Gas Demand Forecast, Mid-West and South-West Distribution System Core Energy Group November 2014

Appendix 4.1

27 November 2014

Response to the ERA's Draft Decision on required amendments to the Access Arrangement for the Mid-West and South-West Gas Distribution System

Connecting WA
to natural gas

Gas Demand Forecast

Mid-West and South-West Gas Distribution System

Gas Access Arrangement 2015 to 2019

November 2014

CORE ENERGY GROUP

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1. Introduction

Core Energy, on behalf of ATCO Gas Australia Pty Ltd ("**ATCO**") developed gas demand forecasts for the Mid-West and South-West Gas Distribution System, which were submitted by ATCO to the Economic Regulatory Authority ("**ERA**") on 17 March 2014. On 27 October 2014, ATCO engaged Core Energy to produce revised demand forecasts to incorporate updated demand data and additional information to 31 October 2014.

Section 2 compares the revised demand forecasts against those previously submitted to the ERA. This comparison is presented with and without the impact of marketing. Note the gas demand forecasts previously submitted to the ERA were inclusive of a marketing impact. Section 2 also compares the impact of marketing on both the original gas demand forecasts submitted, and the revised gas demand forecasts that form this submission.

The second half of this section highlights the impact of marketing on the original demand forecasts submitted to the ERA, and the impact of marketing on the revised demand forecasts that form the basis for this subsequent submission.

Sections 3 to 8 forms the remainder of the report and has been updated since the previous submission to reflect the revised demand forecasts. The revised demand forecasts are inclusive of marketing impact to align with the gas demand forecasts previously submitted to the ERA.

It is important to note, the assumptions that drive the impact of marketing on demand and connections have been revised by ATCO since the previous submission of gas demand forecasts to the ERA. Although these changes are contained within the report (refer Section 6.6 Impact of Marketing), Core Energy were not responsible for the development of any assumptions in relation to the impact of marketing.

Further, the adjustments made to revise demand forecasts were based on updated ATCO demand and connections data to 31 October 2014; and Core Energy did not revisit the application of any existing, qualitative third party data that was used in the process to derive demand forecasts previously. Similarly, the overall methodology used to derive demand forecasts in the model remains unchanged since the previous submission.

2. Report Revisions

2.1. Revised Gas Demand Forecasts

The process to update the demand forecasts included the following adjustments to the weather normalised demand model and gas demand forecast model:

1. Weather normalise additional demand data to 31 October 2014, using the Forecast Weather Normalisation model. Forecast demand and connections for the months of November and December 2014. Demand for November and December 2014 were forecast by using the historical average monthly demand for November and December between 2007 and 2013. It should be noted that for Tariff B3 connections, the average monthly demand was used between 2011 and 2013 to remain consistent with Tariff B3 demand forecasting logic.
2. Transfer additional 2014 weather normalised demand and connections data to the Gas Demand Forecast model.
3. Adjusted the methodology for the half year calculation for forecasting by adding year end connections. Annual growth in connections is applied to the yearend connections, with the average of year end connections used to forecast demand forward.
4. Updated known demand changes for Tariff A1 and A2 customers.
5. Reduced the retail price of gas by 1.04% in 2015 to reflect the repeal of the carbon tax in 2014. This percentage is based on Alinta Energy Retail Supply Charges, an average residential customer demand of 12.95 units per day and proposed cost saving of AUD1.58/GJ as stated in Alinta Energy's Substantiation Statement (Refer Assumptions Tab).
6. Changed the methodology used to derive the price impact adjusted historical trend of Tariff B3, with the average price impact between 2011 and 2013 applied rather the historical trend in price impact.

The following changes to the model relate to how the forecasts are presented in the Demand Summary tab, and do not influence any change to the demand forecasts.

7. Split 2015 demand and connections into two half year periods in Demand Summary. The split of connections for 2015 was derived based on the difference in yearend connection numbers between 2014 and 2015.
8. Change average usage in the half year splits to reflect half year usage in Demand Summary.

