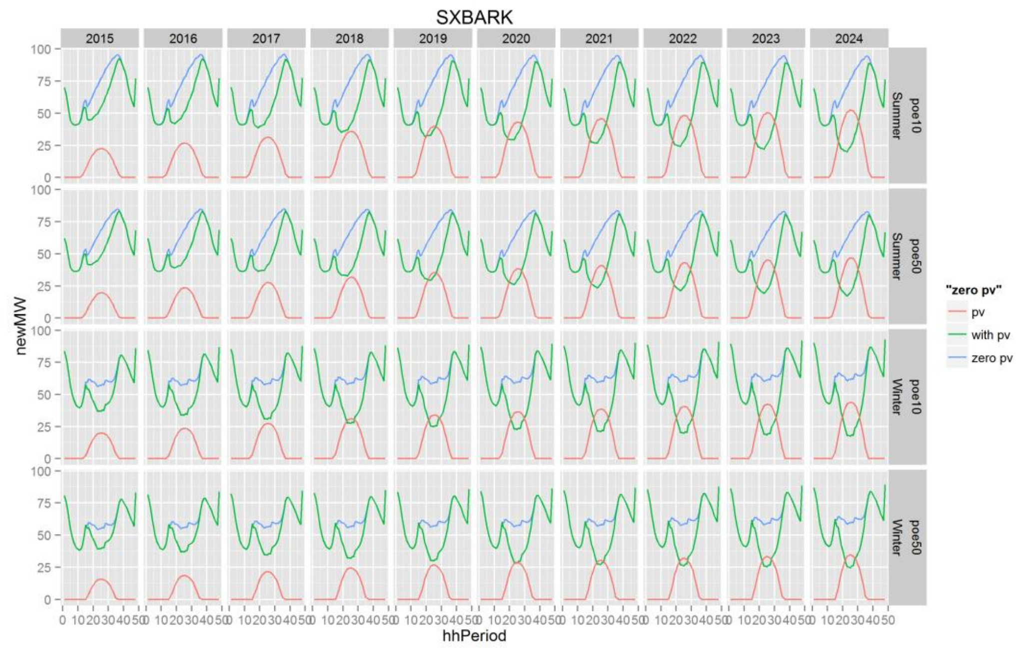
Note also that as the time of MD pushes toward the evening, the additional effect of more solar PV on MD is likely to flatten out and approach a limit. This flattening out is evident in Figure 15 where we compare the sum of the CP PV adjustments against the NEFR adjustments for PV at time of MD. In this case the sum of the CP PV adjustments is larger than the NEFR PV adjustment as the NEFR effectively reflects the coincident PV impact.

