



# Jemena Electricity Networks (Vic) Ltd

## 2021-26 Electricity Distribution Price Review Regulatory Proposal

Attachment 05-03

Electricity demand forecasts report



REPORT TO  
**JEMENA ELECTRICITY NETWORKS LIMITED**  
17 JANUARY 2020

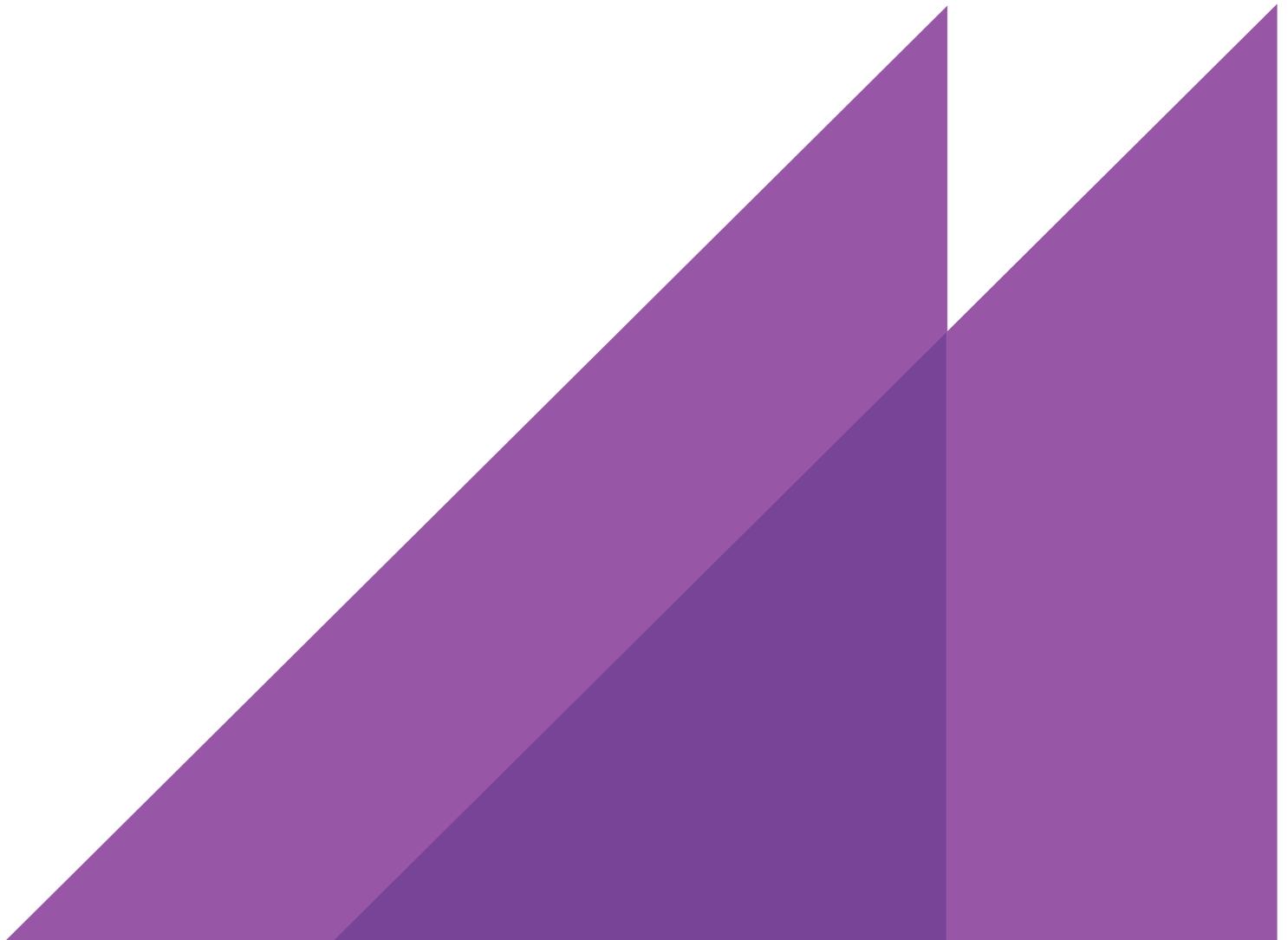
---

# JEN DEMAND FORECASTS 2019-2028

---



CUSTOMER NUMBER, ANNUAL ELECTRICITY  
CONSUMPTION AND NETWORK MAXIMUM  
DEMAND FORECASTS



## EXECUTIVE SUMMARY

VI

---

**1**

---

	<i>Introduction</i>	<i>1</i>
1.1	Background	1
1.2	Scope of work	2
1.3	Structure of this report	3

**2**

---

	<i>Historical overview- Energy consumption and maximum demand</i>	<i>4</i>
2.1	Energy consumption	4
2.2	Customer numbers	8
2.3	System maximum demand	10
2.4	System minimum demand	11

**3**

---

	<i>Main drivers of energy consumption and maximum demand</i>	<i>13</i>
3.1	Economic activity	13
3.2	Population growth and customer numbers	15
3.3	Weather	20
3.4	Electricity prices	24
3.5	Rooftop PV and battery storage	26
3.6	Electric vehicles (EV)	28

**4**

---

	<i>Energy consumption forecasting methodology</i>	<i>30</i>
4.1	Data collection	31
4.2	Data processing	32
4.3	Model specification and estimation	32
4.4	Model testing and validation	38
4.5	Post model adjustments	39

**5**

---

	<i>Maximum demand forecasting methodology</i>	<i>41</i>
5.1	Modelling approach	41
5.2	Model development and forecasting process	41
5.3	Data collection and storage	42
5.4	Data processing	42
5.5	Specification and estimation of the baseline maximum demand models	43
5.6	Model validation and testing	46
5.7	Weather normalisation and stochastic analysis	46
5.8	Apply post model adjustments	47

**6**

---

	<i>Energy consumption and customer numbers forecasts</i>	<i>49</i>
6.1	Customer numbers	49
6.2	Energy consumption forecasts	51

## 7

	<i>Network maximum demand forecasts</i>	<b>55</b>
7.1	Summer system maximum demand forecasts	55
7.2	Winter system maximum demand forecasts	56

## 8

	<i>Rooftop PV and battery storage</i>	<b>59</b>
8.1	Historical trends in rooftop PV uptake	59
8.2	Overview of approach to modelling the uptake of rooftop PV and battery storage	60
8.3	Rooftop PV system costs	61
8.4	Rebates and subsidies	62
8.5	Retail electricity prices	63
8.6	Feed-in tariffs and buy back rates	64
8.7	System output and export rates	64
8.8	Uptake of battery storage systems	65
8.9	Rooftop PV and battery storage forecasts	67

## 9

	<i>Electric vehicles</i>	<b>74</b>
9.1	Introduction	74
9.2	Market for Electric Vehicles	74
9.3	Current Take-Up of Electric Vehicles	78
9.4	Economics of Electric Vehicles	79
9.5	Modelling the Take-Up of Electric Vehicles	91
9.6	Projections of Electric Vehicles	92
9.7	Impact on energy consumption	93

## FIGURES

<b>FIGURE ES 1</b>	HISTORICAL AND FORECAST CUSTOMER NUMBERS FOR THE JEN DISTRIBUTION NETWORK BY CUSTOMER CLASS	VIII
<b>FIGURE ES 2</b>	HISTORICAL AND FORECAST TOTAL ENERGY CONSUMPTION FOR THE JEN DISTRIBUTION NETWORK, GWH	IX
<b>FIGURE ES 3</b>	SUMMER SYSTEM MAXIMUM DEMAND FORECAST, MW, 10POE, 50POE AND 90POE	X
<b>FIGURE ES 4</b>	WINTER SYSTEM MAXIMUM DEMAND FORECAST, MW, 10POE, 50POE AND 90POE	XI
<b>FIGURE 1.1</b>	JEN DISTRIBUTION REGION	1
<b>FIGURE 2.1</b>	TOTAL CONSUMPTION BY TARIFF CLASS	5
<b>FIGURE 2.2</b>	TOTAL RESIDENTIAL CONSUMPTION	5
<b>FIGURE 2.3</b>	TOTAL RESIDENTIAL CONSUMPTION AND ROOFTOP PV GENERATION	6
<b>FIGURE 2.4</b>	SMALL BUSINESS CONSUMPTION	6
<b>FIGURE 2.5</b>	TOTAL SMALL BUSINESS CONSUMPTION AND ROOFTOP PV GENERATION	7
<b>FIGURE 2.6</b>	LARGE BUSINESS LV CONSUMPTION	7
<b>FIGURE 2.7</b>	LARGE BUSINESS HV CONSUMPTION	8
<b>FIGURE 2.8</b>	SUB-TRANSMISSION CONSUMPTION	8
<b>FIGURE 2.9</b>	TOTAL CUSTOMER NUMBERS BY TARIFF CLASS	9
<b>FIGURE 2.10</b>	ANNUAL CHANGE IN CUSTOMER NUMBERS BY TARIFF CLASS	10
<b>FIGURE 2.11</b>	SUMMER SYSTEM MAXIMUM DEMAND BY COMPONENT, 2006-07 TO 2017-18	10
<b>FIGURE 2.12</b>	WINTER SYSTEM MAXIMUM DEMAND BY COMPONENT, 2007 TO 2018	11
<b>FIGURE 2.13</b>	AVERAGE LOAD PROFILE IN JEN NETWORK OVER TIME, 2008 TO 2018	12
<b>FIGURE 3.1</b>	VICTORIAN GROSS STATE PRODUCT (GSP)	14
<b>FIGURE 3.2</b>	VICTORIAN ECONOMIC GROWTH PROJECTIONS	15
<b>FIGURE 3.3</b>	TOTAL ESTIMATED RESIDENT POPULATION IN JEN REGION	17

<b>FIGURE 3.4</b>	PROJECTED POPULATION GROWTH RATE FROM 2017-18 TO 2028-29	18
<b>FIGURE 3.5</b>	PROJECTED POPULATION OF JEN REGION, 2017-18 TO 2028-29	19
<b>FIGURE 3.6</b>	PROJECTED ANNUAL POPULATION GROWTH RATES OF JEN DISTRIBUTION REGION, 2017-18 TO 2028-29	20
<b>FIGURE 3.7</b>	HISTORICAL HEATING DEGREE DAYS (HDD) AND COOLING DEGREE DAYS (CDD) AT MELBOURNE AIRPORT	21
<b>FIGURE 3.8</b>	STYLISED RELATIONSHIP BETWEEN SUMMER DAILY PEAK DEMAND AND AVERAGE DAILY TEMPERATURE	22
<b>FIGURE 3.9</b>	MAXIMUM DEMAND VERSUS AVERAGE TEMPERATURE- WORKING DAYS, SUMMER, 2015-16 TO 2018-19	23
<b>FIGURE 3.10</b>	STYLISED RELATIONSHIP BETWEEN WINTER DAILY MAXIMUM DEMAND AND AVERAGE DAILY TEMPERATURE	23
<b>FIGURE 3.11</b>	MAXIMUM DEMAND VERSUS AVERAGE TEMPERATURE- WORKING DAYS, WINTER, 2015 TO 2018	24
<b>FIGURE 3.12</b>	HISTORICAL ELECTRICITY PRICES FOR RESIDENTIAL AND NON-RESIDENTIAL CUSTOMERS	25
<b>FIGURE 3.13</b>	FORECAST CHANGE IN REAL ELECTRICITY PRICES	26
<b>FIGURE 3.14</b>	INSTALLED ROOFTOP PV CAPACITY AS AT JUNE 30, HISTORICAL AND FORECAST	27
<b>FIGURE 3.15</b>	FORECAST UPTAKE OF BATTERY STORAGE, 2018-19 TO 2028-29	28
<b>FIGURE 3.16</b>	FORECAST ELECTRIC VEHICLE ENERGY CONSUMPTION, 2017-18 TO 2028-29	29
<b>FIGURE 4.1</b>	STEPS IN THE ENERGY FORECASTING PROCESS	31
<b>FIGURE 4.2</b>	RESIDENTIAL CUSTOMERS, PREDICTED VERSUS ACTUAL	33
<b>FIGURE 4.3</b>	RESIDENTIAL CONSUMPTION PER CUSTOMER, PREDICTED VERSUS ACTUAL	34
<b>FIGURE 4.4</b>	SMALL BUSINESS CUSTOMERS, PREDICTED VERSUS ACTUAL	35
<b>FIGURE 4.5</b>	SMALL BUSINESS CONSUMPTION, PREDICTED VERSUS ACTUAL	36
<b>FIGURE 4.6</b>	LARGE BUSINESS LV MONTHLY CUSTOMER NUMBERS	37
<b>FIGURE 4.7</b>	LARGE BUSINESS LV CONSUMPTION, PREDICTED VERSUS ACTUAL	38
<b>FIGURE 4.8</b>	SOLAR CONVERSION FACTORS BY MONTH	39
<b>FIGURE 4.9</b>	GENERATION OF ROOFTOP PV SYSTEMS, HISTORICAL AND FORECAST	40
<b>FIGURE 5.1</b>	STEPS IN THE MAXIMUM DEMAND FORECASTING PROCESS	42
<b>FIGURE 5.2</b>	INCREMENTAL IMPACT OF NEWLY INSTALLED ROOFTOP PV CAPACITY ON SUMMER MAXIMUM DEMAND (MW)	47
<b>FIGURE 5.3</b>	IMPACT OF BATTERY STORAGE ON SUMMER MAXIMUM DEMAND (MW)	48
<b>FIGURE 6.1</b>	HISTORICAL AND FORECAST CUSTOMER NUMBERS FOR THE JEN DISTRIBUTION NETWORK BY CUSTOMER CLASS	50
<b>FIGURE 6.2</b>	ACTUAL AND FORECAST RESIDENTIAL ENERGY CONSUMPTION	51
<b>FIGURE 6.3</b>	ACTUAL AND FORECAST NON-RESIDENTIAL ENERGY CONSUMPTION	51
<b>FIGURE 6.4</b>	ACTUAL AND FORECAST TOTAL ENERGY CONSUMPTION	54
<b>FIGURE 7.1</b>	SUMMER SYSTEM MAXIMUM DEMAND FORECAST, MW, 10POE, 50POE AND 90POE	56
<b>FIGURE 7.2</b>	WINTER SYSTEM MAXIMUM DEMAND FORECAST, MW, 10POE, 50POE AND 90POE	58
<b>FIGURE 8.1</b>	HISTORICAL ROOFTOP PV CAPACITY IN THE JEN DISTRIBUTION NETWORK, JUNE 2010 TO JUNE 2018	59
<b>FIGURE 8.2</b>	ROOFTOP PV ANNUAL INSTALLED CAPACITY IN THE JEN DISTRIBUTION NETWORK, RESIDENTIAL AND SMALL BUSINESS	60
<b>FIGURE 8.3</b>	PROJECTED SYSTEM COST OF ROOFTOP PV SYSTEMS, MELBOURNE \$2019	62
<b>FIGURE 8.4</b>	HISTORICAL AND PROJECTED REAL ELECTRICITY PRICES, \$2018	63
<b>FIGURE 8.5</b>	PROJECTED COST OF BATTERY PLUS INVERTER, \$2019	66
<b>FIGURE 8.6</b>	FORECAST OF BATTERY STORAGE IMPACT ON MAXIMUM SUMMER DEMAND, MW	67
<b>FIGURE 8.7</b>	INSTALLED ROOFTOP PV CAPACITY AS AT JUNE 30, HISTORICAL AND FORECAST	68
<b>FIGURE 8.8</b>	ANNUAL GROWTH IN ROOFTOP PV CAPACITY, HISTORICAL AND FORECAST	69
<b>FIGURE 8.9</b>	RESIDENTIAL INSTALLED ROOFTOP PV CAPACITY AS AT JUNE 30, HISTORICAL AND FORECAST	69
<b>FIGURE 8.10</b>	SMALL BUSINESS INSTALLED ROOFTOP PV CAPACITY AS AT JUNE 30, HISTORICAL AND FORECAST, EXPECTED	70
<b>FIGURE 8.11</b>	NUMBER OF ROOFTOP PV INSTALLATIONS AS AT JUNE 30, HISTORICAL AND FORECAST	70

<b>FIGURE 8.12</b>	NUMBER OF RESIDENTIAL ROOFTOP PV INSTALLATIONS AS AT JUNE 30, HISTORICAL AND FORECAST	71
<b>FIGURE 8.13</b>	NUMBER OF SMALL BUSINESS ROOFTOP PV INSTALLATIONS AS AT JUNE 30, HISTORICAL AND FORECAST	71
<b>FIGURE 8.14</b>	FORECAST UPTAKE OF BATTERY STORAGE, MWH	72
<b>FIGURE 8.15</b>	FORECAST UPTAKE OF BATTERY STORAGE, MW	72
<b>FIGURE 8.16</b>	FORECAST UPTAKE OF BATTERY STORAGE, NUMBER OF INSTALLED SYSTEMS	73
<b>FIGURE 9.1</b>	HISTORICAL PASSENGER AND LIGHT COMMERCIAL VEHICLES REGISTERED IN VICTORIA, 2001 TO 2019	75
<b>FIGURE 9.2</b>	NUMBER OF PASSENGER AND LIGHT COMMERCIAL VEHICLES PER PERSON, VIC, 2001 TO 2018	76
<b>FIGURE 9.3</b>	HISTORICAL AND PROJECTED PASSENGER VEHICLES AND LIGHT COMMERCIAL VEHICLES PER PERSON, VICTORIA 2001 TO 2029	77
<b>FIGURE 9.4</b>	HISTORICAL AND PROJECTED PASSENGER VEHICLES IN VICTORIA, 2001 TO 2029	78
<b>FIGURE 9.5</b>	HISTORICAL AND PROJECTED LIGHT COMMERCIAL VEHICLES IN VICTORIA, 2001 TO 2029	78
<b>FIGURE 9.6</b>	ELECTRIC VEHICLE SALES IN AUSTRALIA, 2011 TO 2017	79
<b>FIGURE 9.7</b>	REAL COST OF VEHICLES: ICE VERSUS PHEV/EV, PROJECTED (\$2018)	80
<b>FIGURE 9.8</b>	AVERAGE VICTORIAN UNLEADED PETROL PRICES, 2002 TO 2018, NOMINAL	81
<b>FIGURE 9.9</b>	FORECAST VICTORIAN ULP PETROL PRICES, 2019 TO 2029, \$2018	82
<b>FIGURE 9.10</b>	REAL ELECTRICITY TARIFF, VICTORIA, REAL (\$2018)	83
<b>FIGURE 9.11</b>	FACTORS THAT AFFECT FUEL CONSUMPTION	84
<b>FIGURE 9.12</b>	AVERAGE FUEL CONSUMPTION OF PASSENGER AND LIGHT COMMERCIAL VEHICLES, 1998 TO 2016 (CALENDAR YEAR ENDING 31 DECEMBER)	85
<b>FIGURE 9.13</b>	FORECAST INTERNAL COMBUSTION ENGINE (ICE) VEHICLE FUEL CONSUMPTION, 2019 TO 2029	86
<b>FIGURE 9.14</b>	FORECAST ELECTRIC VEHICLE FUEL CONSUMPTION, 2019 TO 2029	87
<b>FIGURE 9.15</b>	TOTAL FUEL COSTS OF RUNNING AN ICE VEHICLE, \$2018	87
<b>FIGURE 9.16</b>	TOTAL FUEL COSTS OF RUNNING AN ELECTRIC VEHICLE, \$2018	88
<b>FIGURE 9.17</b>	FUEL COST PER 100 KM TRAVELLED - COMPARISON BY VEHICLE TYPE	89
<b>FIGURE 9.18</b>	RANGE COMPARISON BY VEHICLE TYPE	90
<b>FIGURE 9.19</b>	CHARACTERISTIC SHAPE OF THE LOGISTIC FUNCTION	92
<b>FIGURE 9.20</b>	PLUG-IN ELECTRIC VEHICLE SHARE OF TOTAL LIGHT VEHICLES	93
<b>FIGURE 9.21</b>	PROJECTED NUMBER OF ELECTRIC VEHICLES WITHIN THE JEN DISTRIBUTION NETWORK, 2019 TO 2029	93
<b>FIGURE 9.22</b>	ENERGY IMPACT OF ELECTRIC VEHICLES WITHIN THE JEMENA DISTRIBUTION NETWORK	94

## TABLES

<b>TABLE ES 1</b>	HISTORICAL AND FORECAST CUSTOMER NUMBERS FOR THE JEN DISTRIBUTION NETWORK BY CUSTOMER CLASS	VII
<b>TABLE ES 2</b>	HISTORICAL AND FORECAST ENERGY CONSUMPTION FOR THE JEN DISTRIBUTION NETWORK BY CUSTOMER CLASS, GWH	IX
<b>TABLE ES 3</b>	SUMMER SYSTEM MAXIMUM DEMAND FORECAST, MW, 10POE, 50POE AND 90POE	X
<b>TABLE ES 4</b>	WINTER SYSTEM MAXIMUM DEMAND FORECAST, MW, 10POE, 50POE AND 90POE	XII
<b>TABLE 3.1</b>	JEN CUSTOMER NUMBERS BREAKDOWN BY LOCAL GOVERNMENT AREA, JUNE 2018	16
<b>TABLE 3.2</b>	DERIVING POPULATION WEIGHTS BY LGA IN JEN'S REGION	19
<b>TABLE 4.1</b>	RESIDENTIAL CUSTOMER REGRESSION MODEL	33
<b>TABLE 4.2</b>	RESIDENTIAL CONSUMPTION PER CUSTOMER REGRESSION MODEL	34
<b>TABLE 4.3</b>	SMALL BUSINESS CUSTOMERS REGRESSION MODEL	35
<b>TABLE 4.4</b>	SMALL BUSINESS CONSUMPTION REGRESSION MODEL	36
<b>TABLE 4.5</b>	LARGE BUSINESS LV CONSUMPTION REGRESSION MODEL	38
<b>TABLE 5.1</b>	SYSTEM MAXIMUM DEMAND MODEL (SUMMER), ESTIMATED COEFFICIENTS	44
<b>TABLE 5.2</b>	SYSTEM MAXIMUM DEMAND MODEL (WINTER), ESTIMATED COEFFICIENTS	45
<b>TABLE 6.1</b>	HISTORICAL AND FORECAST CUSTOMER NUMBERS FOR THE JEN DISTRIBUTION NETWORK BY CUSTOMER CLASS	49

<b>TABLE 6.2</b>	HISTORICAL AND FORECAST ENERGY CONSUMPTION FOR THE JEN DISTRIBUTION NETWORK BY CUSTOMER CLASS, GWH	53
<b>TABLE 7.1</b>	SUMMER SYSTEM MAXIMUM DEMAND FORECAST, MW, 10POE, 50POE AND 90POE	55
<b>TABLE 7.2</b>	WINTER SYSTEM MAXIMUM DEMAND FORECAST, MW, 10POE, 50POE AND 90POE	56
<b>TABLE 8.1</b>	SOLAR CREDITS MULTIPLIER AND SHCP REBATE	63
<b>TABLE 8.2</b>	ASSUMED ROOFTOP PV EXPORT RATES	65
<b>TABLE 8.3</b>	MAIN ASSUMPTIONS APPLIED IN STORAGE PROJECTIONS	66
<b>TABLE 9.1</b>	PUBLIC CHARGING INFRASTRUCTURE IN AUSTRALIA, 2018	91



## EXECUTIVE SUMMARY

Jemena Electricity Networks (JEN) is one of five electricity Distribution Network Service Providers (DNSP) in Victoria. It covers an area of 950 square kilometres and distributes electricity to over 340,000 households and businesses throughout the north-west of Melbourne.

As with all electricity distributor network services providers (DNSPs) in the National Electricity Market, JEN is subject to economic regulation administered by the Australian Energy Regulator (AER) under the National Electricity Rules.

JEN is currently preparing its revised regulatory proposal for the electricity distribution price review (EDPR) covering the period from 1 July 2021 to 30 June 2026, which it will submit to the AER by 31 January 2021. As inputs to, and components of, that proposal JEN requires forecasts of:

- system maximum demand (MW)
- energy consumption and
- customer numbers.

JEN engaged ACIL Allen Consulting (ACIL Allen) to assist it in preparing its submission to the AER in relation to consumption, customer numbers and maximum demand forecasting.

The forecasts presented in this report have been prepared as a standalone input to support JEN's regulatory proposal.

The results presented in this report were prepared using econometric techniques. Specifically, regression models were estimated to quantify the relationship between consumption, customer numbers and maximum demand and their drivers. Those models were used with projections of the drivers to produce baseline forecasts.

Additional post model adjustments were made to the forecasts to account for the impact of ongoing take-up of rooftop PV systems, battery storage and electric vehicles. Those impacts were calculated in separate models described in this report.

The forecasts provided in this report cover the 10 year period from 2019 to 2028 and include:

- customer numbers and annual electricity consumption forecasts from 2019 to 2028 for:
  - residential
  - small business
  - large business (Low Voltage)
  - large business (High Voltage)
  - large business (Sub Transmission)
- network maximum demand covering:
  - Summer and Winter maximum demand forecasts for the JEN area
  - The summer forecast period is defined from November 1 to March 31 and covers the horizon from 2019-20 to 2028-29.

- The winter period is defined from April 1 to October 31 and cover the years from 2019 to 2028.
- Maximum demand forecasts have been provided at the 10%, 50% and 90% probability of exceedance (POE) levels

## Customer numbers

Table ES 1 presents the historical and forecast customer numbers for the JEN distribution network. As at 2017-18<sup>1</sup>, JEN had a total of 345,056 customers<sup>2</sup>. This is projected to increase at an average annual growth rate of 1.5 per cent per annum. By 2027-28, JEN is projected to have 400,477 customers.

**TABLE ES 1** HISTORICAL AND FORECAST CUSTOMER NUMBERS FOR THE JEN DISTRIBUTION NETWORK BY CUSTOMER CLASS

Year	Residential	Small business	Large business- LV	Large business- HV	Large business-ST	System
2009	272,528	26,442	1,058	80	4	300,111
2010	274,779	26,627	1,129	79	4	302,617
2011	277,073	26,708	1,210	79	4	305,073
2012	281,405	26,793	1,293	80	4	309,574
2013	285,725	26,630	1,340	79	4	313,777
2014	289,767	26,486	1,377	77	4	317,710
2015	294,791	26,734	1,393	77	4	322,998
2016	300,238	27,154	1,345	80	4	328,820
2017	307,106	27,500	1,435	84	4	336,128
2018	315,219	28,217	1,530	86	4	345,056
2019	321,918	28,967	1,506	88	4	352,482
2020	327,362	29,199	1,527	88	4	358,179
2021	332,757	29,427	1,548	88	4	363,823
2022	337,855	29,702	1,569	88	4	369,218
2023	342,814	29,992	1,590	88	4	374,488
2024	347,865	30,251	1,612	88	4	379,820
2025	353,011	30,492	1,634	88	4	385,228
2026	358,065	30,754	1,656	88	4	390,567
2027	362,761	31,067	1,679	88	4	395,599
2028	367,272	31,412	1,702	88	4	400,477
<b>5 year CAGR %</b>	<b>1.69%</b>	<b>1.23%</b>	<b>0.77%</b>	<b>0.46%</b>	<b>0.00%</b>	<b>1.65%</b>
<b>10 year CAGR %</b>	<b>1.54%</b>	<b>1.08%</b>	<b>1.07%</b>	<b>0.23%</b>	<b>0.00%</b>	<b>1.50%</b>

SOURCE: ACIL ALLEN

By far the largest customer class is residential, which is projected to increase from 315,219 in 2017-18 to 367,272 in 2027-28. This is equivalent to an average annual growth rate of 1.5 per cent. Small business customers are projected to increase from 28,217 in 2017-18 to 31,412 in 2027-28, equivalent to an average growth rate of 1.1 per cent per annum over the forecast period. Large business LV customers are projected to increase at a rate of 1.1 per cent per annum, increasing from

<sup>1</sup> The most recent actual.

<sup>2</sup> Customer numbers are as at 30 June.

1,530 customers in 2017-18 to 1,702 customers in 2027-28. Large business HV and Large business ST customer numbers are projected to remain stable over the forecast period.

Figure ES 1 presents the data in the table graphically.

**FIGURE ES 1** HISTORICAL AND FORECAST CUSTOMER NUMBERS FOR THE JEN DISTRIBUTION NETWORK BY CUSTOMER CLASS



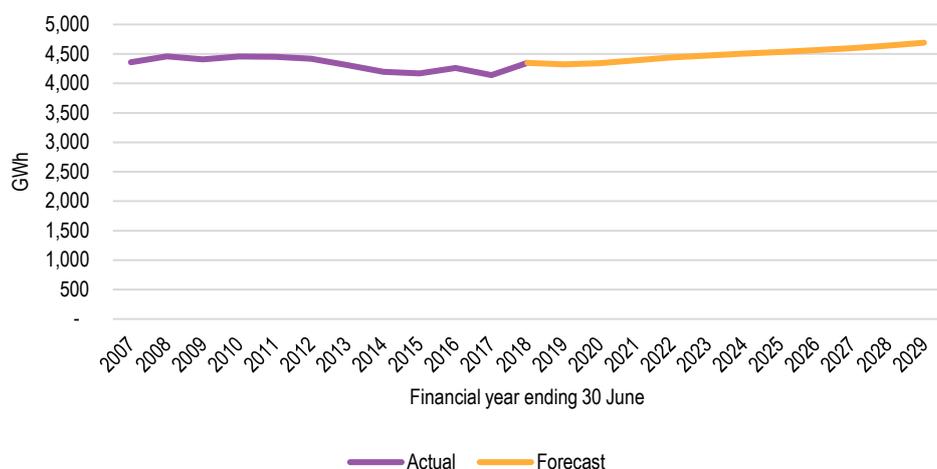
SOURCE: ACIL ALLEN

## Energy consumption

Figure ES 2 shows the historical and forecast total energy consumption in JEN's network from 2006-07 to 2028-29.

Energy consumption forecasts for JEN for both the entire network and by customer class are shown in Table ES 2.

Total energy consumption in JEN's network is expected to rise from 4,347 GWh in 2017-18 to 4,690 GWh in 2028-29. This represents growth at an annualised rate of 0.8 per cent per annum over the forecast period.

**FIGURE ES 2** HISTORICAL AND FORECAST TOTAL ENERGY CONSUMPTION FOR THE JEN DISTRIBUTION NETWORK, GWH

SOURCE: ACIL ALLEN

**TABLE ES 2** HISTORICAL AND FORECAST ENERGY CONSUMPTION FOR THE JEN DISTRIBUTION NETWORK BY CUSTOMER CLASS, GWH

Year	Residential	Small business	Large business- LV	Large business- HV	Large business-ST	System
2009	1,267	847	1,093	827	375	4,409
2010	1,318	838	1,134	792	374	4,455
2011	1,345	838	1,162	735	370	4,451
2012	1,321	777	1,227	728	364	4,417
2013	1,275	759	1,242	702	331	4,309
2014	1,228	710	1,265	682	309	4,195
2015	1,230	720	1,261	656	303	4,170
2016	1,277	730	1,286	643	327	4,262
2017	1,305	687	1,226	623	299	4,140
2018	1,335	732	1,310	637	332	4,347
2019	1,347	700	1,326	627	322	4,323
2020	1,343	702	1,349	627	322	4,343
2021	1,348	725	1,372	626	322	4,392
2022	1,354	745	1,394	626	322	4,440
2023	1,359	752	1,417	625	322	4,475
2024	1,367	750	1,439	625	322	4,503
2025	1,377	747	1,461	624	322	4,531
2026	1,390	743	1,483	624	322	4,562
2027	1,405	742	1,506	623	322	4,598
2028	1,424	742	1,529	623	322	4,639
2028	1,449	745	1,552	623	322	4,690

Year	Residential	Small business	Large business- LV	Large business- HV	Large business-ST	System
5 year CAGR %	0.30%	1.37%	1.65%	-0.07%	0.00%	0.82%
10 year CAGR %	0.73%	0.62%	1.58%	-0.07%	0.00%	0.82%

SOURCE: ACIL ALLEN

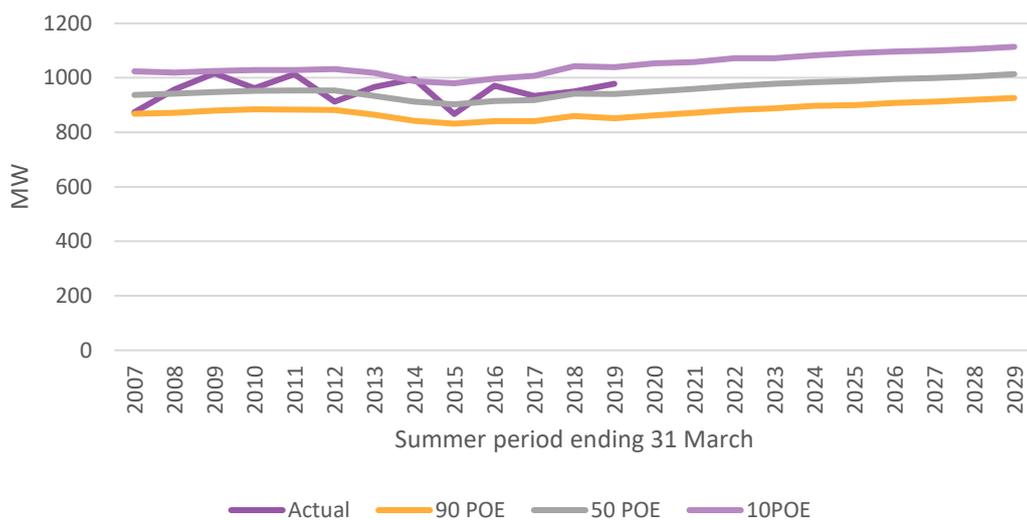
## System Maximum Demand

### Summer maximum demand

Figure ES 3 shows the summer maximum demand forecast for the JEN distribution network for the 10 POE, 50 POE and 90 POE levels. Table ES 3 presents the same information graphically.

Both the 10POE and 50 POE forecast summer maximum demand is expected to grow at 0.7% per annum over the period from 2018-19 to 2028-29. The 10 POE summer maximum demand is forecast to reach 1,114 MW in 2028-29, while the 50 POE summer maximum demand will reach 1,014 MW over the same period.

**FIGURE ES 3** SUMMER SYSTEM MAXIMUM DEMAND FORECAST, MW, 10POE, 50POE AND 90POE



SOURCE: ACIL ALLEN

**TABLE ES 3** SUMMER SYSTEM MAXIMUM DEMAND FORECAST, MW, 10POE, 50POE AND 90POE

Year	Actual	90 POE	50 POE	10 POE
2007	874	868	938	1024
2008	957	872	942	1019
2009	1017	880	948	1025
2010	962	884	953	1029
2011	1014	884	954	1028
2012	913	882	954	1032
2013	966	864	934	1018
2014	995	842	913	987
2015	867	832	903	980

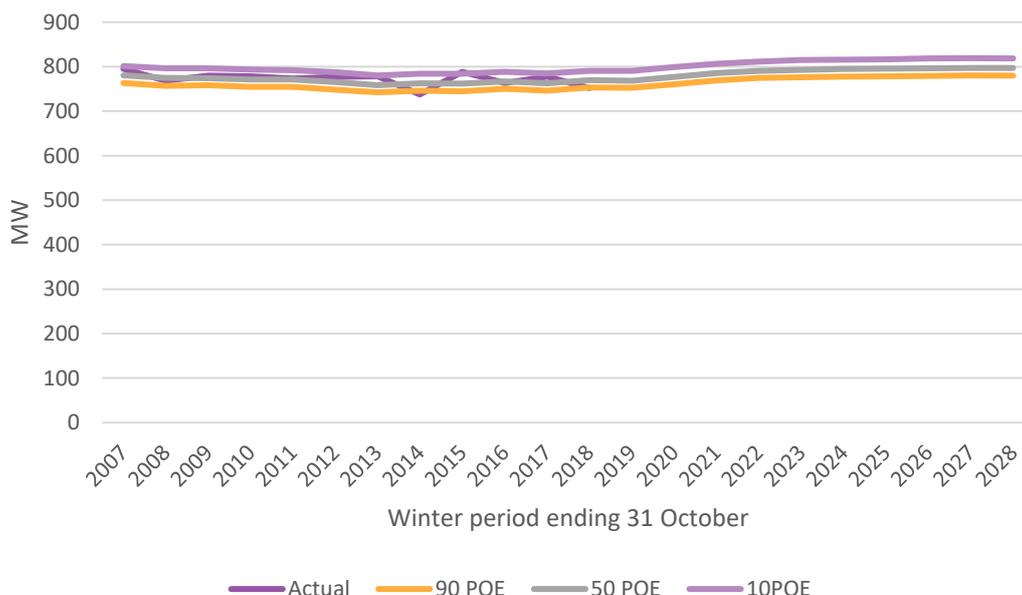
Year	Actual	90 POE	50 POE	10 POE
2016	971	841	915	997
2017	933	842	919	1007
2018	950	860	942	1043
2019	978	851	941	1039
2020		862	950	1053
2021		871	959	1058
2022		882	970	1072
2023		889	978	1072
2024		897	984	1082
2025		900	988	1090
2026		908	996	1096
2027		912	999	1100
2028		920	1006	1106
2029		926	1014	1114
<b>Average growth (5 years)</b>		<b>1.1%</b>	<b>0.9%</b>	<b>0.8%</b>
<b>Average growth (10 years)</b>		<b>0.8%</b>	<b>0.7%</b>	<b>0.7%</b>

SOURCE: ACIL ALLEN

**Winter maximum demand**

Figure ES 4 shows the winter maximum demand forecast for the JEN distribution network for the 10 POE, 50 POE and 90 POE levels. Table ES 3 presents the same information in table format.

**FIGURE ES 4** WINTER SYSTEM MAXIMUM DEMAND FORECAST, MW, 10POE, 50POE AND 90POE



SOURCE: ACIL ALLEN

Winter system maximum demand is forecast to grow at 0.3% per annum over the period from 2018 to 2028 for the 50 POE level of demand. The 10 POE winter maximum demand is forecast to reach 819 MW in 2028, while the 50 POE is forecast to reach 797 MW over the same period.

**TABLE ES 4** WINTER SYSTEM MAXIMUM DEMAND FORECAST, MW, 10POE, 50POE AND 90POE

Year	Actual	90 POE	50 POE	10 POE
2007	795	764	780	801
2008	768	757	774	796
2009	780	758	774	796
2010	778	755	771	794
2011	773	755	771	792
2012	777	748	765	787
2013	778	742	758	780
2014	738	746	762	784
2015	789	744	762	784
2016	764	750	767	789
2017	778	746	762	785
2018	752	753	769	791
2019		752	769	790
2020		761	777	799
2021		769	786	807
2022		775	790	811
2023		776	792	815
2024		778	794	816
2025		778	795	817
2026		779	796	818
2027		780	797	819
2028		780	797	819
<b>Average growth (5 years)</b>		<b>0.6%</b>	<b>0.6%</b>	<b>0.6%</b>
<b>Average growth (10 years)</b>		<b>0.4%</b>	<b>0.3%</b>	<b>0.4%</b>

SOURCE: ACIL ALLEN

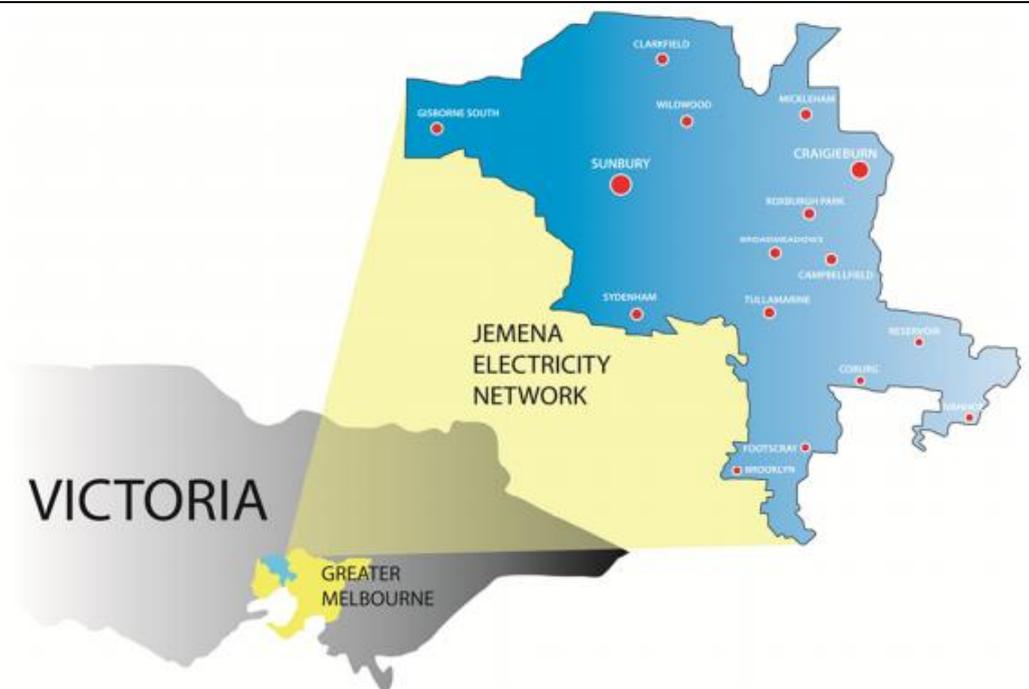
# 1

## INTRODUCTION

### 1.1 Background

Jemena Electricity Networks (JEN) is one of five electricity Distribution Network Service Providers (DNSP) in Victoria. It covers an area of 950 square kilometres and distributes electricity to over 340,000 households and businesses throughout the north-west of Melbourne (see Figure 1.1).

