



Review of Endeavour Energy's demand tariff forecasts

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1 Introduction

1.1 Background

Endeavour Energy (Endeavour) is the operator of the electricity distribution network for western Sydney, the Blue Mountains, the Southern Highlands and the Illawarra region of NSW. Endeavour is considering proposing new kW demand tariffs for residential and general supply customers in preparation of their Tariff Structures Statement (TSS) for the 2019-24 regulatory control period.

The proposed new tariffs are being considered in the context of the change in the National Electricity Rules (NER), introduced by the AEMC on 1 December 2014, requiring regulated network companies to structure their prices to better reflect the consumption choices of individual consumers. Under these changes, network prices are expected to reflect the costs of providing the electricity to consumers with different patterns of consumption. This change in the NER has led most distribution network service providers (DNSPs) in the NEM to introduce or extend their offerings of time-of-use (TOU) and demand based tariffs for residential and small business customers. In Appendix B we provide a summary of the tariffs offered in 2017 by distribution businesses in the NEM.

Frontier Economics has been engaged by Endeavour to provide an independent peer review of, and provide advice on, Endeavour's current methodology for forecasting the numbers of customers and demand volumes for the new kW demand tariffs. We have also been asked to compare Endeavour's forecasting approach with that of AEMO.

1.2 Scope of engagement

The focus of our review is on the methodology used to forecast the numbers of customers and chargeable demand volumes for the new kW demand tariffs. We have not been asked to undertake a review of the methodology used to produce forecasts for existing tariffs.

1.3 About this report

This report is structured as follows:

- Section 2 reviews Endeavour's preliminary forecasting approach.
- Section 3 provides our review of Endeavour's preliminary forecasting approach.
- Section 4 discusses the issue of retail tariffs and demand response.
- Section 5 provides our strategic recommendations.

Appendix A reviews AEMO's forecasting methodology and Appendix B provides a brief summary of network tariffs in the NEM.

2 Endeavour's preliminary forecasting approach

2.1 Endeavour's proposed new tariffs

Endeavour currently has an optional TOU energy (TOUE) tariff for residential and general supply customers. Customers with an interval meter can elect to this tariff at any time.

Effective 1 July 2018, Endeavour proposes to make the TOUE tariff the default tariff for all new customers and for existing customers who upgrade from a single to three phase connection. Customers assigned to the TOUE tariff will have the option to 'opt-out' back to the standard non-TOU tariff.

Effective 1 July 2019 (and subject to AER approval), Endeavour proposes to alter the TOUE tariff by adding a kW demand component (creating a TOU demand or TOUD tariff). The demand charge will be based on the average of the five largest daily working day maximum kW between 3pm and 8pm in each month. This will be the default tariff for new customers and for existing customers who upgrade from a single to three phase connection. Again, all customers on the TOUD tariff will have the option to 'opt-out' to the standard non-TOU tariff.

2.2 Overview of preliminary forecasting approach

Endeavour's preliminary forecasting approach for the new tariffs is set out in four worksheets headed "DEFAULT TOU" in the Excel file "1617 SCI Energy and Customers for KW demand calculations NO LINKS.xlsx" provided to us. The four spreadsheets provide forecasts for, respectively, customer numbers, energy, energy per customer and kW demand.

Since Endeavour does not have historical data on TOUD tariffs for residential and small business customers, and only very limited data on TOU tariffs, it is not possible to develop forecasting models by extrapolating historical trends or estimating regression models based on historical data.

Hence Endeavour's preliminary forecasting approach is to start with the business-as-usual (BAU) forecasts (i.e. without the introduction of the new tariffs), and to modify these forecasts for the introduction of the new tariffs. To do this, assumptions need to be made about the number of customers that will switch to the new tariffs, and the demand and energy for those customers. It would also be desirable obtain the split of energy into TOU billing periods.

The starting point for the forecasts are BAU forecasts for customer numbers and energy. These forecasts are modified to obtain the preliminary forecasts for the

Endeavour's preliminary forecasting approach

new tariffs. The modifications start in 2019/20. We will refer to Endeavour's preliminary forecasts for the new tariffs as 'TOUD forecasts. In the following sections we describe how the BAU forecasts are modified to obtain the TOUD forecasts. We note that Endeavour does not forecast the impact of the new tariffs on the TOU consumption split, which would be expected to start in 2018/19.

2.3 Customer number forecasts

Domestic class

Under BAU, customer numbers are forecast to be constant over the forecast horizon (2017/18 to 2026/27) for all domestic tariffs except the 'N70 – Domestic' tariff. Customer numbers on the two controlled load tariffs are also assumed to remain constant.

To forecast customer numbers under TOUD, it is assumed that all net new customers on the N70 tariff under BAU will be switched to the N76 Domestic TOU network tariff. Note that in the BAU forecasts there are 19 customers on the N76 tariff in every year of the forecast horizon. The new customers are added to these customers.

General supply

For most General Supply tariffs, the BAU customer number forecasts change over the forecast horizon.

To forecast customer numbers under TOUD, it is assumed that all net new customers under BAU on the non-TOU tariffs will be switched to the N84 General Supply TOU network tariff. Note that in the BAU forecasts there are already some customers on the N84 tariff. The new customers are added to these customers.

2.4 Energy (kWh) forecasts

To obtain TOUD estimates of energy for each tariff, Endeavour first calculates average kWh per customer under BAU for each tariff. For all tariffs except the 'new' tariffs, N76 and N84, the energy forecasts in the TOUD case are then obtained by multiplying the TOUD customer number forecasts by the average kWh per customer under BAU.