Figure 12: Hourly demand trace example, SXBARK



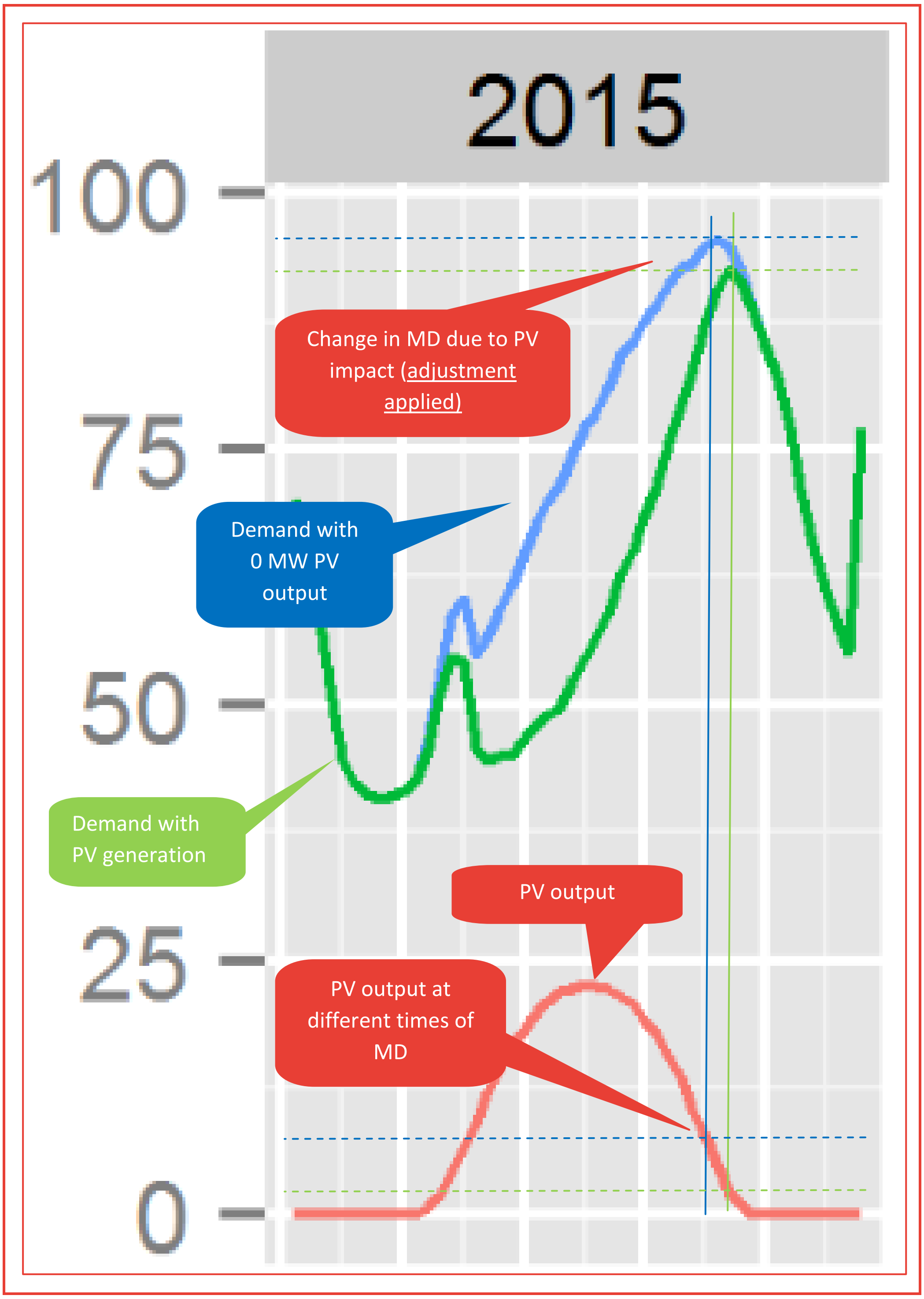
Source: AEMO

Figure 13: Hourly demand with/without PV example: SKBARK



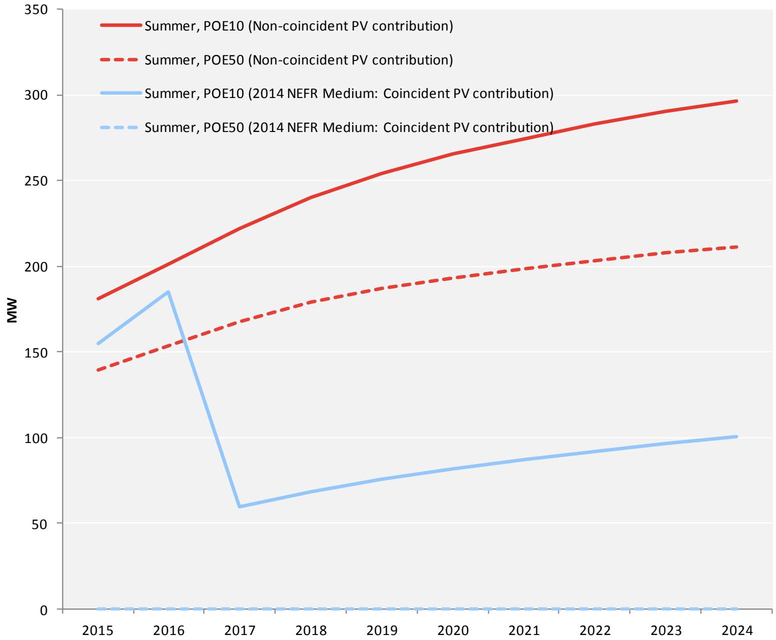
Source: AEMO

Figure 14: Hourly demand with/without PV example: SKBARK, 2015



Source: AEMO

Figure 15: PV comparisons



Non-coincident PV contribution = the sum of each CP for the difference between MD without solar and MD with solar. In most cases the time of MD is closer to the middle of the day without PV output and later in the day with PV output, so this approach does not reflect solar PV output at any given time of day. This estimate will be less than the total solar output at the time of MD (without solar generating) but more than the solar output at time of MD (with solar generating). The latter reflects the NEFR estimates.

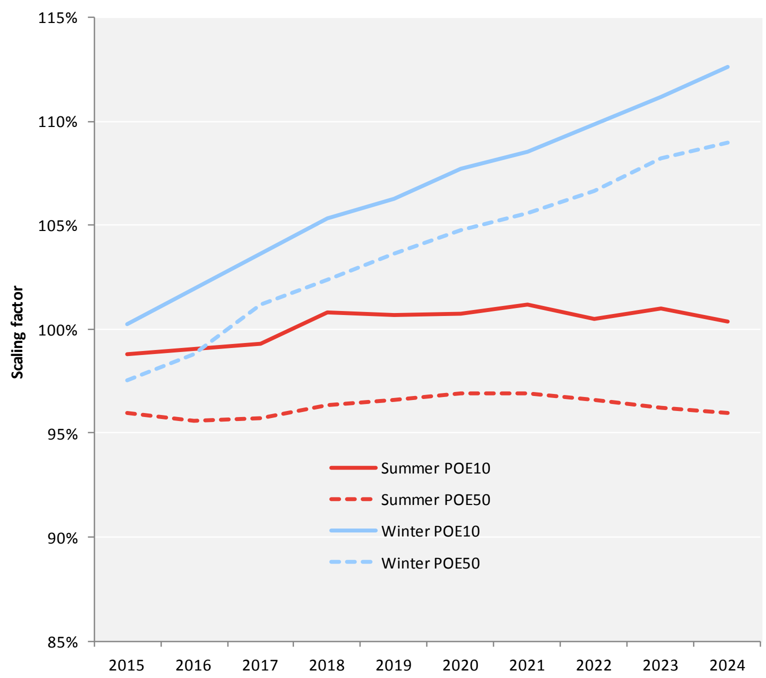
Source: Frontier Economics (analysis of AEMO data)

Frontier has reviewed this revised methodology for PV and it reflects a reasonable improvement to the forecasting approach. Frontier has not reviewed all calculations and code used in applying these PV adjustments in the final implementation, as this was beyond the scope of the review. However, the direction and magnitude of the adjustments applied is reasonable.

3.4 Final check: scaling factors