**FIGURE 1.1** JEN DISTRIBUTION REGION



SOURCE: [HTTPS://JEMENA.COM.AU/GETATTACHMENT/INDUSTRY/ELECTRICITY/NETWORK-PLANNING/2017-DISTRIBUTION-ANNUAL-PLANNING-REPORT.PDF.ASPX](https://jemena.com.au/getattachment/industry/electricity/network-planning/2017-distribution-annual-planning-report.pdf.aspx)

As with all electricity distributor network services providers (DNSPs) in the National Electricity Market, JEN is subject to economic regulation administered by the Australian Energy Regulator (AER) under the National Electricity Rules.

JEN is currently preparing its revised regulatory proposal for the electricity distribution price review (EDPR) covering the period from 1 July 2021 to 30 June 2026, which it will submit to the AER by 31 January 2021. As inputs to, and components of, that proposal JEN requires forecasts of:

- system maximum demand (MW)
- energy consumption and
- customer numbers.

ACIL Allen Consulting (ACIL Allen) has been commissioned by Jemena Electricity Networks (Vic) Ltd (JEN) to develop a set of independent forecasts of energy consumption, customer numbers and maximum demand for its electricity distribution network.

The forecasts presented in this report have been prepared as a standalone input to support JEN's regulatory proposal.

Between 2012 and 2014, the AER rolled out its Better Regulation package, aimed at promoting the long term interests of electricity consumers. As part of this package, the AER suggested a set of “best practice” principles, similar to those nominated by ACIL Allen in 2009, that should be adopted by electricity transmission and distribution businesses when forecasting electricity annual energy consumption and maximum demand.

In our work for AEMO, in 2013 and 2014, we used the AER's principles to establish a consistent methodology for developing electricity transmission connection point peak demand forecasts. These principles were tested with and accepted by all the distribution companies across the NEM.

The “best practice” principles nominate that the annual energy and maximum demand forecasts should:

- be accurate and unbiased
- be transparent and repeatable
- incorporate key drivers
- incorporate suitable methods of weather normalisation
- be subjected to statistical model validation and testing
- use the most recent input information available
- be reconciled between top down and bottom up
- be adjusted for block loads, major customers and rooftop solar PV penetration
- be subject to regular review.

In delivering this work, we have ensured that the annual energy and maximum demand forecasts for the JEN distribution network have been developed consistent with the principles outlined above.

## 1.2 Scope of work

The forecasts provided in this report cover the 10 year period from 2019 to 2028 and include:

- Customer numbers and annual electricity consumption forecasts from 2019 to 2028 for:
  - residential
  - small business
  - large business (Low Voltage)
  - large business (High Voltage)
  - large business (Sub Transmission)
- Network maximum demand covering:
  - Summer and Winter maximum demand forecasts (in kW) for the JEN area
  - The summer forecast period is defined from November 1 to March 31 and cover the horizon from 2019-20 to 2028-29.
  - The winter period is defined from April 1 to October 31 and cover the years from 2019 to 2028.
  - Maximum demand forecasts have been provided at the 10%, 50% and 90% probability of exceedance (POE) levels

The report and model provided provides details of the incremental impacts of each of the following:

- population and economic growth
- consumer response to price changes
- impacts of new technologies such as rooftop PV, battery storage and electric vehicles
- the impact of weather and weather warming trends, including the increasing frequency of extreme weather events
- the impact of emerging and existing market trends such as energy efficient lighting, energy efficient appliances and air conditioning systems
- the role of Government and other policy impacts such as energy efficiency and climate change policies where relevant.

### 1.3 Structure of this report

---

The subsequent sections address the inputs, methodology and forecasts in that order. Specifically:

- section 2 provides an overview of the history of the variables to be forecast, namely consumption and maximum demand
- section 3 provides an overview of the history and forecasts of the drivers of energy consumption and maximum demand
- section 4 describes the methodology by which the energy consumption forecasts were produced, the regression models that were used to produce the baseline and the post model adjustments that were applied to the baseline
- section 5 describes the methodology by which the maximum demand forecasts were produced, the regression models that were used to produce the baseline and any post model adjustments that were applied
- section 6 presents the energy consumption and customer numbers forecasts
- section 7 presents the summer and winter system maximum demand forecasts
- section 8 describes the methodology by which the rooftop PV and battery storage forecasts were produced
- section 9 describes the methodology by which the electric vehicle forecasts were produced



# HISTORICAL OVERVIEW - ENERGY CONSUMPTION AND MAXIMUM DEMAND

# 2

This chapter provides an overview of the history of consumption and customer numbers in JEN's region. JEN has five different customer classes. There is one customer class for residential customers and four for non-residential customers (small business, large business LV, large business HV and sub-transmission).

The data series presented in this section were used as the dependent variables in the regression models described in section 4 and section 5 of this report.

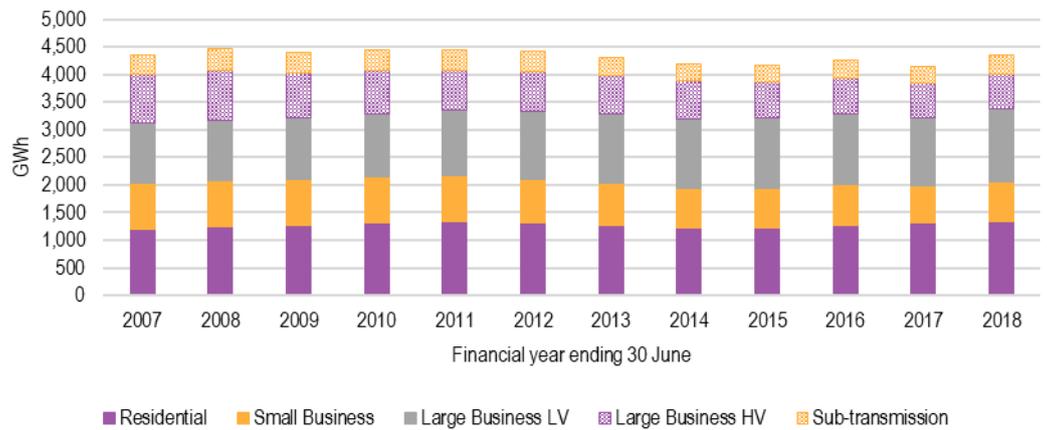
## 2.1 Energy consumption

Figure 2.1 shows the historical consumption in JEN's distribution region from 2006-07 to 2017-18 by customer class. Energy consumption has been relatively stable over this period, declining slightly from 4,357 GWh in 2006-07 to 4,347 GWh in 2017-18. Possible causes for this slow growth include:

- below average economic growth in the post GFC period between 2008-09 and 2013-14
- a significant increase in the real price of electricity from 2008 to 2013
- continued significant uptake of rooftop PV by households and more recently by businesses.

The largest customer class is residential consumption, accounting for 30.7 per cent of total consumption. This was closely followed by large business LV, comprising 30.1 per cent of total consumption. Additionally, small business made up 16.8 per cent of consumption while large business HV accounted for 14.7 per cent. Sub-transmission accounted for the remaining 7.6 per cent of total consumption.

**FIGURE 2.1** TOTAL CONSUMPTION BY TARIFF CLASS

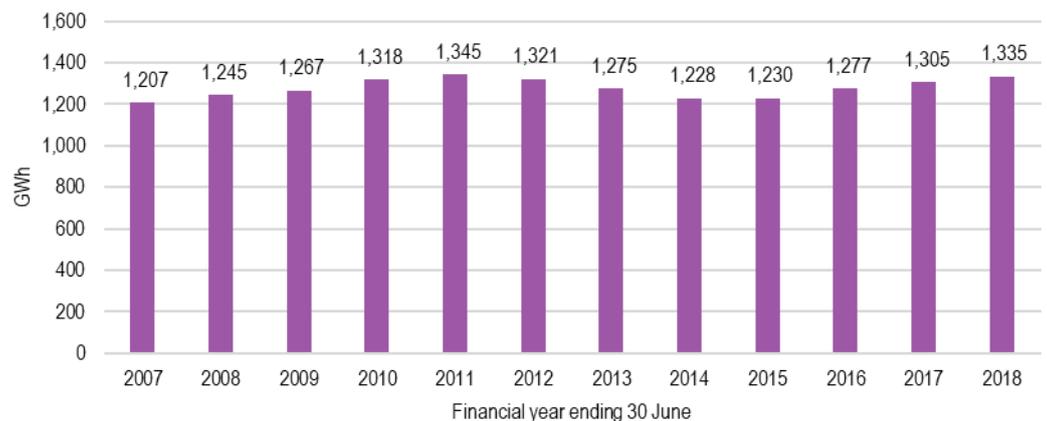


SOURCE: JEMENA ELECTRICITY NETWORKS LIMITED

### 2.1.1 Residential consumption

Figure 2.2 shows the historical residential consumption in JEN's distribution network. In 2006-07, residential consumption stood at 1,207 GWh, increasing to 1,335 GWh in 2017-18.

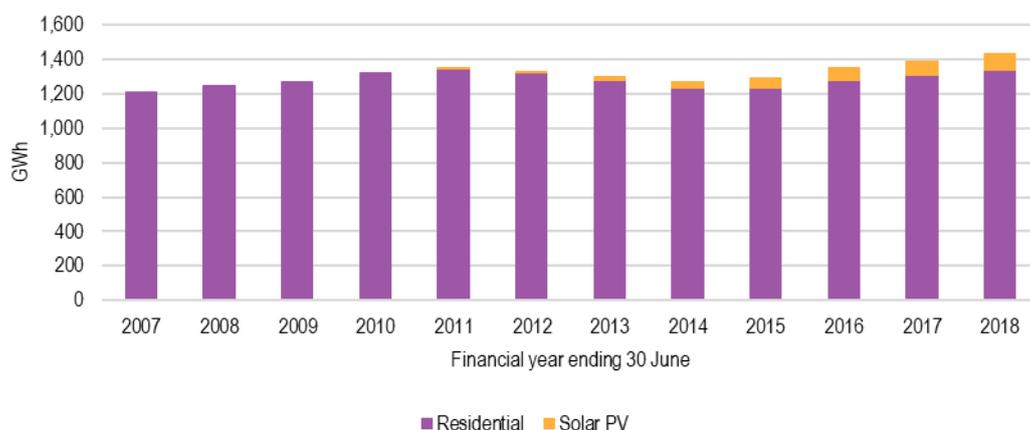
**FIGURE 2.2** TOTAL RESIDENTIAL CONSUMPTION



SOURCE: JEMENA ELECTRICITY NETWORKS LIMITED

For modelling purposes, residential consumption was altered to 'add back' the estimated quantity of consumption avoided through the use of rooftop PV systems. This energy represents energy that is consumed but not seen by the meters from which the historical data were collected. Energy consumed through rooftop PV is added back to the observed consumption from the meters to reveal latent consumption which was fed through the econometric models presented in section 4.

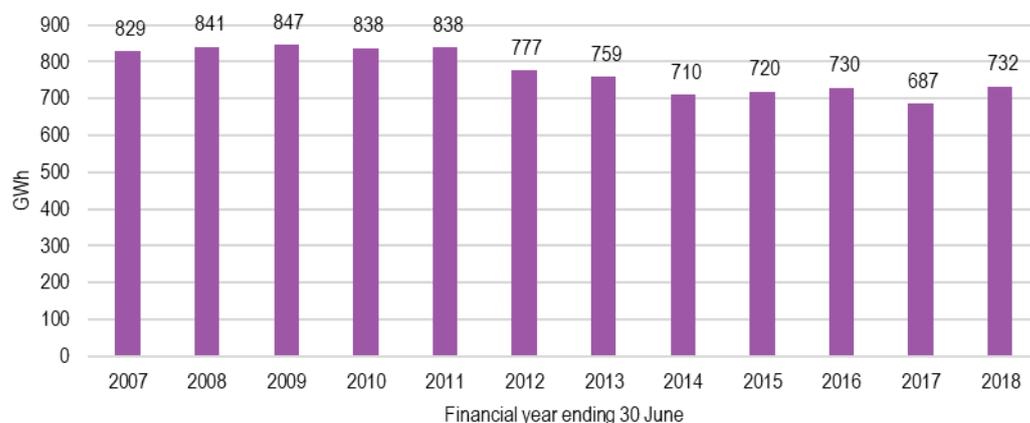
The result is shown in Figure 2.3.

**FIGURE 2.3** TOTAL RESIDENTIAL CONSUMPTION AND ROOFTOP PV GENERATION

SOURCE: JEMENA ELECTRICITY NETWORKS LIMITED

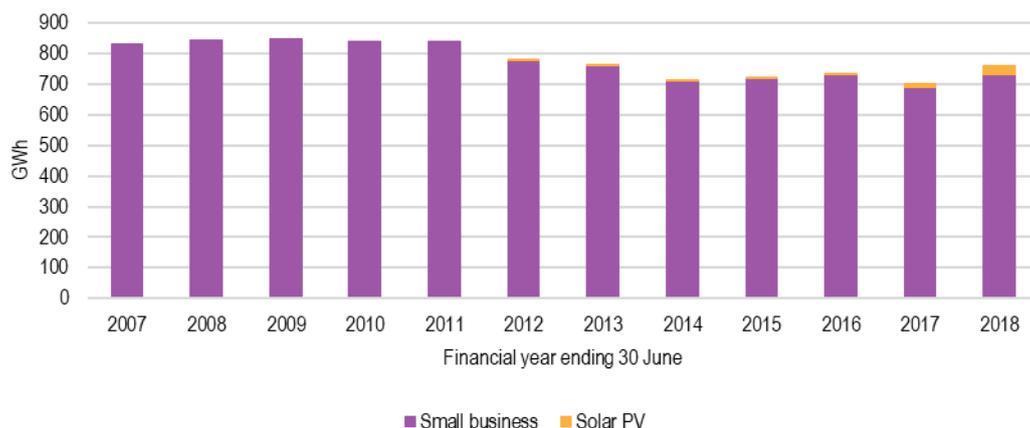
### 2.1.2 Small business consumption

Figure 2.4 shows the historical consumption for small business in JEN's region. Consumption was relatively flat from 829 GWh in 2006-07 to 838 GWh in 2010-11, before declining to 732 GWh in 2017-18. Likely reasons for the decline are the slowdown in the state economy and price increases for small business customers.

**FIGURE 2.4** SMALL BUSINESS CONSUMPTION

SOURCE: JEMENA ELECTRICITY NETWORKS LIMITED

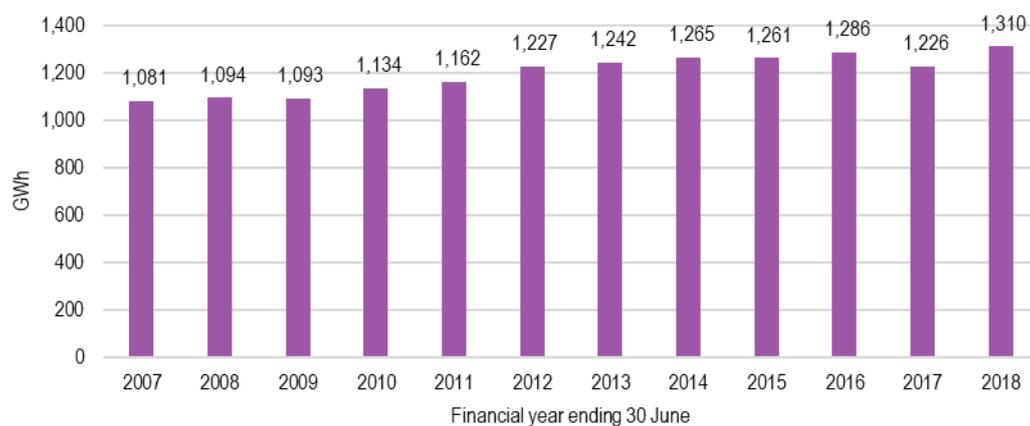
For modelling purposes, small business consumption was also altered to 'add back' the estimated quantity of consumption avoided through the use of rooftop PV systems. The approach to make this adjustment was the same as what was used to reveal latent residential consumption described in section 2.1.1, but altered to reveal latent small business consumption. The result is shown in Figure 2.5.

**FIGURE 2.5** TOTAL SMALL BUSINESS CONSUMPTION AND ROOFTOP PV GENERATION

SOURCE: JEMENA ELECTRICITY NETWORKS LIMITED

### 2.1.3 Large business LV consumption

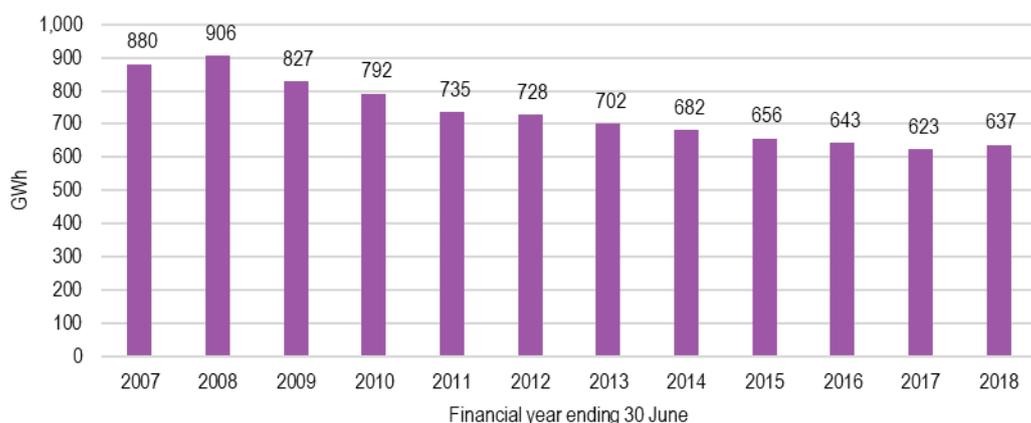
Figure 2.6 shows the historical consumption for large business LV. Consumption has been on an upward trajectory from 1,081 GWh in 2006-07 until 1,265 GWh in 2013-14. Since then, consumption has stabilised, standing at 1,310 GWh in 2017-18.

**FIGURE 2.6** LARGE BUSINESS LV CONSUMPTION

SOURCE: JEMENA ELECTRICITY NETWORKS LIMITED

### 2.1.4 Large business HV consumption

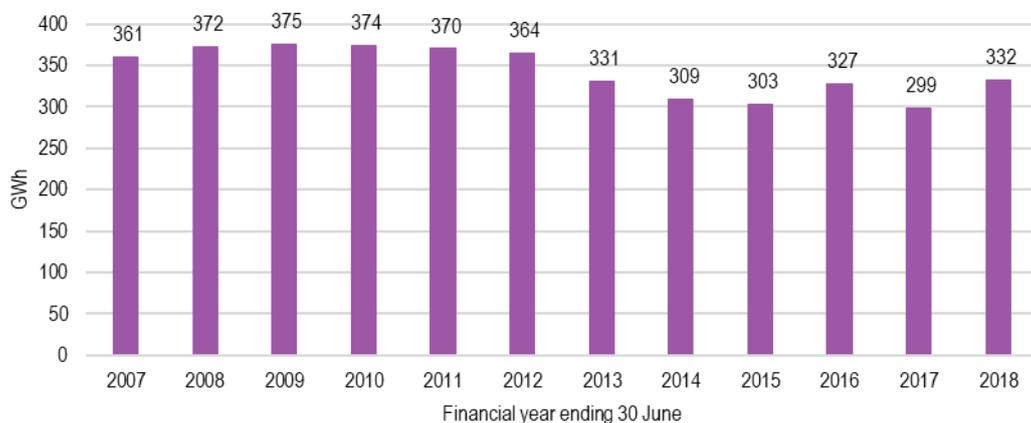
Figure 2.7 shows the historical consumption for large business HV customers. Consumption has been steadily declining from 906 GWh in 2007-08 to 623 GWh in 2016-17. In 2017-18, consumption stood at 637 GWh.

**FIGURE 2.7** LARGE BUSINESS HV CONSUMPTION

SOURCE: JEMENA ELECTRICITY NETWORKS LIMITED

### 2.1.5 Sub-transmission consumption

Figure 2.8 shows the historical consumption for sub-transmission customers in JEN's region. Consumption in this category is driven by a very small number of customers, so large discrete shifts in total consumption will occur when a new customer connects to or disconnects from the network. In 2017-18, sub-transmission customers used a total of 332 GWh of electricity.

**FIGURE 2.8** SUB-TRANSMISSION CONSUMPTION

SOURCE: JEMENA ELECTRICITY NETWORKS LIMITED

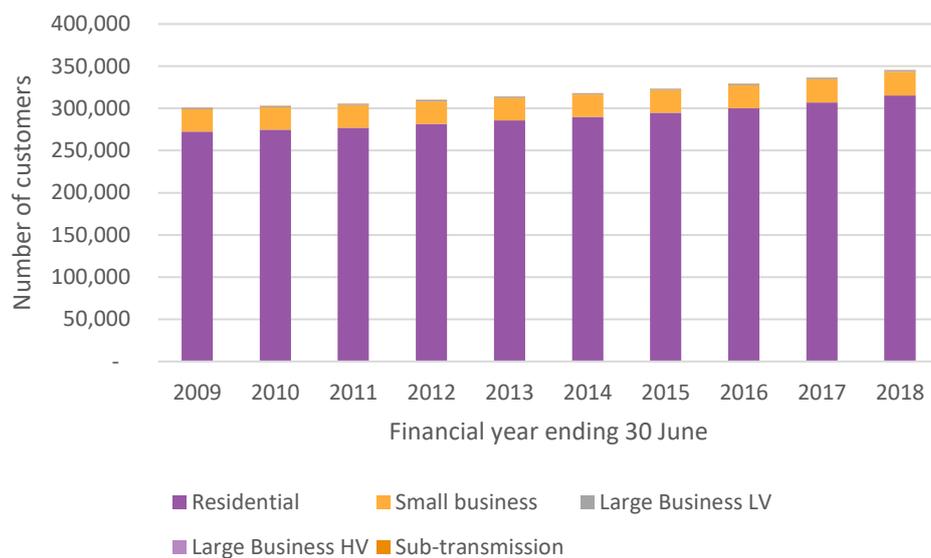
## 2.2 Customer numbers

Figure 2.9 shows the number of customers supplied by the JEN distribution network. There has been a steady increase in customer numbers over time. This is reflective of the number of household services by the network increasing, as well as the number of businesses serving these households. Since 2006-07, customer numbers have grown at a rate of 1.4 per cent per annum.

As at 2017-18, the JEN network contained 345,028<sup>3</sup> customers, comprised of:

- 315,219 residential customers
- 28,217 small business customers
- 1,530 large business LV customers
- 86 large business HV customers
- 4 sub-transmission customers.

**FIGURE 2.9** TOTAL CUSTOMER NUMBERS BY TARIFF CLASS



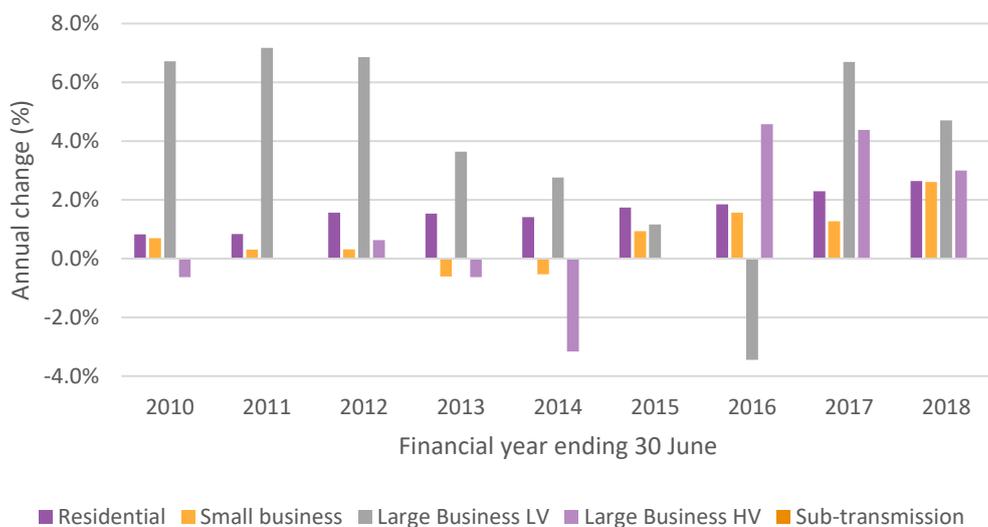
SOURCE: JEMENA ELECTRICITY NETWORKS LIMITED

Figure 2.10 shows the year on year changes in customer numbers by tariff class from 2008-09 until 2017-18. The average annual change over this period has been:

- 1.6 per cent for residential customers
- 0.7 per cent for small business customers
- 4.2 per cent for large business LV customers
- 0.9 per cent for large business HV customers
- 0.0 per cent for sub-transmission customers.

<sup>3</sup> Customer numbers are as at 30 June.

**FIGURE 2.10 ANNUAL CHANGE IN CUSTOMER NUMBERS BY TARIFF CLASS**



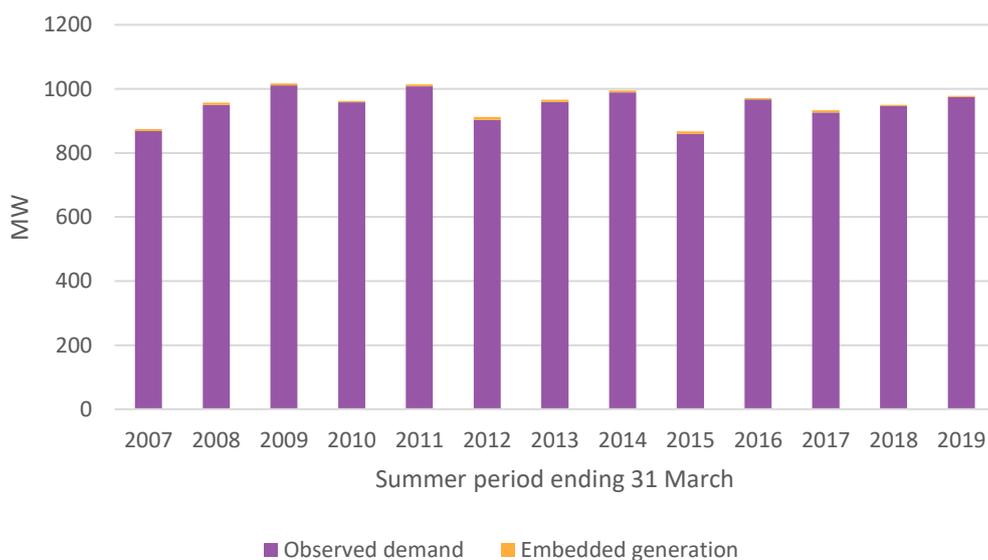
SOURCE: ACIL ALLEN

### 2.3 System maximum demand

This section provides an overview of historical maximum demand in JEN’s region. These data are the basis of the regression models in section 5.

Figure 2.11 and Figure 2.12 show the maximum demand at the system level for summer (from 2006-07 to 2018-19) and winter (from 2007 to 2018) respectively. Embedded generation makes a relatively small contribution to observed demand, contributing a maximum of 3.7 MW in 2018-19 for summer and 2.9 MW in the 2018 winter.

**FIGURE 2.11 SUMMER SYSTEM MAXIMUM DEMAND BY COMPONENT, 2006-07 TO 2017-18**



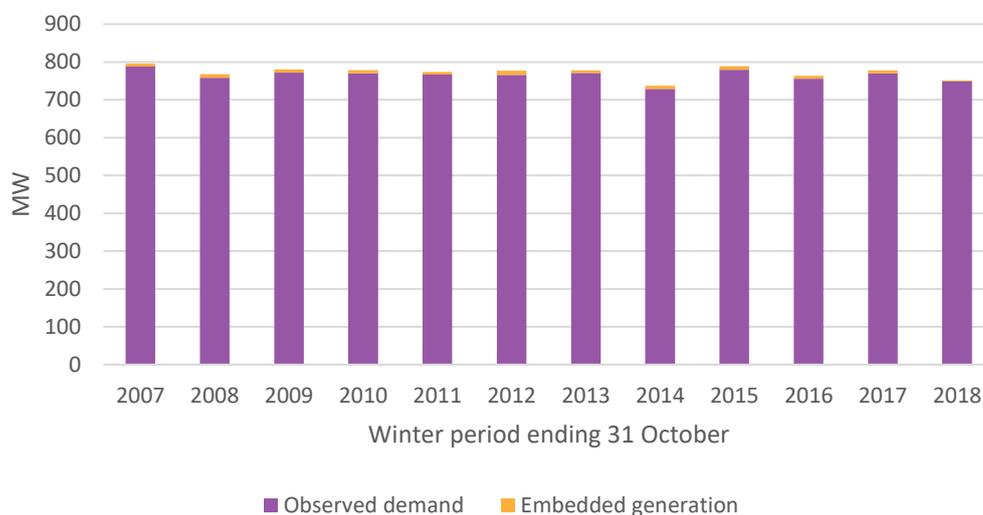
Note: Rooftop PV generation also contributes to latent demand, but is considered as an input variable in the maximum demand model rather than part of the dependent variable.

SOURCE: ACIL ALLEN ANALYSIS OF JEN DATA

Summer system maximum demand displays an upward trend up to the commencement of the global financial crisis (GFC) in 2008-09, after which it has been relatively stable. In 2018-19, summer system maximum demand was 978 MW, increasing from 950 MW in 2017-18.

In the case of winter, system maximum demand has remained relatively steady over the historical period. In 2018, observed winter system maximum demand was 752 MW, decreasing from 778 MW in the previous year.

**FIGURE 2.12** WINTER SYSTEM MAXIMUM DEMAND BY COMPONENT, 2007 TO 2018



SOURCE: ACIL ALLEN ANALYSIS OF JEN DATA

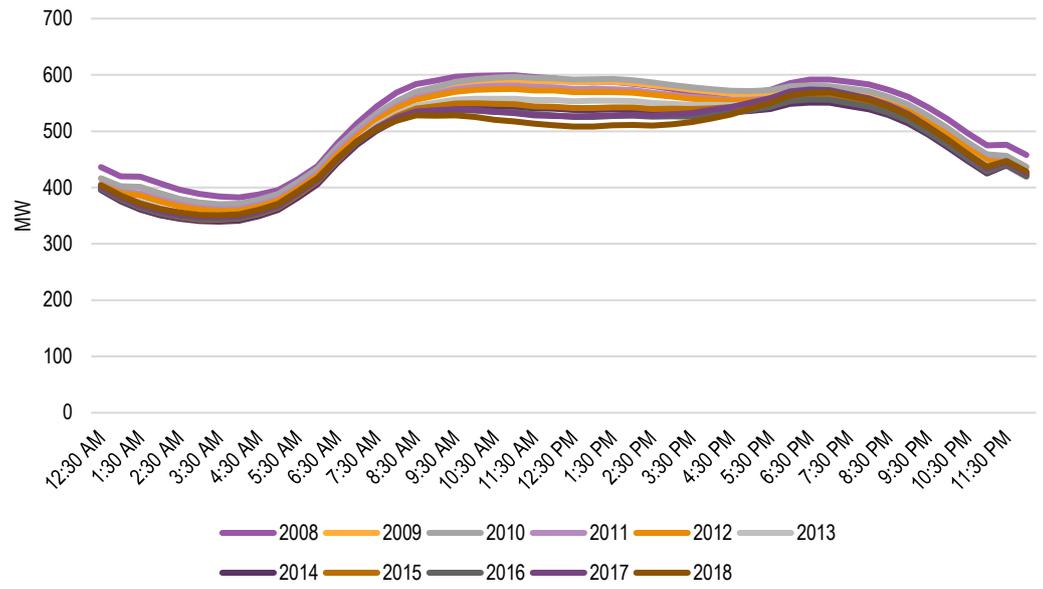
It is important to note that the maximum demand levels shown in the previous two figures are the actual observed peaks and are not temperature corrected. Appropriate methods of weather normalisation are applied as part of the modelling process and are described in more detail in section 5.

## 2.4 System minimum demand

There is some concern that the rapid uptake of rooftop PV within the JEN network is leading to a shift in the shape of the load curve across the system, such that demand between midday and 1 pm (the time of maximum solar generation) is declining sufficiently quickly to fall below the traditional time of the system minimum which occurs at around 3:30 am.

Figure 2.13 shows how the load profile in the JEN network has changed over the last 11 years. The figure shows that the level of demand at around midday has been declining over the last decade in response to more rooftop PV systems. Despite this decline over time, average demand at midday remains significantly higher in the middle of the day compared to the traditional system minimum at 3:30 am. Given this, it is unlikely that system minimum demand will consistently shift from the early morning hours to the middle of the day in the foreseeable future, even if there is significantly more uptake of rooftop PV.

**FIGURE 2.13** AVERAGE LOAD PROFILE IN JEN NETWORK OVER TIME, 2008 TO 2018



SOURCE: ACIL ALLEN ANALYSIS OF JEN DATA



# 3

## MAIN DRIVERS OF ENERGY CONSUMPTION AND MAXIMUM DEMAND

This chapter provides an overview of the history of the likely drivers of consumption in JEN's region. The drivers discussed are:

- economic activity in section 3.1
- customer numbers in section 3.2
- weather in section 3.3
- electricity prices in section 3.4
- rooftop PV and battery storage in section 3.5
- electric vehicles in section 3.6

### 3.1 Economic activity

Growth in economic activity is a major driver of rising incomes. Consumption of electricity is, in part, driven by higher disposable incomes and subsequent demand for new electronic appliances and equipment, as well as increasing commercial and industrial activity. There is typically a strong relationship between economic activity and electricity consumption given that electricity is an important input into many households and industries.

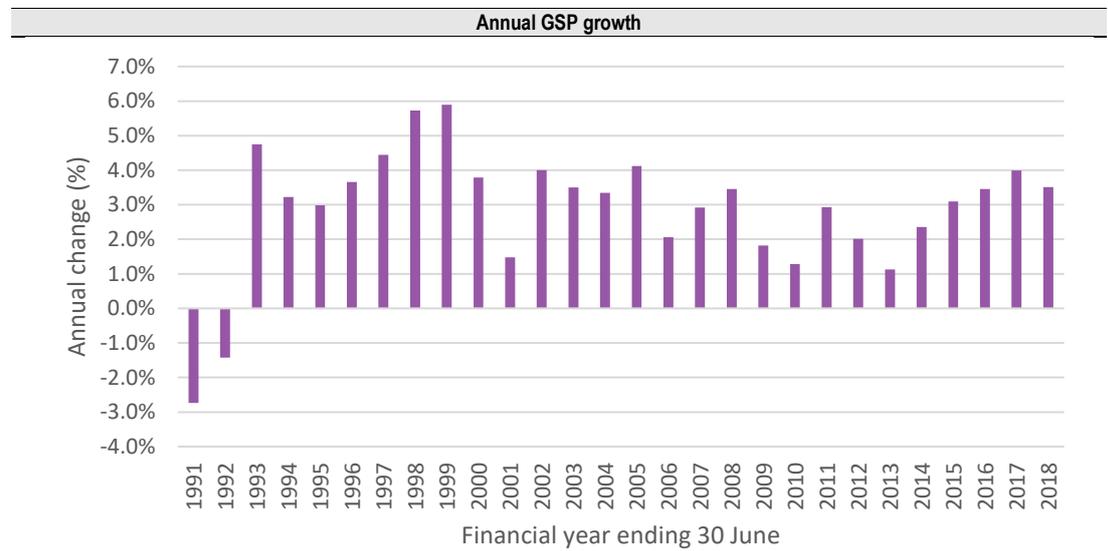
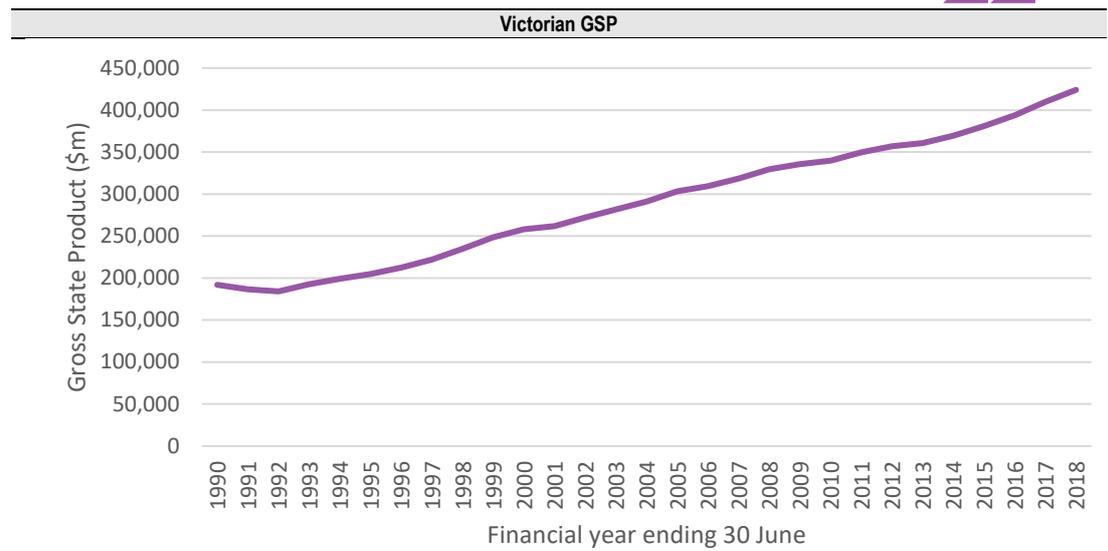
#### 3.1.1 Historical pattern in economic activity

The first pane of Figure 3.1 presents the historical times series of Victorian economic activity from 1989-90 to 2017-18. The first pane presents the value of economic activity, as measured using Gross State Product (GSP) for Victoria.

The second pane of Figure 3.1 presents the annual change in GSP. Victorian economic growth has been positive in all but two years since 1989-90. In 1990-91, Victorian GSP declined by 2.7 per cent. This was followed by a further decline of 1.4 per cent in 1991-92.

Victorian GSP growth slowed in the five-year period following 2008-09. Over this period it averaged just 1.8 per cent per annum. This is compared to a long-term annual average of 2.9 per cent per annum from 1990-91 to 2017-18. Victorian GSP growth has exceeded the long-term average over the last three years, growing at 3.5 per cent in 2015-16, 4.0 per cent in 2016-17 and 3.5 per cent in 2017-18. This recent uptick in economic growth has helped underpin the resumption of growth in energy consumption and maximum demand within the JEN distribution network.

**FIGURE 3.1** VICTORIAN GROSS STATE PRODUCT (GSP)



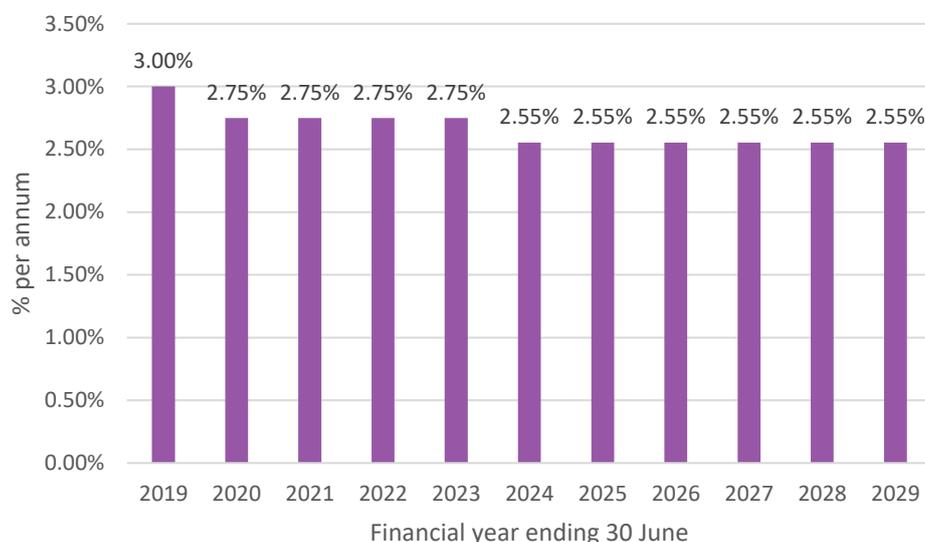
Note: GSP figures are measured as chain volumes measures.

SOURCE: ABS 5220.0 AUSTRALIAN NATIONAL ACCOUNTS: STATE ACCOUNTS, 2017-18

### 3.1.2 Economic growth projections

Figure 3.2 presents the projected economic growth rate for Victoria.

**FIGURE 3.2** VICTORIAN ECONOMIC GROWTH PROJECTIONS



SOURCE: VICTORIAN BUDGET PAPER 2: STRATEGY AND OUTLOOK AND ACIL ALLEN CONSULTING

From 2018-19 to 2022-23, the forecast rate of GSP growth was obtained from the 2019-20 Victorian Government budget. The Victorian budget projects a 3 per cent rate of growth in 2018-19, before moderating to 2.75 per cent for the following four years.

Beyond 2022-23, ACIL Allen has assumed that GSP will continue grow at 2.55 per cent per annum. This corresponds to the average ten-year annual growth rate since 2007-08.

## 3.2 Population growth and customer numbers

Growth in customer numbers is a key driver of electricity consumption. Increasing residential customer numbers are driven by household formation arising from population growth.

The breakdown of the number of residential customers by local government area (LGA) is summarised in Table 3.1. As of June 2018, JEN has a total of 345,056 customers, of which 315,219 are residential. This means that approximately 91 per cent of JEN's customers are residential customers.