The total energy (kWh) for the N76 tariff is obtained by subtracting the sum of all the kWh for the other Domestic class tariffs (i.e. all except N76) from the total kWh for the Domestic class under the BAU scenario.

Analogously, the total energy (kWh) for the N84 tariff is obtained by subtracting the sum of all the kWh for the other General Supply class tariffs (i.e. all except N84) from the total kWh for the General Supply class under the BAU scenario.

The kWh per customer forecasts for the N76 and N84 tariffs are obtained by dividing the TOUD forecasts for total energy for these tariffs by the TOUD forecasts for the respective number of customers.

2.5 Demand (kW) forecasts

Forecasting demand

To forecast the monthly kW amount for each tariff that is subject to a demand charge Endeavour undertakes the following steps:

- divide the forecast of average annual consumption per customer by 8,760 to obtain a forecast of average hourly consumption per customer
- divide the forecast of average hourly consumption per customer by an appropriate load factor to obtain a forecast of average monthly chargeable kW per customer
- multiply by 12 to obtain the forecast of average annual chargeable kW per customer
- multiply by the forecast number of customers to obtain the forecast for total annual chargeable kW.¹

Estimating load factors

To estimate the load factors, Endeavour employs half-hourly load data for three financial years (FY13/14 to FY15/16) from a load research sample of Domestic Class and non-TOU General Supply customers, as well as load data for existing General Supply TOU customers on the N84 and N85 tariffs.

The calculations undertaken to obtain estimates of the load factors are contained in the file “For FE LFs.xlsx” and consist of the following steps:

- estimate average annual consumption per customer from the load data

¹ A more direct, computationally equivalent, approach would be to: (a) use the available load data for each tariff to estimate the ratio R of annual billable demand (kW) to annual consumption (kWh), and (b) multiply the forecasts of total annual consumption for that tariff by the ratio R to obtain forecasts of total annual billable demand for the tariff. While Endeavour’s approach is less direct, the intermediate step of calculating the load factors provides useful insight into the peakiness of the profiles of the different tariffs.

- estimate average annual chargeable kW per customer from the load data
- divide average annual consumption per customer by 8,760 to obtain average hourly consumption per customer
- divide the average annual chargeable kW per customer by 12 to obtain average monthly chargeable kW per customer
- divide average hourly consumption per customer by average monthly chargeable kW per customer to derive the load factor.

3 Review of preliminary forecasting approach

3.1 Introduction

Endeavour's preliminary forecasting approach for the new tariffs starts with the BAU forecasts and modifies these forecasts for the introduction of the new tariffs. Since there is no historical data on TOUD tariffs for residential and small business customers, and only very limited data on TOU tariffs, it is not possible to develop forecasting models by extrapolating historical trends or estimating regression models. Hence it seems reasonable to use the BAU forecasts as a starting point for forecasting the impact of the new tariffs.

Over the medium to long term, as the historical record of billable demand and TOU consumption patterns on the new tariffs develops, it will be possible to develop forecasts using more traditional approaches based on trend analysis and statistical/econometric modelling. Hence the forecasting task faced by Endeavour at the present time is a relatively short-term issue.

We also note that the roll-out of the new tariffs will happen gradually. Endeavour anticipates that the growth in customer numbers will be about 1% to 2% per annum for the Domestic class and about 2% and 2.5% for the General Supply class. Hence the impact over the forthcoming 2019-24 regulatory control period will be quite small for the first few years and will only become material towards the end of the period.

Notwithstanding these arguments, in the next subsection we provide some suggestions for improvements to the preliminary forecasting approach to better reflect the likely impact of the new tariffs on energy and demand.

3.2 Possible improvements to current approach

The preliminary forecasting approach implicitly assumes that there will be no demand response when the new tariffs are introduced. This is a plausible assumption if retailers do not introduce TOU and TOUD retail tariffs in response to the introduction of the new network tariffs, but the experience in Victoria indicates that such retail tariffs will be introduced concurrently with, or soon after, the introduction of the network tariffs. In Section 4 we consider the introduction of retail tariffs and the likely demand response in more detail.

However, even in the absence of any demand response, there are some areas where, in our opinion, the preliminary approach could be improved. Some of these areas are discussed below.

'Net new' vs 'all new' customers

The increase in customer numbers from one year to the next is a combination of new customers and disconnections. It is our understanding that all new customers not yet on TOU tariffs will be switched to TOU tariffs, not just the net new customers. This suggests that the preliminary forecasts underestimate the number of customers that will be switched to the TOU tariffs. We recommend that customer number forecasts be adjusted to reflect this observation.

Customers switching from a single phase to a three-phase meter are also not accounted for in the current approach.²

New customers may be different to existing customers

Even if we don't consider demand response, it is likely that new customers will be different to the average existing customer in a given tariff class. For example, they may be more (or less) likely to live in apartments, new dwellings are likely to be more energy efficient, and so on. By comparing the bills of recent new connections with those of longer-term connections, Endeavour should be able to estimate the difference in consumption between new and existing customers and make a suitable allowance to the forecasts to reflect this difference.

Our understanding is that there may be practical difficulties accessing information on annual bills for individual customers, and identifying whether those individual customers are existing customers or new customers. And we also understand that there are currently relatively few customers for whom interval meter data is available, meaning that it would be difficult to assess whether patterns of consumption are different for existing and new customers.

