Attachment 7.3

Peak demand, energy and customer number forecasts

Access Arrangement Information

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Western Power

363 Wellington Street
Perth WA 6000
GPO Box L921 Perth WA 6842

T: 13 10 87 | Fax: 08 9225 2660
TTY 1800 13 13 51 | TIS 13 14 50

Electricity Networks Corporation
ABN 18 540 492 861

enquiry@westernpower.com.au
westernpower.com.au

Enquiries about this report should be directed to:

AA4 Project Team

Email: AA4@westernpower.com.au

Contents

1. Summary

Western Power forecasts compounding annual growth over the fourth access arrangement (**AA4**) period of:

- -0.6 per cent in network peak demand
- 1.6 per cent in customer numbers
- -0.4 per cent in energy consumption.

Peak demand and customer numbers drive the need for investment in our network to ensure there is sufficient capacity available in the network to connect new customers and to service peak demand. The prices paid by our customers will be affected by the forecast of the number of customers and energy consumption – higher forecasts will lead to lower prices and conversely, lower forecasts will lead to higher prices.

Our growth and demand forecasts are provided in Table 1.1.

Table 1.1: Summary of 2017 forecast energy demand and customer numbers

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 annual average growth
Western Power Network coincident peak demand (**MW**[1])	3,859	3,811	3,792	3,786	3,746	-0.6%
Average customer numbers	1,115,509	1,134,897	1,154,255	1,173,585	1,191,890	1.6%
Grid supplied energy consumption (**GWh**[2])	17,698	17,663	17,628	17,502	17,309	-0.4%

This section presents the 2017 forecasts and provides some commentary on the differences between the 2017 and 2016 forecasts. Western Power has primarily used its 2017 energy, customer numbers and peak demand forecasts as inputs into the AA4 submission as it is the best forecast available at the time of developing the access arrangement.

Updated forecasts became available in May 2017. Where the update of the customer numbers, energy consumption and peak demand forecasts was mechanical (i.e. required only updated to values in models), we have used the 2017 forecasts in this submission. This applies to the opex forecasts and network pricing outcomes.

The 2016 forecasts were developed for the 2016/17 annual planning process and therefore underpin the network development and management plans. These plans were used as the basis for the AA4 capex forecasts in this submission. We have compared the 2017 forecasts to the 2016 forecasts at a high level to ensure that the network investment plans would not require significant changes as a result. While there may be some opportunity to defer some proposed projects, the overall change to our investment plans is

1 Megawatt

2 Gigawatt hours

not expected to be substantial. This is primarily due to the significant portion of proposed optimised asset replacements which are largely agnostic to peak demand variances.

The 2017 forecasts are currently being used to update the capex plans at the project level, and will be available in December 2017[3] and incorporated into Western Power's response to the Economic Regulation Authority's (**ERA**) draft decision.

3 The updated peak demand, customer numbers and energy consumption forecasts as well as the asset condition assessment information will be used to develop the 2018 investment plans. These will ultimately result in the annual Business Plan for 2019/20.

2. Peak demand forecasts

Western Power forecasts peak demand to decrease by an average of 0.6 per cent per annum or 113 MW over the AA4 period. This compares with long-term underlying growth[4] of 1.9 per cent per annum.

The peak demand is the highest average electricity consumption in any five minute interval during the course of one year. We must plan to meet this peak demand, even if this level of demand is only reached for a short period of time. If the network doesn't have sufficient capacity to meet peak demand, it affects our ability to connect customers, and to maintain the security, reliability and quality of supply.