2.1.1. Results | Inclusive of Marketing Impact

Figure 2.1 to 2.15 provide graphical representations of the historical trend of gas demand (± 90% CI), originally submitted demand forecasts and the revised gas demand forecasts for each tariff class, inclusive of marketing impact. Meanwhile, the data in Table 2.1 to 2.15 presents a comparison of original gas demand forecasts against revised demand forecasts for each tariff class, inclusive of marketing impact.

Tariff A1

Figure 2.1: Total Demand | Original vs. November Refresh Forecasts | GJ

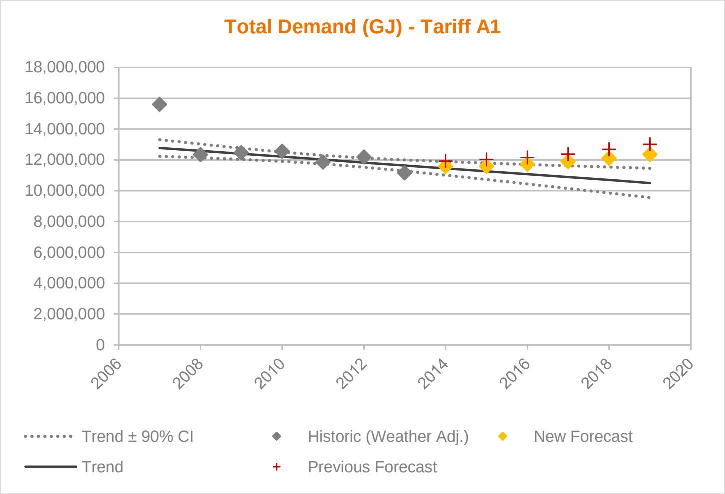


Table 2.1: Total Demand | Original vs. November Refresh Forecasts | GJ

	2014	2015	2016	2017	2018	2019
Original	11,922,065	12,029,555	12,143,688	12,370,908	12,673,841	13,008,602
Revised	11,571,022	11,572,769	11,720,093	11,883,212	12,105,157	12,350,313
Difference	(351,044)	(456,787)	(423,595)	(487,696)	(568,684)	(658,289)

Figure 2.2: Connections | Original vs. November Refresh Forecasts | No.

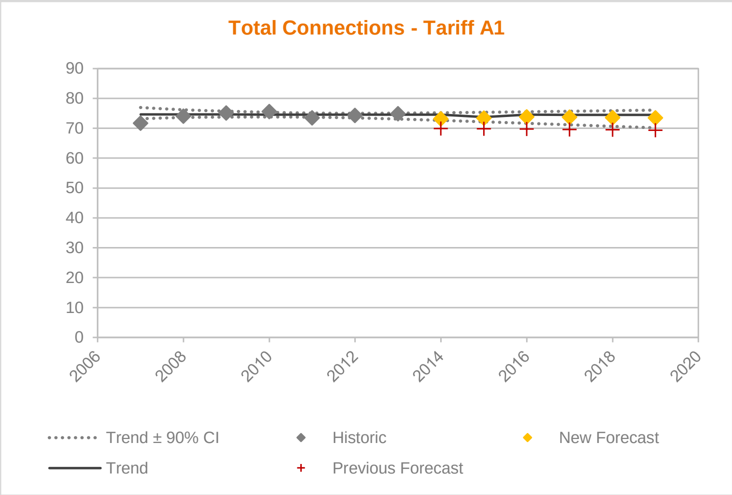


Table 2.2: Connections | Original vs. November Refresh Forecasts | No.

	2014	2015	2016	2017	2018	2019
Original	70	70	70	70	70	69
Revised	73	73	74	74	74	74
Difference	3	4	4	4	4	4