Nevertheless, we recommend that Endeavour investigate using billing information or interval meter data to obtain estimates of the average consumption of new customers and to modify the forecasts to reflect any differences in average consumption between new customers and existing customers.

Customers who opt out

The preliminary approach makes no allowance for customers who opt out of the network tariff. Studies of 'opt out' typically consider cases where mandatory TOU retail tariffs are introduced. We are not aware of any studies of opt-out rates for TOU/D network tariffs where customers continue to have the option of non-TOU retail tariffs. We anticipate that the rates of customers opting out of the TOU/D network tariffs would be very low and can be ignored for some years after their introduction. However, we recommend that Endeavour monitor the opt-out

² It may be possible that customers who require a new single-phase meter for technical reasons will also be fitted with a smart meter and switched to the new network tariff by default. If that is the case, then estimates of the number of such customers should also be accounted for in the forecasts.

rates and make suitable adjustments to the forecasts should the opt-out rates become material.

Use stratum weights to calculate load factors

We understand that the load research sample that has provided the load data for estimating the load factors is stratified into regions. It appears that this stratification has not been taken into account in the estimation of the load profiles.

If the split of customers between regions is similar in both the sample and the population, or if the load factors are similar across regions, then there is no need to take the stratification into account.

However, if the split between regions is different in the sample compared to the split in the population, and if the load factors also differ between regions, then the stratification should be taken into account when estimating the load factors. This can be done in the following steps:

- calculate the sample means of demand (kW) and energy (kWh) in each region
- determine the split of customers between regions in the population and use the proportions as stratum weights
- calculate the stratum-weighted mean demand (kW) and mean energy (kWh)
- calculate the load factors using the stratum-weighted means instead of the simple means.

Calculate energy by TOU periods

While it is not customary to split long-term forecasts by TOU periods, in order to investigate the impact of the new tariffs under different scenarios about demand response, it would be helpful to have forecasts of energy by TOU periods in base case forecasts.

We understand that Endeavour's forecasting approach does forecast energy by TOU periods in its base case forecasts.

4 Retail tariffs and demand response

4.1 Introduction

It can be anticipated that at least some retailers will introduce TOU and/or TOUD tariffs in response to the introduction of the new network tariffs. TOU and TOUD retail tariffs complicate the forecasting of the impact of the introduction of the new tariffs if there is a significant demand response.

Given the competition in the retail market, retail TOU and TOUD tariffs will inevitably be introduced on an opt-in basis. In Victoria, AGL, for example, offers residential opt-in TOUD tariffs in almost all the network supply regions.

It is possible that there will be no, or only a very small demand response to retail TOU and/or TOUD tariffs. This could happen if the majority of customers who opt in to the new retail tariffs do so because they have load profiles that would benefit from the new tariffs without having to modify their consumption patterns. However, it is likely that there will also be customers who opt in and are willing to change their consumption pattern to gain benefit from a TOU or TOUD tariff. The responses after changing tariffs are often classified as conservation (reduction in energy) and load shifting (away from the peak, or ‘peak shaving’).

Customers with batteries would have a large incentive to opt in (regardless of whether they have PV or not) since they can easily modify their maximum demand. Hence customers that already have a battery are most likely to opt in to the new tariffs. The new tariffs may also encourage customers to acquire a battery so they can take advantage of the new tariffs. Note, however, that customers with batteries may have increased consumption, since batteries suffer some loss of charge during the day.

In the remainder of this section we discuss some of the empirical evidence on adoption rates of TOU tariffs and the corresponding demand response. The introduction of tariffs with demand components for residential and small business customers is relatively recent. Hence studies of time-varying tariffs tend to focus on TOU tariffs without a demand component. This is not intended to be a thorough review of the impact of TOU tariffs, but only a glimpse of some of the recent evidence.

4.2 Uptake rates of TOU tariffs

In a recent article, Schneider and Sunstein (2017) summarise some of the evidence on the uptake rates for TOU tariffs.³ They report that in one study, 174,000 customers were randomly assigned into opt-in and opt-out groups. The study found that 19.5% of customers would opt in to a TOU tariff, but that 98% would remain on the TOU tariff when it was offered as the default tariff. The paper also reports on a survey of nine similar studies which found that residential opt-in TOU programs achieve, on average, a participation rate of 28%, while residential default programs achieve, on average, a participation rate of 85%.

These adoption rates are somewhat higher than those found in the Smart Grid, Smart City (SGSC) project.⁴ In the SGSC trials, a seasonal TOU was tested, with some of the participants also being offered an in-house display or access to an online portal. The estimated adoption rate of this tariff for the Ausgrid supply region varied between 7% and 9% depending on the option. However, in trials it is difficult to mimic the way customers are introduced to new tariffs in a real-world situation, suggesting that these opt-in rates should be interpreted with some caution.

We also note that, over time, the proportion of customers on TOU tariffs tends to increase. For example, it has been estimated that 33% of Victorian households and 23% of NSW households are on TOU tariffs.⁵ In the case of NSW, households on TOU tariffs are primarily found in the Ausgrid supply region since Ausgrid (as EnergyAustralia) was an early adopter of a policy to roll out interval meters and residential TOU tariffs.