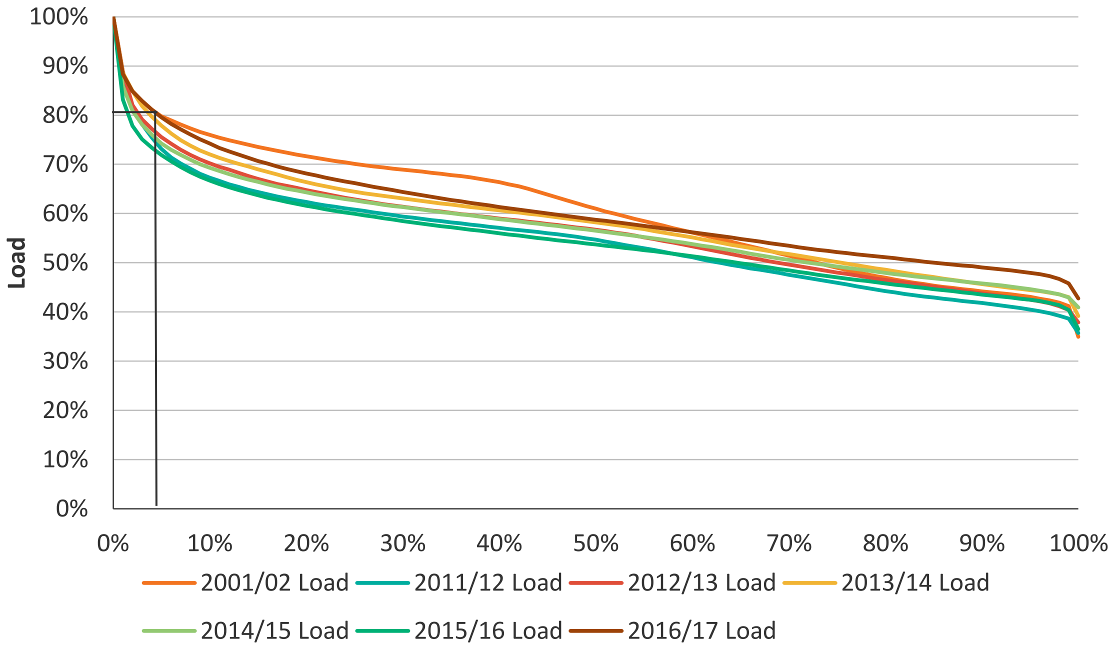
2.1 Characteristics of the network peak demand

The South West Interconnected System (**SWIS**) has a strong summer peak, with around 20 per cent of its capacity required for around two hours each year. This has almost doubled from 2001, where it was only around 10 per cent, indicating a declining network utilisation primarily as a result of an:

- increase in use of air conditioners, typically coinciding with extremes in temperature
- increase in the uptake of distributed solar photovoltaic (**PV**) generation.

Figure 2.1 shows the utilisation of peak capacity in the form of the load duration curve for the SWIS.

Figure 2.1: Load duration curve for the SWIS



4 Calculated as 1999 to 2017.

2.2 Peak demand forecast methodology

The actual peak demand in any year is dependent on a variety of factors such as customer behaviour, summer weather and economic conditions. Peak demand typically occurs on a working weekday following consecutive days where the temperature reaches about 40 degrees Celsius.

As these factors vary from year to year, we forecast peak demand based on two scenarios:

1. a probability of exceedance of 50 per cent (**PoE50**) which represents a forecast value that should not be exceeded any more than one in every two years
2. a probability of exceedance of 10 per cent (**PoE10**) which represents a forecast value that should not be exceeded any more than one in every ten years.

Consistent with our peers we plan the transmission network based on PoE10 and the distribution network on PoE50. The different approaches reflect the criticality of the network equipment. If there is insufficient capacity in the transmission network there is the potential for supply to a large number of customers to be interrupted, whereas insufficient capacity in the distribution network would affect a much smaller number of customers. This ensures that we make capacity and reliability investment decisions that align with the impact on customers.

Peak demand is also based on two growth scenarios:

1. a central growth scenario which includes those large block loads most likely to connect to the network
2. a high growth scenario whereby planners may consider additional large loads that are less likely to connect.

Our investment planning is based on the central growth scenario. However, we also consider the high growth scenario to ensure that we have sufficient flexibility to cater for our customers' needs should the high growth scenario materialise. This is important in relation to our transmission network, as major augmentations are costly, have long lead times for planning, long construction times and are not easily altered.

Western Power develops a forecast of customer numbers, technology, energy exports, energy imports and peak demand in a single forecasting process. These forecasts are completed both bottom up (zone substation level) and top down (network level) using a variety of predominantly time-series forecasting techniques. The bottom up and top down forecasts are then reconciled and compared to ensure local and global trends are incorporated correctly. External variables considered in the forecasts include:

- economic activity: variables that measure the level of activity in the economy
- price: volumetric component of the electricity price
- seasonal: temperature and other weather variables
- substitution: capture any influence of alternatives to network delivered energy.