As a sense check of the final forecasts, Frontier reviewed the scaling factors applied to the SA forecasts during reconciliation. These should generally be expected to be close to 100% if the CP forecasts are consistent with the NEFR forecasts. Figure 16 shows the factors applied for each season/POE. The summer forecasts are generally flat/consistent over time and range between 96-102%, which is suitably close to 100% (suggesting consistency). The winter scaling factors commence at around 100% but increase to around 110% by the end of the forecast period. The reasons for this should be investigated in future forecasting rounds. Similarly, there is no reason why the POE10 scaling should be consistently higher than the POE50 scaling, as is the case here, and the reasons for this should be investigated.

Figure 16: Scaling factors SA



Source: Frontier Economics (analysis of AEMO data)

4 Assessment of AEMO's forecasting procedure

On the basis of our review of AEMO's implementation of the maximum demand forecasting methodology for the SA CPs, Frontier confirms that (a) the revised methodology adopted for the CP forecasts is reasonable and appropriate, and (b) it appears that AEMO has correctly implemented this revised methodology.

Our overall assessment of the methodology and implementation is that it meets the standard of good industry practice. The methodology has been implemented in a professional manner, and where issues of concern have arisen during the implementation of the methodology, all reasonable steps have been taken, within the time and resource constraints, to ensure the statistical integrity of the forecasts.

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