**TABLE 3.1** JEN CUSTOMER NUMBERS BREAKDOWN BY LOCAL GOVERNMENT AREA, JUNE 2018

Local government area	Customers	Proportion of total customers
Banyule	32,557	9.4%
Brimbank	10,152	2.9%
Darebin	47,031	13.6%
Hobsons Bay	16,664	4.8%
Hume	77,975	22.6%
Macedon Ranges	870	0.3%
Maribynong	37,876	11.0%
Melbourne	4,320	1.3%
Melton	8,777	2.5%
Mitchell	6	0.0%
Moonee Valley	56,732	16.4%
Moreland	50,698	14.7%
Whittlesea	88	0.0%
Yarra	1,311	0.4%
<b>Total customers</b>	<b>345,056</b>	
<b>Total residential customers</b>	<b>315,219</b>	
<b>Residential customer share</b>	<b>91%</b>	

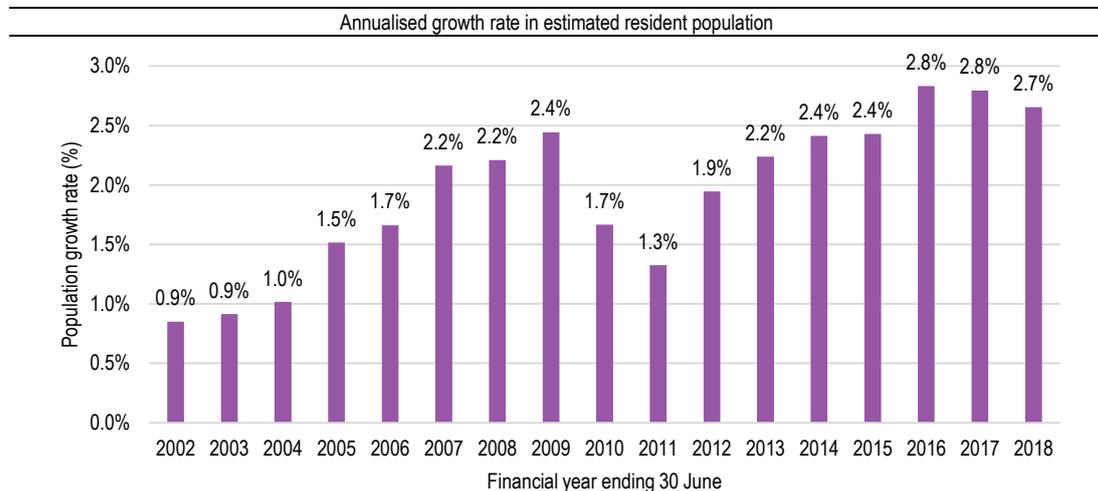
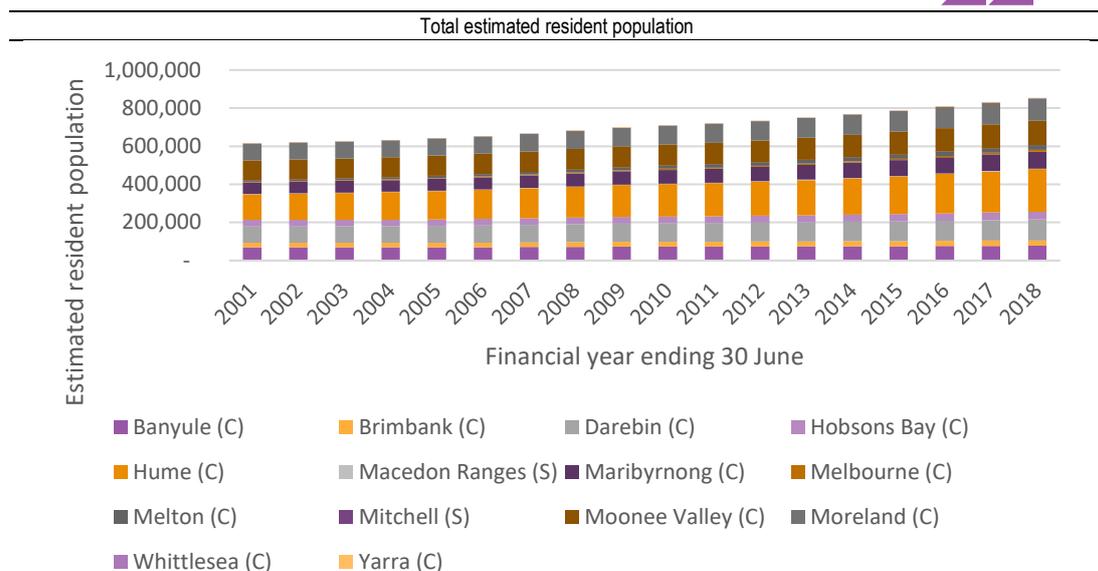
SOURCE: JEMENA

### 3.2.1 Historical pattern in population growth

The first pane of Figure 3.3 shows the historical estimated resident population in the JEN region. In 2007-08, the population in JEN's region was estimated to be 682.5 thousand. This has increased at an average rate of 2.3 per cent per annum to 854.5 thousand in 2017-18.

However, as the second pane of Figure 3.3 shows, the historical growth rate per annum varies across LGAs. Banyule had the lowest growth rate at 0.77 per cent per annum. Meanwhile, Melbourne had the highest growth rate of 6.57 per cent over the same time period. The population growth rate in Hume, Melton, Mitchell and Whittlesea were all strong compared to more established areas such as Moreland and Yarra.

**FIGURE 3.3** TOTAL ESTIMATED RESIDENT POPULATION IN JEN REGION



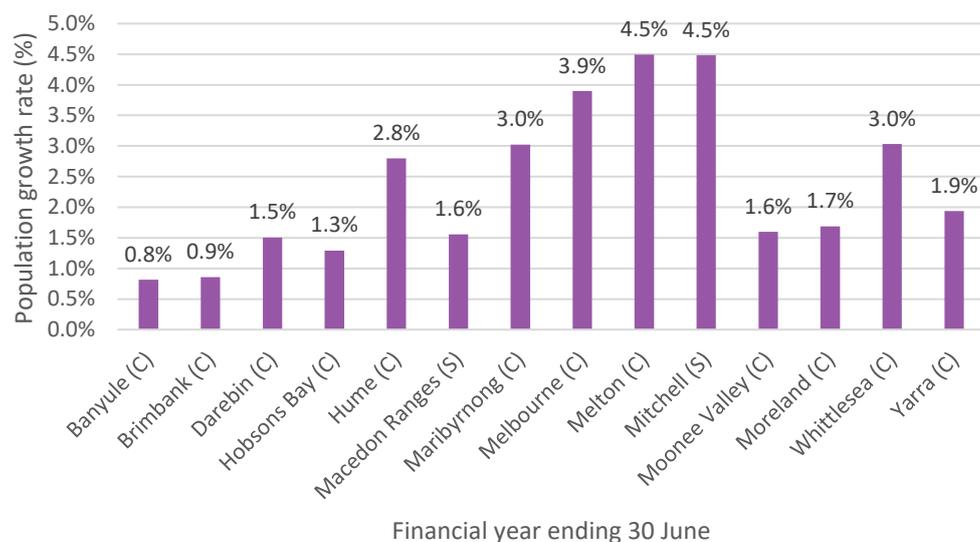
SOURCE: ACIL ALLEN AND ABS 3218.0

### 3.2.2 Population projections

Projections for population have been obtained from the Victoria in Future 2019 (ViF) publication produced by the Department of Environment, Land, Water and Planning.

The ViF produces annual projections of estimated resident population from 2014-15 to 2030-31 by LGA. As shown in Figure 3.3, the growth rate in the estimated resident population varies considerably across LGAs.

Figure 3.4 summarises the projected population growth rates provided by the ViF from 2017-18 to 2028-29. The projections vary by LGA, reflecting how the estimated resident population has grown at different rates historically. Population growth is expected to remain strong in Mitchell, Melton, Melbourne and Maribyrnong relative to Moonee Valley and Moreland.

**FIGURE 3.4** PROJECTED POPULATION GROWTH RATE FROM 2017-18 TO 2028-29

SOURCE: VICTORIA IN FUTURE 2019

If the growth rates considered above were assumed to have equal influence over population growth in JEN's region, then the forecast could be expected to be pushed up by significant growth in Melton and Mitchell. However, as can be seen in Table 3.1, some LGAs contribute to growth in customer numbers more than others. For example, only 2.5 per cent of JEN's customers are located in Melton, so growth there is likely to be less important for JEN than Hume, which is the area with the highest number of JEN customers.

Therefore, an appropriate weighting needs to be considered within each LGA in JEN's region to determine population projections for JEN. The process to generate the appropriate weighting is summarised in Table 3.2 and is as follows:

- use the 91 per cent split of residential customers to total customers in Table 3.1 to derive the total number of residential customers by LGA
- derive an estimate of household size from the population and number of dwellings as measured on Census night from the ABS 2016 Census to calculate average household size by LGA
- multiply the number of residential customers by household size to derive JEN's total population by LGA
- generate weights by LGA using JEN's calculated total population divided by the total estimated resident population for that LGA

The result is a time series of population projections for the JEN region.

**TABLE 3.2** DERIVING POPULATION WEIGHTS BY LGA IN JEN'S REGION

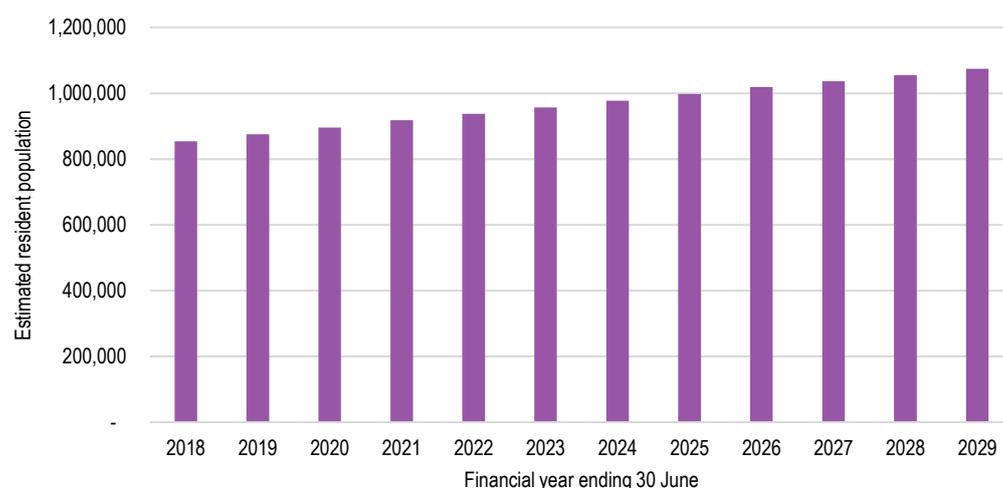
Local government area	Total customers	Residential customers	Household size	Weights
BANYULE	32,557	29,742	2.63	60%
BRIMBANK	10,152	9,274	3.06	13%
DAREBIN	47,031	42,964	2.58	68%
HOBSONS BAY	16,664	15,223	2.63	41%
HUME	77,975	71,232	3.19	100%
MACEDON RANGES	870	795	2.78	4%
MARIBYRNONG	37,876	34,600	2.60	98%
MELBOURNE	4,320	3,947	2.29	5%
MELTON	8,777	8,019	3.16	16%
MITCHELL	6	5	2.85	0%
MOONEE VALLEY	56,732	51,826	2.58	100%
MORELAND	50,698	46,314	2.56	65%
WHITTLESEA	88	81	3.01	0%
YARRA	1,311	1,198	2.27	3%
<b>TOTAL</b>	<b>345,056</b>	<b>315,219</b>		

SOURCE: ACIL ALLEN

The final time series of population projections were used as an input into estimating residential customer number forecasts.

Figure 3.5 below shows the total projected population within the JEN region from 2017-18 to 2028-29.

From 2017-18 to 2028-29, the population living within the JEN region is projected to increase from 854.5 thousand to 1,074.2 thousand. This is equivalent to an average growth rate of 2.1 per cent per annum over the period.

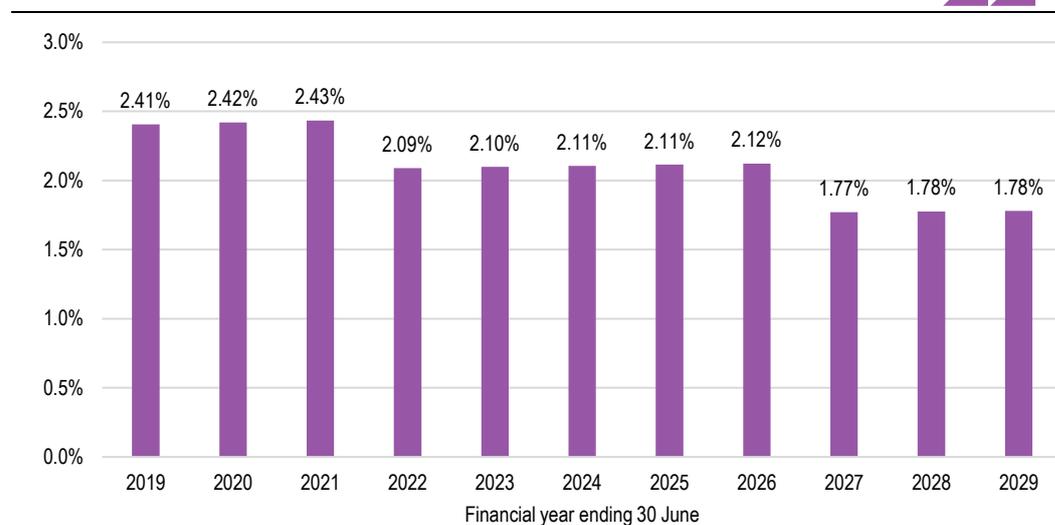
**FIGURE 3.5** PROJECTED POPULATION OF JEN REGION, 2017-18 TO 2028-29

SOURCE: ACIL ALLEN CONSULTING

Figure 3.6 presents the projected annual population growth rate within the JEN region over the forecast horizon. While the average annual growth rate over the whole period is 2.1 per cent, it is

considerably higher in the first three years of the forecast period, reflecting a continuation of the very strong population influx into Victoria that has taken place in recent years.

**FIGURE 3.6** PROJECTED ANNUAL POPULATION GROWTH RATES OF JEN DISTRIBUTION REGION, 2017-18 TO 2028-29



SOURCE: ACIL ALLEN CONSULTING

## 3.3 Weather

### 3.3.1 Weather impact on energy consumption

Weather is a key driver of electricity consumption. Consumption will vary with regards to the 'heating requirement' and 'cooling requirement' of its customers. In summer, the hotter the season, the greater the cooling requirement and the greater the consumption. Similarly, in winter, the cooler the season, the greater the heating requirement and the greater the electricity consumption.

It is necessary to 'remove' the effect of weather variations from historical consumption data. This requires a measure of the heating and cooling requirements in the same historical period as the historical consumption data.

Two measures of the heating requirement are currently in use in Australia, namely heating degree days (HDD) and effective degree days (EDD). These two approaches are similar, differing in the input data they use. EDD is a richer measure that accounts for factors not included in HDD.

#### Calculating HDD and CDD

The number of HDD in a given month is calculated as the sum of the difference between a threshold temperature and the average temperature on each day, given that the maximum is below the threshold. In this analysis, we define the threshold temperature at 18 degrees Celsius. Any given day makes a contribution to the total number of HDD only if the average temperature on that day is below 18 degrees.

For example, if the average temperature today is 10 degrees Celsius, then the number of HDD contributed to the monthly total from that day is 8. If the average temperature exceeds 18 on a given day, then that day contributes zero to the total number of HDDs for the month. The higher the number of HDDs in a month, the colder the month.

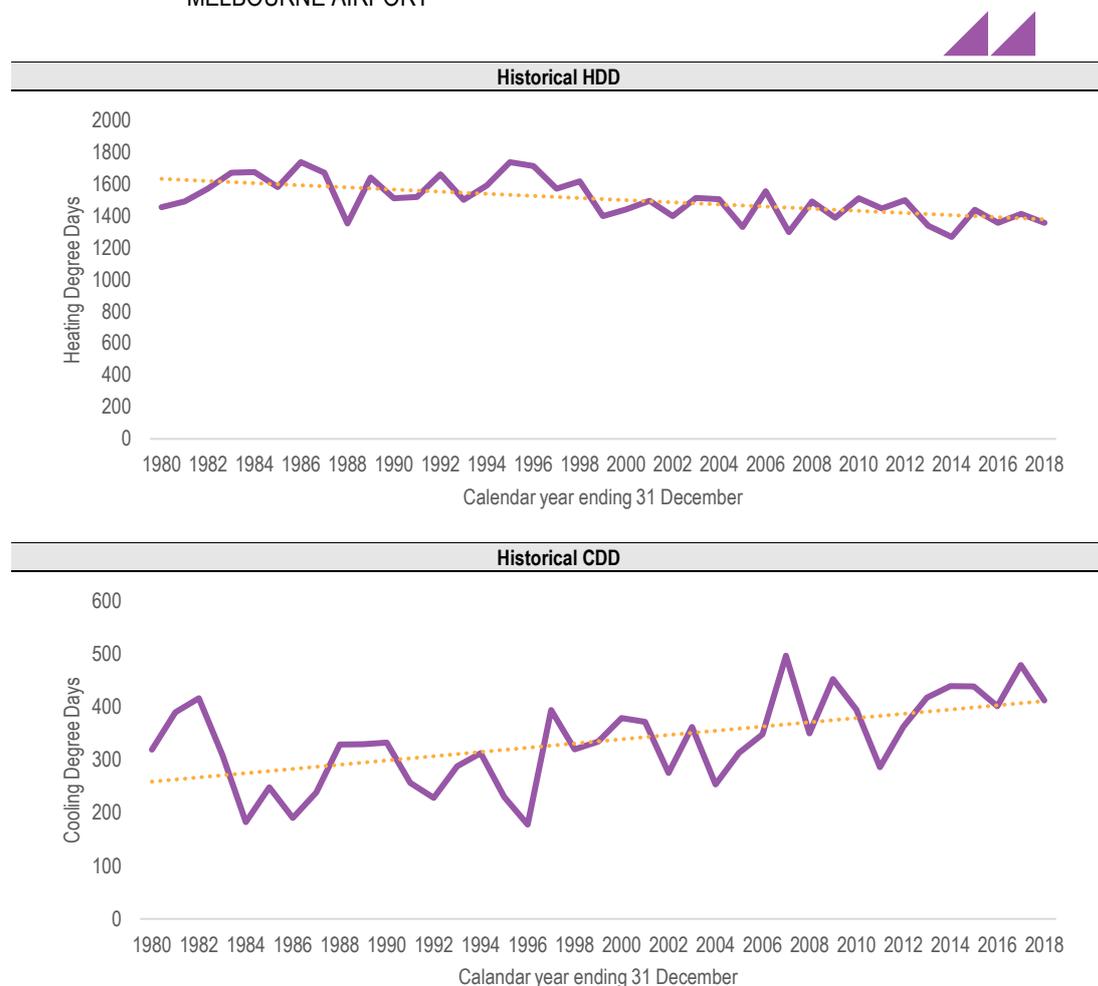
The concept is similar for CDD, but the formula takes the sum of degrees that exceed the threshold temperature of 18 degrees Celsius for each day. CDD is therefore an indication of how hot a given month is, with a higher number of CDDs reflecting a hotter month.

## Historical pattern in weather

The first pane of Figure 3.7 shows the annual number of HDDs from 1980 to 2018 as measured at the Melbourne Airport weather station. There is a slight downward trend over this period, indicating milder winters in more recent years.

The second pane of Figure 3.7 shows the annual number of CDDs for the same time period and weather station. There is a slight upward trend over this period that reflects hotter summer conditions in recent years.

**FIGURE 3.7** HISTORICAL HEATING DEGREE DAYS (HDD) AND COOLING DEGREE DAYS (CDD) AT MELBOURNE AIRPORT



SOURCE: BUREAU OF METEOROLOGY

## Weather projections

HDD and CDD are projected on a monthly basis to capture the seasonal variability in weather within each year. They have both been projected using the same approach.

A regression was fitted to the historical monthly time series of HDD (CDD) going back to January 1980. The regression line represents the underlying trend in HDD (CDD) which is then extrapolated to produce baseline projections of HDD (CDD).

Seasonal variability is introduced to the baseline projections by comparing the actual HDD (CDD) with the baseline for the three most recent financial years. The average difference between the actual and baseline level of HDD (CDD) was calculated for each month and then aggregated by month. The average monthly differences were then applied to the corresponding months in the baseline projections.

### 3.3.2 Weather impact on maximum demand

The weather is a key driver of maximum demand in both summer and winter.

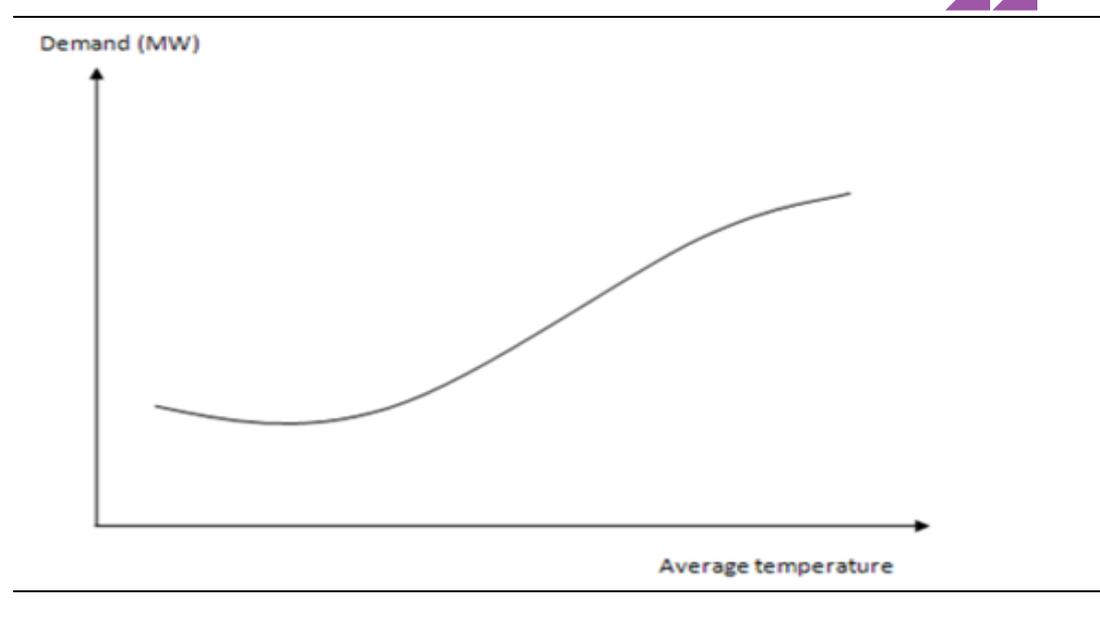
In winter, demand that varies with weather conditions is driven primarily by the 'heating requirement'. Generally, cooler seasons would be associated with a greater heating requirement, and therefore a greater maximum demand. In summer this pattern is reversed, with cooling becoming the driver of weather-related demand.

Establishing a relationship between peak load and weather will also enable weather normalisation to be applied and comparisons of peaks on a weather adjusted basis to be made.

The most important weather variable for the modelling of peak demand is temperature.

The relationship between temperature and daily maximum demand is non-linear. This is because there is a range of temperatures where demand becomes unresponsive to changes in temperature. In the summer season models, this range will appear at the lower end of the temperature range, on milder days (see Figure 3.8).

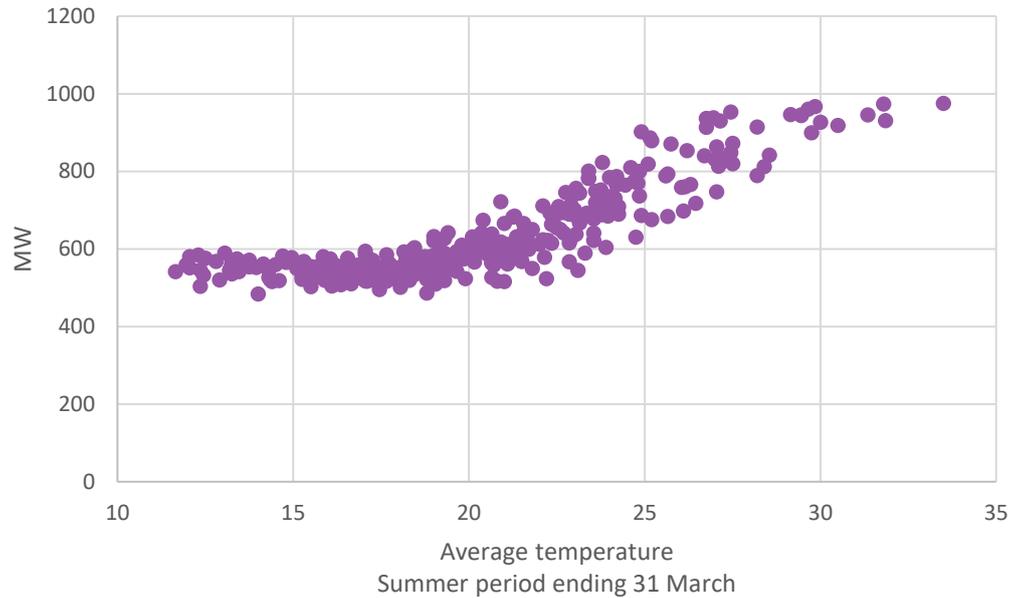
**FIGURE 3.8** STYLISED RELATIONSHIP BETWEEN SUMMER DAILY PEAK DEMAND AND AVERAGE DAILY TEMPERATURE



There is also a point on the extreme right of the curve where demand becomes saturated at extremely hot temperatures. At this point, demand becomes unresponsive once again to changes in temperature. This saturation point is rarely observed in practice and corresponds to levels of demand that are well above the 10 POE level.

Figure 3.9 below shows the relationship between daily maximum demand and daily average temperature for the last three summer seasons.

**FIGURE 3.9** MAXIMUM DEMAND VERSUS AVERAGE TEMPERATURE- WORKING DAYS, SUMMER, 2015-16 TO 2018-19



Note: Average daily temperature calculated as the average of maximum and minimum temperature from the Melbourne Airport weather station  
 SOURCE: ACIL ALLEN CONSULTING

In the case of winter, the unresponsive part of the curve lies at the upper end of the temperature range, again on milder days (see Figure 3.10).

**FIGURE 3.10** STYLISED RELATIONSHIP BETWEEN WINTER DAILY MAXIMUM DEMAND AND AVERAGE DAILY TEMPERATURE

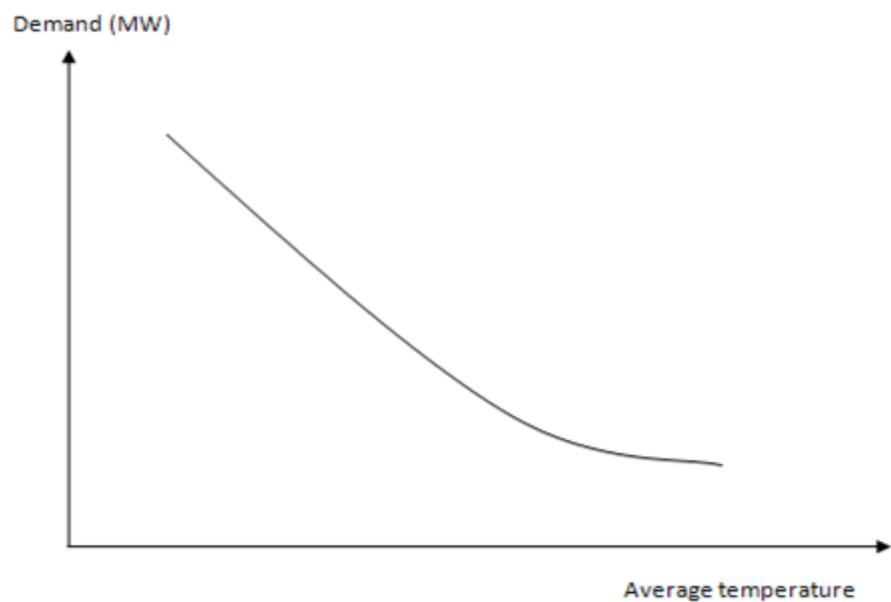
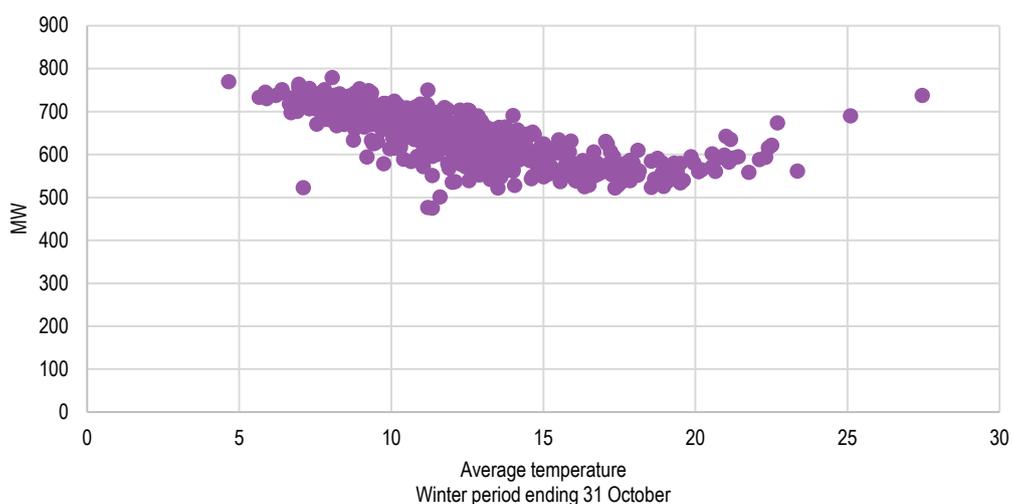


Figure 3.11 below shows the actual relationship between daily winter maximum demand and average temperature for the last three winter seasons. The stylised pattern described above is evident.

**FIGURE 3.11** MAXIMUM DEMAND VERSUS AVERAGE TEMPERATURE- WORKING DAYS, WINTER, 2015 TO 2018



Note: Average daily temperature calculated as the average of maximum and minimum temperature from the Melbourne Airport weather station  
 SOURCE: ACIL ALLEN CONSULTING

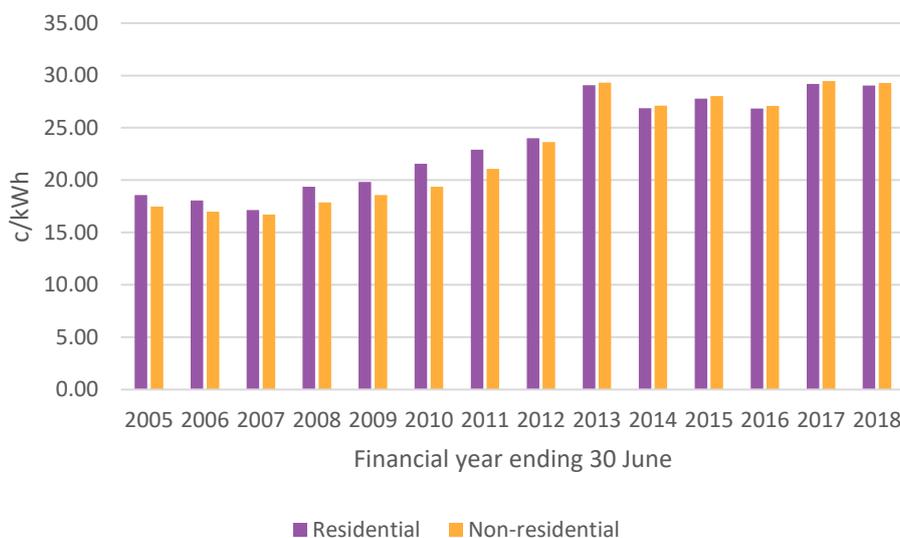
## 3.4 Electricity prices

Price is also a likely driver of electricity consumption and maximum demand. The responsiveness of consumption to changes in price is known as the price elasticity of demand. The degree of responsiveness is thought to differ considerably across customer classes. Residential customers are thought to be generally less responsive to price changes than non-residential customers. This is because energy costs comprise a significantly larger proportion of the total expenditures for non-residential customers. Significant price increases might lead to adaptive behaviour designed to reduce consumption/demand and hence costs. For example, higher electricity prices would be expected to reduce maximum demand and consumption by creating incentives for customers to become more energy efficient (through appliances and housing design).

### 3.4.1 Historical pattern in prices

Figure 3.12 shows time series of electricity prices for residential and non-residential customer classes respectively. Residential prices have historically been lower than non-residential prices. Since 2013, residential and non-residential prices have been largely similar.

Since 2007, there has been a rapid ascent in prices for all customer classes. It is reasonable to expect that the strong price rises since 2007 have had a dampening effect on consumption across the range of JEN customers.

**FIGURE 3.12** HISTORICAL ELECTRICITY PRICES FOR RESIDENTIAL AND NON-RESIDENTIAL CUSTOMERS

Note: All prices are in \$2019 real terms

SOURCE: ACIL ALLEN ANALYSIS OF HISTORICAL DATA FROM ESSENTIAL SERVICES COMMISSION

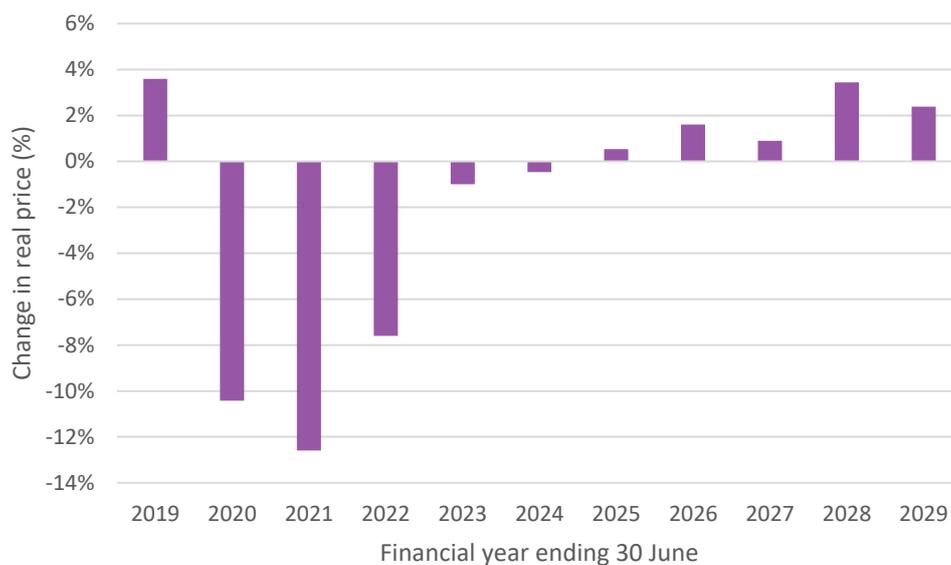
### 3.4.2 Price projections

ACIL Allen forecasts retail electricity prices using a bottom-up approach. Electricity prices are broken into three components:

1. network use of system (NUOS) charges: the costs involved in using JEN's network to supply electricity to its customers
2. wholesale electricity costs: projected using ACIL Allen's proprietary *PowerMark* model
3. other costs: these include retail margin, renewable energy schemes and other green schemes.

The final price change series (in real growth terms) is shown in Figure 3.13. A strong decline in the projected electricity price is expected after 2019. The main contributors to this decline are:

- a significant decline in the price of wholesale energy due to an influx of new large scale solar and wind generation
- a significant decline in environmental costs, particularly a drop in Large Scale Renewable Energy Target (LRET) and Small-scale Renewable Energy Scheme (SRES) costs
- a moderate decline in retail costs and margin

**FIGURE 3.13** FORECAST CHANGE IN REAL ELECTRICITY PRICES

SOURCE: ACIL ALLEN

## 3.5 Rooftop PV and battery storage

### 3.5.1 Rooftop PV uptake

The use of rooftop PV systems has increased dramatically in recent years. To date, this has mainly been in response to government incentives, rising electricity prices and falling system installation costs. Rooftop PV systems have a fairly straightforward impact on energy sales. Simply put, when the output of a PV system is used 'on site', it reduces the quantity of energy supplied by the wholesale market.

The rapid increase in installations of rooftop PV systems at the household level has not only changed the growth rate in energy and maximum demand to be satisfied by centralised generation sources, it has also changed the shape of the daily demand profile by shifting the time of the maximum demand from mid-afternoon to late-afternoon / early evening.

Standard regression techniques do not cope well with this change since it has occurred rapidly over a short period of time. Further, the effect of rooftop PV on maximum demand at the margin will diminish over the next few years as the timing of the maximum demand moves from daylight hours towards the evening. These sorts of changes are hard to properly characterise in a regression model. Therefore, we have removed the impact of rooftop PV from the estimated regression data and forecast the impact of rooftop PV independently.

Forecasts of rooftop PV capacity over the forecast period were developed by ACIL Allen and the methodology used to generate them is described in greater detail section 8.

Figure 3.14 shows the forecast uptake of rooftop PV within the JEN network. Installed rooftop PV capacity is expected to reach 302 MW by June 2029 from 107 MW as at June 2018.

**FIGURE 3.14** INSTALLED ROOFTOP PV CAPACITY AS AT JUNE 30, HISTORICAL AND FORECAST

SOURCE: ACIL ALLEN

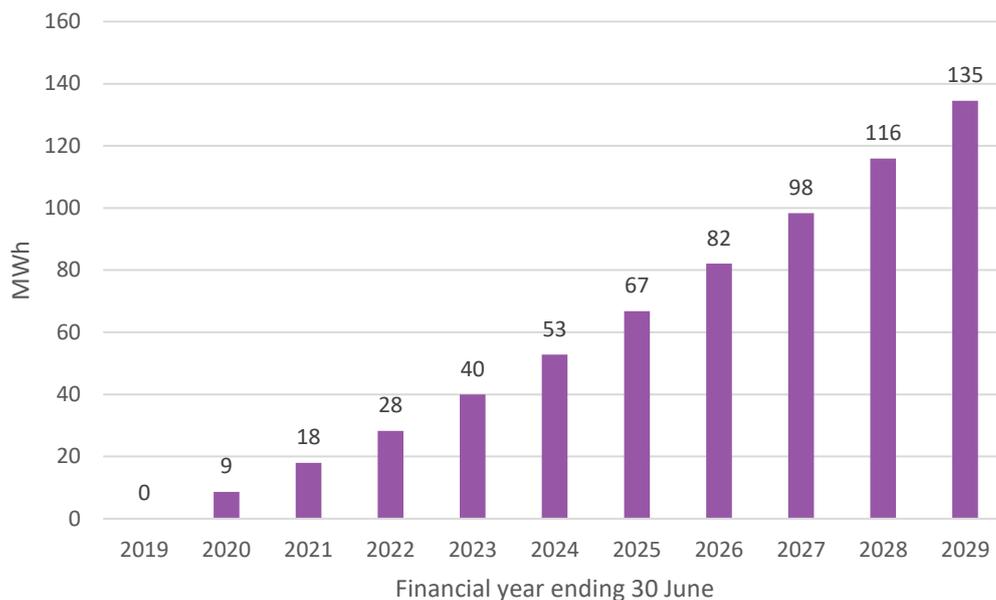
This is equivalent to a rate of growth of 9.9 per cent per annum over the period. While this is a significant rate of growth, it represents a slow-down compared to historical rates of growth which have been considerably faster, averaging 19.6 per cent per annum between 2013-14 and 2017-18.

### 3.5.2 Battery storage

To date the deployment of home energy storage systems in Australia has been negligible. However, prices for battery technology are widely expected to reduce in the future and this could have major implications for battery uptake and the level of maximum demand that is required to be met using network services. As with the reduction in cost of PV systems over the last decade, a reduction in cost of battery systems could be accelerated by a large scale, subsidy assisted, deployment of this technology as observed in Germany or other countries where there are currently subsidies for the installation of home energy storage systems.

Forecasts of the uptake of battery storage were developed by ACIL Allen. The methodology used to develop the forecasts is described in more detail in section 8.

Figure 3.15 shows the forecast increase in storage capacity which is expected to reach 135 MWh by 2028-29.

**FIGURE 3.15** FORECAST UPTAKE OF BATTERY STORAGE, 2018-19 TO 2028-29

SOURCE: ACIL ALLEN

### 3.6 Electric vehicles (EV)

Projections of the energy impact arising from the uptake of electric vehicles on the JEN distribution network were developed by ACIL Allen. The underlying methodology is described in more detail in section 9 of this report.

Figure 3.16 shows the forecast annual consumption of electric vehicles to the end of the 2028-29 financial year. By 2028-29, energy consumption by EVs in the JEN region is forecast to be 89 GWh. Given current levels of energy consumption within the JEN distribution network, the impact of electric vehicles is expected to be relatively small over the forecast period.

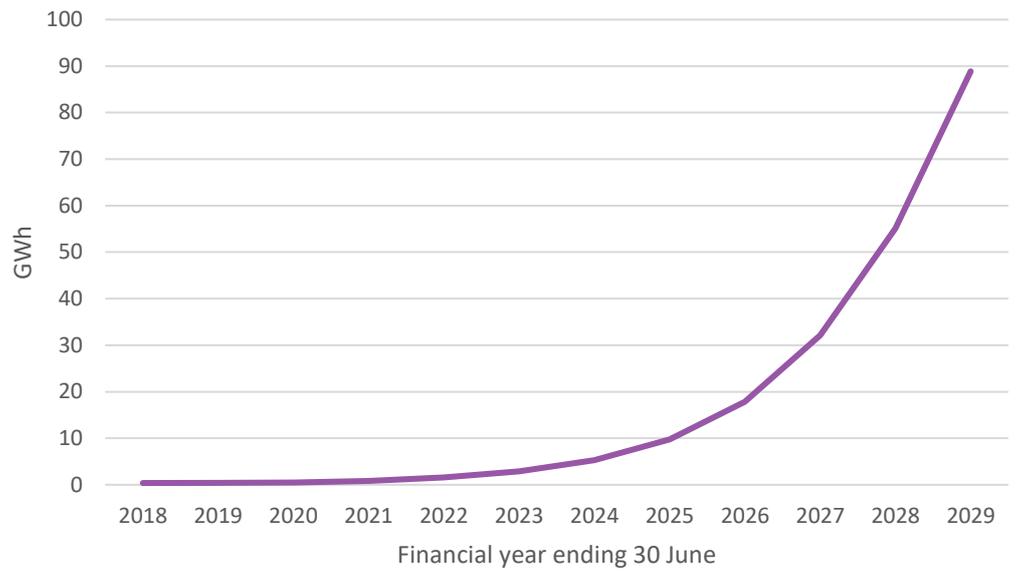
Electric vehicles are not expected to have any significant impact on maximum demand. It is anticipated that sufficient tariff incentives will be put in place to ensure that electric vehicles are mostly charged during off peak times.