4.3 Demand response to TOU tariffs

A summary of the demand response to TOU tariffs is shown in Figure 1, which plots the estimated reduction in peak demand for 92 TOU tariffs. The responses are separated into cases where the introduction also included enabling technologies to such as an in-house display or control devices for appliances.

Figure 1 shows that the impact on peak demand varies considerably across different cases. However, as expected the response tends to increase as the ratio between the peak price and the off-peak price increases. The addition of a

³ Schneider, I. & C. Sunstein, (2017), "Behavioral considerations for effective time-varying electricity prices", *Behavioural Public Policy*, 1(2), 219-251.

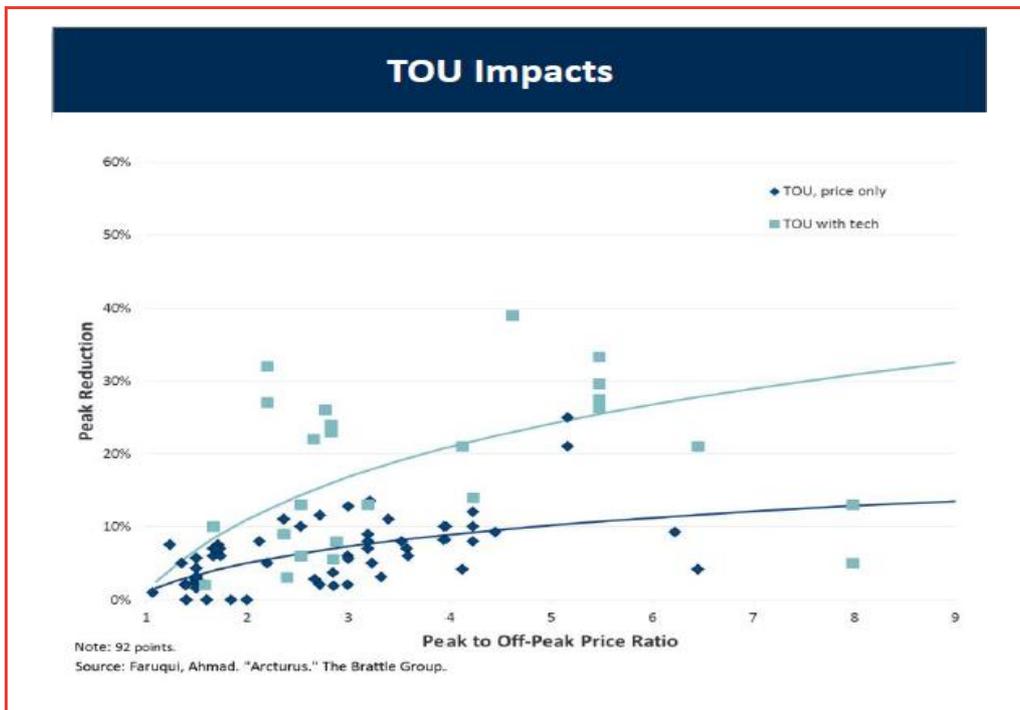
⁴ The Smart Grid, Smart City (SGSC) project trialled a number of different network and retail products in 2013-14. The project was delivered and funded by the Australian Government in partnership with Ausgrid, EnergyAustralia and their consortium partners.

⁵ Hall, N. et al (2016), "Cost-reflective electricity pricing: Consumer preferences and perceptions", *Energy Policy*, 95, 62-72.

technology component also appears to have quite a marked impact on the reduction in peak demand.

In the *SGSC* trials, the impact on demand of the seasonal TOU tariff varied by season, with a much higher impact in winter. This can be seen in and Table 1 which shows the impact of the tariff on consumption by season. Note that the impact varies considerably for the different variants of the tariff, but all variants show a reduction in consumption in Winter 2013.

Figure 1: Impact of TOU tariffs on peak demand



Source: Faruqui et al (2017), Indiana Energy Association Conference,
http://www.brattle.com/system/publications/pdfs/000/005/511/original/The_Future_of_Tariff_Reform_A_Global_Survey.pdf?1506627441o

Table 1: Reduction in average consumption by product and season

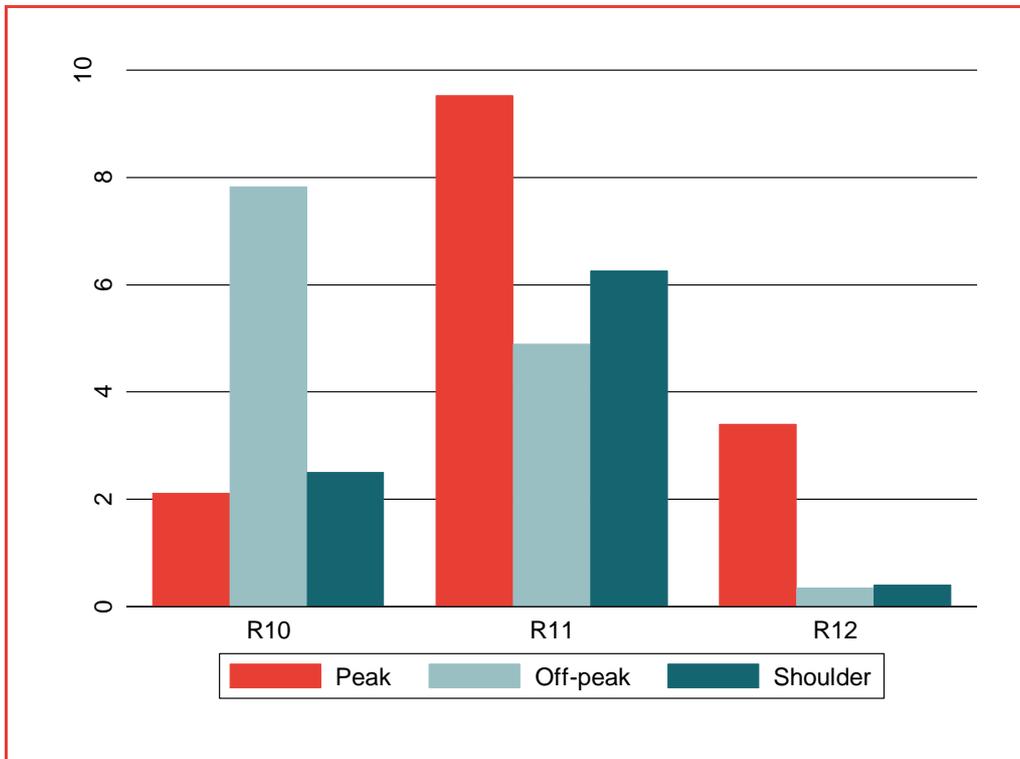
	Shoulder 2013	Winter 2013	Summer 2013-2014
R10	0.45	4.90	2.98
R11	1.80	7.00	-0.35
R12	-1.95	1.60	-4.24