Manual interventions were applied to incorporate proposed network changes, large block load customers and emerging technologies like batteries.

2.3 Forecast network peak demand

Western Power forecasts peak demand to decrease by an average of 0.6 per cent per annum or 113 MW over the AA4 period. This forecast includes the impact of the connection of approximately 80,000 behind the meter batteries in the Western Power Network.

Our 2017 forecast is lower than the annual average peak demand growth of 0.2 per cent forecast in 2016, primarily driven by:

- Economic growth – We have forecast slow economic growth over the early part of the AA4 period which has dampened growth in grid supplied energy.
- Commercial solar PV – We have included an increased commercial PV uptake greater than previous estimates.
- Batteries[5] – For the first time, we have included the impact of expected battery storage uptake during the AA4 period due to a combination of maturing in technology that is leading to rapidly declining prices as well as expected rising electricity prices.

Since the high peak demand growth rates forecast in 2013, the PoE50 peak demand forecasts under the central growth scenario have been revised downwards each year until 2016. This is reflective of a combination of lower economic activity, resulting in little or flat growth in annual peak demand, growing solar PV generation impacts and revised block loads connections.

The 2015/16 summer period was particularly hot and recorded the highest load[6] at system peak in the SWIS to date. In comparison, the 2016/17 summer was comparatively mild, producing an eight year low peak. Greater volatility of demand related to weather is emerging as a new feature of peak demand, as demonstrated by the last two years.

Figure 2.2 and Table 2.1 show the 2017 PoE50 and PoE10 peak demand forecasts for the AA4 period using the central growth scenario.

5 Without the inclusion of batteries, we have forecast annual average growth of 0.1 per cent.

6 It should be noted that the peak occurred very early in 2015/16, likely surprising many large customers. This would have increased the demand as many of these customers would have otherwise shut down in anticipation of a peak.