The main drivers that are likely to play a significant role in the future take up of electric vehicles are:

- vehicle prices
- petrol and electricity prices
- vehicle fuel efficiency
- running costs
- range
- charging convenience
- emissions standards.

As upfront vehicle prices continue to decline and the range that the vehicles can travel before recharging increases, we can expect sales of electric vehicles to increase.

**FIGURE 3.16** FORECAST ELECTRIC VEHICLE ENERGY CONSUMPTION, 2017-18 TO 2028-29



SOURCE: ACIL ALLEN



# ENERGY CONSUMPTION FORECASTING METHODOLOGY

# 4

An econometric approach has been adopted to forecast energy consumption in the JEN distribution network.

The econometric approach to forecasting sector energy consumption establishes a statistical relationship between energy use and those factors that influence it. By incorporating the major factors affecting the demand for energy, the econometric approach improves the forecaster's ability to explain changes in the structure of demand.

The approach sets the model coefficients so as to maximise parameter efficacy through a range of statistical tests using analysis of variation (ANOVA). Minimising the sum of the squared errors between the values predicted by the model and actual values forms the basis of least squares. Minimising the sum of squared errors is equivalent to maximising the  $R^2$  (explanatory power) of the regression.

A key aspect of the approach involves identifying the key economic, demographic and weather parameters that are important drivers of energy consumption, and therefore necessary inclusions into any model that attempts to explain their historical contribution to energy consumption.

By establishing a statistical relationship between energy and its drivers, the econometric approach allows the forecaster to incorporate their view (or the views of other experts) on the future course of these drivers into the forecasts. This is not possible with simple trend analysis (which essentially assumes that drivers will not vary from past behaviour) and is the main advantage of this approach.

The consumption forecasts were prepared using a set of regression models at the customer class level. This section describes the models that were estimated and compares their results to the relevant historical data.

The coefficients estimated by these models were then used in conjunction with the projected drivers from section 3 to produce the baseline forecasts described in this section. These baseline forecasts are then adjusted through the application of a set of post model adjustments. The final forecasts of energy consumption and customer numbers are presented in section 6.

Separate models were developed for each customer class. The rationale is that the drivers of energy growth between customer classes is likely to differ due to:

- consumption in the residential sector being closely correlated with population growth and household formation
- consumption in the non-residential sector more likely being driven by economic activity, though relationships may vary for small businesses and larger businesses.

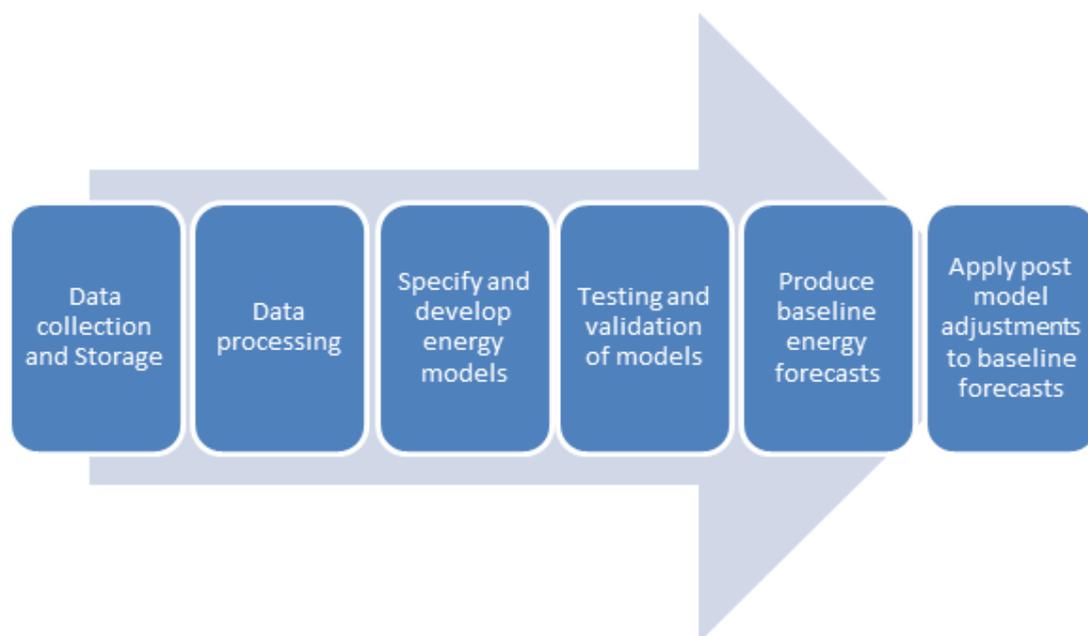
With these differences, a forecasting methodology that models customer classes separately is likely to produce a superior set of baseline forecasts than one which does not.

Energy consumption for JEN is forecast on a monthly and annual basis from 2018-19 to 2028-29, on a financial year (July 1 to June 30) basis.

The model development process can be broken down into six separate steps shown in Figure 4.1 below. The major steps in the forecasting process are:

1. data collection
2. data processing
3. model specification and estimation
4. model validation and testing
5. produce base line energy forecasts
6. apply post model adjustments.

**FIGURE 4.1** STEPS IN THE ENERGY FORECASTING PROCESS



## 4.1 Data collection

The first step in implementing the methodology was to collect the required data described in section 2 and section 3 of this document. The main sources of data were:

- energy consumption and customer numbers data from JEN
- economic growth forecasts from the Victorian Government
- population growth forecasts from Victoria in Future 2019 (ViF)
- historical estimated resident population data from the Australian Bureau of Statistics (ABS)
- daily maximum and minimum temperature data for the Melbourne Airport weather station covering the period from January 1 1987, from the Bureau of Meteorology.

### Model calibration

The models were calibrated using monthly time series dating back to July 2006 for all customer classes. Both the residential and non-residential time series covered the period up to the end of April 2019.

## 4.2 Data processing

Before any energy regression models could be estimated, some intermediate processing was required to render the data suitable for use in the modelling process.

Key aspects of the intermediate data processing included:

- creation of time series that could be used to estimate the underlying econometric relationships
- checking the continuity of the data, identifying any discrete jumps in the time series which may arise due to system changes or changes in the way customers are classified. These shifts, when detected were corrected for through the appropriate use of dummy variables in the specified models
- checking for measurement errors in the data
- converting the data into monthly time series where necessary. This was done for the historical GSP and population series which are annual and quarterly respectively. The conversion was done using interpolation
- adjusting the baseline historical energy consumption data to remove the impact of rooftop PV before the calibration of the baseline energy models. The rooftop PV is forecast separately and then added back as a post model adjustment
- transformation of the daily air temperature data into the heating degree day (HDD18) and cooling degree day (CDD18) variables
- checking and imputing for missing data where necessary.

## 4.3 Model specification and estimation

### 4.3.1 Residential consumption models

The baseline forecasts for the residential class were separated into two components:

1. residential customer numbers
2. residential consumption per customer.

Separate regressions were estimated for each component. The outputs from these two regression models were multiplied together to arrive at the baseline consumption forecasts for the residential class.

#### Estimating customer numbers

As described in section 3.2, changes in residential customer numbers are largely driven by household formation arising from population growth. A regression model was used to forecast customer numbers. The historical monthly time series of residential customer numbers was regressed on monthly population figures derived from estimated resident population by the process described in section 3.2.2.

The regression model is described by the equation below:

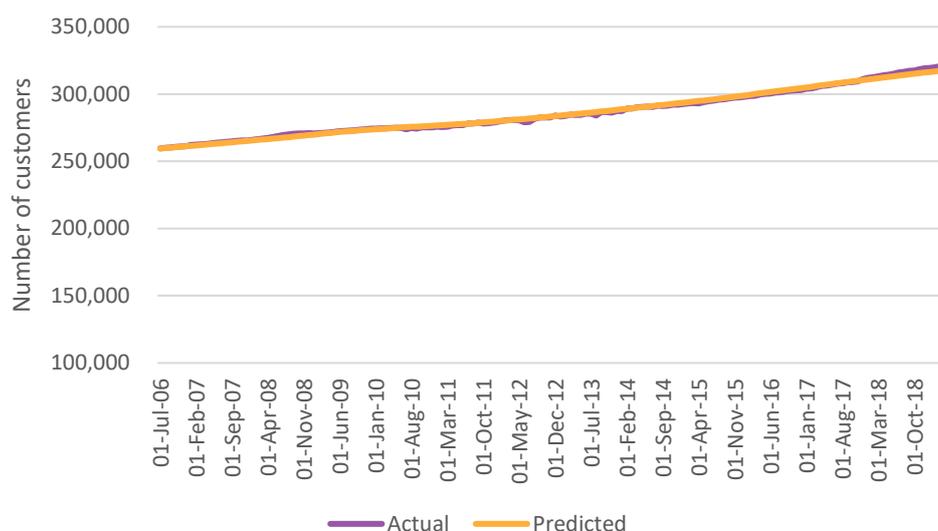
$$\log(\text{customers})_t = \beta_1 + \beta_2 \times \log(\text{population})_t + \epsilon_t$$

The estimated coefficients of this model ( $\beta_i$ ) are summarised in Table 4.1. On average, a one per cent increase in population leads to a 0.71 per cent increase in residential customer numbers.

Figure 4.2 compares actual residential customer numbers with the predicted values. The predicted number of residential customers matches closely with the actuals. This indicates that population is a good predictor of residential customer numbers. The variation in population explains 99.5 per cent of the variation in residential customer numbers.

**TABLE 4.1** RESIDENTIAL CUSTOMER REGRESSION MODEL

Coefficient	Estimate	Standard error	t-statistic	p-value
<b>Customer regression</b>				
Constant	2.9788	0.0541	55.0831	0.0000
log(POP)	0.7086	0.0040	177.2116	0.0000
R-squared: 0.99518				
SOURCE: ACIL ALLEN				

**FIGURE 4.2** RESIDENTIAL CUSTOMERS, PREDICTED VERSUS ACTUAL

SOURCE: ACIL ALLEN

### Estimating consumption per customer

Changes in consumption per customer (or household) are likely to vary with weather conditions. During different times of the year, households are likely to have different heating and cooling requirements, as described in section 3.

Consumption per customer is forecast using a regression model. The dependent variable is monthly latent consumption per customer – metered consumption, plus PV output consumed on site. The model is described by the equation below:

$$\log(\text{consumption per customer})_t = \beta_1 + \beta_2 \times \text{CDD}_t + \beta_3 \times \text{HDD}_t + \epsilon_t$$

The estimated coefficients ( $\beta_i$ ) are summarised in Table 4.2. On average:

- an additional CDD leads to a 0.19 per cent increase in consumption per customer
- an additional HDD leads to a 0.17 per cent increase in consumption per customer.

Figure 4.3 shows actual historical consumption per customer compared to the predicted consumption per customer. The predicted values match the actual consumption per customer values well. There is more volatility in the actuals since 2013-14, though the predicted values present a smoother pattern in consumption per customer. Ultimately, 60.4 per cent of the variation exhibited in the actual data is being explained by the explanatory variables.

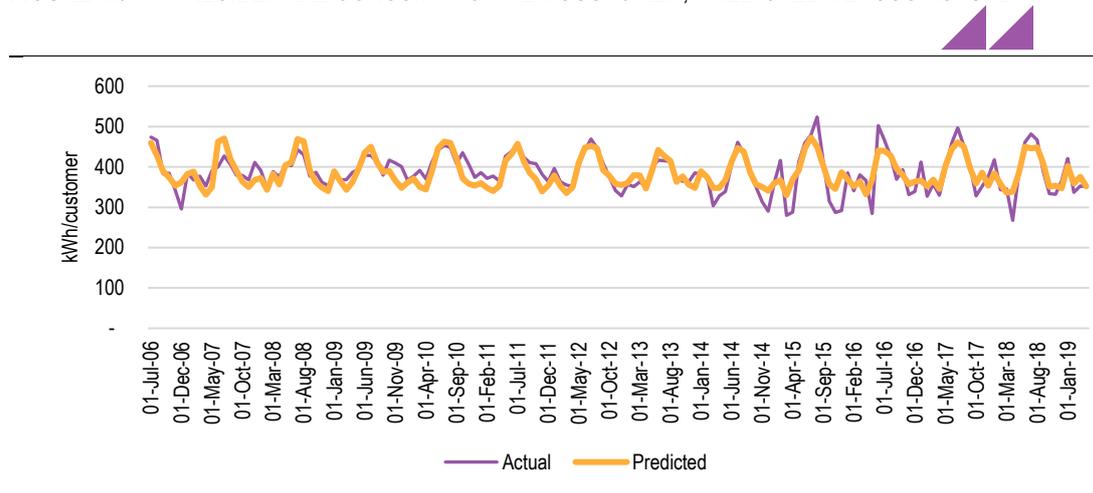
**TABLE 4.2** RESIDENTIAL CONSUMPTION PER CUSTOMER REGRESSION MODEL

Coefficient	Estimate	Standard error	t-statistic	p-value
Constant	5.69198	0.02262	251.66368	0.00000
CDD	0.00190	0.00025	7.48171	0.00000
HDD	0.00165	0.00012	13.82371	0.00000

R-squared: 0.60404

SOURCE: ACIL ALLEN

**FIGURE 4.3** RESIDENTIAL CONSUMPTION PER CUSTOMER, PREDICTED VERSUS ACTUAL



SOURCE: ACIL ALLEN

### 4.3.2 Non-residential consumption models

As described in section 2, there are four separate types of non-residential classes:

1. small business
2. large business LV
3. large business HV
4. sub-transmission.

Baseline forecasts for each class is forecast separately and independently as described below.

#### Small business model

Baseline forecasts for small business were produced separately for:

1. small business customer numbers
2. small business consumption.

Separate regressions were completed for each component and these are described below.

#### Estimating customer numbers

Small business customer numbers are likely to be driven by changes in overall economic activity. Population can also act as a proxy for growth in the number of small businesses.

Historical monthly small business customers numbers have been regressed on GSP, our measure of economic activity, and population as illustrated by the equation below:

$$\log(\text{customers})_t = \beta_1 + \beta_2 \times \log(\text{GSP})_t + \beta_3 \times \log(\text{population})_t + \epsilon_t$$

The coefficient estimates ( $\beta_i$ ) of this regression are presented in Table 4.3. On average:

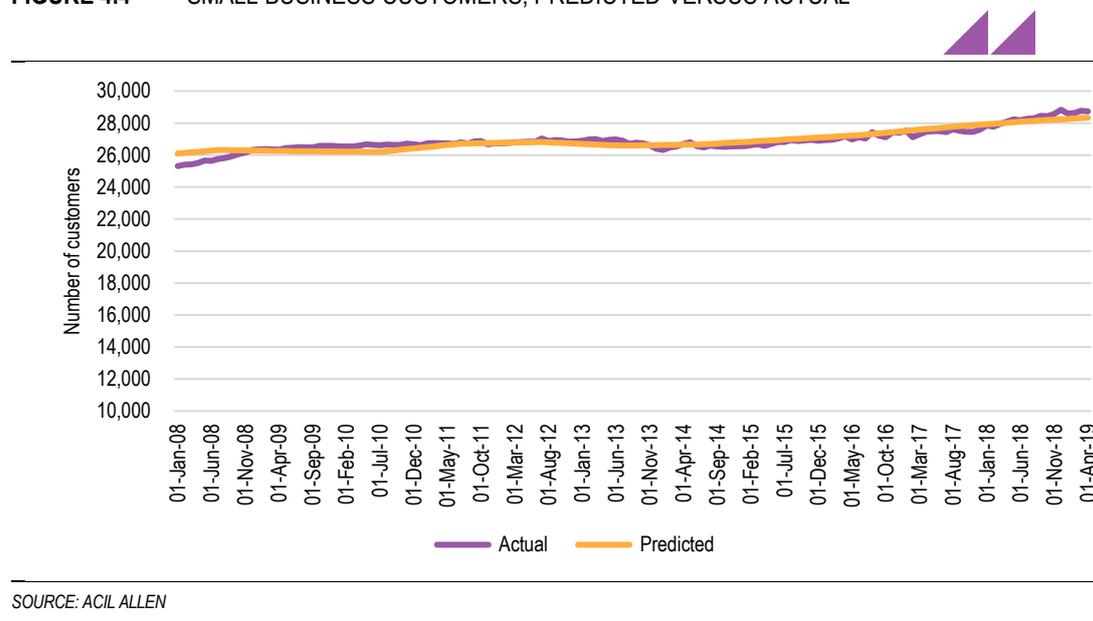
- a one per cent increase in population reduces small business customer numbers by 0.95 per cent
- a one per cent increase in economic activity increases small business customer numbers by 1.11 per cent.

Figure 4.4 compares the predicted customer numbers with the actuals. The predicted values are a close match to the underlying trend in movements in the actual customer numbers, with 82.7 per cent of the variation in small business customer numbers explained by the variation in the explanatory variables.

**TABLE 4.3** SMALL BUSINESS CUSTOMERS REGRESSION MODEL

Coefficient	Estimate	Standard error	t-statistic	p-value
Constant	8.8467	0.3823	23.1402	0.0000
log(GSP)	1.1082	0.1418	7.8139	0.0000
log(POP)	-0.9490	0.1601	-5.9286	0.0000
R-squared: 0.8269				
SOURCE: ACIL ALLEN				

**FIGURE 4.4** SMALL BUSINESS CUSTOMERS, PREDICTED VERSUS ACTUAL



### Estimating consumption

As described in section 3.4, small business consumption is likely to be influenced by changes in electricity prices given they comprise a significant portion of operating costs. Similarly, just like with residential customers, small business consumption is also likely to be influenced by the heating and cooling requirements for office buildings.

The monthly historical pattern in small business consumption is illustrated in Figure 4.5. Consumption in December is lower than the other months, which is likely to reflect holiday festivities resulting in a reduced number of working days for the month.

Taking these considerations into account, monthly latent consumption was regressed on price, HDD and an indicator variable for December as described by the equation below:

$$\begin{aligned} \log(\text{consumption})_t &= \beta_1 + \beta_2 \times \log(\text{Price})_t + \beta_3 \times \text{HDD}_t + \beta_4 \times \text{CDD}_t + \beta_5 \times \text{DEC}_t \\ &+ \epsilon_t \end{aligned}$$

The coefficient estimates ( $\beta_i$ ) of this regression are summarised in Table 4.4. On average:

- a one per cent rise in electricity prices for small business leads to a fall in consumption by 0.30 per cent
- an additional CDD increases consumption by 0.06 per cent
- an additional HDD increases consumption by 0.06 per cent
- consumption in December is 6.75 per cent lower than when compared to other months.

Figure 4.5 also compares the predicted values of small business consumption with the actuals. Overall, the model is a good fit – 61.7 per cent of the total variation in consumption is explained by the variation in the explanatory variables.

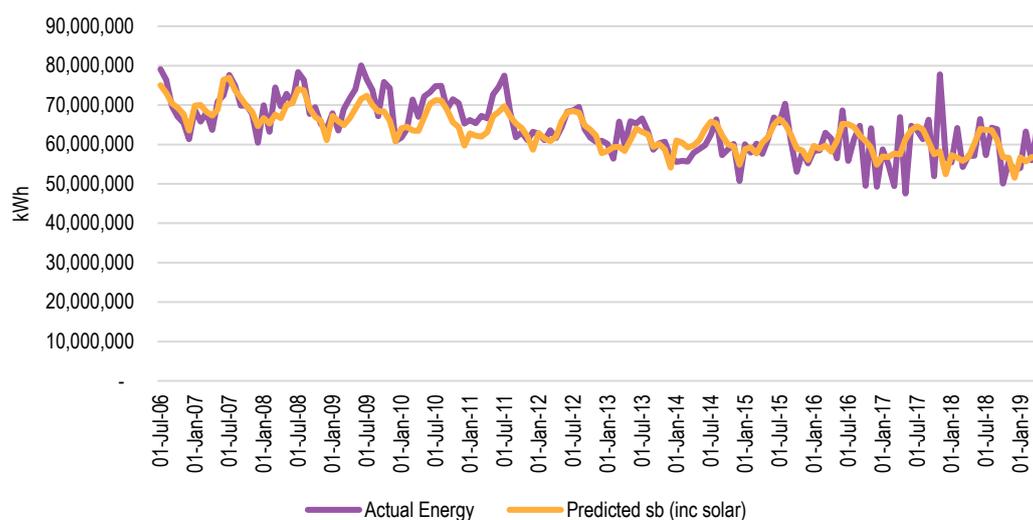
**TABLE 4.4** SMALL BUSINESS CONSUMPTION REGRESSION MODEL

Coefficient	Estimate	Standard error	t-statistic	p-value
Constant	18.8465	0.0804	234.4281	0.0000
log(Price)	-0.3031	0.0248	-12.2174	0.0000
CDD	0.0006	0.0002	2.6531	0.0088
HDD	0.0006	0.0001	6.1712	0.0000
December	-0.0675	0.0198	-3.4093	0.0008

R-squared: 0.6167

SOURCE: ACIL ALLEN

**FIGURE 4.5** SMALL BUSINESS CONSUMPTION, PREDICTED VERSUS ACTUAL

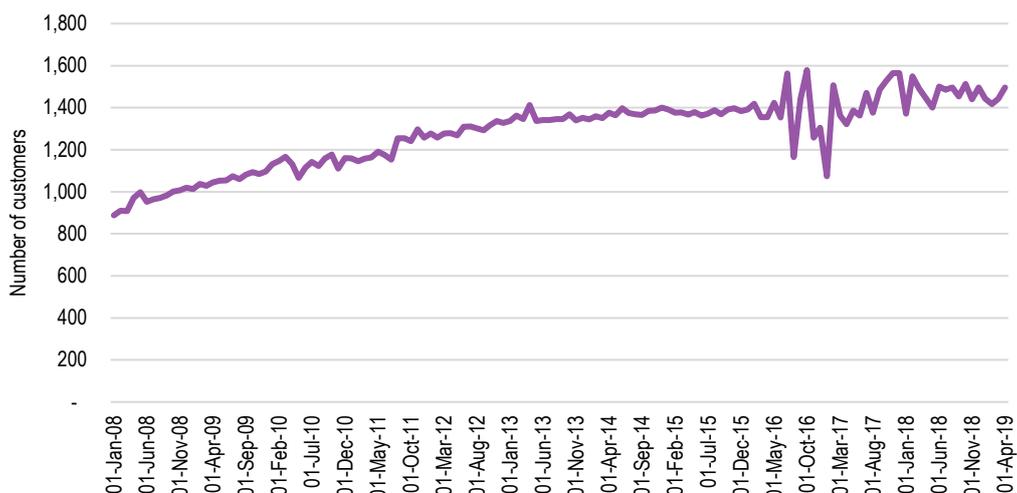


SOURCE: ACIL ALLEN

## Large business LV model

### *Estimating customer numbers*

Figure 4.6 shows the historical monthly pattern in large business LV customer numbers. There have been a number of jumps in the historical time series, most recently in 2016-17 which are difficult to account for using a regression.

**FIGURE 4.6** LARGE BUSINESS LV MONTHLY CUSTOMER NUMBERS

SOURCE: ACIL ALLEN

As an alternative, an annual growth rate of 1.35 per cent was applied to forecast customer numbers going forward. This rate was based on extending the historical annual growth rate in the past three years.

### Estimating consumption

Similar to small business, consumption for large business LV is likely to be sensitive to changing heating requirements in winter. Additionally, a higher level of economic activity should also increase activity for large business LV customers.

Baseline forecasts for large business LV consumption were estimated using a monthly regression where economic activity and HDD were regressors, as summarised by the equation below:

$$\log(\text{consumption})_t = \beta_1 + \beta_2 \times \log(\text{GSP})_t + \beta_3 \times \text{HDD}_t + \epsilon_t$$

The coefficient estimates ( $\beta_i$ ) of this regression are summarised in Table 4.5. On average:

- a one per cent increase in economic activity leads to an increase in consumption by 0.60 per cent
- an additional HDD leads to an increase in consumption by 0.01 per cent.

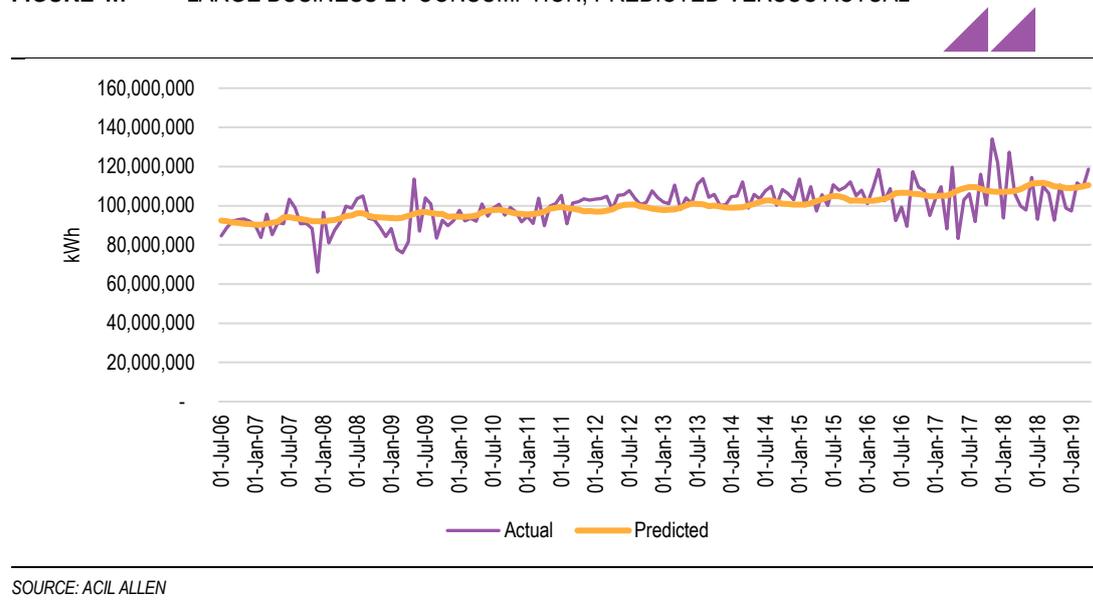
Figure 4.7 compares the predicted consumption values with the actual historical ones. The predicted model fits the underlying trend in consumption for large business LV well. However, only 30.8 per cent of the total variation in actual consumption is explained by the variation in the predicted values. This is due to large month to month random movements in consumption that cannot be explained by the model, particularly in the early and latter part of the estimation period.

**TABLE 4.5** LARGE BUSINESS LV CONSUMPTION REGRESSION MODEL

Coefficient	Estimate	Standard error	t-statistic	p-value
Constant	10.6982	0.9500	11.2610	0.0000
log(GSP)	0.6020	0.0742	8.1154	0.0000
HDD	0.0001	0.0001	1.6701	0.0970

R-squared: 0.3079

SOURCE: ACIL ALLEN

**FIGURE 4.7** LARGE BUSINESS LV CONSUMPTION, PREDICTED VERSUS ACTUAL

### Large business HV and sub-transmission forecasts

Consumption and customer numbers were not modelled using regression in the large HV and sub-transmission customer classes. This is because the very small number of large and heterogeneous customers in these classes makes regression an unsuitable tool.

In the absence of a suitable time series relating consumption, customer numbers and their drivers, the most recent year's values were used as the starting point for the forecasts. No other adjustments were made.

## 4.4 Model testing and validation

The specified and estimated econometric models have been validated using standard statistical diagnostic tools.

The main methods of model validation used are:

- the theoretical basis of the coefficient size and sign
- the goodness of fit of the regression
- the statistical significance of the explanatory variables
- unit root testing and testing for stationarity
- identifying the presence of heterocedasticity and multicollinearity.

The choice of model variables has been based on theoretical considerations of key drivers to explain the measured variation in energy consumption. As a consequence, some sense of the likely size and direction of model coefficients is possible. Where a variable produced an effect contrary to that understood by economic theory it was excluded from any model specification.

The most commonly used measure of the goodness of fit of the regression model to the observed data is  $R^2$ . In the model validation process, the  $R^2$  is considered as part of a suite of statistical tools available. Emphasis is placed on the overall fit of the models as well as on the statistical significance of individual explanatory variables.

## 4.5 Post model adjustments

It was also necessary to make additional adjustments arising from factors that were not included in the baseline econometric models. The two main post model adjustments applied to the energy consumption forecasts were for rising uptake of rooftop PV and the increasing energy consumption over time due to the uptake of electric vehicles. There was no post model adjustment applied for battery storage. This is because battery storage, while likely to reduce maximum demand, is not expected to have a material impact on energy consumption over the forecast period.

### 4.5.1 Rooftop PV adjustment

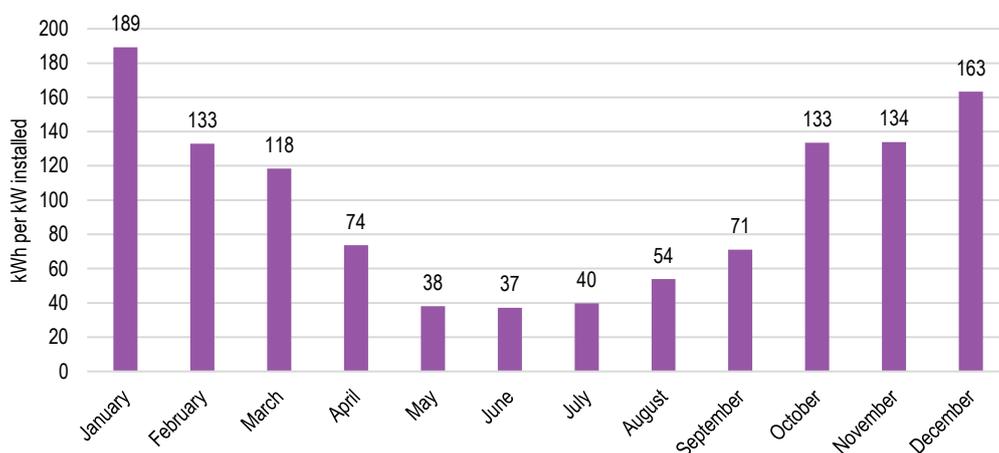
As mentioned previously, the dependent variables in the baseline econometric models were stripped of any impact of rooftop PV before the models were calibrated.

This means that the impact of rooftop PV needs to be re-introduced into the baseline econometric forecasts to generate the final forecasts.

To estimate the contribution of rooftop PV over the historical and forecast horizon, the Clean Energy Regulator's (CER) output rating for Victoria of 1185 kWh per kW installed was apportioned across each of the months in the year using solar insolation data from the Bureau of Meteorology to create a set of twelve conversion factors.

These are shown in Figure 4.8 below. It is evident that rooftop PV systems are operating at peak output during the summer months, with December and January generating more output than the other months of the year.

**FIGURE 4.8** SOLAR CONVERSION FACTORS BY MONTH

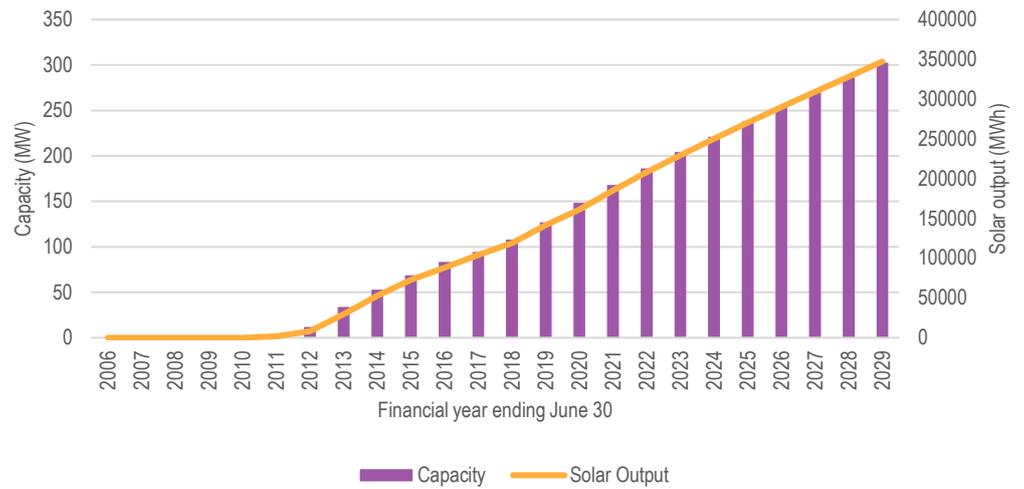


SOURCE: CER AND ACIL ALLEN

These factors were then multiplied by the total capacity installed in a given month (both historical and forecast) to estimate the total energy generated by rooftop PV systems within the JEN distribution network.

Figure 4.9 presents the total solar capacity and energy generated by PV systems. Rooftop PV capacity is forecast to reach 301.8 MW in 2028-29, generating a total of 347.3 GWh.

**FIGURE 4.9** GENERATION OF ROOFTOP PV SYSTEMS, HISTORICAL AND FORECAST



SOURCE: ACIL ALLEN

#### 4.5.2 Electric vehicle adjustment

Another post-model adjustment required as part of the energy forecasting methodology is to add on the impact of electric vehicles. Forecasts of the energy impact of electric vehicles were developed by ACIL Allen. The methodology used to develop the forecasts is outlined in section 9 of this report.



## 5.1 Modelling approach

Just as in the energy consumption forecasting methodology, an econometric approach to forecasting maximum demand within the JEN distribution network was adopted. This approach establishes a statistical relationship between daily maximum demand and those key economic, demographic and weather factors that drive it and then uses the estimated relationships to generate forecasts of maximum demand. Separate regression models were specified and estimated for the hotter (summer) and colder months (winter) of the year.

These estimated statistical relationships were used in conjunction with a long run weather series dating back to 1980 to conduct a stochastic analysis. This was used to weather normalise the peak demand forecasts. This is described further in section 5.7.

Maximum demand was forecast on a seasonal basis (summer and winter) covering a forecast horizon from 2019-20 to 2028-29 in the case of summer and 2019 to 2028 for winter. Forecasts were produced under 10 POE<sup>4</sup>, 50 POE and 90 POE weather conditions.

## 5.2 Model development and forecasting process

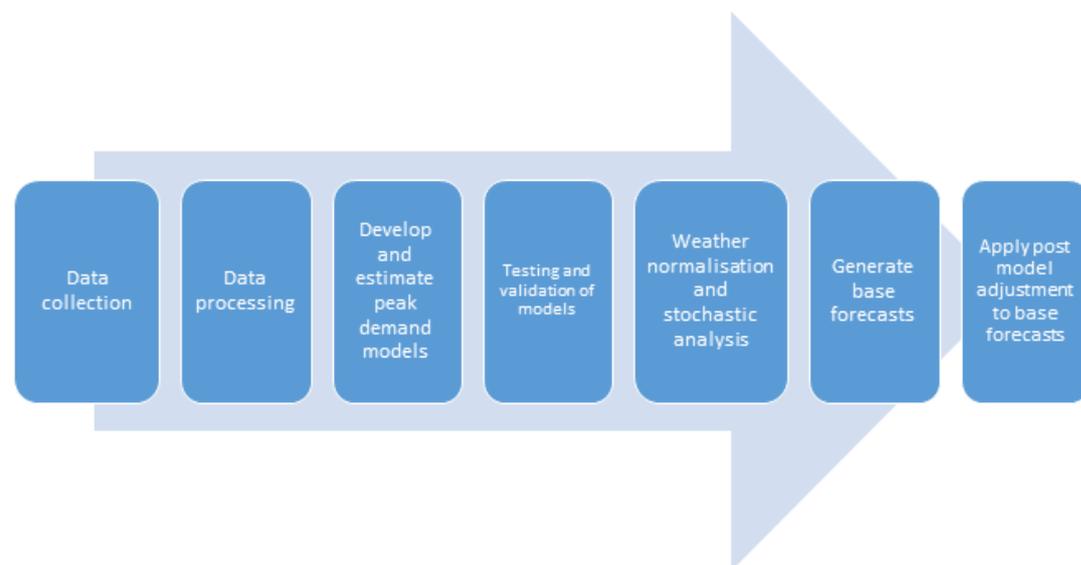
The steps required in maximum demand forecasting process are shown in Figure 5.1 below.

These steps can be broken down as follows:

- data collection
- data processing
- base model specification and estimation
- model testing and validation
- weather normalisation and stochastic analysis
- base forecast generation
- post model adjustments.

While these steps follow a similar structure to the energy forecasting methodology, a key extra step in the maximum demand methodology is weather normalisation, which is the most complex and important step in the maximum demand methodology.

<sup>4</sup> Probability of Exceedance (POE) refers to the likelihood that a given level of maximum demand will be met or exceeded. The 50 POE maximum demand is the level of maximum demand in a given season, summer or winter, that is expected to be exceeded one year in two on average. The 10 POE level of maximum demand is that level of maximum demand which is expected to be exceeded one year in ten on average. The 90 POE level of maximum demand is that which is expected to be exceeded nine years out of every ten on average.

**FIGURE 5.1** STEPS IN THE MAXIMUM DEMAND FORECASTING PROCESS

### 5.3 Data collection and storage

The data used in the maximum demand modelling process were:

- 15 minute demand data for the JEN distribution system
- 15 minute embedded generation data within the JEN distribution system
- Monthly historical rooftop PV capacity for domestic and business customers
- Historical quarterly Gross State Product data for the Australian Bureau of Statistics (ABS)
- Historical retail price data
- daily maximum and minimum temperature data from the Melbourne Airport weather station covering the period from January 1 1980.

#### Model calibration

The summer model was calibrated using daily time series dating from 17 November 2004 to 29 March 2019. The winter model was calibrated with daily data from 4 April 2005 to 29 October 2018.

### 5.4 Data processing

There were several important data processing steps required before the maximum demand modelling could proceed. These are described below.

#### 5.4.1 Prepare peak demand time series for regression analysis

The first step in the data preparation process was to create a time series data set suitable for conducting a regression analysis. This involved the following:

- extracting maximum summer and winter demands with associated date / time stamp
- extracting daily maximum demand for inclusion in the regression dataset
- creation of seasonal, day of the week and monthly dummy variables
- addition of other explanatory variables to the daily dataset such as economic activity and temperature variables
- checking for, identifying and rectifying any errors in the data or missing data.

### 5.4.2 Removing weekends, other non-working days and Christmas holiday period from the dataset

Maximum demand is typically lower on weekends, non-working days and holiday periods. For this reason, any estimated regression model will need to account for this characteristic of the data. The regression data set was adjusted by:

- removing weekends from the dataset
- removing other non-working days such as public holidays (eg: Australia Day)
- removing the Christmas holiday period starting from December 20th and ending on January the 10th of each summer.

An additional adjustment was to remove the milder days from the modelling data sets before any regressions were estimated. This was done to remove the flat or non-responsive part of the relationship between daily maximum demand and temperature. When we do this, we are left with a relationship that is approximately linear.

A threshold average temperature of 18 degrees Celsius was applied to the estimated summer regression model, while for the winter regression model the threshold average temperature was 16 degrees. In the case of the summer model, those days where the average temperature did not exceed 18 degrees were omitted from the regression. In the case of the winter model, milder days where the average temperature exceeded 16 degrees Celsius were omitted from the regression. This threshold was determined by visually inspecting the historical relationship between daily maximum demand and average temperature.

## 5.5 Specification and estimation of the baseline maximum demand models

The methodology adopted by ACIL Allen to forecast maximum demand is a multiple regression approach. Two separate regression models were estimated, one for the warmer months of the year (November to March inclusive), which we refer to as the summer model and one for the colder months (April to October) which we refer to as the winter model.

Separate regression models are necessary to capture the different relationship between daily maximum demand and temperature in the summer and winter seasons. Higher maximum demands in the summer are driven by cooling loads which increase in response to hot weather conditions. On the other hand, maximum demand increases in the winter months due to cold weather conditions which drive heating loads. For the summer model, we expect a positive relationship between maximum demand and temperature while the winter model is expected to produce a negative relationship.

### 5.5.1 System level maximum demand - summer

At the system level, daily summer maximum demand was modelled from a dataset showing daily maximum demand for all 'non-mild' days.<sup>5</sup> The model expresses daily maximum demand as a function of the following factors:

- **GSP<sub>t</sub>**: gross state product
- **Min<sub>t</sub>**: minimum daily temperature
- **Max<sub>t</sub>**: maximum daily temperature
- **Max<sub>t-1</sub>**: maximum daily temperature on the previous day
- **Max<sub>t-2</sub>**: maximum daily temperature on two days prior
- **Price<sub>t</sub>**: Real retail electricity price
- **PVcap<sub>t</sub>**: Rooftop PV installed capacity
- **Maxgt34<sub>t</sub>**: dummy variable, equal to '1' if the daily maximum temperature exceeds 34 degrees, '0' otherwise
- **November<sub>t</sub>**: dummy variable, equal to '1' if month is November, '0' otherwise
- **December<sub>t</sub>**: dummy variable, equal to '1' if month is December, '0' otherwise

<sup>5</sup> 'non-mild' days means that weekends, public holidays and days with mild temperatures were omitted.