Source: Frontier Economics (2014), *Smart Grid Smart City - Customer Applications Trials: Data analysis methodology report*.

Note: R10, R11 and R12 were 3 retail products offered in the trials with a seasonal TOU tariff. R10 consisted only of the tariff, R11 also included an in-house display showing real-time consumption, R12 has an on-line portal instead of the in-house display.

However, the reduction in consumption in the SGSC trials wasn't restricted to the peak period, but occurred across all TOU periods. This can be seen in Figure 2 which shows the impact of each of the 3 variants of the seasonal TOU tariff offer in each of the TOU periods in Winter 2013.

Figure 2: Reduction in peak, shoulder and off-peak periods for an average working day in Winter 2013 for SeasonSmart products



Source: Frontier Economics (2014), *Smart Grid Smart City - Customer Applications Trials: Data analysis methodology report*.

Note: R10, R11 and R12 were 3 retail products offered in the trials with a seasonal TOU tariff. R10 consisted only of the tariff, R11 also included an in-house display showing real-time consumption, R12 has an on-line portal instead of the in-house display.

5 Strategic recommendations

Based on our review of Endeavour's preliminary approach to forecasting customer numbers, energy and demand for the new TOUD tariffs, we make a number of strategic recommendations for Endeavour's preparation of their Tariff Structures Statement (TSS) for the 2019-24 regulatory control period:

Recommendation 1 – Adjust forecasts to incorporate all new customers

The preliminary forecasts assume all net new customers will be allocated to the new tariffs. However, we understand that all new customers will be put on new tariffs, not just net new customers. Further, customers switching from a single phase to a three-phase meter are currently also not accounted for in the current approach.⁶

We recommend that customer number forecasts be adjusted to reflect these observations.

Recommendation 2 – Adjust forecasts for customers who 'opt out'

At present no allowance is made for customers who opt out of the new network tariffs. Studies of opt-out rates typically consider cases where mandatory TOU retail tariffs are introduced. We anticipate that the rates of customers opting out of the new TOU/D network tariffs would be very low, since customers can still choose to stay on non-TOU retail tariffs. Hence the opt-out rate can be ignored for some years after the introduction of the new tariffs. However, we recommend that Endeavour monitor the opt-out rates and make suitable adjustments to the forecasts should the opt-out rates become material.

Recommendation 3 – Consumption of new customers versus existing customers

It is likely that new customers will have different average consumption to the existing customers in a given tariff class, or different patterns of consumption. We recommend that Endeavour investigate using billing information or interval meter data to obtain estimates of the average consumption of new customers and to modify the forecasts to reflect any differences in average consumption between new customers and existing customers.

Recommendation 4 – Incorporate stratum weights in the estimation of load factors

We recommend that the regional stratification of the load research samples that provide the data for the estimation of the load profiles be investigated along the

⁶ It may be possible that customers who require a new single-phase meter for technical reasons will also be fitted with a smart meter and switched to the new network tariff by default. If that is the case, then estimates of the number of such customers should also be accounted for in the forecasts.

lines suggested in Section 3.2. If the split between regions is different in the sample compared to the split in the population, and if the load factors also differ between regions, then we recommend that the stratification should be taken into account when estimating the load factors.

Recommendation 5 – Allow for demand response

It is expected that TOU and TOUD retail tariffs will follow the introduction of the new network tariffs. This will likely lead to a demand response. We recommend that Endeavour modify its forecasting procedures to allow for such a demand response. The demand response will depend on both the rate at which new customers opt in to retail TOU/D tariffs and their response to the retail TOU/D tariff structures.

There is considerable uncertainty about both of these factors. However, on the basis of the *SGSC* trials, about 7% to 9% of customers might be expected to opt in to TOU/D tariffs initially. On the basis of the experience in Victoria and Ausgrid's network, this is likely to increase to around 35% to 40% over the following five years.

Evidence summarised in Figure 1 on the demand response of customers opting in to TOU/D tariffs depends on the ratio of the peak to offpeak price. At present, Origin and AGL offer TOU tariffs for the Endeavour supply area with a peak to offpeak price ratio of about 2.3. Figure 1 shows that this would lead to a reduction in peak demand of about 6%.