Figure 2.2: Western Power network peak demand forecasts

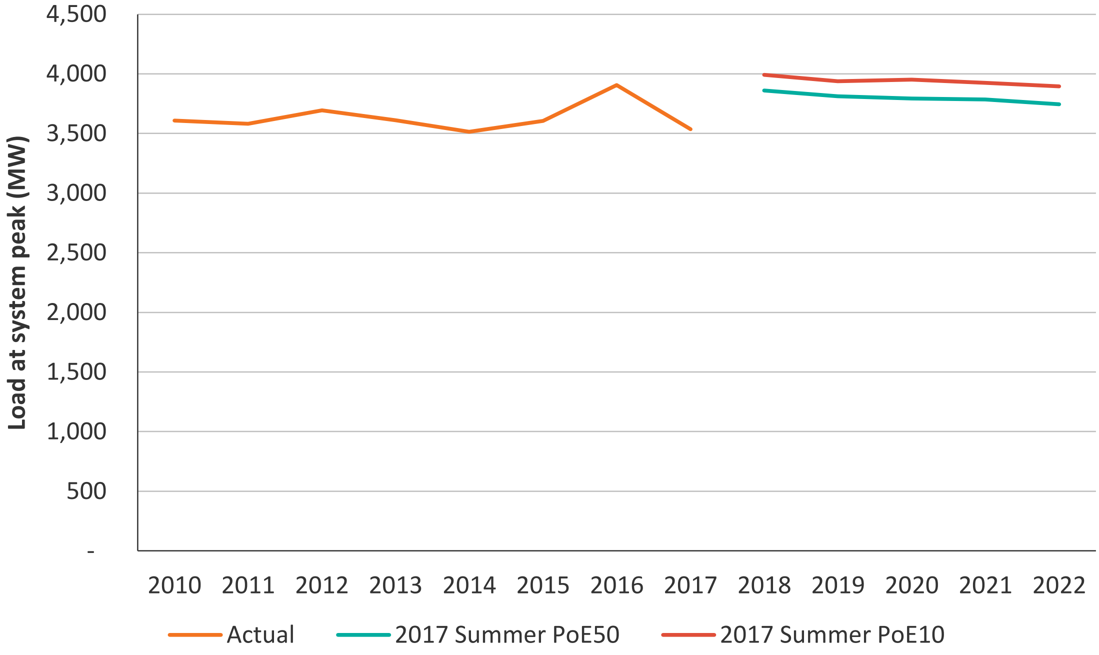


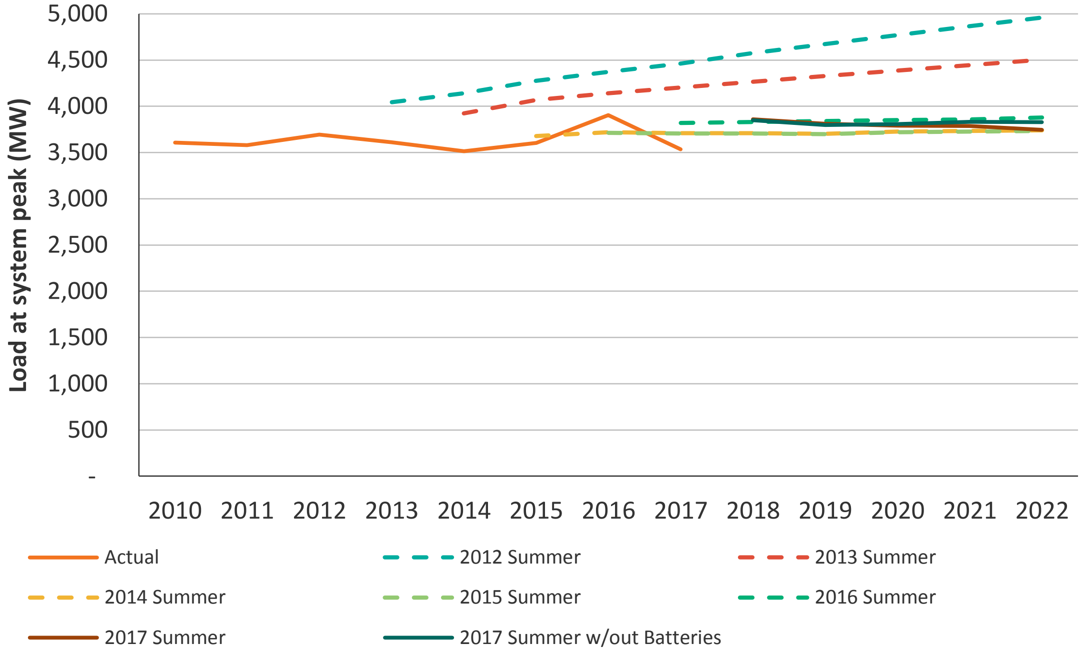
Table 2.1: Western Power network peak demand forecast, central growth scenario

	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
Actual peak demand (MW)	3,535					
PoE50 peak demand forecast (MW)		3,859	3,811	3,792	3,786	3,746
PoE10 peak demand forecast (MW)		3,991	3,939	3,951	3,926	3,896
Annual change in demand (MW)		324	-48	-19	-6	-40
Annual change in demand (%)		9.17%	-1.2%	-0.5%	-0.2%	-1.1%

We anticipate the relatively flat forecast peak demand at a system level will continue in the medium-term. In general, this has translated to lower network capacity requirements and fewer network capacity expansion works than historical levels.

Figure 2.3 highlights that the 2017 peak demand forecasts (with batteries) is expected to experience an annual growth rate of -0.5 per cent. Without the inclusion of batteries, the 2017 peak demand forecasts would still experience an annual positive growth of 0.1 per cent.

Figure 2.3: Comparison of network peak demand forecasts, 2012 to 2017



Despite overall reduced growth, there are 'pockets' of forecast peak demand growth for a number of load areas which will drive network investment over the AA4 period. In particular, the Mandurah, Bunbury and Muja load areas are expected to experience steady growth in peak demand. This is primarily due to:

- a number of expansion projects expected to impact substations supplying the Kwinana industrial area over the next year
- numerous urban development projects expected to maintain demand growth observed on substations supplying the coastal region between Baldivis and Margaret River - particularly the area around Mandurah and Meadow Springs and the area between Bunbury and Busselton.

Our forecast of customer growth by load area is provided in Table 2.2.