- **February<sub>t</sub>**: dummy variable, equal to '1' if month is February, '0' otherwise
- **March<sub>t</sub>**: dummy variable, equal to '1' if month is March, '0' otherwise
- **April<sub>t</sub>**: dummy variable, equal to '1' if month is April, '0' otherwise
- **Monday<sub>t</sub>**: dummy variable, equal to '1' if day is Monday, '0' otherwise
- **Friday<sub>t</sub>**: dummy variable, equal to '1' if day is Friday, '0' otherwise.

This specification provided a good balance between explanatory power, sensible coefficients, and model parsimony. The final model is shown in equation (1). The error term in the model is represented by  $\varepsilon_t$ .

$$(1) MD_t = -127.9945 + 0.000818 \times GSP_t + 14.2126 \times Max_t + 5.5934 \times Min_t + 2.3609 \times Max_{t-1} + 1.1065 \times Max_{t-2} - 1.4326 \times Price_t - 1.12365 \times PVcap_t + 33.12897 \times Maxgt34_t - 10.0113 \times Monday_t - 24.5613Friday_t + 8.3703 \times November_t + 23.6272 \times December_t + 22.6151 \times February_t + 15.3986 \times March_t + \varepsilon_t$$

Table 5.1 summarises the coefficients estimated using this specification.

**TABLE 5.1** SYSTEM MAXIMUM DEMAND MODEL (SUMMER), ESTIMATED COEFFICIENTS

Variable	Coefficient	Standard error	t-statistic	p-value
GSP	0.0008	0.0001	5.8192	0.0000
MAX <sub>t</sub>	14.2126	0.4111	34.5684	0.0000
MIN <sub>t</sub>	5.5934	0.5262	10.6302	0.0000
MAX <sub>t-1</sub>	2.3609	0.3614	6.5326	0.0000
MAX <sub>t-2</sub>	1.1065	0.2874	3.8496	0.0001
Price <sub>t</sub>	-1.4326	0.7097	-2.0185	0.0439
PVcap <sub>t</sub>	-1.1237	0.1033	-10.8746	0.0000
MAXgt34	33.1290	5.3373	6.2070	0.0000
MON	-10.0113	3.5146	-2.8485	0.0045
FRI	-24.5613	3.4699	-7.0783	0.0000
NOV	8.3703	4.6588	1.7967	0.0728
DEC	23.6272	4.8655	4.8561	0.0000
FEB	22.6151	3.9717	5.6940	0.0000
MAR	15.3986	4.2059	3.6612	0.0003
Constant	-127.9945	40.3805	-3.1697	0.0016
R <sup>2</sup> (Adjusted):	0.8673	Standard error of regression:	37.0907	

SOURCE: ACIL ALLEN

The coefficient on GSP is positive, meaning that as the economy grows, the forecast maximum demand increases also. For every \$100 million increase in GSP, summer peak demand increases by 0.08 MW.

There is also a positive relationship between daily maximum and minimum temperature and maximum demand. For every 1 degree Celsius increase in the daily maximum temperature, maximum demand increases by 14.2 MW, while a degree increase in the overnight minimum temperature increases maximum demand by 5.6 MW. An additional boost to maximum demand of 33.1 MW is provided on the days where the maximum temperature exceeds 34 degrees.

The coefficients on lagged temperature are positive, meaning that as temperature increases over several days, maximum demand is forecast to increase also. There is a negative relationship

between the real price of electricity and maximum demand. For every 1 cent increase in the real price, summer maximum demand is reduced by 1.4 MW.

Moreover, peak demand is 10.0 MW lower on average on Mondays compared to the other days of the week and 24.6 MW lower on average on Fridays.

### 5.5.2 System level maximum demand - winter

For winter system level forecasts, maximum demand was modelled as a function of the following factors:

- **GSP<sub>t</sub>**: gross state product
- **Max<sub>t</sub>**: maximum daily temperature
- **Min<sub>t</sub>**: minimum daily temperature
- **Max<sub>t-1</sub>**: maximum daily temperature on the previous day
- **Max<sub>t-2</sub>**: maximum daily temperature on two days prior
- **Price<sub>t</sub>**: Real retail electricity price
- **Monday<sub>t</sub>**: dummy variable, equal to '1' if day is Monday, '0' otherwise
- **Friday<sub>t</sub>**: dummy variable, equal to '1' if day is Friday, '0' otherwise
- **April<sub>t</sub>**: dummy variable, equal to '1' if month is May, '0' otherwise
- **May<sub>t</sub>**: dummy variable, equal to '1' if month is May, '0' otherwise
- **August<sub>t</sub>**: dummy variable, equal to '1' if month is August, '0' otherwise
- **September<sub>t</sub>**: dummy variable, equal to '1' if month is September, '0' otherwise
- **October<sub>t</sub>**: dummy variable, equal to '1' if month is October, '0' otherwise.

This specification provided a good balance between explanatory power, sensible coefficients, and model parsimony. The final model is shown in equation (2). The error term in the model is represented by  $\varepsilon_t$ .

$$(2) \quad MD_t = 870.8705 + 0.00011 \times GSP_t - 6.1316 \times Max_t - 2.4905 \times Min_t - 1.5633 \times Max_{t-1} - 1.7770 \times Max_{t-2} - 2.1642 \times Price_t - 6.1394 \times Monday_t - 17.5862 \times Friday_t - 37.8625 \times April_t - 10.8720 \times May_t - 5.5001 \times August_t - 32.9453 \times September_t - 41.1180 \times October_t + \varepsilon_t$$

Table 5.2 summarises the coefficients estimated using this specification.

**TABLE 5.2** SYSTEM MAXIMUM DEMAND MODEL (WINTER), ESTIMATED COEFFICIENTS

Variable	Coefficient	Standard error	t-statistic	p-value
GSP	0.00011	0.0000	2.9543	0.0032
MAX <sub>t</sub>	-6.1316	0.2303	-26.6269	0.0000
MIN <sub>t</sub>	-2.4905	0.2194	-11.3494	0.0000
MAX <sub>t-1</sub>	-1.5633	0.2331	-6.7073	0.0000
MAX <sub>t-2</sub>	-1.7770	0.1959	-9.0706	0.0000
Price <sub>t</sub>	-2.1642	0.2976	-7.2721	0.0000
MON	-6.1394	1.4009	-4.3826	0.0000
FRI	-17.5862	1.3998	-12.5632	0.0000
APR	-37.8625	2.5684	-14.7419	0.0000
MAY	-10.8720	1.8247	-5.9583	0.0000
AUG	-5.5001	1.6221	-3.3908	0.0007
SEP	-32.9453	1.9008	-17.3324	0.0000
OCT	-41.1180	2.3519	-17.4826	0.0000
Constant	870.8705	8.2013	106.1870	0.0000

Variable	Coefficient	Standard error	t-statistic	p-value
R <sup>2</sup> (Adjusted):	0.7799	Standard error of regression:	22.7615	

SOURCE: ACIL ALLEN

The positive coefficient on GSP suggests that maximum demand increases with higher levels of economic activity. For every \$100 million increase in GSP, winter maximum demand increases by 0.011 MW.

The negative coefficients on the daily maximum and minimum temperature variables indicate that as temperature drops in the colder months, maximum demand increases due to rising heating loads. For every 1 degree decline in the daily maximum temperature, winter maximum demand increases by 6.1 MW, while a 1 degree decline in the daily overnight minimum raises winter maximum demand by 2.5 MW.

A negative coefficient on lagged temperature implies an impact of sequences of cold days, in the same way as sequences of hot days increase electricity demand in summer.

As expected, there is a negative relationship between the real price of electricity and maximum demand. For every 1 cent increase in the electricity price winter maximum demand declines by 2.2 MW.

Finally, daily maximum demand in was found to be lower in April, May, August, September and October on average, relative to June and July. As with the summer model, demand is forecast to be lower on both Mondays and Fridays relative to the other weekdays.

## 5.6 Model validation and testing

As in the case of the energy consumption models, the estimated maximum demand models were validated and tested in the following ways;

- confirmation that established relationships fit with theory (direction and significance of the coefficients)
- assessment of the statistical significance of explanatory variables
- assessment of goodness of fit
- in-sample forecasting performance of the model against actual data
- unit root testing and testing for stationarity
- identifying the presence of heterocedasticity and multicollinearity

## 5.7 Weather normalisation and stochastic analysis

A stochastic analysis was conducted on the calibrated summer and winter demand models to generate a distribution of seasonal maximum demands. The 10, 50 and 90 POE maximum demand was then derived from this distribution. The 50 POE level of demand corresponds to the level of demand that is exceeded in 1 out of every 2 years. The 10 POE level of demand is exceeded in 1 out of every 10 years.

The process for generating maximum demand forecasts for summer and winter was to use the models described above to estimate daily maximum demands for each forecast year. The estimated daily maximum demands were calculated by:

- using historical temperature data from each day for a period of 39 years dating back to January 1 1980
- using the values of other drivers relating to that forecast year
- generating a draw from a normal distribution with mean zero and standard deviation equal to the standard error of the estimated regression and adding it to the daily demand.

The maximum demand for each year of temperature data was stored and the process simulated 100 times.

The 10, 50 and 90 POE peak demand levels were then determined by considering percentiles of the 3,900 simulated maximum demand values in each forecast year. We obtain 3,900 years simulated peak demand values because we use 38 years of data simulated 100 times (39×100=3,900).

The error term of each calibrated regression model was factored into the stochastic analysis to capture the tendency for the estimated regression models to under predict the seasonal maximum demand. This is because the maximum demand is also influenced by other random factors that are unrelated to temperature. By adding a stochastic term to each fitted daily maximum demand this tendency to under predict the peak demand is removed.

## 5.8 Apply post model adjustments

As in the cast of the energy consumption methodology, there were several post model adjustments that needed to be added back to the baseline maximum demand econometric forecasts as these were excluded from the baseline models.

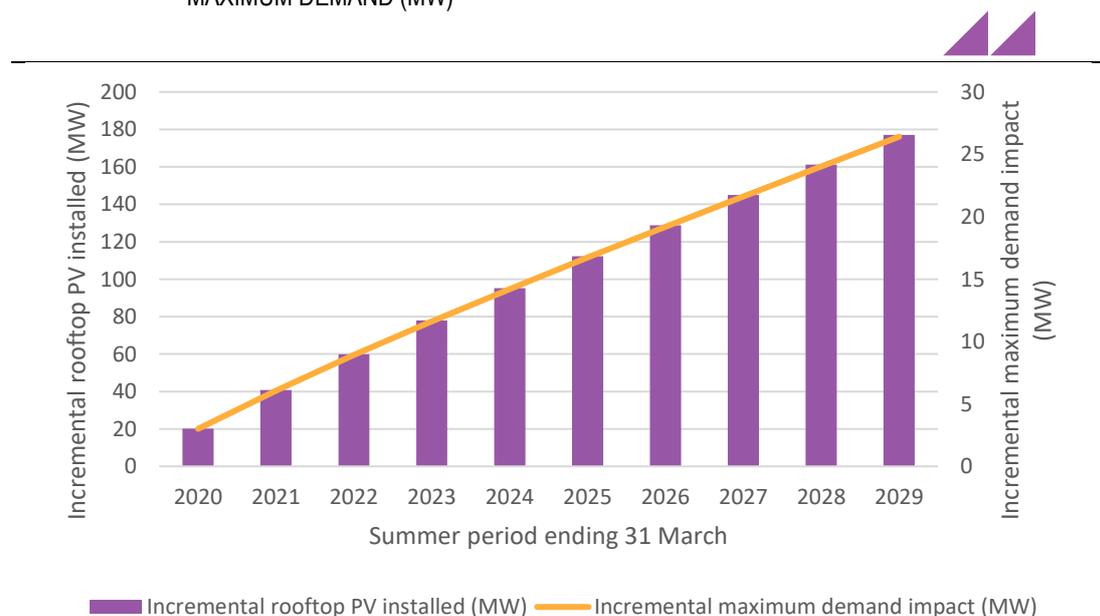
A post model adjustment was made to account for the impact of increased penetration of rooftop PV. The method by which that adjustment was estimated is discussed in more detail in section 8. Broadly, a financial model was used to estimate take up rates for PV systems. The incremental output of those systems during likely maximum demand times was estimated and subtracted from the projected baseline demand.

In the case of the summer maximum demand forecasts, we assume that the peak demand during the forecast period occurs at 4pm in February. At this time of the day, rooftop PV was estimated to be operating at 15 per cent of capacity (based on solar insolation data). The rapid increase in rooftop PV penetration has pushed the time of the maximum demand to later in the day, such that the incremental impact of new installed capacity is reasonably small. February was used because it is the most common peak demand month over the last four summers.

Figure 5.2 below shows the additional impact on summer maximum demand in the JEN distribution network over the forecast horizon. By 2028-29, an addition 177 MW of installed rooftop PV capacity results in a 26 MW reduction in the baseline summer maximum demand forecasts.

There was no post model adjustment made for rooftop PV to the winter system maximum demand forecasts. Maximum demand in winter has tended to occur in the early evening around 6pm. At this time rooftop PV systems are not generating energy.

**FIGURE 5.2** INCREMENTAL IMPACT OF NEWLY INSTALLED ROOFTOP PV CAPACITY ON SUMMER MAXIMUM DEMAND (MW)

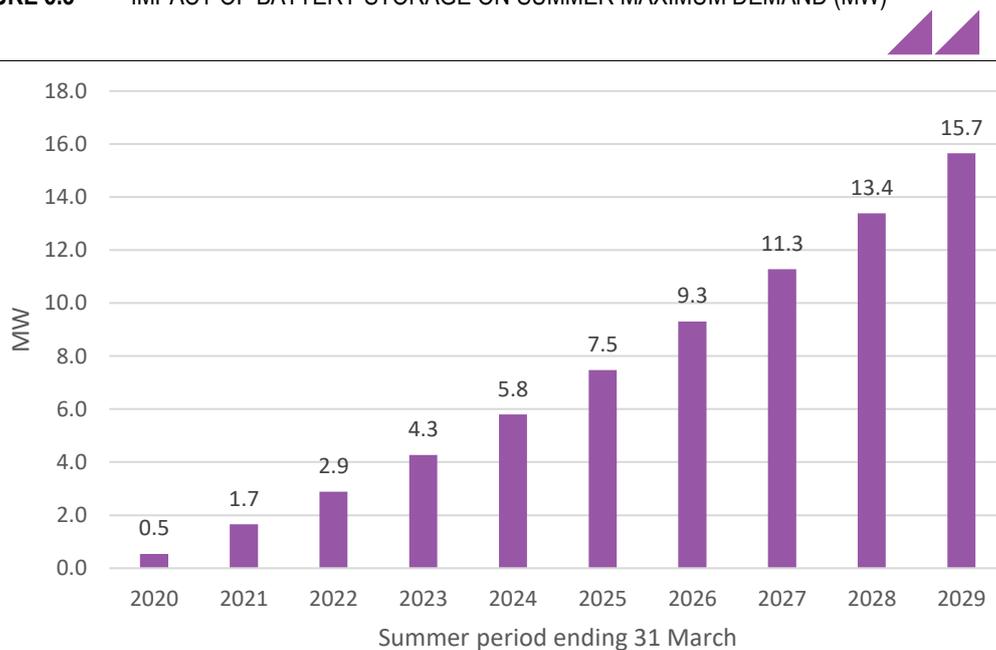


SOURCE: ACIL ALLEN

An adjustment was also made for the uptake of battery storage systems. While there are currently only a negligible number of systems installed within the JEN distribution network, uptake of battery storage systems is expected to increase over time as the price of the systems declines over time. The methodology used to calculate the impact of battery storage on summer maximum demand is described in section 8. The projected maximum demand impact of battery storage systems at the time of the peak is assumed to be 12.5 per cent of the installed capacity. This percentage is in line with the assumption applied by AEMO in its peak demand forecasts for the South West Interconnected System (SWIS) in Western Australia.

Figure 5.3 shows that the impact of battery storage on summer maximum demand is projected to remain relatively small, reaching 16 MW by the summer of 2028-29. There is no adjustment for battery storage made to the baseline winter system maximum demand forecasts.

**FIGURE 5.3** IMPACT OF BATTERY STORAGE ON SUMMER MAXIMUM DEMAND (MW)



SOURCE: ACIL ALLEN

An additional post model adjustment was made for the presence of embedded generation at the time of the maximum demand. In the case of summer peak demand, the base forecast was adjusted downwards by 4.5 MW, which corresponds to the average volume of embedded generation at the time of the system peak for the last four summer seasons.

In the case of the winter system peak, a similar approach was taken, averaging the volume of embedded generation over the most recent seasons, and then applying this average into the forecast period. The base winter system forecasts were adjusted downwards by 2.9 MW in each year of the forecast period.



# 6

## ENERGY CONSUMPTION AND CUSTOMER NUMBERS FORECASTS

In this section we present the final energy consumption and customer numbers forecasts generated after applying the methodology described in the previous sections of this report.

Section 6.1 presents the customer numbers forecasts. Section 6.2 relates to forecasts of energy consumption.

### 6.1 Customer numbers

Table 6.1 presents the historical and forecast customer numbers for the JEN distribution network. As at 2017-18<sup>6</sup>, JEN had a total of 345,056 customers<sup>7</sup>. This is projected to increase at an average annual growth rate of 1.5 per cent per annum. By 2027-28, JEN is projected to have 400,477 customers.

**TABLE 6.1** HISTORICAL AND FORECAST CUSTOMER NUMBERS FOR THE JEN DISTRIBUTION NETWORK BY CUSTOMER CLASS

Year	Residential	Small business	Large business- LV	Large business- HV	Large business-ST	System
2009	272,528	26,442	1,058	80	4	300,111
2010	274,779	26,627	1,129	79	4	302,617
2011	277,073	26,708	1,210	79	4	305,073
2012	281,405	26,793	1,293	80	4	309,574
2013	285,725	26,630	1,340	79	4	313,777
2014	289,767	26,486	1,377	77	4	317,710
2015	294,791	26,734	1,393	77	4	322,998
2016	300,238	27,154	1,345	80	4	328,820
2017	307,106	27,500	1,435	84	4	336,128
2018	315,219	28,217	1,530	86	4	345,056
2019	321,918	28,967	1,506	88	4	352,482
2020	327,362	29,199	1,527	88	4	358,179
2021	332,757	29,427	1,548	88	4	363,823
2022	337,855	29,702	1,569	88	4	369,218

<sup>6</sup> The most recent actual.

<sup>7</sup> Customer numbers are defined as the number of customers as at 30 June.

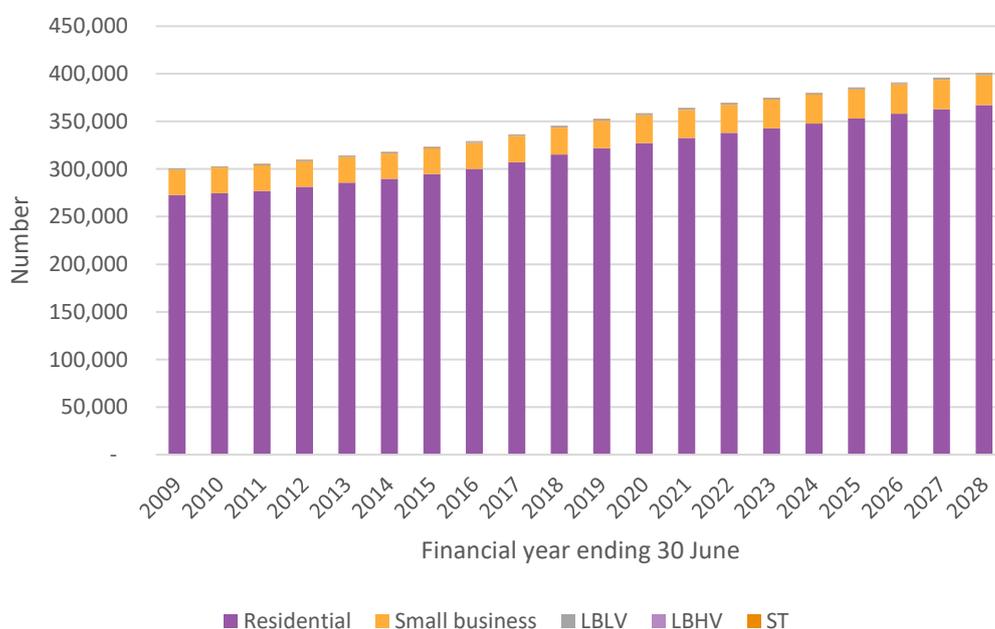
Year	Residential	Small business	Large business- LV	Large business- HV	Large business-ST	System
2023	342,814	29,992	1,590	88	4	374,488
2024	347,865	30,251	1,612	88	4	379,820
2025	353,011	30,492	1,634	88	4	385,228
2026	358,065	30,754	1,656	88	4	390,567
2027	362,761	31,067	1,679	88	4	395,599
2028	367,272	31,412	1,702	88	4	400,477
<b>5 year CAGR %</b>	<b>1.69%</b>	<b>1.23%</b>	<b>0.77%</b>	<b>0.46%</b>	<b>0.00%</b>	<b>1.65%</b>
<b>10 year CAGR %</b>	<b>1.54%</b>	<b>1.08%</b>	<b>1.07%</b>	<b>0.23%</b>	<b>0.00%</b>	<b>1.50%</b>

SOURCE: ACIL ALLEN

By far the largest customer class is residential, which is projected to increase from 315,219 in 2017-18 to 367,272 in 2027-28. This is equivalent to an average annual growth rate of 1.5 per cent. Small business customers are projected to increase from 28,217 in 2017-18 to 31,412 in 2027-28, equivalent to an average growth rate of 1.1 per cent per annum over the forecast period. Large business LV customers are projected to increase at a rate of 1.1 per cent per annum, increasing from 1,530 customers in 2017-18 to 1,702 customers in 2027-28. Large business HV and Large business ST customer numbers are projected to remain stable over the forecast period.

Figure 6.1 presents the data in the table graphically.

**FIGURE 6.1** HISTORICAL AND FORECAST CUSTOMER NUMBERS FOR THE JEN DISTRIBUTION NETWORK BY CUSTOMER CLASS



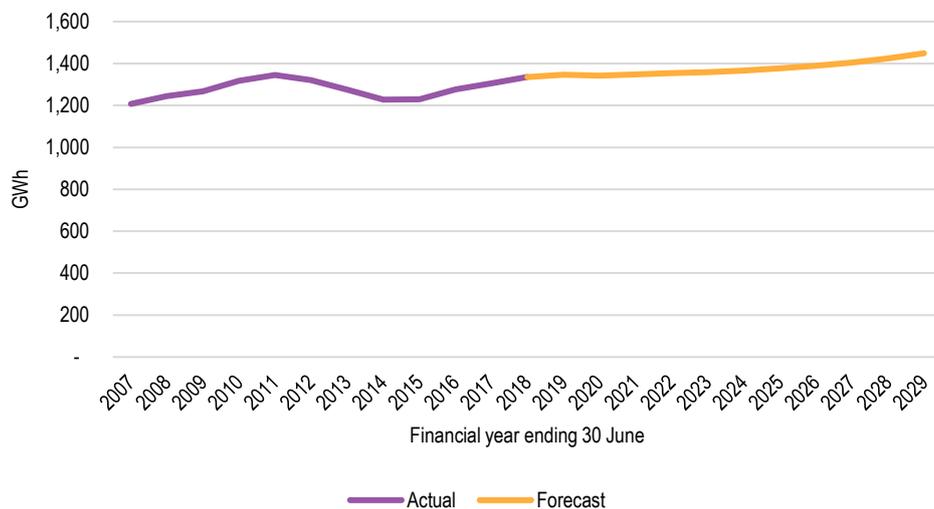
SOURCE: ACIL ALLEN

## 6.2 Energy consumption forecasts

### 6.2.1 Residential energy consumption

Figure 6.2 shows the historical and forecast residential energy consumption from 2006-07 to 2028-29. Residential consumption is expected to continue to grow for the residential class at an annual rate of 0.73 per cent per annum from 1,335 GWh in 2017-18 to 1,449 GWh in 2028-29.

**FIGURE 6.2** ACTUAL AND FORECAST RESIDENTIAL ENERGY CONSUMPTION



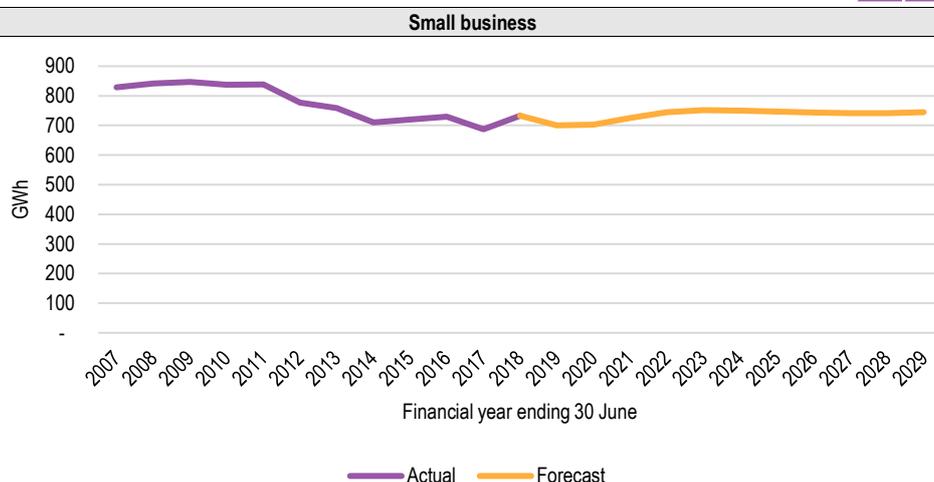
SOURCE: ACIL ALLEN

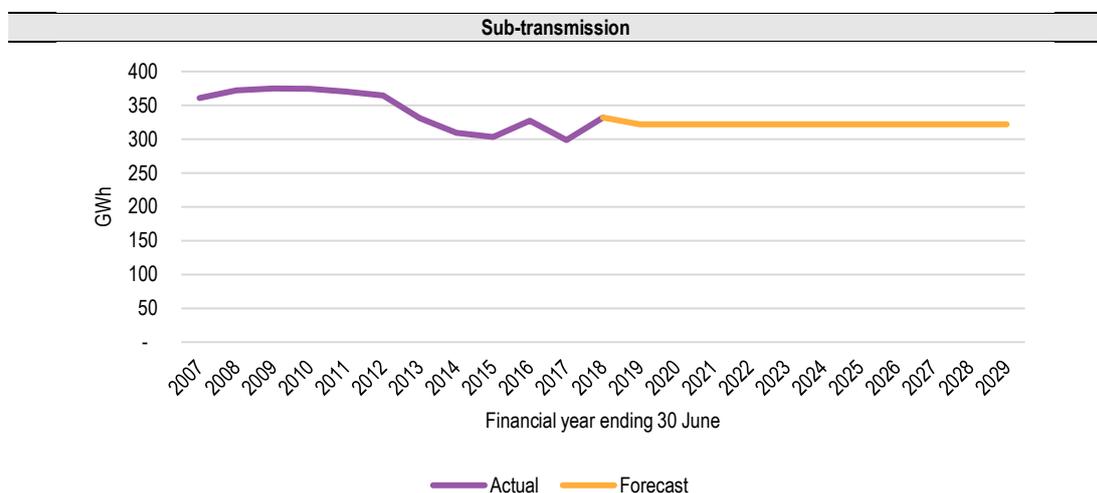
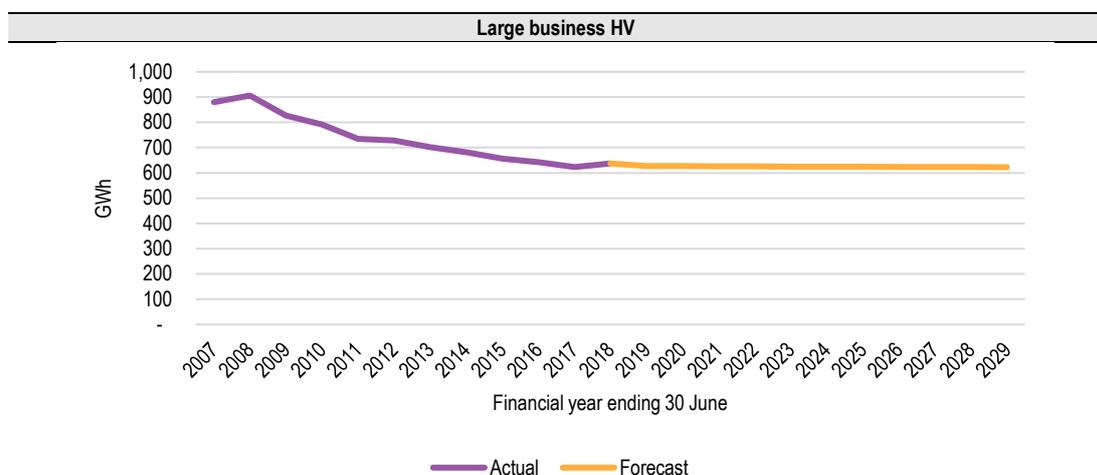
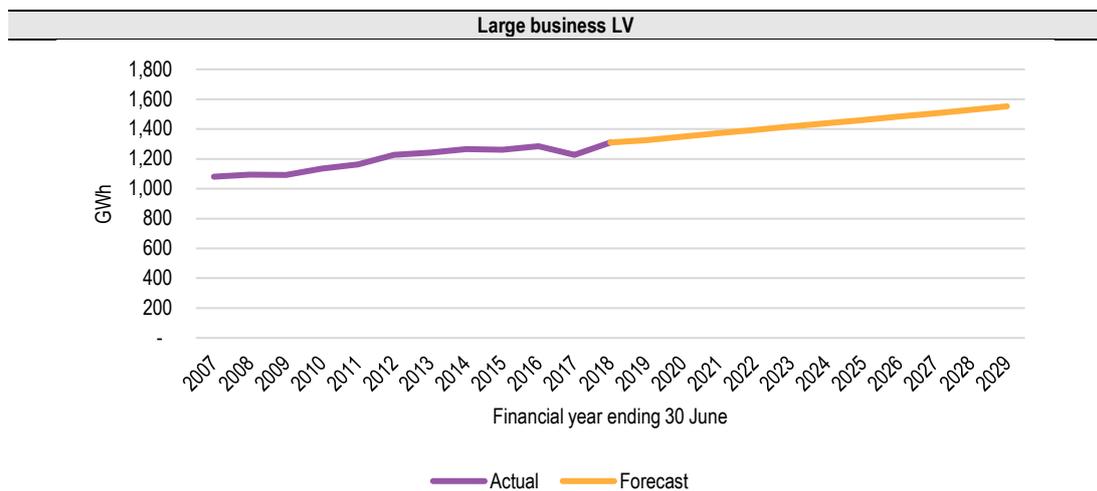
### 6.2.2 Non-residential energy consumption

Figure 6.3 shows the historical and forecast non-residential energy consumption from 2006-07 to 2028-29 for:

- small business in the first pane
- large business LV in the second pane
- large business HV in the third pane
- sub-transmission in the final pane.

**FIGURE 6.3** ACTUAL AND FORECAST NON-RESIDENTIAL ENERGY CONSUMPTION





SOURCE: ACIL ALLEN

Small business consumption is expected to remain relatively flat. It grows at an annual rate of 0.6 per cent per annum from 732 GWh in 2017-18 to 752 GWh 2022-23, before falling to 745 GWh in 2028-29.

Large business LV consumption is expected to continue to rise at an annual rate of 1.6 per cent per annum from 1,310 GWh in 2017-18 to 1,552 GWh in 2028-29.

Large business HV consumption is expected to decline slightly from 637 GWh in 2017-18 to 623 GWh in 2028-29. Sub-transmission forecasts are assumed to remain stable at 332 GWh from 2017-18 to 2028-29.

### 6.2.3 Total energy consumption

Total energy consumption forecasts for JEN were obtained by aggregating the residential and non-residential energy consumption forecasts in the previous sections. These are presented in Table 6.2 below.

**TABLE 6.2** HISTORICAL AND FORECAST ENERGY CONSUMPTION FOR THE JEN DISTRIBUTION NETWORK BY CUSTOMER CLASS, GWH

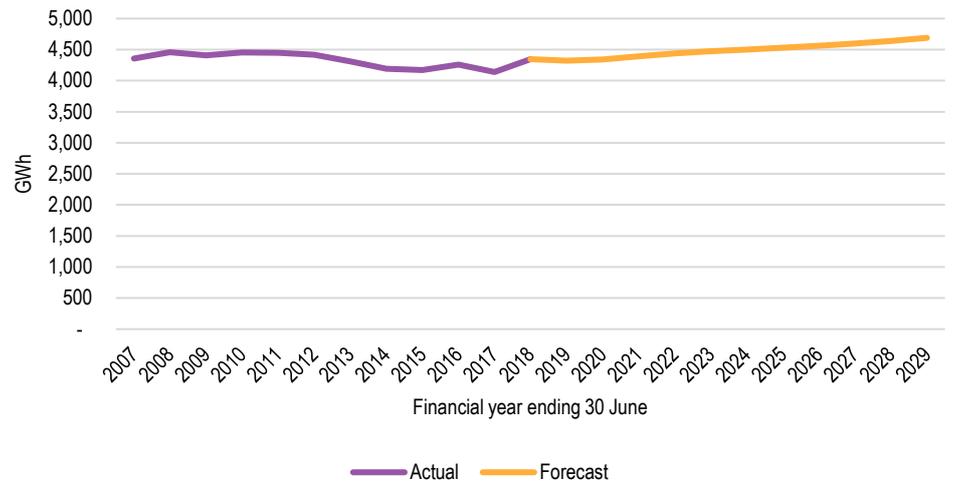
Year	Residential	Small business	Large business- LV	Large business- HV	Large business-ST	System
2009	1,267	847	1,093	827	375	4,409
2010	1,318	838	1,134	792	374	4,455
2011	1,345	838	1,162	735	370	4,451
2012	1,321	777	1,227	728	364	4,417
2013	1,275	759	1,242	702	331	4,309
2014	1,228	710	1,265	682	309	4,195
2015	1,230	720	1,261	656	303	4,170
2016	1,277	730	1,286	643	327	4,262
2017	1,305	687	1,226	623	299	4,140
2018	1,335	732	1,310	637	332	4,347
2019	1,347	700	1,326	627	322	4,323
2020	1,343	702	1,349	627	322	4,343
2021	1,348	725	1,372	626	322	4,392
2022	1,354	745	1,394	626	322	4,440
2023	1,359	752	1,417	625	322	4,475
2024	1,367	750	1,439	625	322	4,503
2025	1,377	747	1,461	624	322	4,531
2026	1,390	743	1,483	624	322	4,562
2027	1,405	742	1,506	623	322	4,598
2028	1,424	742	1,529	623	322	4,639
2029	1,449	745	1,552	623	322	4,690
<b>5 year CAGR %</b>	<b>0.30%</b>	<b>1.37%</b>	<b>1.65%</b>	<b>-0.07%</b>	<b>0.00%</b>	<b>0.82%</b>
<b>10 year CAGR %</b>	<b>0.73%</b>	<b>0.62%</b>	<b>1.58%</b>	<b>-0.07%</b>	<b>0.00%</b>	<b>0.82%</b>

SOURCE: ACIL ALLEN

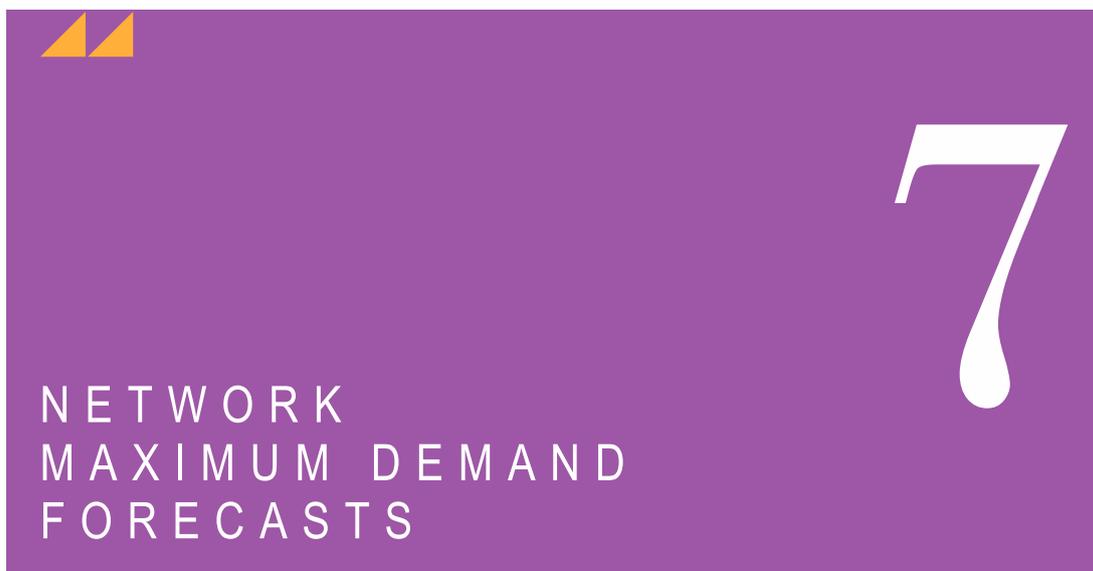
Figure 6.4 shows the historical and forecast total energy consumption in JEN's network from 2006-07 to 2028-29.

Total energy consumption in JEN's network is expected to rise from 4,347 GWh in 2017-18 to 4,690 GWh in 2028-29. This represents growth at an annualised rate of 0.8 per cent per annum over the forecast period.

**FIGURE 6.4** ACTUAL AND FORECAST TOTAL ENERGY CONSUMPTION



SOURCE: ACIL ALLEN



# NETWORK MAXIMUM DEMAND FORECASTS

This section summarises the forecasts of system maximum demand for both summer and winter within the JEN distribution network.

Section 7.1 relates to the forecasts of summer maximum demand. Section 7.2 relates to forecasts of winter maximum demand.

## 7.1 Summer system maximum demand forecasts

The forecasts of summer maximum demand in the JEN distribution network are shown in Table 7.1.

**TABLE 7.1** SUMMER SYSTEM MAXIMUM DEMAND FORECAST, MW, 10POE, 50POE AND 90POE

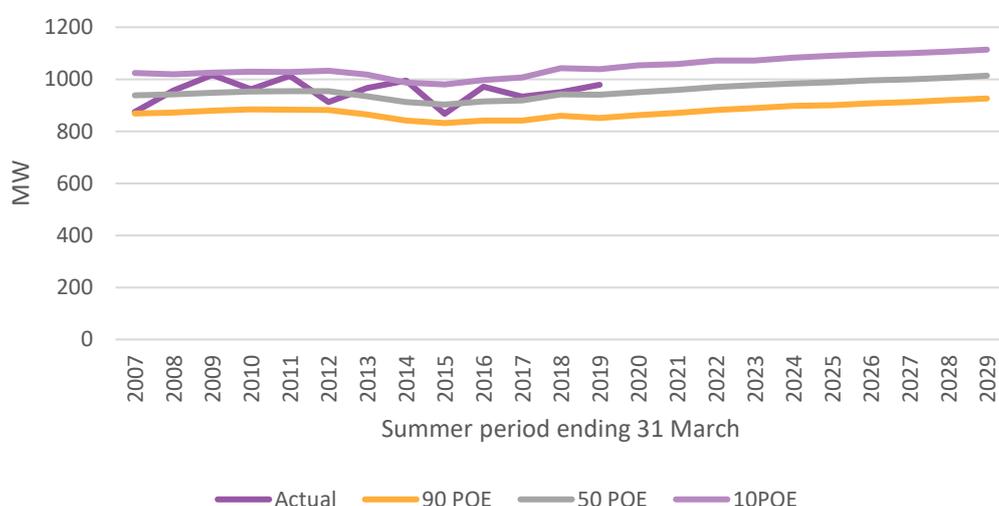
Year	Actual	90 POE	50 POE	10 POE
2007	874	868	938	1024
2008	957	872	942	1019
2009	1017	880	948	1025
2010	962	884	953	1029
2011	1014	884	954	1028
2012	913	882	954	1032
2013	966	864	934	1018
2014	995	842	913	987
2015	867	832	903	980
2016	971	841	915	997
2017	933	842	919	1007
2018	950	860	942	1043
2019	978	851	941	1039
2020		862	950	1053
2021		871	959	1058
2022		882	970	1072
2023		889	978	1072
2024		897	984	1082
2025		900	988	1090

Year	Actual	90 POE	50 POE	10 POE
2026		908	996	1096
2027		912	999	1100
2028		920	1006	1106
2029		926	1014	1114
<b>Average growth (5 years)</b>		<b>1.1%</b>	<b>0.9%</b>	<b>0.8%</b>
<b>Average growth (10 years)</b>		<b>0.8%</b>	<b>0.7%</b>	<b>0.7%</b>

SOURCE: ACIL ALLEN

The results in the table are also presented graphically in Figure 7.1 below.

**FIGURE 7.1** SUMMER SYSTEM MAXIMUM DEMAND FORECAST, MW, 10POE, 50POE AND 90POE



SOURCE: ACIL ALLEN

Both the 10POE and 50 POE forecast summer maximum demand is expected to grow at 0.7% per annum over the period from 2018-19 to 2028-29. The 10 POE summer maximum demand is forecast to reach 1,114 MW in 2028-29, while the 50 POE summer maximum demand will reach 1,014 MW over the same period.

This growth in maximum demand is driven by solid forecast economic growth over the forecast horizon, from a high of 3.0% in 2018-19, before declining moderately to 2.75% for the following four years to 2022-23, and from then on averaging 2.55% for the remainder of the forecast horizon. Also, a decline in the projected real price of electricity provides some additional impetus. Conversely, some downward pressure is provided from the continued uptake in rooftop PV and the installation of battery storage systems within the JEN distribution network over the next decade.