Recommendation 6 – Modify forecasting tools to allow for scenario investigation

Given that there is a considerable amount of uncertainty about key parameters that feed into the forecasts, such as opt-out rates and demand response, we recommend that Endeavour modify the structure of its forecasting spreadsheet to allow alternative assumptions about these parameters to be easily used. This will facilitate the investigation of alternative scenarios to test the sensitivity of the forecasts to different assumptions.

In addition to these strategic recommendations for Endeavour's preparation of their Tariff Structures Statement (TSS) for the 2019-24 regulatory control period, we would also make a longer term recommendations to continue to gather data to assist with future forecasting.

Appendix A – Review of AEMO’s forecasting methodology

This Appendix provides a brief overview of AEMO’s methodology for forecasting energy and maximum demand for residential and business customers in the National Electricity Forecasting Report (NEFR). AEMO does not provide forecasts for different types of tariffs, TOU periods or chargeable demand.

Our review is based on the most recent methodology information paper published in 2016.⁷ AEMO did not publish a methodology paper for the 2017 forecasts since the methodology was largely unchanged from that used for the 2016 NEFR. We note that the methodology used for the 2016 NEFR represents a marked departure from the methodology used in previous years.

We would note that AEMO’s forecasts are regional forecasts (for NSW and the ACT as a whole) rather than forecasts for individual distribution areas (such as Endeavour’s distribution area). While it can be useful to consider AEMO’s methodology, we would note that there are reasons to expect that patterns of consumption in Endeavour Energy’s distribution area will differ from those in NSW and the ACT in general. These include that weather conditions are different, that the housing stock is different, that the availability of alternative fuels (particularly reticulated natural gas) is different, that the appliance mix is different and that macroeconomics and demographic conditions are different. The available evidence – including the net system load profiles published by AEMO – bears out the fact that patterns of consumption vary across NSW.

A.1 Forecasts for the residential sector

Consumption per connection

In a departure from the previous methodology, the consumption measure that is forecast for the residential sector is ‘underlying’ consumption, which is defined as actual consumption on the premise, consisting of delivered energy plus PV generation and battery storage.

The methodology used for forecasting consumption per connection consisted of two main steps:

- a short-term base model was estimated to develop projections for base load, cooling load and heating load for 2015-16

⁷ AEMO (July 2016), Forecasting Methodology Information Paper: 2016 National Electricity Forecasting Report.

- using 2015-16 as the base year, long-term forecasts of annual consumption for the period 2015-16 to 2035-36 were obtained by:
 - applying the forecast impacts of annual energy efficiency savings, appliance fuel switching, PV generation, and PV storage all expressed as growth relative to the base year 2015–16, and
 - applying forecasts of residential retail prices as percentages of growth relative to the base year 2015–16.

The short-term model was estimated using weekly underlying consumption data as the dependent variable and a constant, cooling degree days (CDD) and heating degree days (HDD).⁸ The specification for consumption in week t and financial year y is:

$$Res_Con_{t,y} = \beta_{0,y} + \beta_{1,y}HDD_{t,y} + \beta_{2,y}CDD_{t,y} + \varepsilon_{t,y}$$

Separate models were estimated for FY2014 and FY2015. These models were then used to weather normalise consumption for FY2014 and FY2015, and to split weather-normalised consumption into base load (i.e. the temperature insensitive component β_0 , multiplied by the number of weeks), heating load and cooling load.

Next, the estimated weather-normalised annual consumption for 2013–14 was used to project consumption for 2015–16, taking into consideration the estimated impact of changes to electricity retail price, modelled energy efficiency savings in appliances and enhanced building thermal efficiency, and growth in electricity appliance uptakes between 2013–14 and 2015–16.

For the long-term model, AEMO developed projections for the modelled consumption drivers under several different scenarios. Some added to forecast consumption (for example, electricity appliance uptake, and gas to electricity appliance switching). Others acted to reduce residential consumption (such as forecast electricity retail price increases, and forecast energy efficiency savings driven by both Commonwealth and State government energy policies). AEMO engaged consultants to develop projections for PV generation, battery storage and energy efficiency. Note that some of these drivers have a different impact on cooling load than on heating load.

For future residential electricity prices, AEMO assumed that they will fall for the first five years from 2015-16 to 2020, and then increase for the remainder of the forecast period. Price impacts were estimated in the case of increases, but not for temporary price reductions. The price elasticity was assumed to be -0.1, applying equally to base load, heating, and cooling. That is, a 1% change in price was assumed to result in a 0.1% change in annual residential consumption.

⁸ The critical temperatures vary by region. For New South Wales the critical CDD temperature is taken to be 19.5 degrees Celsius and for HDD 17.0 degrees Celsius.

To obtain forecasts of ‘delivered’ annual energy, the forecasts of underlying consumption were adjusted down for consumption met by PV and battery storage, so that in year y :

$$\text{Delivered_Total}_y = \text{Underlying_Total}_y - \text{PV_Total}_y - \text{Storage_Total}_y.$$

Customer numbers

The forecast of residential connections was obtained from forecasts of the total number of connections (across all customer classes), using a scaling factor that describes the fraction of meters assigned to the residential sector. Historical data shows that the number of residential meters as a fraction of total meters is stable with a very mild trend. The trend observed in the past five years was extrapolated into the future.