Figure 2.3: Demand per Connection | Original vs. November Refresh Forecasts | GJ

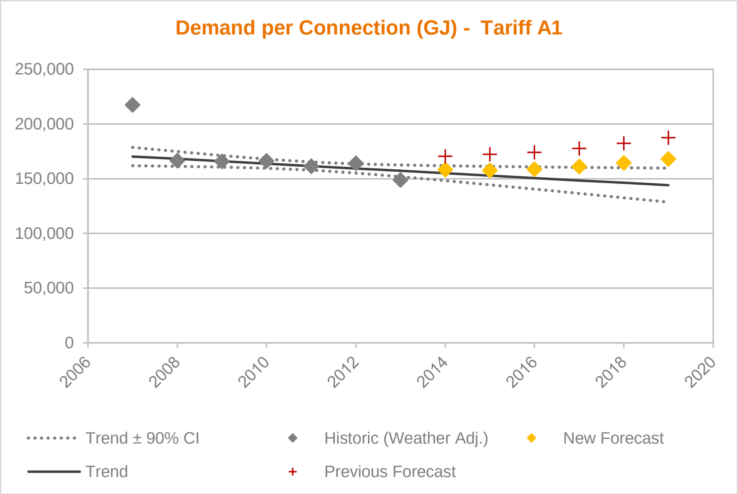


Table 2.3: Demand per Connection | Original vs. November Refresh Forecasts | GJ

	2014	2015	2016	2017	2018	2019
Original	170,406	172,218	174,132	177,675	182,318	187,435
Revised	158,146	157,570	158,732	161,180	164,434	168,013
Difference	(12,260)	(14,648)	(15,399)	(16,495)	(17,884)	(19,421)

Tariff A2

Figure 2.4: Total Demand | Original vs. November Refresh Forecasts | GJ

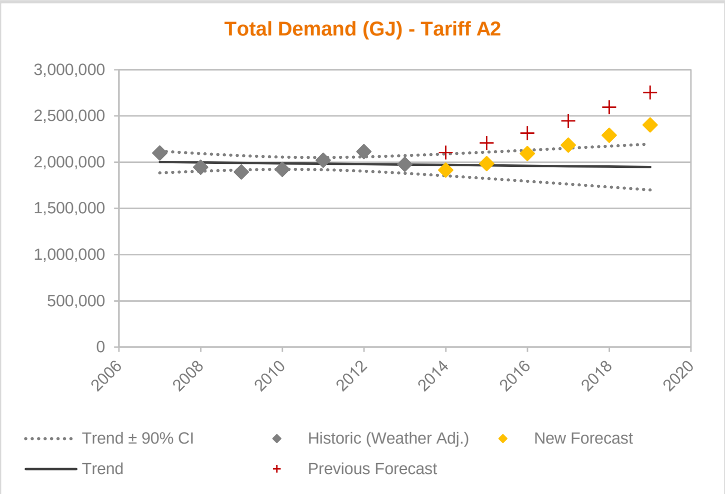


Table 2.4: Total Demand | Original vs. November Refresh Forecasts | GJ

	2014	2015	2016	2017	2018	2019
Original	2,103,786	2,208,644	2,315,018	2,445,268	2,593,941	2,752,930
Revised	1,914,907	1,982,745	2,092,394	2,184,157	2,288,724	2,400,155
Difference	(188,878)	(225,899)	(222,624)	(261,112)	(305,217)	(352,776)

Figure 2.5: Connections | Original vs. November Refresh Forecasts | No.

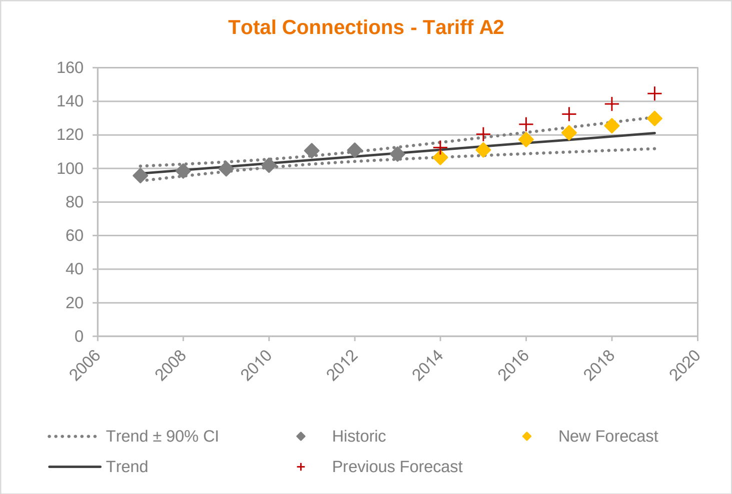


Table 2.5: Connections | Original vs. November Refresh Forecasts | No.