## 7.2 Winter system maximum demand forecasts

The forecasts of winter maximum demand in the JEN distribution network are shown in Table 7.2.

**TABLE 7.2** WINTER SYSTEM MAXIMUM DEMAND FORECAST, MW, 10POE, 50POE AND 90POE

Year	Actual	90 POE	50 POE	10 POE
2007	795	764	780	801
2008	768	757	774	796

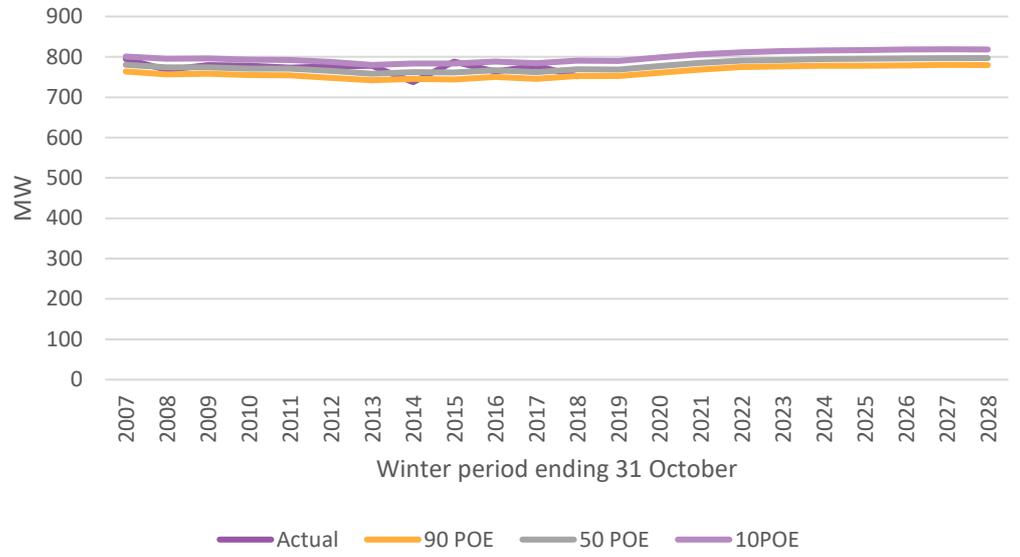
Year	Actual	90 POE	50 POE	10 POE
2009	780	758	774	796
2010	778	755	771	794
2011	773	755	771	792
2012	777	748	765	787
2013	778	742	758	780
2014	738	746	762	784
2015	789	744	762	784
2016	764	750	767	789
2017	778	746	762	785
2018	752	753	769	791
2019		752	769	790
2020		761	777	799
2021		769	786	807
2022		775	790	811
2023		776	792	815
2024		778	794	816
2025		778	795	817
2026		779	796	818
2027		780	797	819
2028		780	797	819
<b>Average growth (5 years)</b>		<b>0.6%</b>	<b>0.6%</b>	<b>0.6%</b>
<b>Average growth (10 years)</b>		<b>0.4%</b>	<b>0.3%</b>	<b>0.4%</b>

SOURCE: ACIL ALLEN

The 10 POE and 50 POE winter system maximum demand is forecast to grow at 0.3 per cent and 0.4 per cent per annum respectively over the period from 2018 to 2028. The 10 POE winter maximum demand is forecast to reach 819 MW in 2028, while the 50 POE is forecast to reach 797 MW over the same period.

Figure 7.2 presents the results in the table graphically.

**FIGURE 7.2** WINTER SYSTEM MAXIMUM DEMAND FORECAST, MW, 10POE, 50POE AND 90POE



SOURCE: ACIL ALLEN

# 8

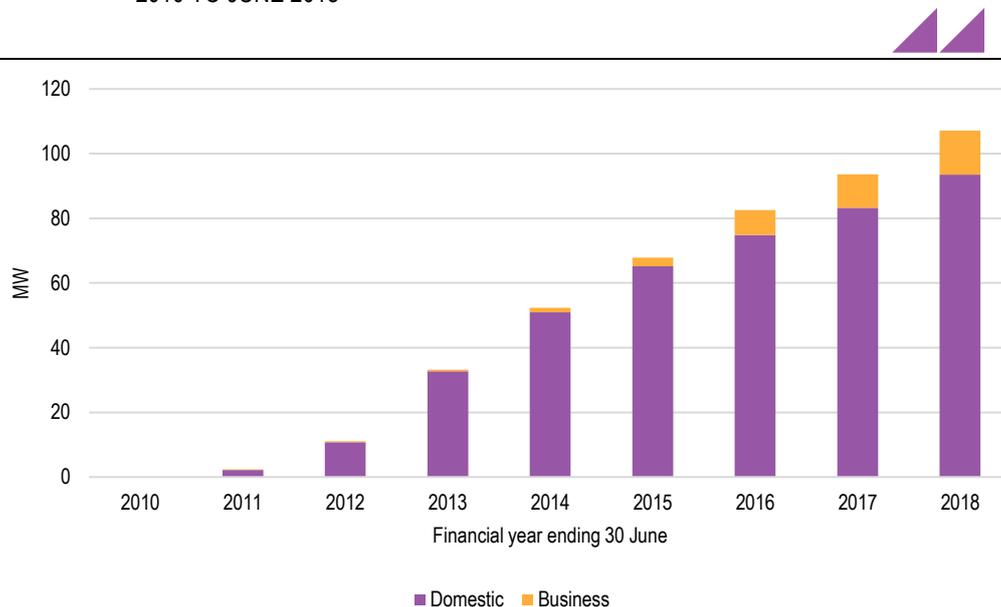
## ROOFTOP PV AND BATTERY STORAGE

In this section we outline our methodology and assumptions underlying the rooftop PV and battery storage forecasts.

### 8.1 Historical trends in rooftop PV uptake

The historical capacity of rooftop PV in the JEN distribution network reached 107 MW by June 2018 (see Figure 8.1). Of this, 93 MW of capacity consisted of residential systems and 14 MW consisted of non-residential systems (classified as small business in the forecasts).

**FIGURE 8.1** HISTORICAL ROOFTOP PV CAPACITY IN THE JEN DISTRIBUTION NETWORK, JUNE 2010 TO JUNE 2018



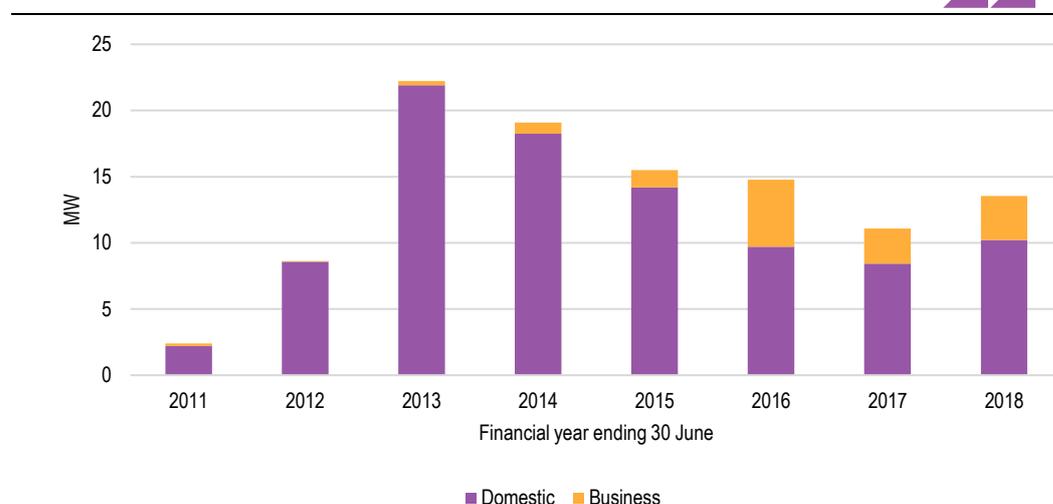
SOURCE: JEMENA ELECTRICITY NETWORKS

Figure 8.2 shows the installed capacity of rooftop PV in the JEN network on an annual basis.

In the 2017-18 financial year, there was a total of 13.5 MW installed in the JEN distribution network, of which 10.2 MW was installed by households and 3.3 MW by businesses. The highest volume of rooftop PV capacity installed was in 2012-13, when 22.2 MW of rooftop PV capacity was installed. This is a pattern that has been consistent across the country and reflects the reality of persistently rising electricity prices over time as well as continued falls in the price of installation of new rooftop PV

systems. New installations have also been encouraged by the presence of a feed in tariff and the subsidy provided by the creation of STCs under the SRES and through the Solar Credit multiplier.

**FIGURE 8.2** ROOFTOP PV ANNUAL INSTALLED CAPACITY IN THE JEN DISTRIBUTION NETWORK, RESIDENTIAL AND SMALL BUSINESS



SOURCE: JEMENA ELECTRICITY NETWORKS

Future growth rates are not expected to be as strong as those observed historically due to more moderate declines in rooftop PV system costs, lower rates of growth in future electricity prices and the phasing out of subsidies, such as the annual reduction in the deeming period associated with the creation of STCs upon installation. Furthermore, future growth in rooftop PV systems will occur from a significantly higher base than the growth rates experienced up until very recently, meaning that historical rates of growth in rooftop PV uptake are unlikely to be repeated.

## 8.2 Overview of approach to modelling the uptake of rooftop PV and battery storage

ACIL Allen's forecast of the uptake of rooftop PV systems and battery storage is based on regression analysis of historic financial returns to rooftop PV systems and associated rates of uptake.

The historic relationship between financial returns and uptake is established in this way and is used as the basis of forecasting of future rooftop PV uptake, given expectations about changes in rooftop PV system costs and electricity prices (among other things). Future financial returns of rooftop PV systems with and without battery storage are also calculated to estimate uptake of storage.

### 8.2.1 Historic financial returns to rooftop PV

Assumptions for the model relate principally to either historic uptake of rooftop PV (the regression model's 'dependent variable') or to the real net financial return to rooftop PV installations (the regression model's key 'explanatory variable'). These are discussed separately below. Further, as real financial returns are driven by several distinct factors, these are discussed separately. These factors are:

- PV system installation costs (see section 8.3)
- Rebates and subsidies (see section 8.4)
- Retail electricity prices and the structure of these charges to consumers (see section 8.5)
- Payments for exported electricity, generally known as 'feed-in tariffs' or 'buyback rates' (see section 8.6)
- System output and export assumptions (see section 8.7).

## 8.2.2 Regression analysis

The model for the uptake of rooftop PV systems uses a quarterly resolution and separately estimates the uptake of rooftop solar as the percentage of eligible dwellings/buildings where a PV system is installed. Uptake is estimated based on a regression of historical uptake rates against a measure of payback (NPV) to households/businesses from installing a certain amount of solar capacity. Separate regression models are estimated for both small scale residential and commercial systems.

Projections of future financial returns from rooftop PV and battery storage as measured by NPV are then used to estimate the future uptake of rooftop PV capacity.

It should be noted that a range of other factors may affect household and business decisions to install rooftop PV systems. Many of these factors are not easily quantifiable, such as environmental attitudes, marketing and anecdotal responses to the experiences of friends and family. Nevertheless, it is still reasonable to project future installation rates for this technology as being related to the financial attractiveness of the systems, even if the decision-making process of the households and businesses making the decision is not directly or exclusively financial.

## 8.3 Rooftop PV system costs

The capital cost of a rooftop PV system is made up of the module cost and the balance of system cost (BOS).

The rooftop PV module cost is the cost of the PV cells themselves. These are generally driven by factors such as raw material costs, predominantly silicon prices as well as the cost of processing, manufacturing and assembly. The balance of system costs includes the cost of the structural and electrical system required for the rooftop PV cells to operate. These costs include site preparation, racks, inverters, transformers, wiring and electrical installation costs.

The cost of installing a PV system has decreased over time. ACIL Allen's estimates of historic system cost are derived by taking a Victorian average system cost which is scaled to account for differences in cost due to system size and to account for differences in system costs between different states and territories. No allowance is made for the cost of inverter replacement or for ongoing system maintenance costs.

For the period from October 2012, the average cost of installing a PV system in Melbourne is based on SolarChoice's *PV Price Check* publication (renamed more recently to the residential and commercial solar PV price index).<sup>8</sup> That publication sets out offered prices for systems of different sizes in each capital city.

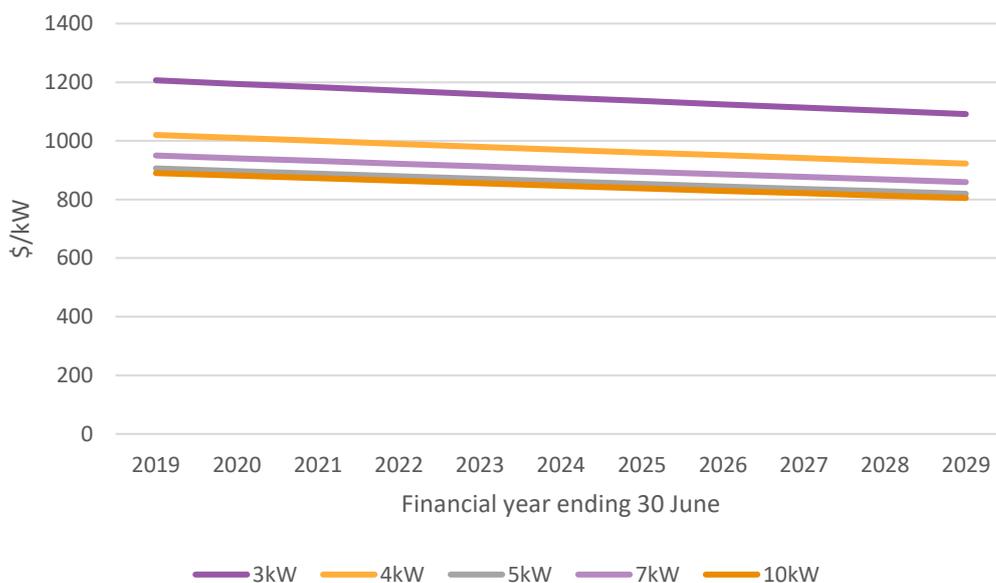
Prior to December 2012 this data was unavailable, so different data sources were used in order to recreate a complete historical time series for regression purposes.

The system cost projections anticipate a continuation of recent cost trends in rooftop PV, with system prices flattening on a per kW basis. The main factors at play in the solar rooftop PV market include changes in the AUD/USD exchange rate, increasing competition in the domestic market and continued improvements in technical efficiency leading to further reductions in system prices.

ACIL Allen assumes a 1 per cent decline in the real price of rooftop PV systems over the forecast period. This is considerably slower than the rate of price decline observed historically, however, this reflects the fact that the technology has now matured.

Figure 8.3 shows the projected system cost of a small-scale rooftop PV system under the assumed 1 per cent per annum real price decline. The starting value is the Solar Choice's June 2019 Solar PV index. For a 5 kW system, the per kW system cost is projected to decline from \$906/kW in 2018 to \$819 in 2029.

<sup>8</sup> See [www.solarchoice.net.au](http://www.solarchoice.net.au).

**FIGURE 8.3** PROJECTED SYSTEM COST OF ROOFTOP PV SYSTEMS, MELBOURNE \$2019

SOURCE: SOLAR CHOICE, SOLAR PV INDEX- JUNE 2019

## 8.4 Rebates and subsidies

Two sources of upfront rebates and subsidies for PV installations are taken into account:

- the former Solar Homes and Communities Program (SHCP), which provided an upfront cash rebate
- the indirect subsidy provided by the creation of STCs under the SRES, including the creation of additional STCs through the 'Solar Credits multiplier'.

Under SHCP, customers who installed rooftop PV systems received an upfront rebate of \$8,000. SHCP was in place at the beginning of 2009, and was closed during June 2009. However, as systems installed in the second half of that year received assistance based on prior applications for the rebate, it is analysed as having an effect on some installations in the second half of 2009.

In addition to the upfront payment through SHCP, rooftop PV systems were eligible to create certificates for the renewable electricity they generate during the historic period. The value of these certificates (initially RECs created under the Renewable Energy Target and then STCs created under the SRES) provides an upfront subsidy to installation of PV systems.

The value of this subsidy depends on the system size and certificate price. From June 2009 until 31 December 2012, it also depended on the 'solar credit multiplier', which was established under the Solar Credits scheme and allowed eligible customers who installed PV systems were deemed to create additional RECs/STCs, thereby increasing the amount of the subsidy. The multiplier was originally 5, meaning that a PV system would create 5 solar credits for every MWh of electricity it was deemed to generate, for the first 1.5 kW of capacity installed. The multiplier then declined over time.

The SHCP was phased out in favour of Solar Credits during 2009. Customers could benefit from either the SHCP or the Solar Credits multiplier, but not both. To address the overlap between these two policies, 50% of PV installations in quarter 3 2009, and 20% in quarter 4 2009 were assumed to receive the SHCP rebate. The remainder were assumed to use the Solar Credits multiplier to generate extra certificates.

The solar multiplier and certificate values factored into the analysis are shown in Table 8.1. In effect, a rooftop PV system installed in 2009 was assumed to receive part of the SHCP grant and part of its entitlement through Solar Credits.

**TABLE 8.1** SOLAR CREDITS MULTIPLIER AND SHCP REBATE

	Until July 2009	Q3 2009	Q4 2009	Q1 2010 – Q2 2011	Q3 2011 – Q2 2012	Q3 & Q4 2012	From January 2013
Solar Credits multiplier	1	3.0	4.2	5	3	2	1
SHCP value	\$8,000	\$4,000	\$1,600	\$0	\$0	\$0	\$0

SOURCE: ACIL ALLEN, RENEWABLE ENERGY (ELECTRICITY) REGULATIONS 2001

Unlike the SHCP payment, the value of RECs/STCs, and therefore the total rebate derived from these certificates, varied over time according to the market price at the time. Up until May 2017, the STC price was very close to the Clearing house price of \$40/STC. From June 2017 onwards, the STC price declined due to an oversupply in certificates, before staging a recovery. The STC market price as at 13 September 2019 was \$36.50.

Beyond 2019, the STC is assumed to remain constant (in nominal terms), returning to its longer term average at \$40 per certificate, which is the Clearing house price.

Until 1 January 2017, all systems are assumed to create 15 years of 'deemed' RECs/STCs at the time of installation, and then cease to be eligible for further certificates after 15 years. Between 2017 and 2030 the deeming period is assumed to decline by one year in each year so that systems installed in 2030 are deemed to create certificates for one year only.

## 8.5 Retail electricity prices

Retail electricity prices are important to the financial return on rooftop PV and battery storage as every kWh of solar output that is consumed by the owner of the system avoids the variable component of the retail electricity price. The significant rise in retail electricity prices in recent history has provided a major spur to households and businesses to install rooftop PV capacity.

Figure 8.4 shows the historical and projected electricity price in real terms. ACIL Allen has generated its own electricity price forecasts using its own proprietary electricity market model *PowerMark*.

**FIGURE 8.4** HISTORICAL AND PROJECTED REAL ELECTRICITY PRICES, \$2018



SOURCE: ACIL ALLEN

The real electricity charge in 2019 is 30.08 cents per kWh for residential customers and 30.34 cents per kWh for small business customers. The electricity price is projected to decrease to about 22 cents by 2022, before stabilising.

## 8.6 Feed-in tariffs and buy back rates

When rooftop PV systems produce more power than is required at the premises at which they are installed, the electricity is exported to the grid and on-sold to other customers. The value of this exported electricity is another important component of the financial return to PV installation.

In general, exported PV output always displaces electricity that would otherwise be purchased from the wholesale market, and therefore provides some value to the retailer that on-sells this electricity. Accordingly, retailers that supply power to owners of rooftop PV systems are generally willing to pay some amount for exported PV output that is separate from, and additional to, any premium feed-in tariff that might be imposed by legislation. The term 'buyback rate' refers to these payments by retailers that reflect the value of exported PV output to the retailer, and which, whilst sometimes regulated, are not intended to offer a premium rate or purposefully subsidise PV systems.

Premium feed-in tariffs were in place in Victoria from the beginning of the period analysed until September 2012. The rates were:

- the retail price of electricity until 31 August 2009
- 60 c/kWh from 1 September 2009 until 31 December 2011, payable from the date of installation until 30 June 2024
- 25 c/kWh between 1 January and 30 September 2012, payable from the date of installation until 30 June 2016

From July 1 2017, the Victorian Government mandated a higher minimum solar feed in tariff of 11.3 cents per kWh, which replaced the regulated minimum buy-back rate of 5 cents per kWh, available up until the end of June 2017.

From July 1 2018, the Victorian Government has introduced two types of government mandated feed-in tariff, a flat minimum rate of 9.9 cents per kWh or a time varying rate between 7 cents and 29 cents per kWh. Exports of rooftop PV output will receive 7.1 cents per kWh during off-peak periods, 10.3 cents per kWh during the shoulder period and 29.0 cents per kWh during the peak period.

From the financial year commencing 1 July 2019, the single rate minimum feed-in-tariff increased from 9.9 cents per kWh to 12 cents per kWh. For those customers on the time varying tariff, the off-peak rate and shoulder rate have increased to 9.9 cents per kWh and 11.6 cents per kWh respectively, while the peak rate has been significantly reduced to 14.6 cents per kWh.

## 8.7 System output and export rates

System output is estimated based on four solar zones created by the CER for the purpose of calculating REC and STC creation by rooftop PV, which have different assumed rates of solar output per kW of installed capacity. Each postcode is assigned a zone, whereas multiple solar zones may exist in a given state, territory or network area. These zones as the solar output values are as follows:<sup>9</sup>

- Zone 1: 1.622 MWh per kW of capacity
- Zone 2: 1.536 MWh per kW of capacity
- Zone 3: 1.382 MWh per kW of capacity
- Zone 4: 1.185 MWh per kW of capacity.

In the case of JEN, we assume that its customers are located within Zone 4.

Table 8.2 shows the assumed rooftop PV export rates by system size. These are broadly aligned with sampled data from the solar energy consultancy SunWiz.

<sup>9</sup> Clean Energy Regulations 2001, Schedule 5

For commercial systems we have assumed a lower export rate of on average 10% due to the better match between commercial load profiles and solar electricity generation.

**TABLE 8.2** ASSUMED ROOFTOP PV EXPORT RATES

System size (kW)	Low	Medium	High
1.5	35%	35%	35%
2	45%	45%	45%
3	60%	60%	60%
4	65%	65%	65%
5	70%	70%	70%
6	70%	70%	70%
8	70%	70%	70%
10	70%	70%	70%
10 < and <100 (Commercial)	10%	10%	10%

SOURCE: ACIL ALLEN

## 8.8 Uptake of battery storage systems

At the household level, battery storage systems are currently economically unviable for most consumers in Australia. This is due to high installation costs and technical limitations relating to depth of discharge and the number of charge/discharge cycles that can be achieved. The number of cycles that can be achieved with a system plays a crucial role in determining its profitability. At a given rate of use, the number of cycles amounts to the system's useful life.

The benefits to end user customers from using an energy storage system are that they can:

- store solar generation that would otherwise be exported to the grid, thus enhancing the financial value of that electricity to the customer
- avoiding network charges especially charges related to peak network demand i.e. kVa charges noting that most households are not charged for peak demand at present, though this is likely to change in the medium term
- using lower priced off-peak electricity to meet day time energy demand<sup>10</sup>.

By storing excess solar generation in an energy storage system, customers forego any payments they would otherwise receive for electricity exported to the network i.e. renewable energy buyback rates or feed-in tariffs. Net benefits to households from storing excess solar generation therefore arise from the difference in the renewable energy buyback rate and the variable electricity tariff incurred by the household.

ACIL Allen models the impact of battery storage systems on maximum demand by projecting the uptake of such systems. It does this by relating installation rates of battery storage systems to the Net Present Value (NPV) achieved by installing such a system.

Storage has not been adopted in any meaningful volume by households in Australia, and so storage (battery) costs are not relevant to ACIL Allen's analysis of historic financial returns to rooftop PV systems. However, this analysis did examine the potential for widespread uptake of battery storage by households and businesses in the future based on expected financial returns to storage.

This analysis was based on two main elements:

- The financial cost of storage, being upfront battery installation costs and expected battery replacement costs

<sup>10</sup> The same electricity tariffs have been assumed to apply in projecting battery storage as in the case of rooftop PV systems.

- The financial benefit of storage, being the change in export rates multiplied by the difference between the retail price of electricity (the benefit of own consumed electricity) and the buy-back rate for exported electricity (the benefit of exporting electricity).

We assume that the relationship between NPV and installation rates of battery storage systems will be similar to the relationship between NPV and installation rates of rooftop PV systems which could be observed historically. All existing and future residential and commercial solar installations are assumed to be candidates for the installation of battery storage.

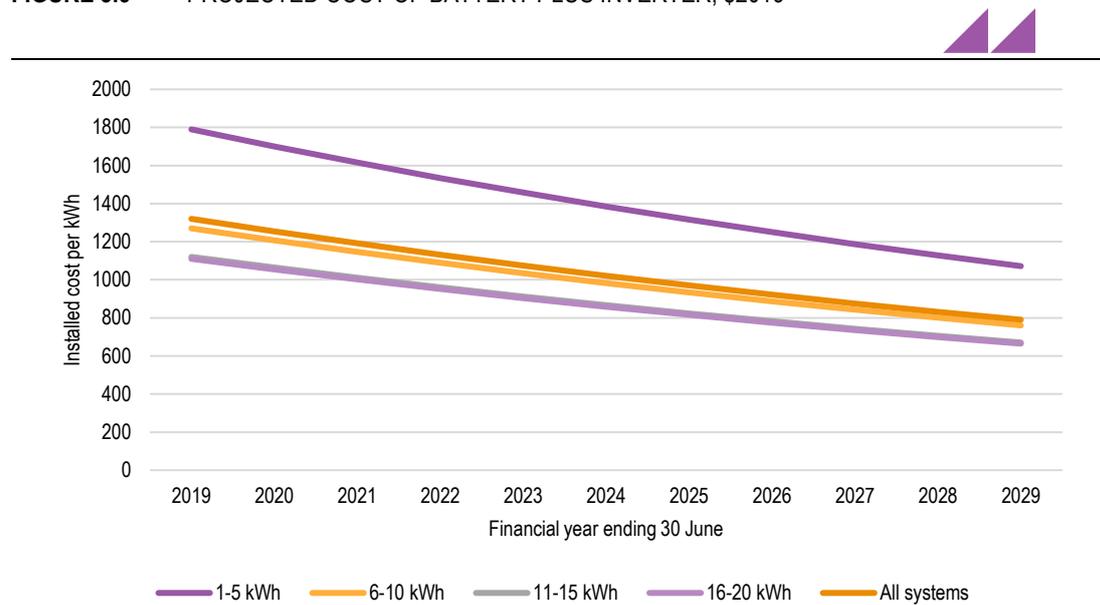
The economics of battery installations are also affected by the technical characteristics of battery technology. The depth of battery discharge negatively affects battery life – the higher the depth of discharge the shorter the life of the battery. We assume daily cycling of the battery with a depth of discharge of 80% and a lifetime of 10 years (equivalent to 3,650 cycles in its lifetime). The main assumptions deployed shown in Table 8.3 below.

**TABLE 8.3** MAIN ASSUMPTIONS APPLIED IN STORAGE PROJECTIONS

Battery storage assumptions	
Battery pack life (years)	10.00
Real battery cost decline rate (% p.a.)	5.0%
Efficiency	90.0%
Cycle depth	80%

Figure 8.5 shows the projected real cost of a battery plus inverter assuming a real decline of 5 per cent per annum. The cost of a battery plus inverter across all system sizes is projected to decline from \$1320 per kWh in 2019 to \$790 per kWh in 2029.

**FIGURE 8.5** PROJECTED COST OF BATTERY PLUS INVERTER, \$2019



SOURCE: SOLAR CHOICE, BATTERY STORAGE INDEX- MAY 2019 AND ACIL ALLEN CALCULATIONS

Battery storage is expected to reduce the summer peak demand over time as the installed capacity of systems increases.

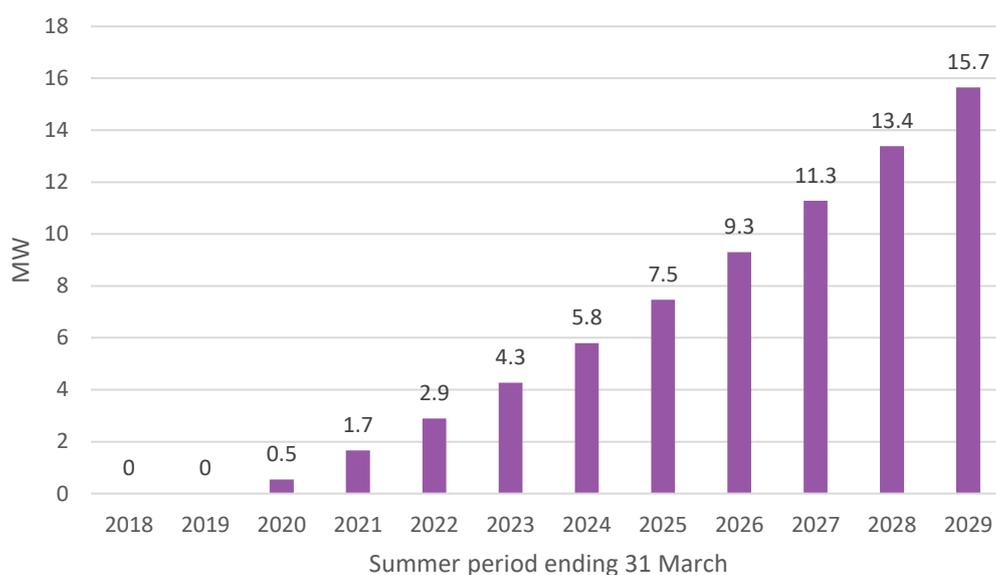
To calculate the impact of new battery storage systems on summer peak demand the following assumptions were made:

- batteries are charged at a constant rate in the morning and early afternoon hours.
- battery systems are charged only from the households attached rooftop PV panels and not from the grid

- batteries are then discharged in the late afternoon / early evening which includes the time of summer system maximum demand.
- batteries are used only to shift consumption of rooftop PV generation over the course of the day and for no other purpose
- the batteries charge and discharge rates do not contravene the technical constraints of the technology.

The forecast impact of battery storage on summer peak demand is shown in Figure 8.6. Battery storage systems are forecast to reduce maximum demand by 15.7 MW in 2028-29. Even with the very fast rate of growth in battery storage systems, storage is expected to make only a small impact on overall maximum demand.

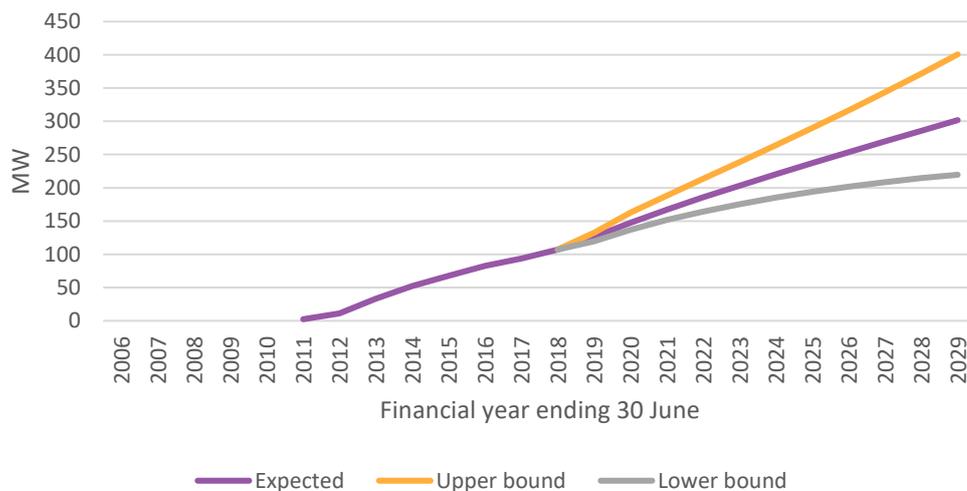
**FIGURE 8.6** FORECAST OF BATTERY STORAGE IMPACT ON MAXIMUM SUMMER DEMAND, MW



SOURCE: ACIL ALLEN

## 8.9 Rooftop PV and battery storage forecasts

Total rooftop PV installed in the JEN distribution region is projected to increase from 107 MW at June 30 2018 to 302 MW in June 2029 (see Figure 8.7).

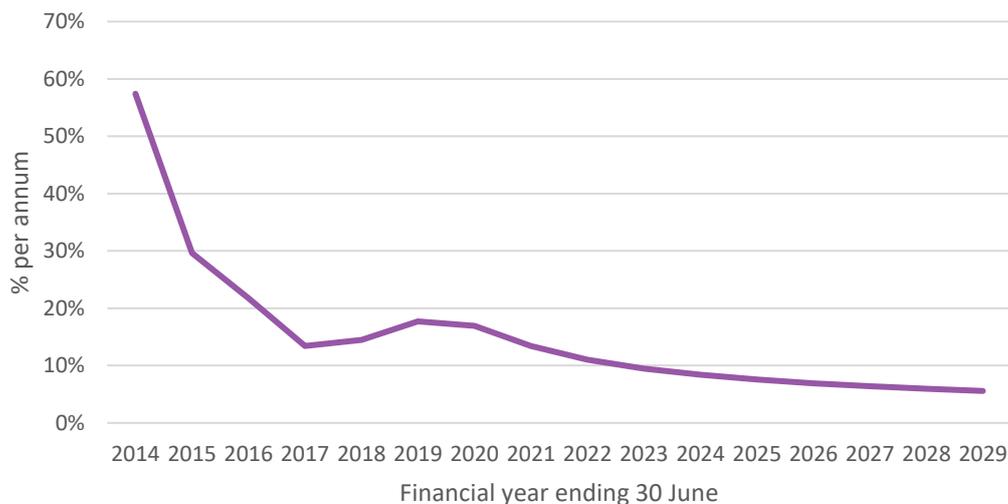
**FIGURE 8.7** INSTALLED ROOFTOP PV CAPACITY AS AT JUNE 30, HISTORICAL AND FORECAST

SOURCE: ACIL ALLEN

This is equivalent to an annualised growth rate of 9.9% per annum over the full period. Figure 8.8 shows the year on year growth rate during the forecast period. The figure shows a steady downward trend in the annual growth of rooftop PV systems, starting at 18% in 2018-19 and then declining steadily to 6% by 2028-29. There are several reasons for this:

- Real electricity prices which have grown considerably over the historical period are projected to stop rising after 2019 and then commence a decline
- The number of STCs created under the SRES for each new system declines in every year of the forecast period as the deeming period is assumed to decline by 1 year in each year after 2017. A system installed in 2029 will be deemed to create certificates for 2 years, while a system installed prior to 2017, was deemed to create certificates for 15 years
- As the installed capacity continues to rise strongly, the number of available residences in which rooftop PV can be installed declines.

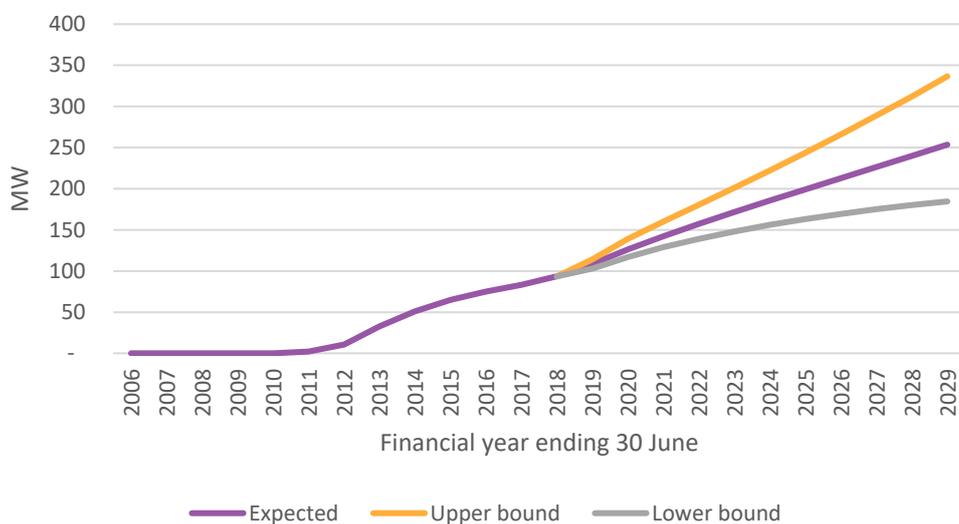
**FIGURE 8.8** ANNUAL GROWTH IN ROOFTOP PV CAPACITY, HISTORICAL AND FORECAST



SOURCE: ACIL ALLEN

Figure 8.9 shows the historical and projected residential rooftop PV capacity for the JEN distribution network. Residential rooftop PV is expected to increase from 94 MW in June 2018 to 254 MW in June 2029. This is equivalent to an annual growth rate of 9.5% per annum over the next decade.

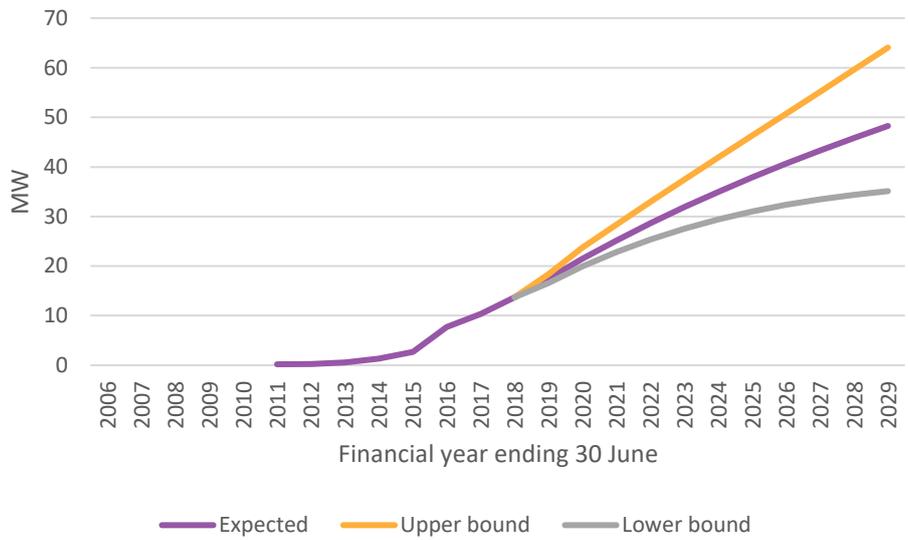
**FIGURE 8.9** RESIDENTIAL INSTALLED ROOFTOP PV CAPACITY AS AT JUNE 30, HISTORICAL AND FORECAST



SOURCE: ACIL ALLEN

Figure 8.10 presents the historical and projected small business rooftop PV installed in the JEN distribution network over the forecast period.

**FIGURE 8.10** SMALL BUSINESS INSTALLED ROOFTOP PV CAPACITY AS AT JUNE 30, HISTORICAL AND FORECAST, EXPECTED

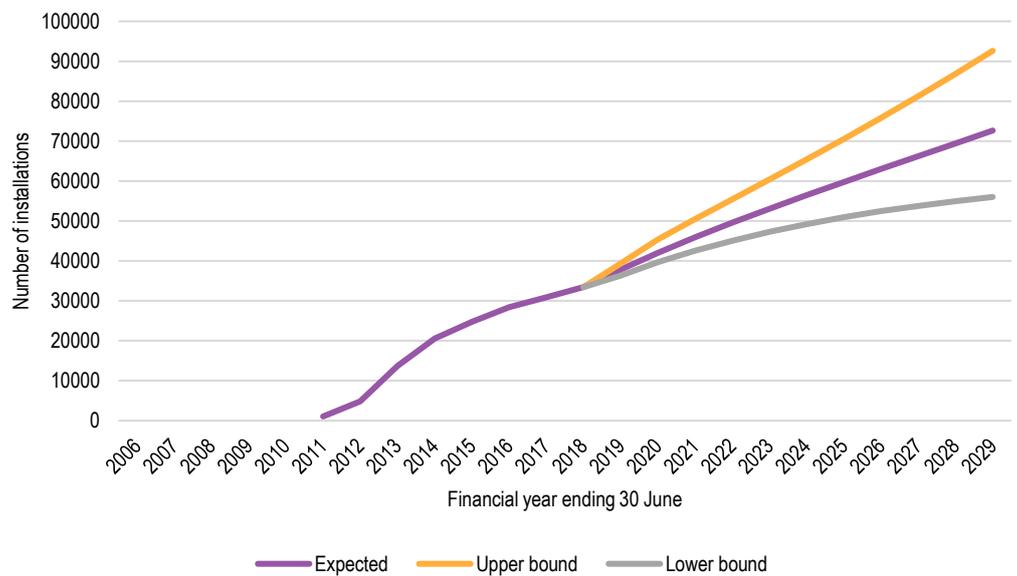


SOURCE: ACIL ALLEN

Small business PV capacity in the JEN network is projected to increase from 14 MW as at June 30 2018 to 48 MW in 2029. This is equivalent to an annualised rate of growth of 12.1%.

The number of installed rooftop PV systems in the JEN distribution region is projected to increase from 33.4 thousand at June 30 2018 to 72.6 thousand in June 2029 (see Figure 8.11).