Forecasts for the total number of net new connections in a given year were obtained by correlating new connections to the growth in the dwelling stock in the NEM region. Forecasts of dwelling stock growth were provided by the Housing Industry Association (HIA). HIA provided forecasts for the period 2015–16 to 2025–26. Beyond 2026, the number of connections was forecast using the same year-on-year growth rate as the ABS population projections. The forecasts from HIA were modified by AEMO to ensure a smooth transition to the growth rate of the long-term ABS population projections.

A.2 Forecasts for business consumption

For non-residential customers, AEMO did not forecast customer numbers, but instead forecast consumption at the aggregate level rather than by connection. As for the residential sector, the measure of consumption that is forecast is underlying consumption.

The methodology used for forecasting consumption for the business class consisted of the following main steps:

- developing a short-term base model for total business consumption for the first year in the forecasting horizon
- developing two long-term econometric models for the two main categories (manufacturing and other business)
- surveying and interviewing most large industrial customers, seeking advice on near-term and highly probable adjustments to forecasts
- applying post-modelling adjustments to account for emerging factors, such as growth of rooftop PV and battery storage, and energy efficiency growth.

Forecasts for the LNG manufacturing sector and the coal mining sector were produced separately.

The consumption data was derived from two sources:

- AEMO's database of metering data
- the Energy Statistics Data (ESD) published by the Office of the Chief Economist. The ESD provided a means to segment total business consumption into the main categories of manufacturing and other business sectors.

Short-term base model

The short-term base model was estimated using daily data for 2014-15 for each NEM region. The specification of the model was:

$$Bus_Con_i = \beta_0 + \beta_1 HDD_i + \beta_2 CDD_i + \beta_3 Holiday_i + \beta_4 Sat_i + \beta_5 Sun_i + \varepsilon_i$$

where i indicates days. This model was estimated using daily data for the colder months of April to September. A second model, without the HDD variable, was estimated using data for the other months.

The short-term models were used to project consumption for 2015-16 using forecasts for the temperature variables. The 2015-16 forecasts were taken as the starting point for the long-term forecasts.

Long-term models

Two long-term models, for the manufacturing sector and the other business sector, were developed to estimate the elasticities of demand corresponding to various economic drivers. These models were estimated using annual data from 2001–02 to 2013–14.

Long-term model for manufacturing

The econometric model estimated for manufacturing consumption is:

$$(Man_C_t) = \beta_0 + \beta_1 \ln(Input_PPI_t) + \beta_2 \ln(GSP_t) + \delta_1 GFC_t + \varepsilon_t$$

where t indicates years.

The explanatory variables used in the model are defined in Table 2.

Long-term model for other business

The econometric model estimated for other business consumption is:

$$\ln(Other_C_t) = \beta_0 + \beta_1 \ln(POP_t) + \beta_2 \ln(HDI_t) + \beta_3 \ln(Elec_P_t) + \delta_1 HDD_t + \delta_2 CDD_t + \delta_3 GFC_t + \varepsilon_t$$

where t indicates years.

The explanatory variables used in the model are defined in Table 3.

Table 2: Explanatory variables used in long term model for manufacturing

Variable names	ID	Units	Description
Input Producer Price Index	Input_PPI	Index	An input PPI measures the rate of change in the prices of goods and services purchased as inputs by the producer for the manufacturing sector.
Gross State Product	GSP	\$ million (FY 2012 real)	GSP is a measurement of the economic output of a state. It is the sum of all value added by industries within the state.
Dummy for the Global Financial Crisis	GFC	{0,1}	A dummy variable that captures the economic shock

Source: AEMO (July 2016), *Forecasting Methodology Information Paper: 2016 National Electricity Forecasting Report*

Table 3: Explanatory variables used in long term model for other business

Variable names	ID	Units	Description
Population	POP	Persons	Population level of a state (net of deaths, births, and migration).
Household disposable income	HDI	\$ million (FY 2012 real)	Real level of money that households have available for spending and saving after income taxes have been deducted.
Electricity price	Elec_P	\$/MWh	Retail electricity price for business users.
Heating Degree Days	HDD	°C	The number of degrees that a day's average temperature is below a critical temperature. It is used to account for deviation in weather from normal weather standards.
Cooling Degree Days	CDD	°C	The number of degrees that a day's average temperature is above a critical temperature. It is used to account for deviation in weather from normal weather standards.

Source: AEMO (July 2016), *Forecasting Methodology Information Paper: 2016 National Electricity Forecasting Report*

To develop the long-term forecasts, AEMO obtained projections of the various economic drivers, externally or internally, and applied the changes in consumption due the changes in the drivers to base year consumption to produce forecasts of annual consumption beyond 2015–16.

Post-modelling adjustments were made to account for potential impacts that were not captured in the econometric models, including plant expansion/closure and energy efficiency growth. Finally, consumption met by rooftop PV generation and battery storage was removed to get delivered consumption.

A.3 Forecasts for maximum demand

Maximum demand is forecast for each NEM region at the global level. The methodology used to forecast maximum demand in the 2016 NEFR represents a major departure from the methodology used in previous years.

For each NEM region, 48 models of demand corresponding to each half-hour in the day were developed. These models describe the relationship between underlying demand and independent variables including calendar effects (public holidays, day of the week, and month in the year) and weather effects.