Table 2.2: Customer growth by load area

	Outer Metropolitan Area				Inner Metropolitan Area						Rest of the Western Power Network				
	Mandurah	Kwinana	Far Northern Suburbs	Midland	Perth	Northern Suburbs	Fremantle	Western Suburbs	Southern Suburbs	Cannington	South West & Albany	Bunbury	East Country	Kalgoorlie	North Country & Geraldton
2008/09	3.47%	1.95%	2.32%	1.53%	1.67%	1.64%	1.40%	0.63%	2.44%	0.67%	1.24%	2.71%	1.17%	1.86%	1.64%
2009/10	3.95%	2.28%	2.98%	1.72%	2.72%	1.69%	1.25%	0.94%	3.42%	0.91%	1.42%	3.24%	1.01%	1.35%	2.30%
2010/11	4.60%	3.04%	3.28%	1.80%	1.61%	1.70%	1.22%	0.45%	3.18%	1.31%	1.40%	3.32%	0.67%	0.82%	1.84%
2011/12	3.53%	2.66%	2.56%	1.17%	2.06%	1.96%	1.31%	0.87%	2.62%	1.03%	1.26%	2.50%	0.54%	0.88%	1.72%
2012/13	3.21%	2.14%	2.37%	1.10%	1.48%	1.64%	1.18%	0.82%	2.38%	1.23%	0.94%	2.13%	0.42%	1.03%	1.62%
2013/14	4.14%	2.86%	3.11%	1.43%	0.67%	2.00%	1.19%	0.59%	2.44%	1.05%	1.06%	2.28%	0.35%	0.37%	1.48%
2014/15	4.80%	3.61%	3.39%	1.55%	1.40%	2.51%	1.63%	0.79%	2.89%	1.42%	1.05%	2.74%	0.47%	0.28%	1.55%
2015/16	4.03%	3.83%	3.08%	1.22%	1.79%	2.42%	1.71%	0.79%	3.23%	2.31%	0.64%	2.13%	0.52%	0.15%	0.67%
2016/17	2.70%	2.69%	2.03%	0.82%	1.46%	2.19%	1.57%	1.48%	2.65%	2.27%	0.93%	1.41%	0.83%	-0.41%	0.94%
2017/18	2.23%	1.40%	2.07%	0.97%	1.24%	2.12%	1.70%	1.04%	2.76%	1.65%	1.09%	1.74%	0.60%	-0.14%	1.21%
2018/19	2.62%	0.90%	2.12%	1.09%	1.67%	2.04%	1.48%	1.01%	2.73%	1.52%	1.23%	2.43%	0.43%	0.44%	1.28%
2019/20	2.96%	0.79%	1.99%	1.12%	0.90%	2.00%	1.41%	1.01%	2.68%	1.60%	1.26%	2.42%	0.50%	0.56%	1.31%
2020/21	3.11%	0.69%	1.72%	1.03%	2.05%	1.88%	1.43%	0.97%	2.53%	1.52%	1.17%	2.22%	0.47%	0.69%	1.22%
2021/22	3.16%	0.82%	1.66%	1.04%	1.27%	1.86%	1.52%	0.99%	2.48%	1.52%	1.18%	2.30%	0.49%	0.53%	1.22%

The full 2017 substation demand forecasts, including the forecasting methodology, are provided in Attachment 7.3.1.

2.4 Verification of our forecasts

Our peak demand forecasts have been verified internally against the peak demand forecasts published by the Australian Energy Market Operator (**AEMO**) in the annual Electricity Statement of Opportunities for Western Australia. They have also been independently reviewed by the National Institute of Economic and Industry Research (**NIEIR**).

In verifying our forecasts against the AEMO's peak demand forecasts, we need to consider the difference between the two forecasts. These differences arise because the forecasts are used for different purposes and therefore forecast the peak demand at a different point in the system. The AEMO forecasts the peak demand that is required to be supplied by generators. As a result, it includes losses on the transmission and distribution network. Our forecast of peak demand does not include losses in the transmission network and some consumption outside the boundaries of the Western Power network.