	2014	2015	2016	2017	2018	2019
Original	112	120	126	132	138	145
Revised	107	111	117	121	125	130
Difference	(6)	(9)	(9)	(11)	(13)	(15)

Figure 2.6: Demand per Connection | Original vs. November Refresh Forecasts | GJ

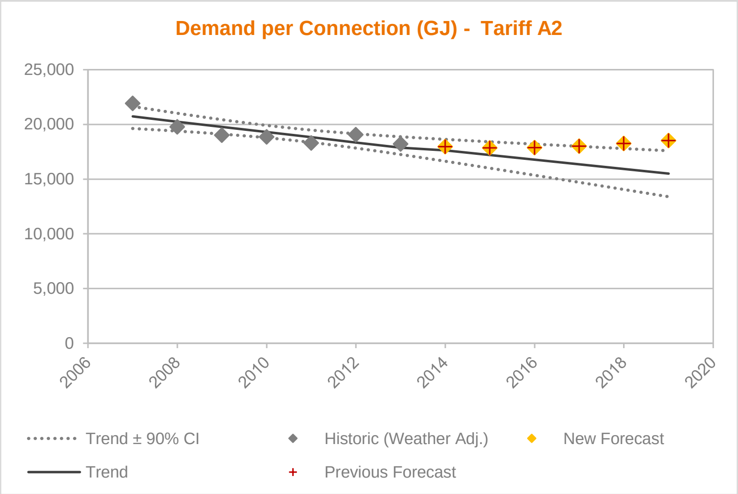


Table 2.6: Demand per Connection | Original vs. November Refresh Forecasts | GJ

	2014	2015	2016	2017	2018	2019
Original	18,703	18,352	18,331	18,482	18,743	19,042
Revised	17,966	17,856	17,861	18,007	18,239	18,503
Difference	(736)	(496)	(470)	(475)	(504)	(539)

Tariff B1

Figure 2.7: Total Demand | Original vs. November Refresh Forecasts | GJ

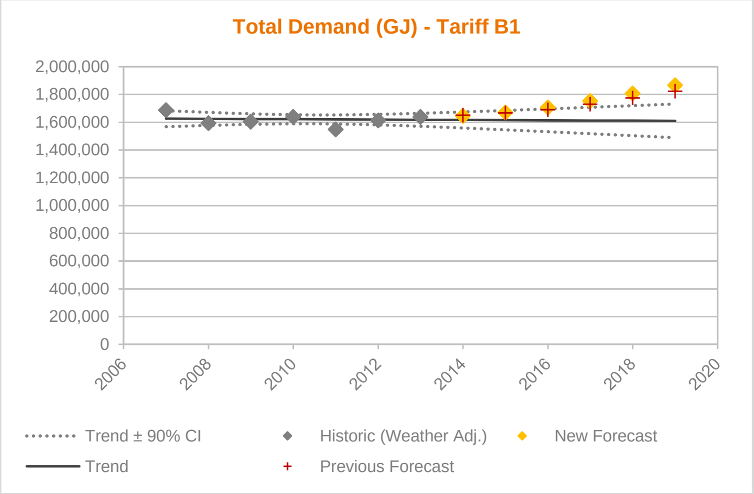


Table 2.7: Total Demand | Original vs. November Refresh Forecasts | GJ

	2014	2015	2016	2017	2018	2019
Original	1,652,379	1,667,284	1,691,685	1,729,881	1,775,516	1,823,895
Revised	1,646,743	1,671,627	1,706,345	1,754,091	1,808,694	1,866,278
Difference	(5,637)	4,343	14,660	24,211	33,178	42,383

Figure 2.8: Connections | Original vs. November Refresh Forecasts | No.