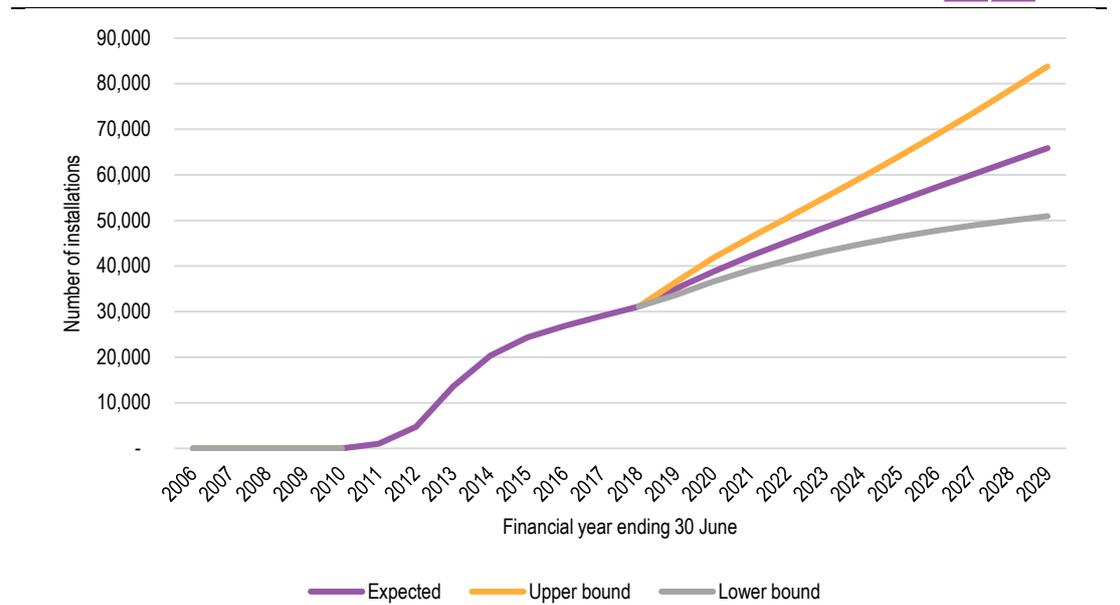
**FIGURE 8.11** NUMBER OF ROOFTOP PV INSTALLATIONS AS AT JUNE 30, HISTORICAL AND FORECAST



SOURCE: ACIL ALLEN

Figure 8.12 shows that the number of residential rooftop PV systems installed in the JEN distribution region is projected to increase from 31.2 thousand at June 30 2018 to 65.9 thousand in June 2029.

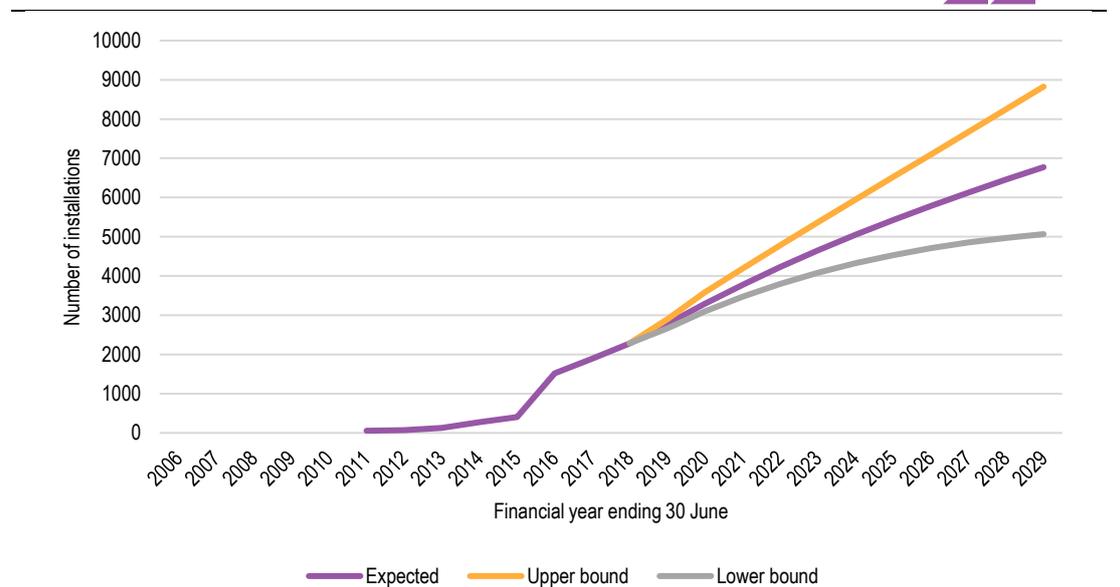
**FIGURE 8.12** NUMBER OF RESIDENTIAL ROOFTOP PV INSTALLATIONS AS AT JUNE 30, HISTORICAL AND FORECAST



SOURCE: ACIL ALLEN

Figure 8.13 shows that the number of small business rooftop PV systems installed in the JEN distribution region is projected to increase from 2.3 thousand at June 30 2018 to 6.8 thousand in June 2029.

**FIGURE 8.13** NUMBER OF SMALL BUSINESS ROOFTOP PV INSTALLATIONS AS AT JUNE 30, HISTORICAL AND FORECAST

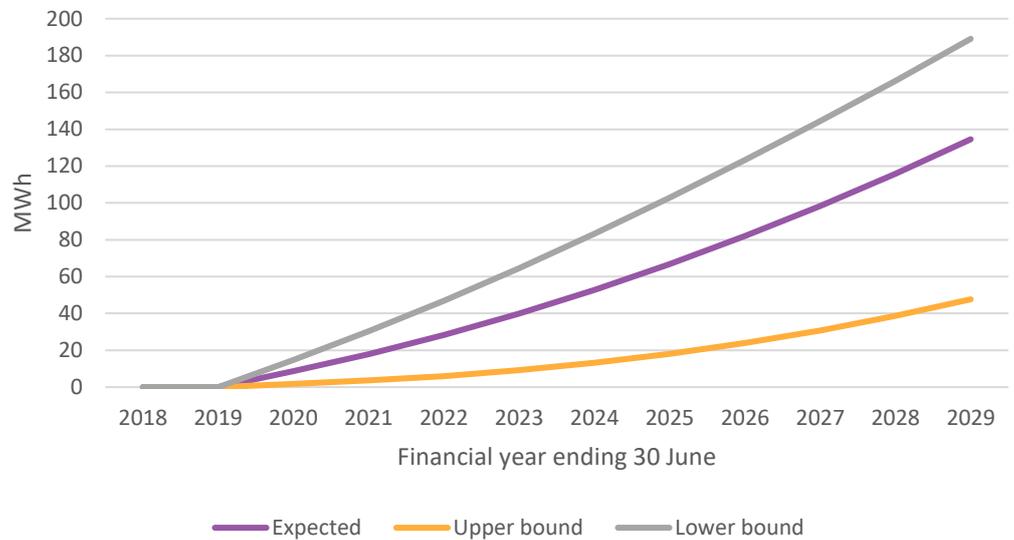


SOURCE: ACIL ALLEN

The projected uptake of total battery storage systems in the JEN distribution network is presented in Figure 8.14 below. The capacity of installed battery systems is projected to increase from an estimated 0 MWh in 2019 to 135 MWh in 2029. This strong rate of growth is very much a function of a

sustained and strong reduction in the projected cost of installation as battery costs continue to decline and economies of scale lead to further cost reductions.

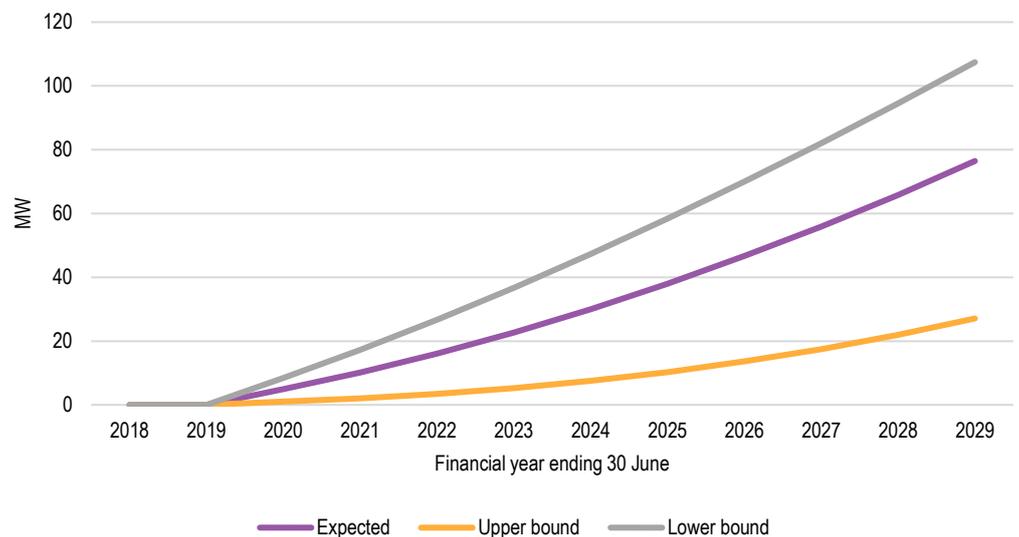
**FIGURE 8.14** FORECAST UPTAKE OF BATTERY STORAGE, MWh



SOURCE: ACIL ALLEN

Figure 8.15 shows the growth in battery storage capacity measured in MWs. The capacity of installed battery systems is projected to increase from an estimated 0 MW in 2019 to 76 MW in 2029.

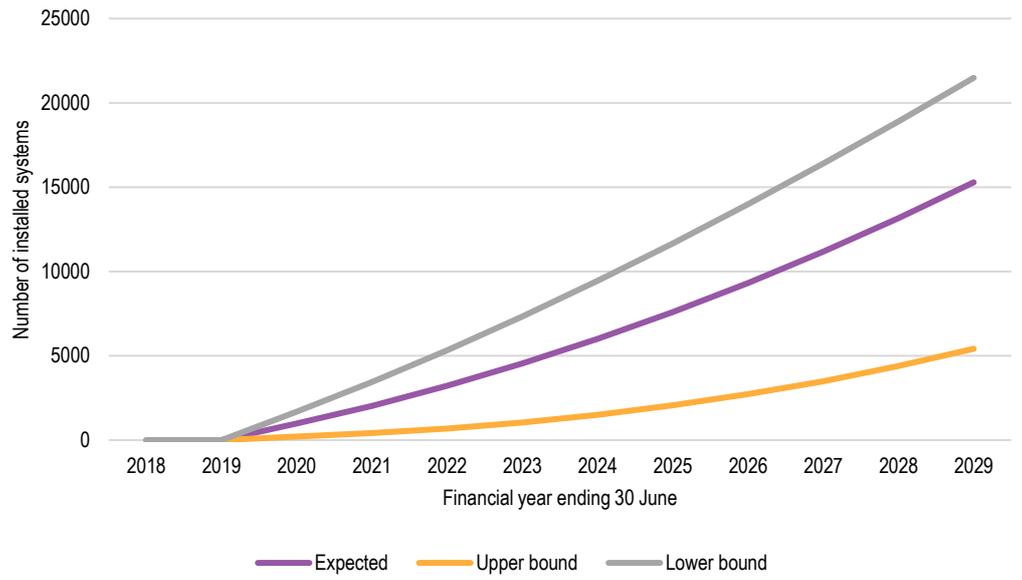
**FIGURE 8.15** FORECAST UPTAKE OF BATTERY STORAGE, MW



SOURCE: ACIL ALLEN

The number of battery storage systems installed in the JEN distribution network is shown in Figure 8.16 below. The number of installed battery systems is projected to increase from close to zero in 2019 to 15.3 thousand in 2029.

**FIGURE 8.16** FORECAST UPTAKE OF BATTERY STORAGE, NUMBER OF INSTALLED SYSTEMS



SOURCE: ACIL ALLEN



## 9.1 Introduction

This section examines the possible take-up of electric vehicles covering the period from 2019 to 2029. The approach taken involves projecting the number of passenger and light commercial vehicles for Victoria, and then estimating the share located within the JEN distribution region based on JEN's share of Victoria's population. We then apply logistic model specification to calculate the share of new vehicle sales that are captured by plug-in electric vehicles.

The market share of electric vehicles will depend on the financial and other attributes of plug-in electric vehicles relative to conventional internal combustion engine (ICE) vehicles. The most important factors to be accounted for are the relative upfront capital costs of purchasing the vehicle, vehicle running costs, including relative fuel prices and fuel consumption over time, and the relative ranges that the vehicles can travel.

Forecasts of both the number, market share and energy impact of electric vehicles are produced.

### 9.1.1 Definition of Vehicles

There are four specific vehicle types. These are:

- ICE (internal combustion engine)
- HEV (hybrid electric vehicle)
- PHEV (plug-in hybrid electric vehicle)
- EV (electric vehicle)

While HEVs are classified as electric vehicles, we do not consider these as part of the projections and instead focus on plug-in electric vehicles.

The two categories of vehicles which are relevant to this study are PHEVs and EVs. Both are charged by connecting to the electricity grid. While PHEVs also run on conventional fossil fuels, EVs are completely powered by electricity.

Separate projections are produced for passenger and light commercial vehicles.

## 9.2 Market for Electric Vehicles

The potential size of the market for electric vehicles is limited only by the size of the market for passenger and light commercial vehicles.

## 9.2.1 Historical Vehicle Registrations

The number of light passenger vehicles and light commercial vehicles in Victoria has grown steadily over time (see Figure 9.1).

The number of light passenger vehicles in Victoria has grown from 2.68 million vehicles in 2001 to 3.91 million in 2019. This is equivalent to an average annual growth rate of 2.1 per cent over the period. Similarly, the number of light commercial vehicles has increased from 410.8 thousand to 731.1 thousand over the same period. This is equivalent to an average annual growth rate of 3.3 per cent.

**FIGURE 9.1** HISTORICAL PASSENGER AND LIGHT COMMERCIAL VEHICLES REGISTERED IN VICTORIA, 2001 TO 2019



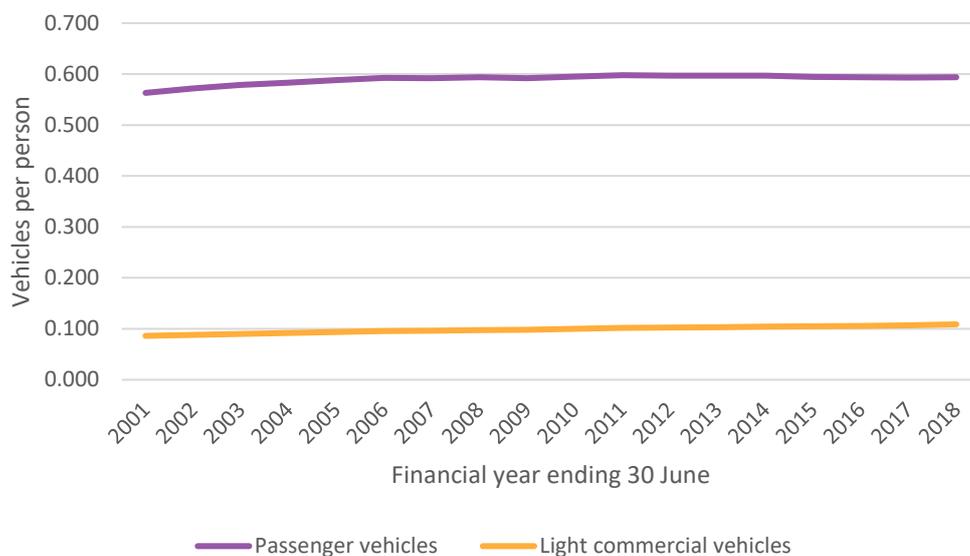
SOURCE: ABS, MOTOR VEHICLE CENSUS, AUSTRALIA

Over the more recent seven-year period, growth in passenger vehicles has been equivalent to the long term average, with average annual growth measuring 2.1 per cent over the period from 2012 to 2019. In the case of light commercial vehicles, growth has also matched the long term average over the last seven years, with average annual growth measuring 3.3 per cent, the same growth rate as over the last 18 years.

## 9.2.2 Vehicle Ownership Rates

The car remains the preferred form of transport for the majority of Australians. Figure 9.2 shows that the rate of light passenger and light commercial vehicle ownership in Victoria continues to rise over time. Between 2001 and 2018, the number of registered passenger vehicles has increased from 0.563 per person to 0.594 per person. This is equivalent to an average annual growth rate of 0.30 per cent. Over the most recent seven years, growth has stalled, with average annual growth in the ownership rate of passenger vehicles measuring -0.07 per cent.

**FIGURE 9.2** NUMBER OF PASSENGER AND LIGHT COMMERCIAL VEHICLES PER PERSON, VIC, 2001 TO 2018



SOURCE: ABS, MOTOR VEHICLE CENSUS, AUSTRALIA

In the case of light commercial vehicles, average annual growth in the number of vehicles per person, has measured 1.30 per cent over the period from 2001 to 2018. This rate of growth has decelerated over the last seven years, declining to 0.83 per cent per annum.

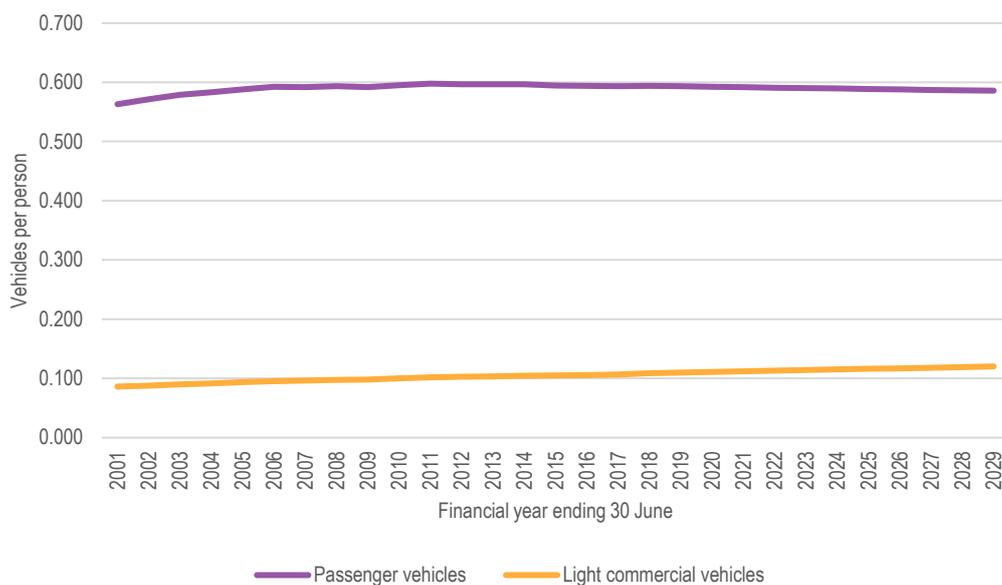
### 9.2.3 Projected Vehicle Ownership Rates

To project the potential size of the market for electric vehicles in Victoria and subsequently within the JEN distribution network, it is necessary to project vehicle ownership rates going forward. At some point, it can be expected that the rate of vehicle ownership will reach saturation and will plateau. The difficulty lies in determining when this point is likely to be reached.

In projecting the rate of motor vehicle ownership in Victoria, ACIL Allen has fitted and extrapolated a linear trend based on the last 5 years of data. Figure 9.3 shows the historical and projected passenger vehicles per person in Victoria.

The number of passenger vehicles per person in Victoria is forecast to decline from 0.594 vehicles per person in 2018 to 0.586 vehicles per person in 2029. The number of light commercial vehicles per person in Victoria is forecast to increase from 0.109 vehicles per person in 2018 to 0.120 vehicles per person in 2029.

**FIGURE 9.3** HISTORICAL AND PROJECTED PASSENGER VEHICLES AND LIGHT COMMERCIAL VEHICLES PER PERSON, VICTORIA 2001 TO 2029



SOURCE: ABS AND ACIL ALLEN

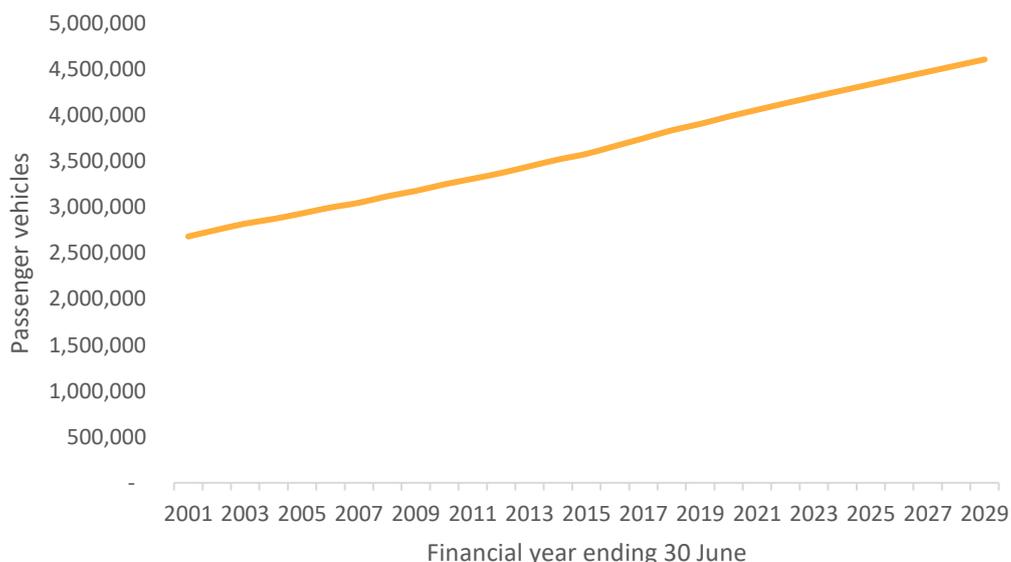
#### 9.2.4 Projected Passenger and Light Commercial Vehicle Numbers

The projected total number of passenger and light commercial vehicles have been calculated by multiplying the forecast vehicle ownership rate with the projected Victorian population in each year.

The number of passenger vehicles is projected to increase from 3.84 million vehicles in 2018 to 4.61 million passenger vehicles in 2029 (see Figure 9.4). This is equivalent to an average annual rate of growth of 1.68 per cent.

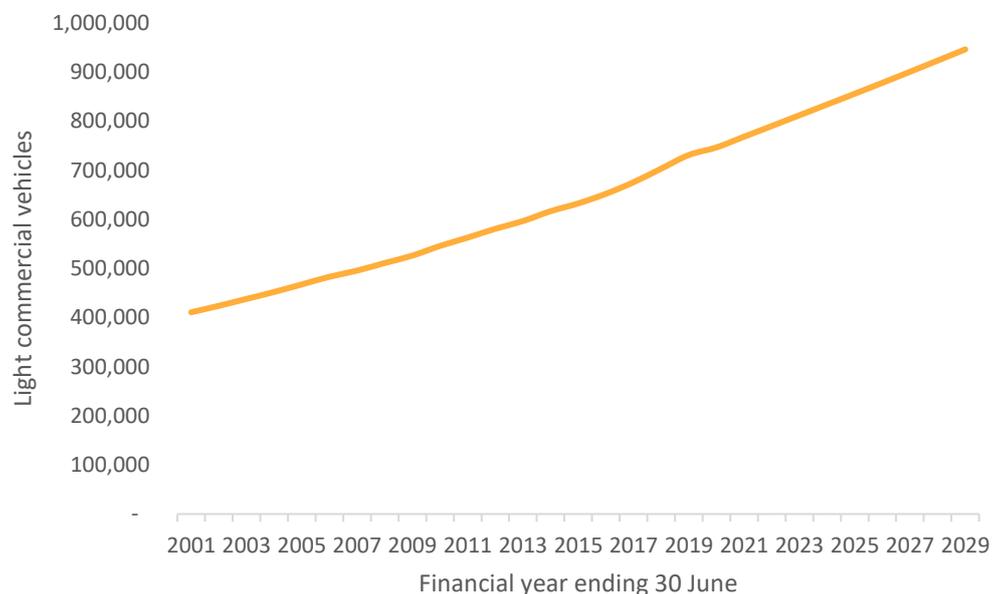
The number of light commercial vehicles are projected to increase from 703.3 thousand vehicles in 2018 to 946.1 thousand in 2029 (see Figure 9.5). This is equivalent to an average annual growth rate of 2.73 per cent.

**FIGURE 9.4** HISTORICAL AND PROJECTED PASSENGER VEHICLES IN VICTORIA, 2001 TO 2029



SOURCE: ABS AND ACIL ALLEN

**FIGURE 9.5** HISTORICAL AND PROJECTED LIGHT COMMERCIAL VEHICLES IN VICTORIA, 2001 TO 2029



SOURCE: ABS AND ACIL ALLEN

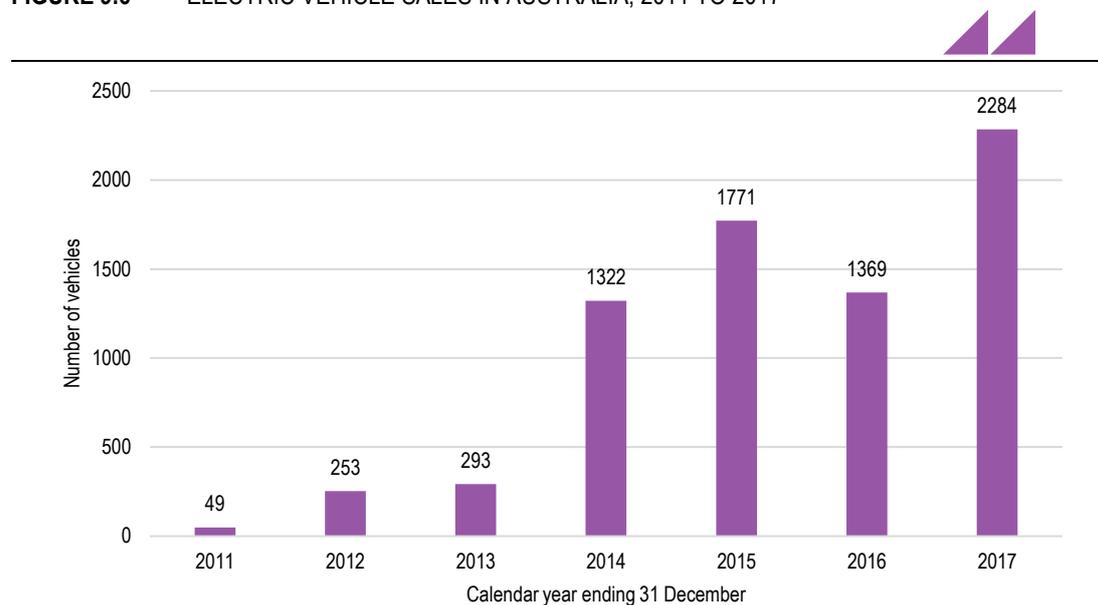
### 9.3 Current Take-Up of Electric Vehicles

According to a report released by ClimateWorks Australia and the Electric Vehicle Council in June 2018, entitled “The State of Electric Vehicles in Australia”, there were 2,284 electric vehicles sold in Australia in 2017, a 67 per cent increase on the previous year.

In 2016, Australians bought 701 plug-in hybrid electric vehicles and 668 fully electric vehicles.

Figure 9.6 shows the number of plug-in electric vehicle sales from 2011 to 2017. Interestingly, there appeared to be a loss of momentum in 2016, with sales declining by 23 per cent to 1,369 compared to 1,771 in 2015.

**FIGURE 9.6** ELECTRIC VEHICLE SALES IN AUSTRALIA, 2011 TO 2017



SOURCE: THE STATE OF ELECTRIC VEHICLES IN AUSTRALIA, CLIMATEWORKS AND ELECTRIC VEHICLE COUNCIL, JUNE 2018

According to the same publication, there were 1,324 purchases of electric vehicles in Victoria between 2011 and 2017. JEN's share of these purchases is 176 vehicles, which is the starting value for our forecasts.

## 9.4 Economics of Electric Vehicles

This section considers the key economic factors that are likely to play a significant role in the potential take up of electric vehicles in the next decade or more.

These key factors are:

- vehicle prices
- fuel costs (including fuel prices and fuel consumption)
- range
- charging convenience.

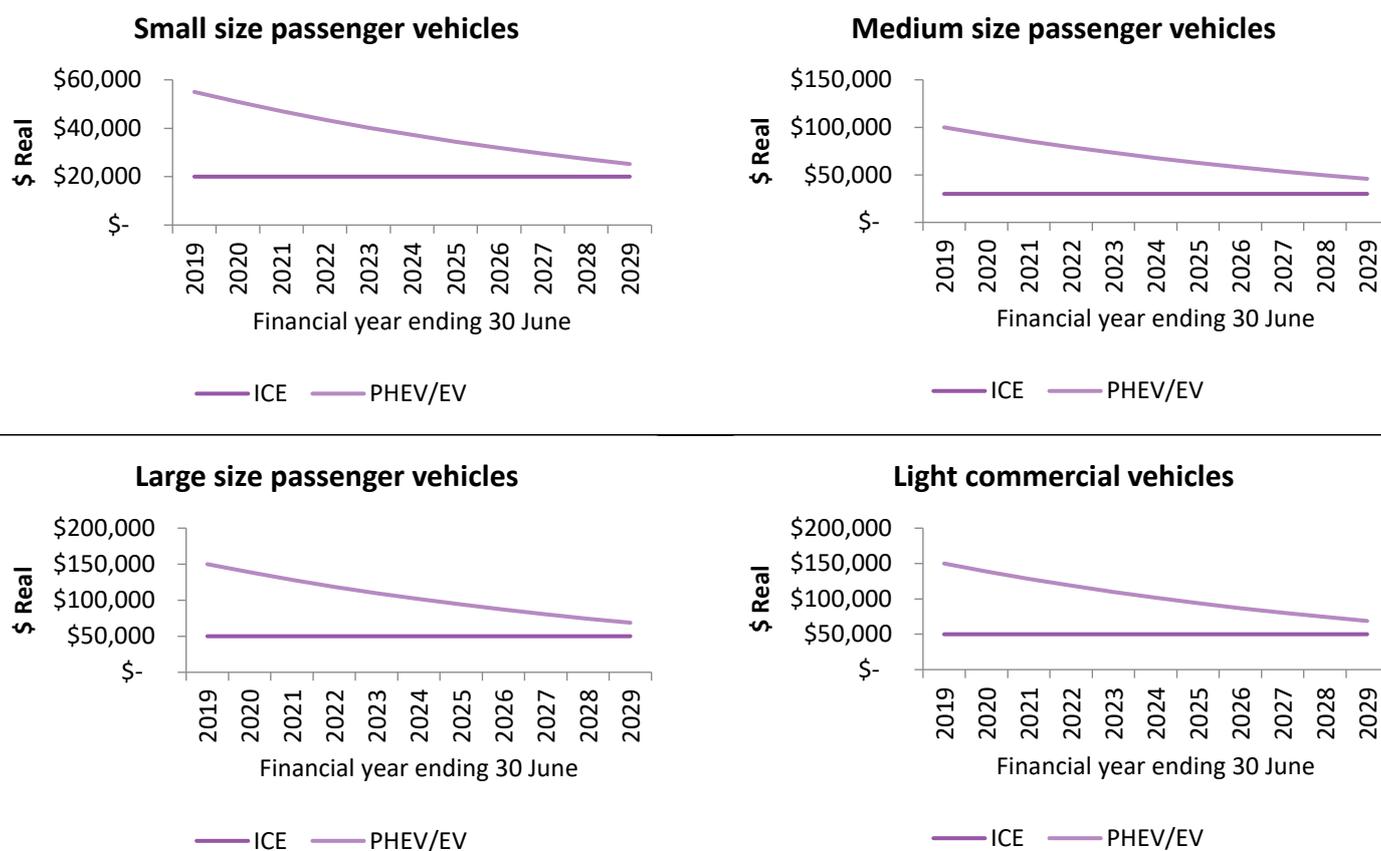
### 9.4.1 Vehicle Prices

The largest and most significant cost associated with plug-in electric vehicles at present is the relatively large upfront cost. This cost is largely attributed to the relatively high cost of the battery required to power the vehicle. Future reductions in the price of the vehicles will come from the development of cheaper battery technology over time.

Figure 9.7 shows that as at 2019, the price differential between ICE and PHEV/EV vehicles is very large, making PHEV/EVs very unattractive against conventional ICE vehicles based on vehicle cost. Vehicle price comparisons are made across small, medium and large passenger vehicles.

The distinction across the three size classes is made on the basis engine size. A small passenger car is the equivalent of a passenger vehicle with 1-3 cylinders, a medium sized vehicle is the equivalent of a 4 cylinder engine and a large passenger vehicle is equivalent to a 6 cylinder engine.

FIGURE 9.7 REAL COST OF VEHICLES: ICE VERSUS PHEV/EV, PROJECTED (\$2018)



SOURCE: ACIL ALLEN

As part of the modelling exercise, ACIL Allen assumes that the real price of electric vehicles will decline by 7.5 per cent per annum over time relative to the price of ICE vehicles. This is equivalent to a rate of growth that will see the price of electric vehicles approach that of ICEs by the second half of the 2020s and is in line with industry expectations.

It is important to note that it is the relative price that matters in projecting the market share of electric vehicles, rather than the absolute prices of the vehicles. For this reason, the real prices of ICE vehicles have been fixed at their 2019 levels for the entire forecasting horizon, while allowing the price of EVs to decline by 7.5 per cent every year.

Under these assumptions, the real prices of plug-in electric vehicles approach those of ICE vehicles by the late 2020s.

#### 9.4.2 Fuel Costs

##### Petrol Prices

Petrol prices in Australia are largely determined by the following factors:

- the international benchmark retail petrol price known as Singapore Mogas (Mogas 95) (about 45 per cent of the pump price)<sup>11</sup>
- customs and excise duty and GST (about 40 per cent of the pump price)
- other costs and margins (about 15 per cent of the retail price), covering retail and wholesale operating costs and margins

<sup>11</sup> How are petrol prices determined in Australia?, Australian Institute of Petroleum. See <https://www.aip.com.au/resources/glance-how-are-petrol-prices-determined-australia>

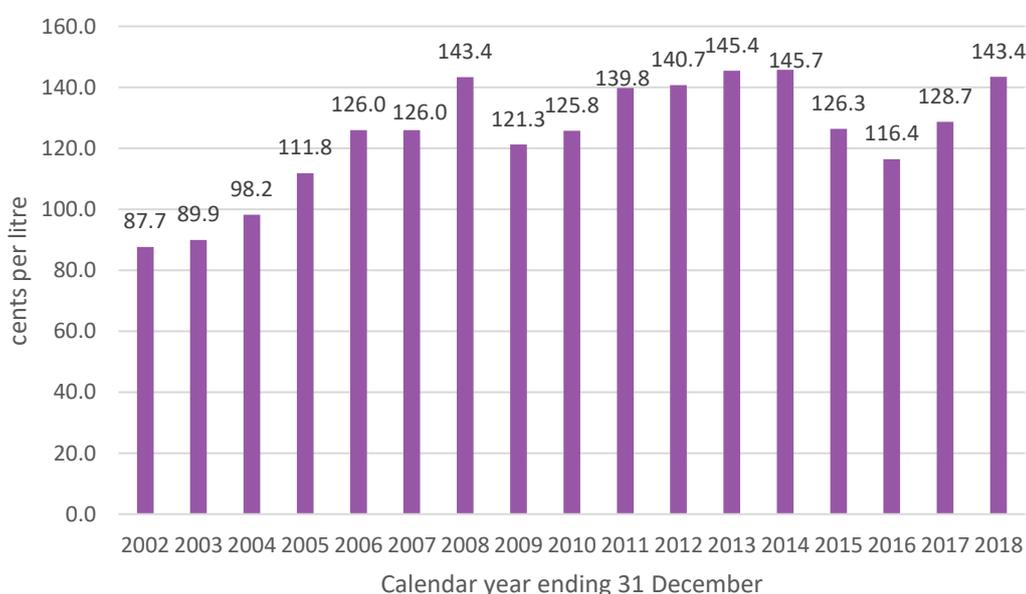
Changes in the international benchmark price of petrol are the main driver of movements in the Australian petrol price over time. Movements in international oil prices and the US\$/A exchange rate play a key role in the underlying retail cost of the product sold in Australia.

As oil is a fundamental input into the refining process, increases in the price of oil will translate into higher petrol prices in Australia, all other things being equal. Oil is priced in US dollars. Consequently, any movements in the exchange rate will change the Australian dollar price of petrol as well. If the exchange rate appreciates over time, this reduces the Australian dollar price of the international benchmark and lead to a reduction in Australian retail petrol prices. If the exchange rate depreciates, this results in an increase in the international benchmark price which flows through to higher retail petrol prices in Australia.

### Historical Petrol Prices

Figure 9.8 shows the average annual retail price of petrol in Victoria from 2002 to 2018. The figure shows that there has been quite a bit of variation in petrol prices over time in Victoria, although for most of the period there has been an upward trend. In 2018, Victorian petrol prices averaged 143.4 cents per litre, having declined from a high of 145.7 cents per litre in 2014.

**FIGURE 9.8** AVERAGE VICTORIAN UNLEADED PETROL PRICES, 2002 TO 2018, NOMINAL



SOURCE: AUSTRALIAN INSTITUTE OF PETROLEUM

### Petrol price forecasts

An econometric model was used to forecast petrol prices in Victoria out to 2029. The approach involved fitting a log-linear regression to monthly ULP petrol prices in Victoria. The main explanatory variables used in the regression were:

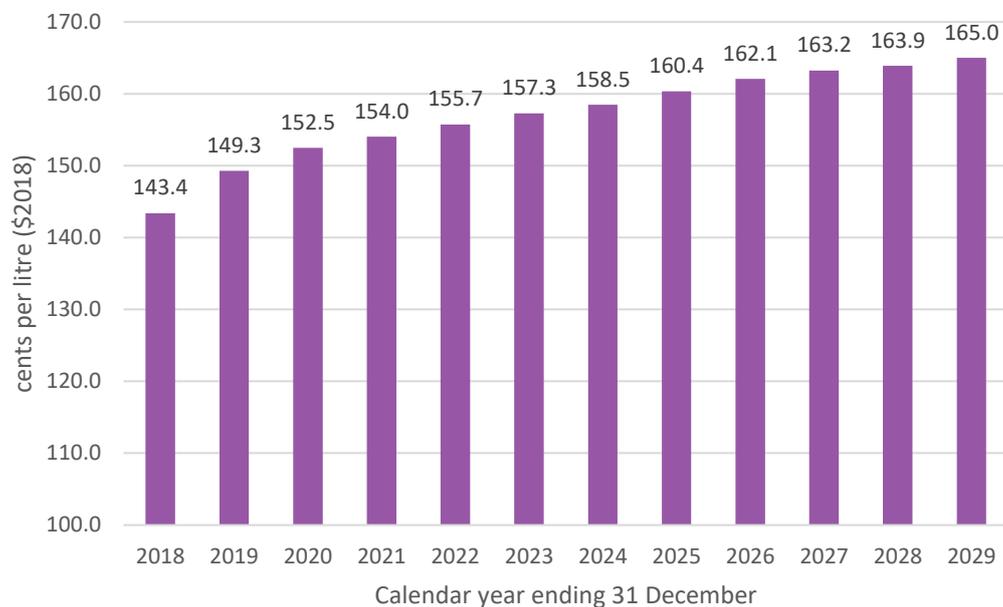
- an intercept term
- the US\$ oil price (WTI)
- The US\$/A exchange rate
- a trend term.

While the oil price and exchange rate were used to capture movements in the international benchmark over time, the trend term was included to capture the impact of changes in wholesale and retail costs and margins over time.

The estimated coefficients were then combined with forecasts of the explanatory variables to generate forecasts of the Victorian retail petrol price.

Forecasts of Victorian ULP petrol prices are shown in Figure 9.9. The real price of ULP in Victoria is projected to increase from 143.4 cents per litre in 2018 to 165.0 cents in 2029.

**FIGURE 9.9** FORECAST VICTORIAN ULP PETROL PRICES, 2019 TO 2029, \$2018

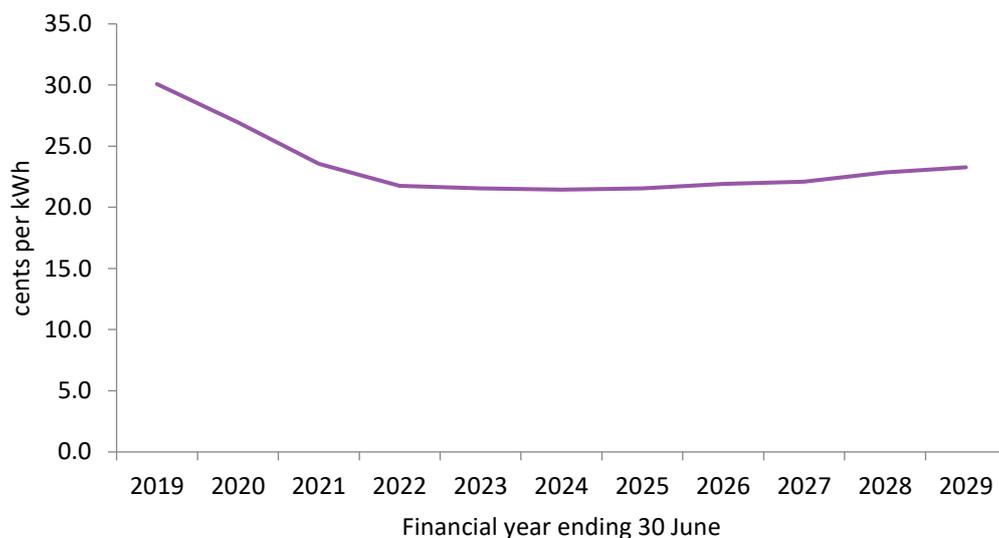


SOURCE: ACIL ALLEN

### 9.4.3 Retail Electricity Prices

A key input into the costs of running an electric vehicle is the retail price of electricity. ACIL Allen has projected the real price of electricity to 2029 based on its own internal modelling, utilising its proprietary electricity market model, PowerMark.