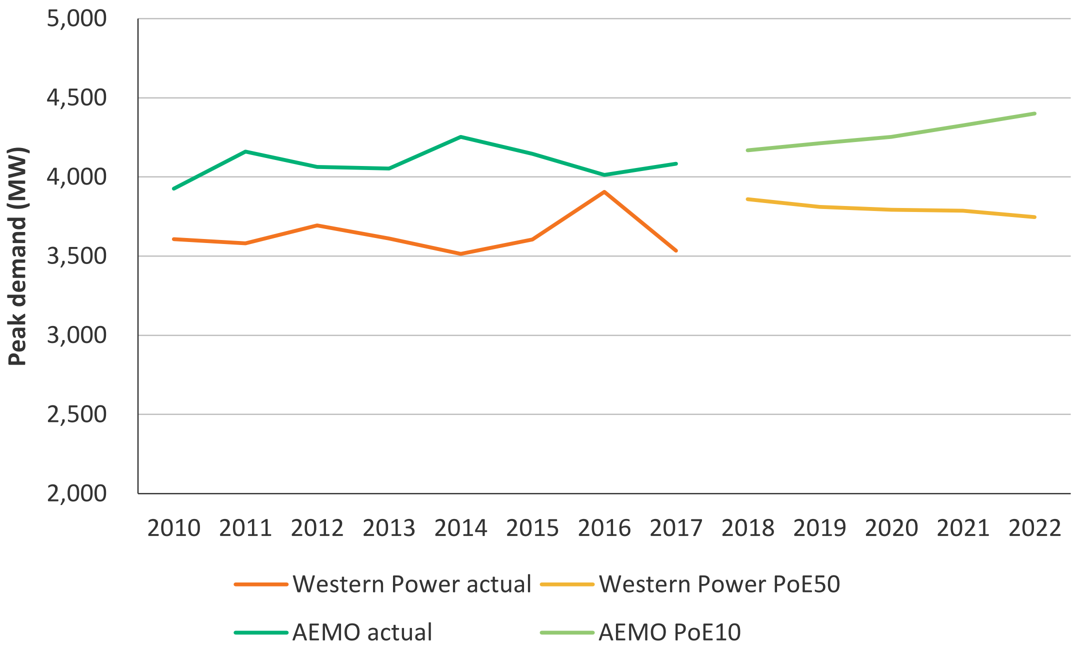
The key differences between Western Power and the AEMO's forecast methodologies are provided in Table 2.3.

Table 2.3: Differences in forecast methodology, the AEMO and Western Power

Reason	AEMO	Western Power
Model Choice	Top down ordinary least squares structural models – typically good for identifying the cause of variation but have poor predictive capacity	Bottom up time series models with exogenous variables – less useful for identifying cause but much better predictive capacity Forecasting network exports and imports separately Top down reconciliation using generalised additive model spline structural models
Variable Selection	Excluded all negatively correlated inputs (price, energy efficiency)	Far greater consideration for price and energy efficiency
Technology	AEMO and WP took very similar views on PV, battery and Electric Vehicle uptake, although the assumptions on impact vary	
Block Loads (large new customers)	AEMO and WP took a very similar view on block loads	
Economic Growth	3.3% p.a. (10yr)	1.8% p.a. (5yr)
Population/Customers	WA tomorrow (ignores economic downturn)	Regression on customer numbers
Residential Consumption	0.3% p.a. (10yr)	-2.1% p.a. (5yr)
Non-Residential Consumption	0.8% p.a. (10yr)	0.1% p.a. (5yr)

While Western Power and the AEMO each develop forecasts for different purposes and using different methodologies, the trends are still comparable. Figure 2.4 shows the comparison of our network peak demand forecast and the AEMO's peak demand forecast.

Figure 2.4: Comparison of Western Power and the AEMO forecasts of peak demand



We periodically commission independent auditors to review our annual peak demand forecasting methods to ensure that good industry practice is applied consistently.

In 2016, the NIEIR was commissioned to perform such a review. While favourable, the NIEIR suggested changes in method that may lead to further improvement in terms of insight and forecast accuracy. In summary, these are to:

- produce top-down demand model to validate bottom up process
- segment demand into base load and temperature sensitive load
- directly incorporate weather correction into the PoE50 demand forecasts
- improve the solar photovoltaic power systems modelling for both energy & peak demand forecasts
- estimate models based on interval specific peak times where possible.

Three of the recommendations have been implemented. We are in the process of assessing the remaining recommendations with a view to implementing those that will improve our current forecasting methods.

3. Customer number forecasts

Western Power forecasts that the number of customers will increase by an average of 1.7 per cent per annum or around 96,000 customers over the AA4 period. This compares with 1.7 per cent over the third access arrangement (AA3) period.