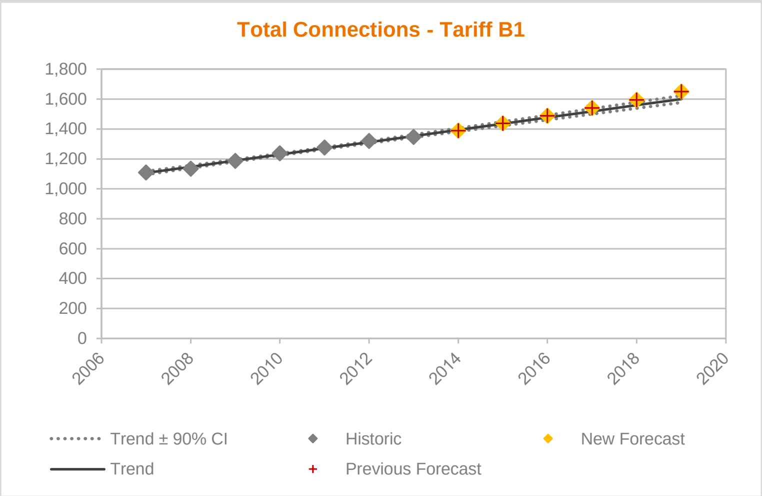


Table 2.8: Connections | Original vs. November Refresh Forecasts | No.

	2014	2015	2016	2017	2018	2019
Original	1,410	1,468	1,528	1,589	1,652	1,717
Revised	1,389	1,438	1,489	1,541	1,595	1,650
Difference	(21)	(30)	(39)	(48)	(57)	(67)

Figure 2.9: Demand per Connection | Original vs. November Refresh Forecasts | GJ

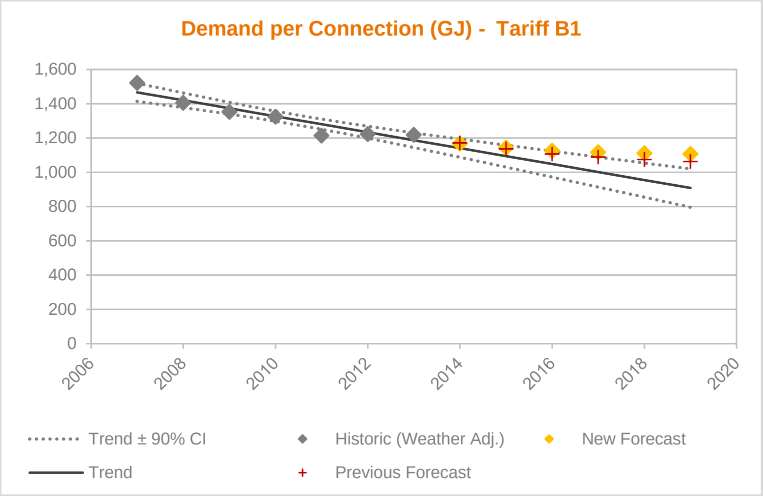


Table 2.9: Demand per Connection | Original vs. November Refresh Forecasts | GJ

	2014	2015	2016	2017	2018	2019
Original	1,172	1,136	1,107	1,089	1,075	1,062
Revised	1,185	1,162	1,146	1,138	1,134	1,131
Difference	13	26	39	50	59	69