The projections are presented in Figure 9.10 below. The figure shows that real electricity prices are projected to decline from 29.0 cents per kWh in 2017-18 to a low of 21.4 cents in 2023-24, before commencing an upward trajectory, rising to 23.3 cents in 2028-29.

**FIGURE 9.10** REAL ELECTRICITY TARIFF, VICTORIA, REAL (\$2018)

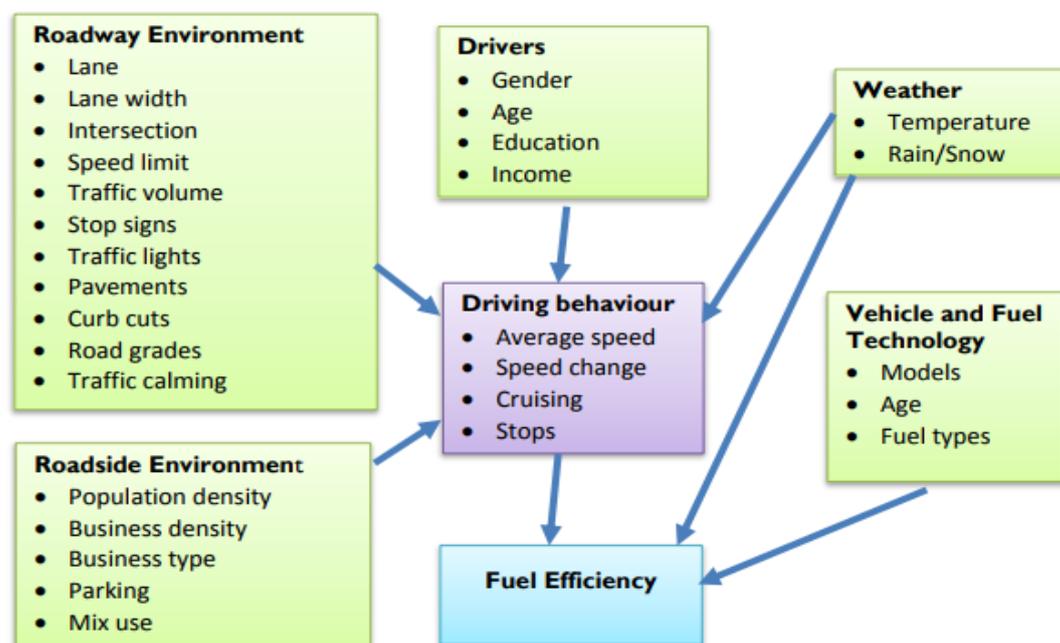
SOURCE: ACIL ALLEN

#### 9.4.4 Fuel Consumption

The average rate of fuel consumption of motor vehicles is driven by a large number of factors. These include vehicle and fuel technology, driving behaviour, weather factors, and the roadway and roadside environment. The large array of factors is summarised by a diagram presented in the BITRE report, *Fuel Economy of Australian Passenger Vehicles-A Regional Perspective*<sup>12</sup>. This report was based on the ABS Survey of motor vehicle use covering the 12-month period ending on 31 October 2016. The diagram has been reproduced in Figure 9.11 below.

<sup>12</sup> Please see [https://bitre.gov.au/publications/2017/files/is\\_091.pdf](https://bitre.gov.au/publications/2017/files/is_091.pdf)

FIGURE 9.11 FACTORS THAT AFFECT FUEL CONSUMPTION



SOURCE: BITRE, FUEL ECONOMY OF AUSTRALIAN PASSENGER VEHICLES-A REGIONAL PERSPECTIVE

The BITRE report notes that fuel consumption depends on many factors which have very little to do with the vehicle itself. These include weather conditions, driver behaviour such as hard braking and speed changes, road conditions such as the type of road surface. These and the other factors shown in the diagram can increase the rate of fuel consumption to levels that are well above the official fuel consumption that is published in the Green Vehicle Guide (GVG)<sup>13</sup>.

The weight of vehicle and the engine size are important factors in driving fuel economy. BITRE cites a study by Knittel (2009)<sup>14</sup> which found that a 10 per cent decrease in a vehicle's weight is associated with a 4 per cent improvement in fuel economy. Moreover, a 10 per cent reduction in engine size was associated with a 2.6 per cent improvement in fuel economy.

Speed plays a role in fuel efficiency. According to *Fuel Economy.Gov*, an online resource maintained by the US Department of Energy, vehicle fuel economy decreases as the speed increases beyond a threshold which was estimated to be around 89 km per hour.

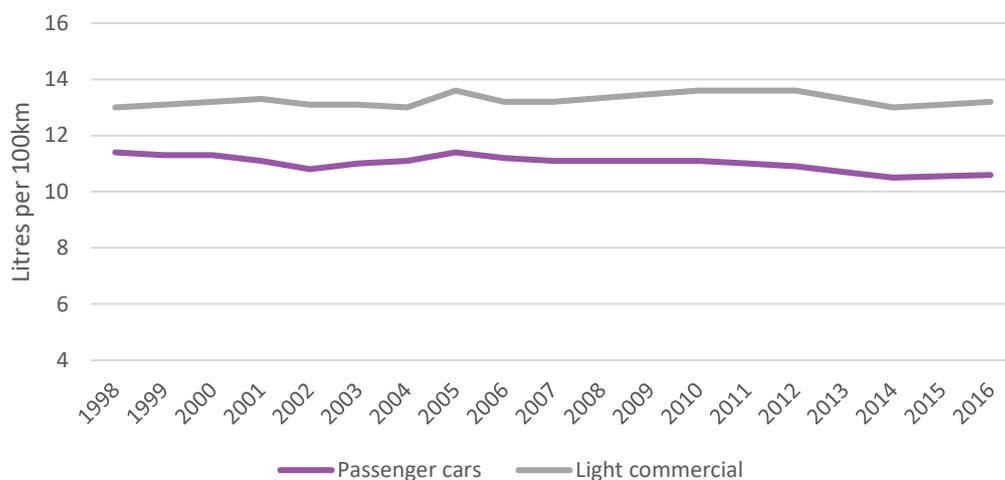
Figure 9.12 below shows the average rate of fuel consumption of Australian passenger and light commercial vehicles over time. From 1998 to 2016, average fuel consumption has declined slowly, probably reflecting improvements in vehicle and fuel technology, although it is not possible to completely rule out changes in behavioural patterns or the road environment.

In 1998, the average passenger vehicle on the road consumed 11.4 litres of petrol per 100 km travelled. By 2016, this had declined to 10.6 litres per 100 km, a decline of 7 per cent over the entire historical period. In contrast, fuel consumption of light commercial vehicles remained steady over the period, hovering around 13 litres per 100 km. It is important to note that these estimates are based on an ABS survey and are therefore subject to some degree of statistical error.

<sup>13</sup> Please see <https://www.greenvehicleguide.gov.au/>

<sup>14</sup> Knittel, C., "Automobiles on Steroids: Product Attribute Trade-Offs and Technological Progress in the Automobile Sector", NBER Working Paper 15162, 2009.

**FIGURE 9.12** AVERAGE FUEL CONSUMPTION OF PASSENGER AND LIGHT COMMERCIAL VEHICLES, 1998 TO 2016 (CALENDAR YEAR ENDING 31 DECEMBER)

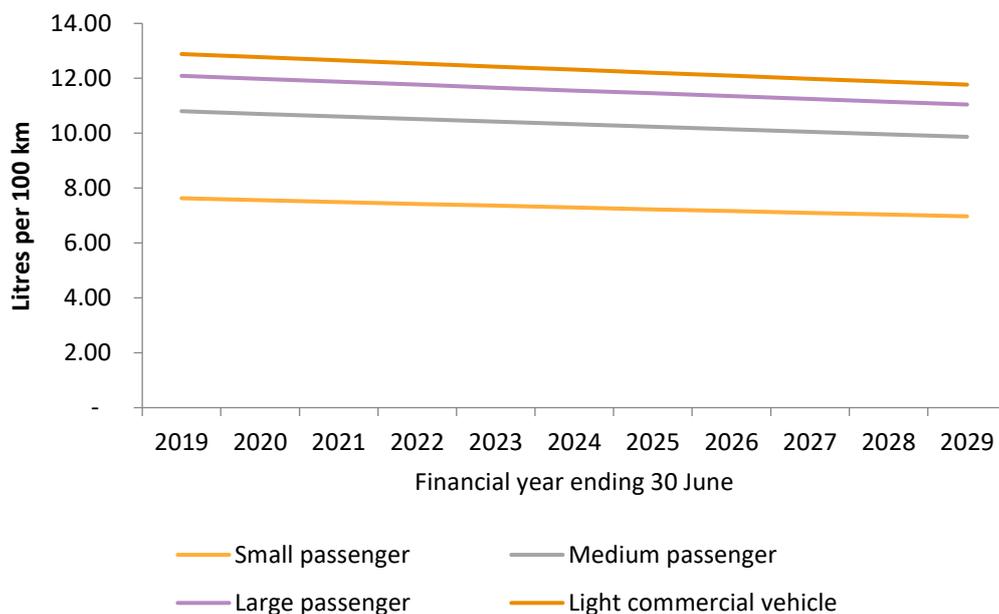


SOURCE: ABS, SURVEY OF MOTOR VEHICLE USE

### Internal Combustion Engine (ICE) vehicles

For the purposes of forecasting the fuel consumption of ICE vehicles over time, ACIL Allen has applied an annual improvement of 0.4 per cent per annum over the entire forecasting horizon. This value corresponds to the historical average annual reduction in fuel consumption in passenger vehicles from 1998 to 2016.

The projections are shown in Figure 9.13. Separate projections are presented by vehicle size and type. The fuel consumption of a medium sized vehicle is projected to decrease from 10.9 litres/100km in 2018 to 9.87 litres/100km in 2029. For small passenger vehicles, fuel consumption is projected to decline from 7.7 litres/100km in 2018 to 6.97 litres/100 km in 2029, while for large vehicles, fuel consumption is projected to decline from 12.2 litres/100 km to 11.0 litres/100km over the same period.

**FIGURE 9.13** FORECAST INTERNAL COMBUSTION ENGINE (ICE) VEHICLE FUEL CONSUMPTION, 2019 TO 2029

SOURCE: ABS, SURVEY OF MOTOR VEHICLE USE AND ACIL ALLEN

### Electric Vehicles

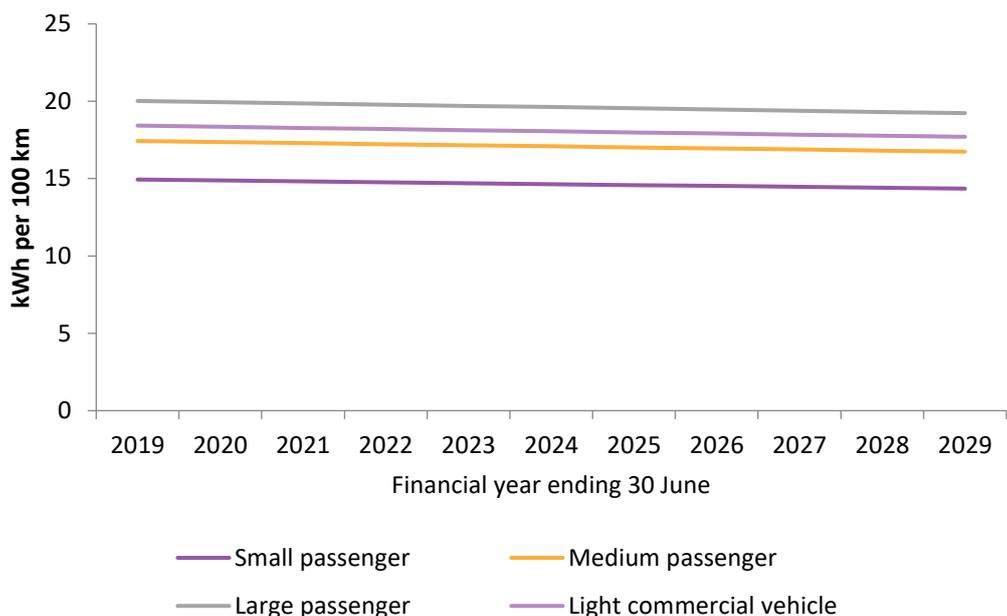
In the case of electric vehicles, a similar rate of improvement in fuel consumption is assumed to ICE vehicles (see Figure 9.14). This is because electric vehicles are a very new technology and there is little historical information to enable the reliable estimation of changes to fuel consumption over time. Future improvements in the fuel economy of electric vehicles are subject to a high degree of uncertainty and may vary significantly from the assumptions made in this report.

Starting electricity consumption values were obtained from the published specifications for current electric vehicle models on sale in Australia. For a large passenger vehicle, ACIL Allen used the specified electricity consumption of the Tesla Model S, which uses 20.1 kWh of electricity per 100km travelled. This is projected to decline to 19.2 kWh per 100km by 2029.

For the small passenger class, ACIL Allen used the specifications of the BMWi3 and Nissan Leaf as the basis of its starting value in 2019. The small passenger electric vehicle is estimated to use 15.0 kWh per 100km travelled. This is projected to decline gradually to 14.35 kWh per 100km by 2029.

The middle sized electricity consumption starting value was obtained by taking a point in the mid-range between the small and large passenger vehicle. Electricity consumption of a medium-sized plug-in electric vehicle is projected to decline from 17.5 kWh per 100km travelled to 16.7 kWh per 100km in 2029.

**FIGURE 9.14** FORECAST ELECTRIC VEHICLE FUEL CONSUMPTION, 2019 TO 2029



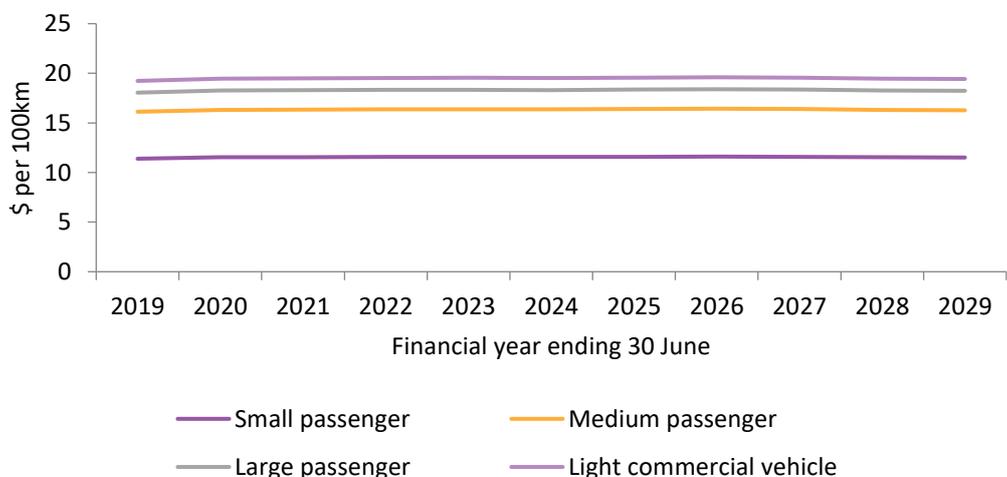
SOURCE: ACIL ALLEN

### 9.4.5 Total fuel costs

Projected fuel prices and fuel consumption can then be combined to calculate the total fuel cost of travelling 100 km. The estimates are shown in Figure 9.15 for ICE vehicles.

For a small ICE passenger vehicle, the cost of driving 100 km is \$11.04 in 2018. This is projected to increase slightly over time, reaching \$11.50 in real terms in 2029. In the case of a medium-sized passenger vehicle, the cost of travelling 100 km increases from \$15.63 in 2018 to \$16.28 in 2028. For large passenger vehicles, the cost of travelling 100 km is projected to increase from \$17.49 to \$18.22 in 2029.

**FIGURE 9.15** TOTAL FUEL COSTS OF RUNNING AN ICE VEHICLE, \$2018

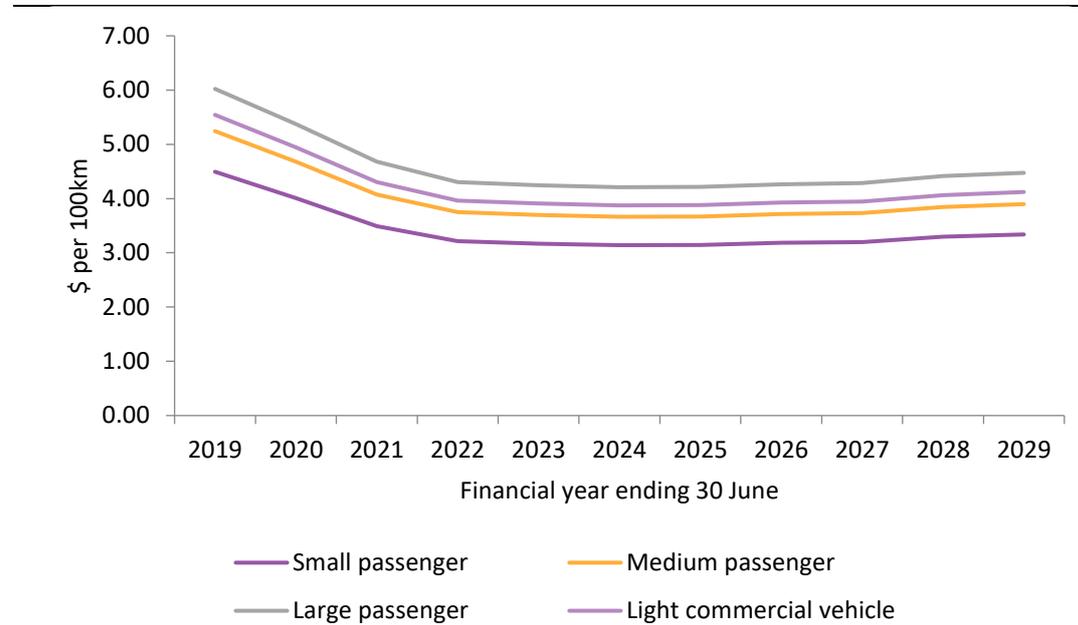


SOURCE: ACIL ALLEN

The total fuel cost of running an electric vehicle for 100 km is shown in Figure 9.16.

The real electricity cost of driving an electric vehicle for 100km is projected to fall rapidly over the next 4 years to 2022 in line with falling electricity prices, before stabilising. For a medium-sized electric vehicle, the electricity cost is projected to fall from \$5.84 per 100 km in 2018 to \$4.21 per 100km in 2022, before rising slightly to \$4.48 per 100 km in 2029.

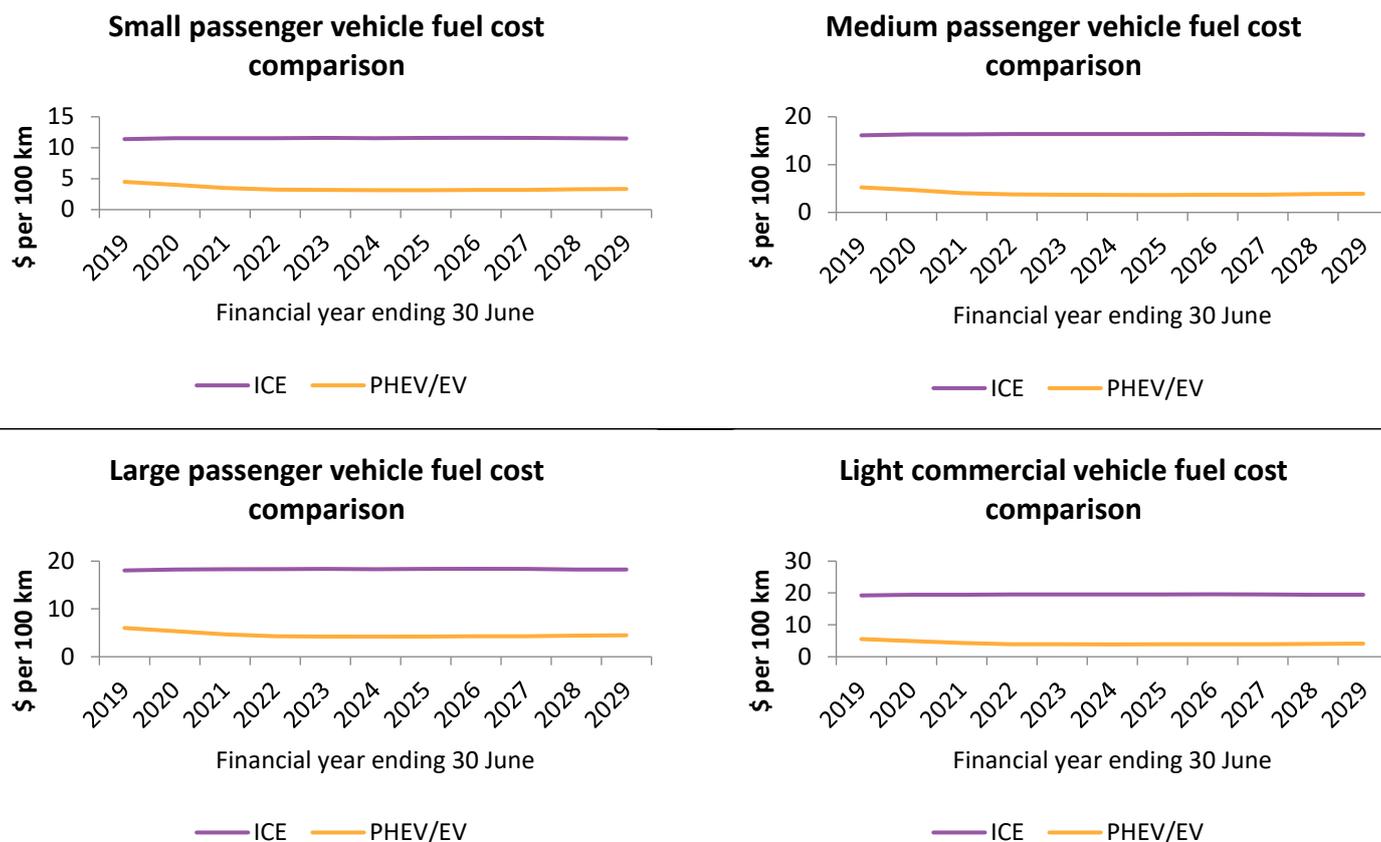
**FIGURE 9.16** TOTAL FUEL COSTS OF RUNNING AN ELECTRIC VEHICLE, \$2018



SOURCE: ACIL ALLEN

The combination of fuel consumption and fuel prices allows the cost of travelling a given distance to be calculated. This then allows a direct comparison of fuel costs between ICE and PHEV/EV vehicles. Figure 9.17 shows the cost of travelling 100 km in the various categories of ICE and EV vehicles.

FIGURE 9.17 FUEL COST PER 100 KM TRAVELLED - COMPARISON BY VEHICLE TYPE



SOURCE: ACIL ALLEN

From these figures, it is clear that plug-in electric vehicles have a significant cost advantage over ICE vehicles when it comes to running costs for all classes of vehicle.

For example, for a medium sized passenger vehicle, the cost of travelling 100 km is \$15.63 in an ICE in 2018. For a medium PHEV/EV, the cost of travelling an equivalent distance is only \$5.08. Similar cost advantages are also evident in the other size categories.

Moreover, not only is this advantage clear in 2018, but the cost advantage of electric vehicles is expected to increase over the next decade.

This suggests that take up of PHEV/EVs is expected to accelerate significantly once the problem of the relatively high up-front cost is surmounted. As the price of plug-in electric vehicles approaches that of ICEs, the low running costs of electric vehicles are likely to make them very attractive alternatives to ICEs.

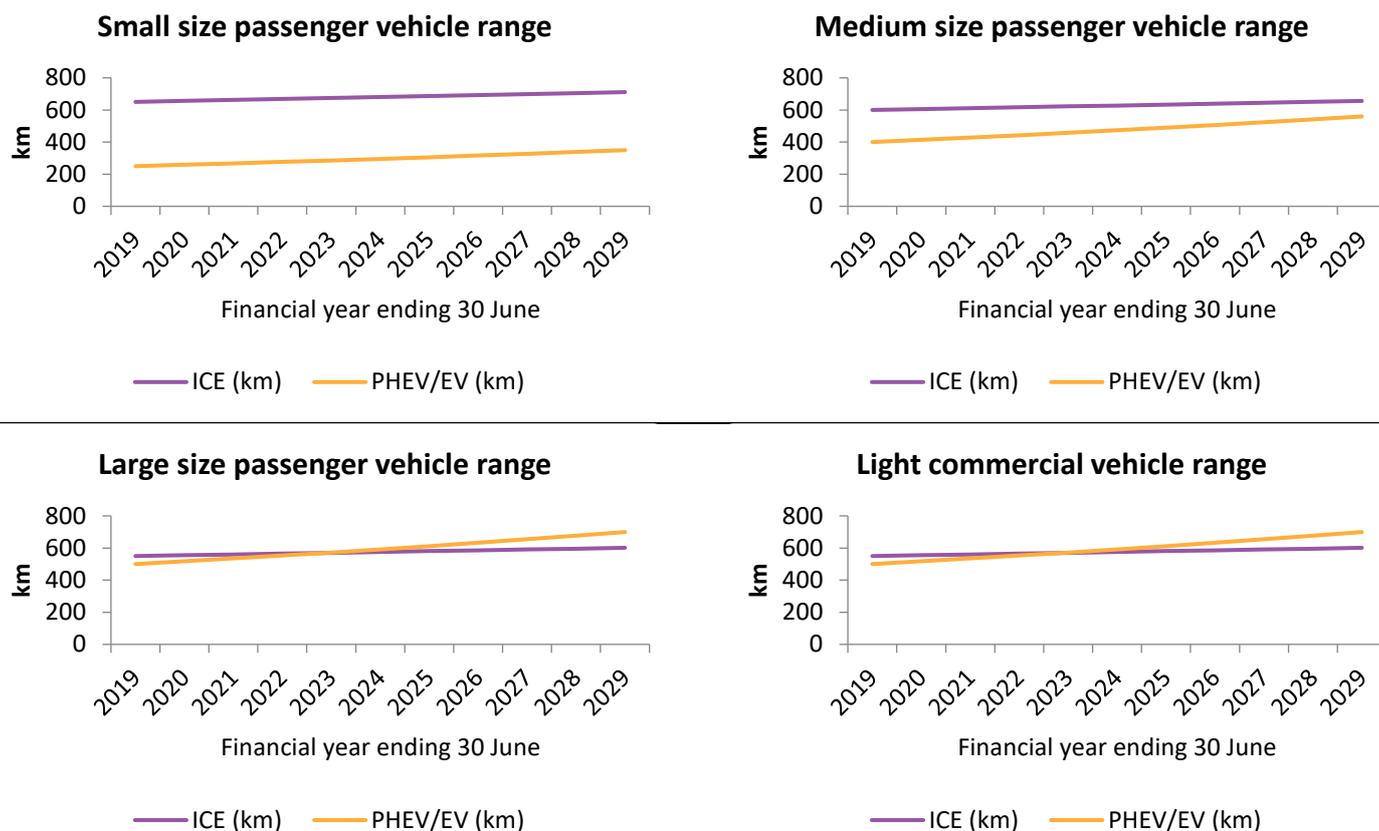
#### 9.4.6 Range

Another factor that currently limits the potential of electric vehicles concerns their limited range compared to conventional ICEs.

For a large-sized passenger vehicle, an ICE has a range of about 550 km before it requires re-fuelling. A large passenger electric vehicle such as the Tesla Model S has a current range of about 410km.

The range of a small electric vehicle is only about 250 km by comparison (see Figure 9.18). This compares unfavourably with the range available from a typical small passenger ICE vehicle which is around 650 km.

FIGURE 9.18 RANGE COMPARISON BY VEHICLE TYPE



SOURCE: ACIL ALLEN

The range of the vehicles is assumed to increase over time in line with improvements in fuel economy. Moreover, ACIL Allen has assumed that the range of EVs will increase at an additional rate of 3 per cent per year as technological improvements accrue over time.

#### 9.4.7 Convenience

A potential difficulty with PHEV/EVs is the lack of convenience when it comes to ease of charging.

There are several issues that are relevant here. These are:

- insufficient charging locations
- slow rate of charging.

##### Charging Locations

A potential constraint to the take up of electric vehicles is the limited number of locations where the car can be charged.

While we expect most vehicles to be charged at night when they are garaged, there will be a need for some vehicles to have access to charging facilities at other locations.

The slow roll-out of charging infrastructure could impose a constraint on the take up of electric vehicles. Table 9.1 shows that Victoria has a total of 216 charging stations available to electric vehicle drivers. This is equivalent to 3.4 charging stations per 100,000 people. Adjusted for population size, Victoria has more charging stations than the ACT, NSW, NT, and Queensland and fewer than SA, Tasmania and WA. Nevertheless, the number of charging locations should continue to increase as the economic attractiveness of EVs continue to improve against conventional ICE vehicles.

**TABLE 9.1** PUBLIC CHARGING INFRASTRUCTURE IN AUSTRALIA, 2018

Charging locations	ACT	NSW	NT	QLD	SA	TAS	VIC	WA
Total number of charging stations	20	161	5	162	76	21	216	122
Charging stations per 100,000 residents	3.17	2.04	2.03	3.27	4.4	4.02	3.4	4.72
Total AC charging stations	17	148	5	138	70	21	208	107
Total DC charging stations	3	13	0	24	6	0	8	15
Total capital city charging stations	20	86	3	58	32	4	114	77
Total regional charging stations	0	75	2	104	44	17	102	45

SOURCE: THE STATE OF ELECTRIC VEHICLES IN AUSTRALIA, CLIMATEWORKS AND ELECTRIC VEHICLE COUNCIL, JUNE 2018

### Rate of Charging

There is currently an issue with the slow rate of charging electric vehicles. Charging is slow, with even the most rapid forms of charging expected to take at least 30 minutes. According to the report, "The State of Electric Vehicles in Australia" jointly published by Climateworks and the Electric Vehicle Council, the majority of chargers available in Australia are AC chargers which require the car to be parked for at least an hour. The report states that AC charging power levels range from 2.4 kW to 22 kW, with an average installation of 11 kW. At the average power level, charging the vehicle delivers 50 km of range per hour.

In contrast, DC chargers which are much fewer in number (8 DC chargers in Victoria versus 208 AC chargers), offer significantly faster charging rates.

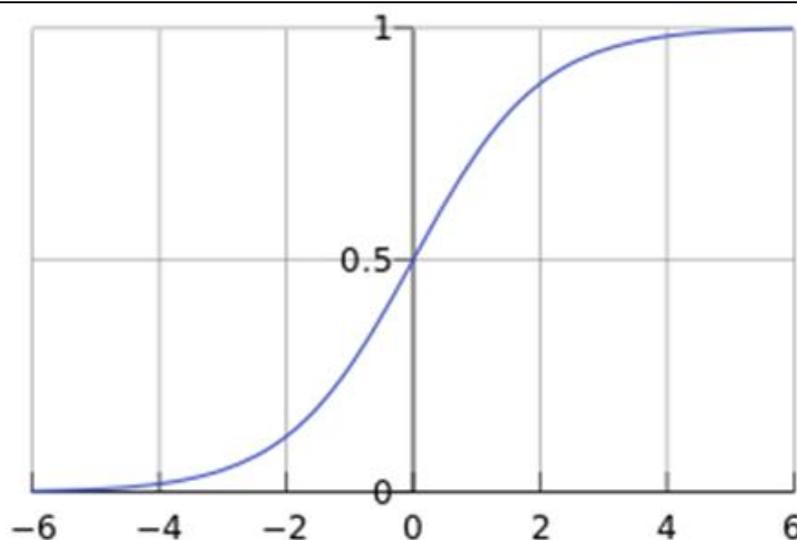
ACIL Allen believes the most common form of charging will take place over a period of 3 to 4 hours when the car is garaged overnight. Slower rates of charging are therefore only an inconvenience when the vehicle is travelling longer distances which necessitate charging the vehicle at a location away from home.

## 9.5 Modelling the Take-Up of Electric Vehicles

### 9.5.1 Logistic Framework

A logistic modelling framework is used to convert the underlying economic drivers of electric vehicles into an impact on the market share and take-up of the technology. It involves creating a model that values each attribute that drives the decision to adopt the technology and then applying an elasticity or measure of responsiveness of market share to each factor.

The logistic function is useful in that it can take as its inputs any value from negative to positive infinity (i.e. the key economic drivers described previously) and convert them into an output whose value is confined to lie between 0 and 1. This value can then be interpreted as the market share of the new technology. The function takes the form of an S curve and is shown in the following figure.

**FIGURE 9.19** CHARACTERISTIC SHAPE OF THE LOGISTIC FUNCTION

The logistic formula takes the form:

$$\pi(x) = 1 / (1 + \exp(-y))$$

where  $y = \beta_0 + \beta_1 x_1 + \beta_2 x_2 + \beta_3 x_3 + \dots + \beta_n x_n$

The value of  $y$  is constructed as a linear function of the driving factors denoted by  $x_1$  to  $x_n$  in the equation, and the  $\beta$ 's which represent the relative weights associated with each of the factors.

This formula simply converts the set of driving factors and their weights into some value between zero and one that represents the market share of the new technology over time. This value is represented by  $\pi(x)$ .

This approach will be used to determine the market share of each technology under consideration. The market shares are then be applied to a base number of projected motor vehicles in NSW to convert the market share into a projected number of electric vehicles.

### 9.5.2 Key Economic Drivers

The key drivers used as inputs into the modelling process are:

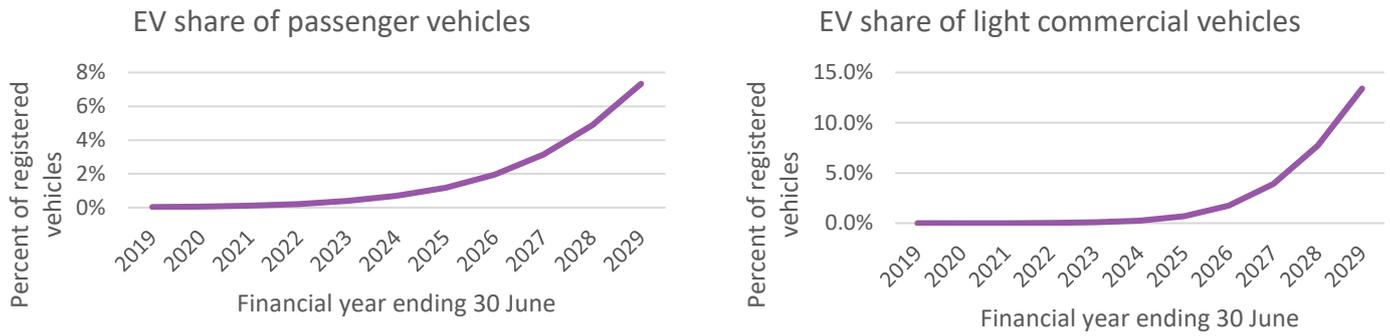
- vehicle price
- running costs
- range.

## 9.6 Projections of Electric Vehicles

Figure 9.20 shows the share of the light vehicle fleet that is projected to be made up of plug-in electric vehicles. The electric vehicle share of the stock of light passenger vehicles is projected to reach 7.3 per cent by 2029. In the case of light commercial vehicles, 13.4 per cent of the stock of motor vehicles is projected to be electric vehicles by 2029.

The charts demonstrate a rapid increase in the share of electric vehicles commencing from the mid 2020's, which corresponds with the relative improvement in the economic attractiveness of EVs relative to ICE vehicles.

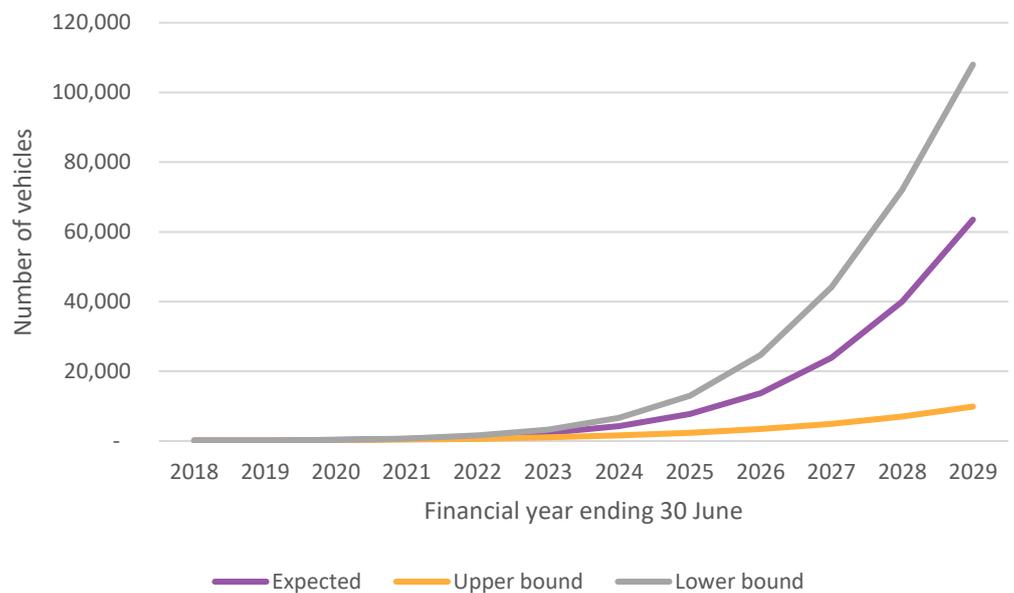
**FIGURE 9.20** PLUG-IN ELECTRIC VEHICLE SHARE OF TOTAL LIGHT VEHICLES



SOURCE: ACIL ALLEN

Figure 9.21 shows the projected number of electric vehicles within the JEN distribution network. The stock of electric vehicles is projected to reach 63.5 thousand vehicles by 2029. The take up of electric vehicles is projected to remain low well into the 2020s, before undergoing a significant growth phase after the middle of the decade. The uplift will be driven by improvements in the financial attractiveness of the vehicles relative to conventional cars.

**FIGURE 9.21** PROJECTED NUMBER OF ELECTRIC VEHICLES WITHIN THE JEN DISTRIBUTION NETWORK, 2019 TO 2029



SOURCE: ACIL ALLEN

## 9.7 Impact on energy consumption

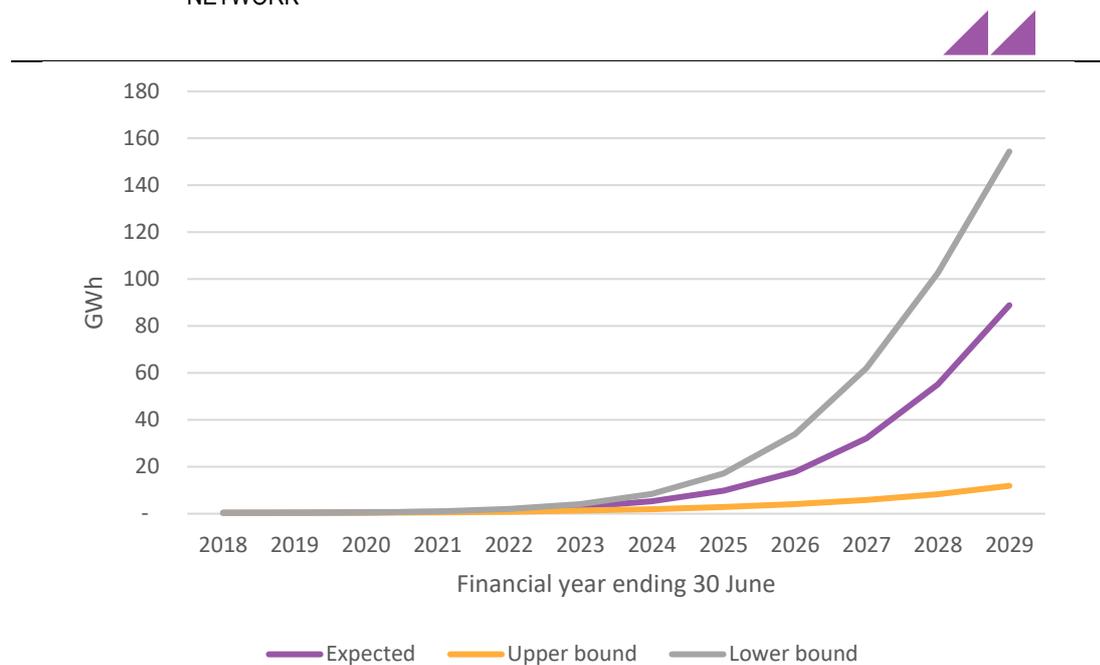
To calculate the energy consumption of the stock of electric vehicles we apply an assumption for the average distance driven per day by Victorians. ABS statistics indicate that the weighted average

distance travelled per day by passenger and light commercial vehicles is 39.4 km. This is equivalent to 14,379 kilometres per annum<sup>15</sup>.

The average driving distance is then multiplied by the actual and projected fuel consumption of electric vehicles. The energy consumption of the average electric vehicle is determined in this way. The total energy consumption of the entire stock of electric vehicles is then calculated by multiplying this measure by the number of projected electric vehicles.

Figure 9.22 below shows the forecast EV energy consumption of vehicles owned by households and businesses within the Jemena distribution network. EV energy consumption is forecast to reach 88.9 GWh by 2029.

**FIGURE 9.22** ENERGY IMPACT OF ELECTRIC VEHICLES WITHIN THE JEMENA DISTRIBUTION NETWORK



SOURCE: ACIL ALLEN

<sup>15</sup> 92080DO001\_1231201610 Survey of Motor Vehicle Use, Australia, 12 months ended 30 June 2016  
<http://www.abs.gov.au/AUSSTATS/abs@.nsf/DetailsPage/9208.012%20months%20ended%2030%20June%202016?OpenDocument>