The forecast number of customers:

- drives the forecast increase in energy consumption (see section 4)
- drives investment in new customer connections and meters for those customers
- is an input into the determination of distribution tariffs.

Figure 3.1 and Table 3.1 show the forecast number of customers for AA4 by customer type.

Figure 3.1: Customer numbers by type

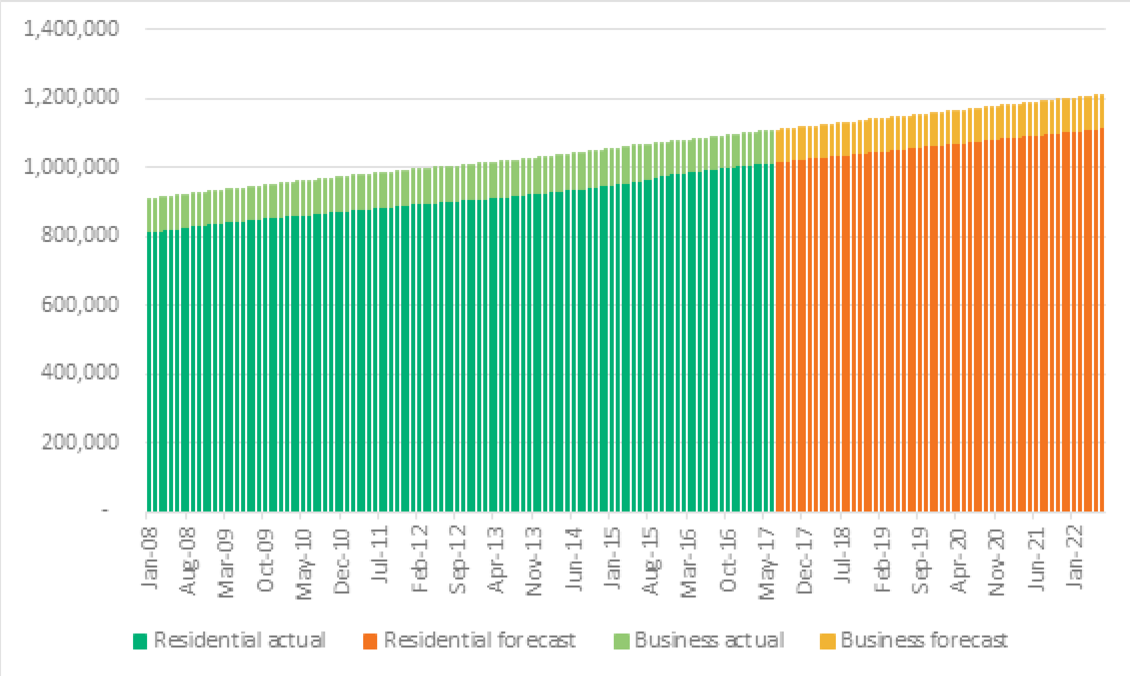


Table 3.1: Forecast number of customers by customer type

Average customers per financial year	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 annual average growth
Residential customers	1,006,586	1,025,661	1,045,638	1,065,614	1,085,590	1,105,567	1.89%
Business customers	90,421	89,810	89,221	88,602	87,955	87,283	-0.70%
Streetlights & unmetered supplies	281760	288862	296782	304908	312864	320847	2.63%

Average customers per financial year	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 annual average growth
Transmission customers	38	38	38	39	40	40	1.03%
Total customers (excl. street lights and unmetered supplies)	**1,097,045**	**1,115,509**	**1,134,897**	**1,154,255**	**1,173,585**	**1,192,890**	**1.7%**

The full 2017 customer number forecasts, including the forecasting methodology, are provided in Attachment 7.3.5 (2017).

4. Energy consumption forecasts

Western Power forecasts that the energy consumed by our customers will decrease by an average of 0.5 per cent per annum or around 455 Mega Watt hours (**MWh**) over the AA4 period. This compares with 0.8 per cent growth over the AA3 period.

The energy consumption forecast is a key input into the determination of distribution tariffs. For a given revenue requirement, the higher the energy forecast, the lower the distribution tariffs. Although investment in the network is driven by peak demand rather than energy consumption, energy consumption has been used as a proxy in setting distribution tariffs.