This was followed by a simulation stage, where numerous instances of weather patterns were simulated based on historical weather patterns using a resampling technique. The simulated weather patterns produced in this way were then used as input into the 48 half-hourly models, resulting in a series of realisations of possible half-hourly demand patterns, which can be described by a distribution of possible demands for each half hour. At the same time, solar radiation patterns were used to simulate rooftop PV and battery storage effects.

For the forecasts, the demand distributions for each half hour were projected using information from the residential and business consumption forecasts. This was done separately for different components of demand, separated by end-use, which represents one of the main differences to the previous methodology.

The forecast demand components, PV generation, and battery charging were then assembled together to produce numerous 20-year, half-hourly profiles of delivered demand. The forecast demand at different probabilities of exceedance were then extracted from the simulated half-hourly probability distributions.

A.4 Comments on AEMO's modelling

The new methodology for forecasting annual consumption adopted by AEMO in 2016 differs markedly from the earlier methodology, and in many respects from the methodology used by Endeavour. It is not yet possible to assess the forecasts produced by the new approach against actual outcomes. AEMO has not provided any information on how the methodology has been assessed. It is customary when

producing forecasts to provide measures of how the methodology fits the data. This could be done, for example, by undertaking an ‘out of sample’ validation task on the last one or two years of actual data.

A number of assumptions made in the new approach are made with no or little evidence-based underpinning. For example, the assumption that the long-term price elasticity for residential customers is -0.1 for price increases and 0 for (temporary) price decreases is made without any reference to empirical investigations. This elasticity is quite low compared to estimates in the literature. The 0 elasticity for price decreases also makes it impossible to investigate how customers would respond to medium or longer-term price decreases, as canvassed in the current political discussion.

It is also noteworthy that some of the forecasts of the impact of PV and energy efficiency (EE) on consumption have changed dramatically between the last two versions of AEMO’s forecasts. Table 4 compares the forecasts for the NEM of the impact of PV and EE in 2036 made by AEMO on 30 March 2017 (NEFR), on 30 June 2017 (NEFR), and on 5 September 2017 (ESOO), the two latest versions available on AEMO’s website. The forecasts are split between residential and business.

Table 4 shows that all four forecasts decreased between the first and the second versions; in one case by 75%. The total decrease across all four forecasts amounts to more than 11 TWh or 21%. The PV forecasts remained roughly the same between the second and third forecasts, but the EE forecasts increased considerably, by 363% between these forecasts made only a few months apart. Large changes between forecasts made at the different time points also occur at the regional level.

The above discussion suggests that the new methodology for producing the forecasts is still in a state of flux and that AEMO’s recent forecasts need to be treated with considerable caution.

Table 4: Forecasts for PV and EE in the NEM in 2036 made several months apart

Variable	Forecast for 2036 made on 30/03/2017 (GWh)	Forecast for 2036 made on 30/06/2017 (GWh)	Forecast for 2036 made on 05/09/2017 (GWh)
PV residential	18,617	18,511	18,296
PV business	6,824	5,993	5,993
EE residential	18,171	14,569	16,371
EE business	8,911	2,185	10,110
Total	52,523	41,258	50,770
Changes since previous forecast (%)			
PV residential		-0.6%	-1.2%
PV business		-12.2%	0.0%
EE residential		-19.8%	12.4%
EE business		-75.5%	362.7%
Total		-21.4%	23.1%

Source: Frontier Economics analysis of information on AEMO's website:
<http://forecasting.aemo.com.au/Electricity/AnnualConsumption/Operational>

Appendix B – Summary of network tariffs in the NEM

Table 5: Summary of network tariffs in the NEM for residential and small business customers

Network business	Proposed tariffs from 2017
Ergon	Opt-in Seasonal Time-of-Use Energy and Seasonal Time-of-Use Demand tariffs
Energex	Opt-in Demand tariff includes Hot Water Tariff for Demand customers
Ausgrid	Opt-in Time-of-Use tariffs. From 1 July 2018, all new customers assigned to Time-of-Use tariffs with opportunity to opt-out to a transitional tariff. All existing customers with digital metering to be assigned to this transitional tariff on 1 July 2018
Essential	Time-of-Use tariff default for new customers, new Solar PV installations and metering upgrades. Opt-in to Demand-based tariffs also available
Endeavour	Opt-in Time-of-Use tariffs. All new customers with interval meters assigned to Time-of-Use tariffs from 1 July 2018 on opt-out basis
ActewAGL	Time-of-Use tariff default for all new residential and small business customers. Small business customers can opt-in to Demand tariffs. Possible gradual introduction from 1 December 2017 of residential demand tariff
Citipower, Powercor, Unite, Jemena, Ausnet	Opt-in residential Demand Tariffs (not available in Ausnet service area until 2018). Opt-in Demand tariffs for all small business customers consuming <60 MWh pa. United and Jemena: Demand tariffs mandatory for small businesses consuming >60 MWh pa. Powercor, CitiPower and Ausnet: transitional Demand tariff mandatory for small business consuming >60 MWh pa. Cost-reflectivity of the transitional tariff will increase between 2017 and 2022
South Australia Power Networks	Opt-in cost-reflective residential Demand tariff. Opt-in “fully” cost-reflective demand tariff for small business customers. Mandatory assignment to transitional Demand tariff (50% cost-reflective Demand) for new 3-phase customers and progressive increases in cost-reflectivity until 2022

Source: Nelson, T. et al (2017), “The changing nature of the Australian electricity industry”, *Economic Papers*, 36(2), 104-120, Table 1.

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