Figure 4.1 and Table 4.1 show the forecast number of customers for residential and business distribution connected customer customers, and transmission connected customers over the AA4 period.

Figure 4.1: Energy consumption by customer connection type

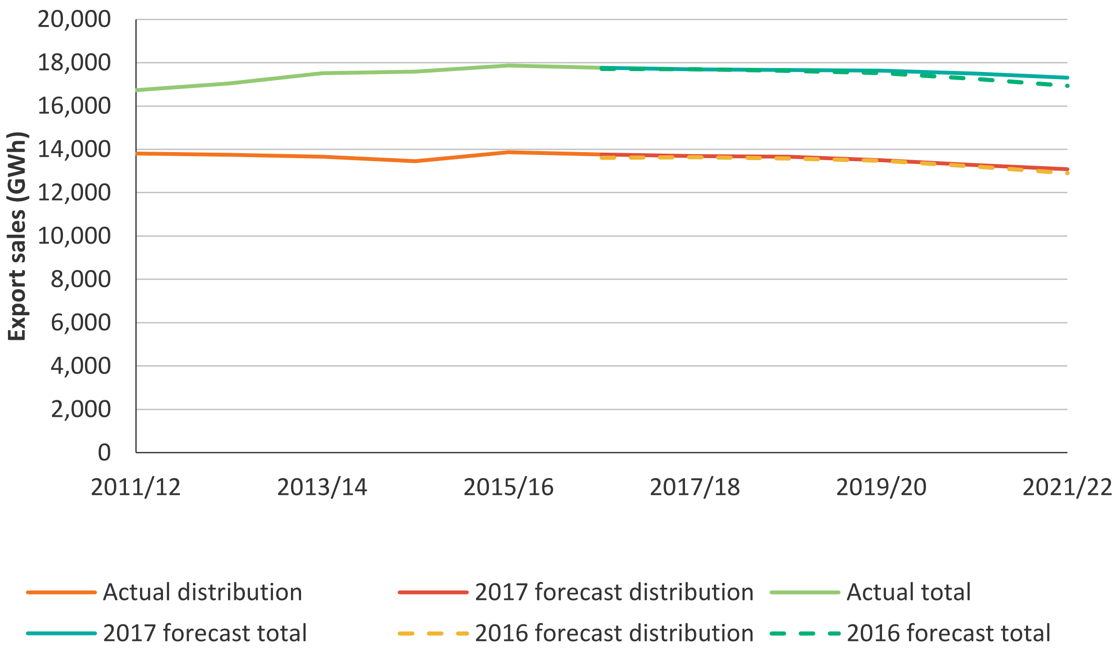


Table 4.1: Forecast energy consumption by customer connection type, MWh

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 annual average growth
Distribution connected residential	5,359	5,302	5,191	5,076	4,965	-2.12%
Distribution connected business	8,163	8,178	8,133	8,015	7,931	-0.36%
Streetlights and unmetered supplies	171	176	181	184	189	2.26%
Total distribution connected	13,693	13,656	13,505	13,275	13,085	-1.0%

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 annual average growth
Total transmission connected	4,007	4,007	4,123	4,226	4,226	1.1%
Total	**17,698**	**17,663**	**17,628**	**17,502**	**17,309**	**-0.5%**

The decrease in energy consumption over the forecast period is driven by an average -1.0 per cent per annum decrease in distribution connected customer energy consumption, partially offset by a 1.1 per cent per annum increase in transmission energy consumption.

[redacted]

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

[redacted]

The AEMO also prepare energy consumption forecasts as part of the annual Electricity Statement of Opportunities for Western Australia. While Western Power and the AEMO each develop our forecasts for different purposes and using different methodologies, the trends are still comparable. Figure 2.4

As provided in Table 2.3, Western Power has a number of different assumptions underpinning its forecasts. Without full information regarding the AEMO's forecasting methodology and access to the model, Western Power is unable to comment in detail on the reason behind these differences. However, we expect that the large majority of this can be explained by Western Power's:

- more conservative forecast economic growth assumptions
- higher forecast of customer defection from network-supplied energy as a result of the continued increase in solar PV coupled with the uptake in batteries,

A comparison of our energy consumption forecasts with AEMO's is shown in Figure 4.2.

Figure 4.2: Comparison of Western Power and the AEMO forecasts of total energy consumption