Tariff B2

Figure 2.10: Total Demand | Original vs. November Refresh Forecasts | GJ

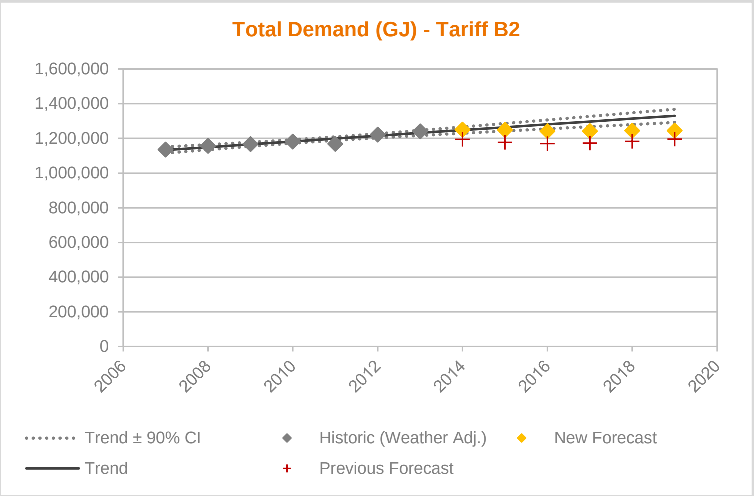


Table 2.10: Total Demand | Original vs. November Refresh Forecasts | GJ

	2014	2015	2016	2017	2018	2019
Original	1,194,484	1,177,612	1,169,788	1,173,334	1,183,114	1,195,512
Revised	1,251,134	1,249,783	1,242,812	1,242,746	1,244,572	1,245,362
Difference	56,650	72,172	73,024	69,412	61,458	49,849

Figure 2.11: Connections | Original vs. November Refresh Forecasts | No.

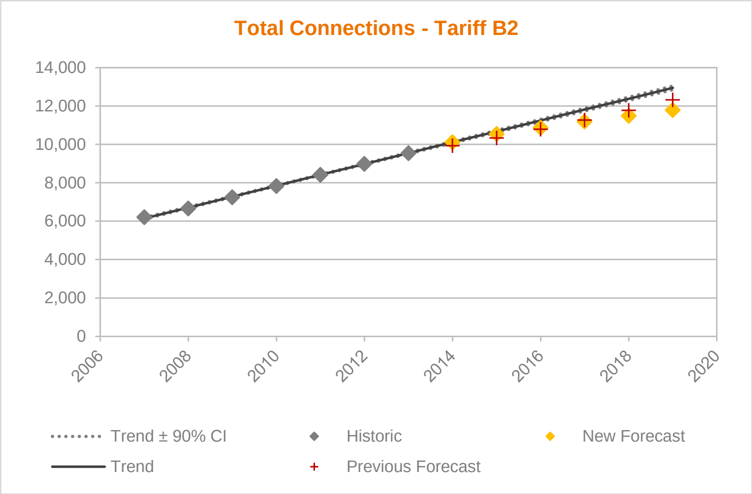


Table 2.11: Connections | Original vs. November Refresh Forecasts | No.

	2014	2015	2016	2017	2018	2019
Original	9,932	10,346	10,792	11,270	11,781	12,326
Revised	10,118	10,542	10,873	11,193	11,500	11,793
Difference	186	196	82	(77)	(281)	(533)

Figure 2.12: Demand per Connection | Original vs. November Refresh Forecasts | GJ

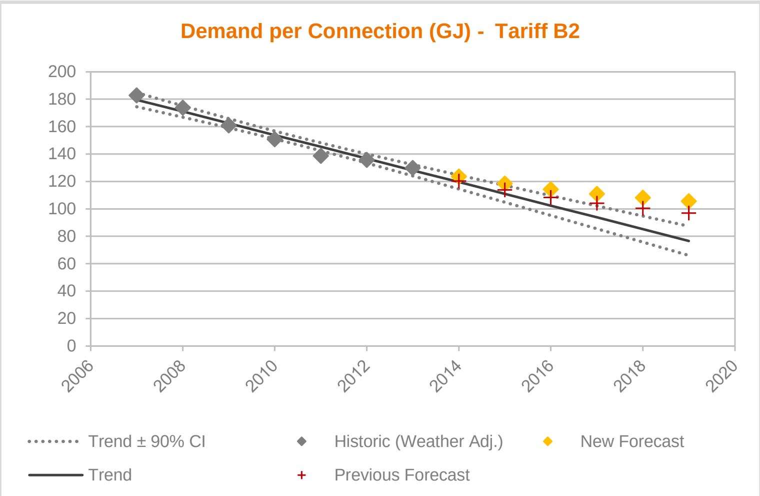


Table 2.12: Demand per Connection | Original vs. November Refresh Forecasts | GJ

	2014	2015	2016	2017	2018	2019
Original	120	114	108	104	100	97
Revised	124	119	114	111	108	106
Difference	3	5	6	7	8	9

Tariff B3

Figure 2.13: Total Demand | Original vs. November Refresh Forecasts | GJ

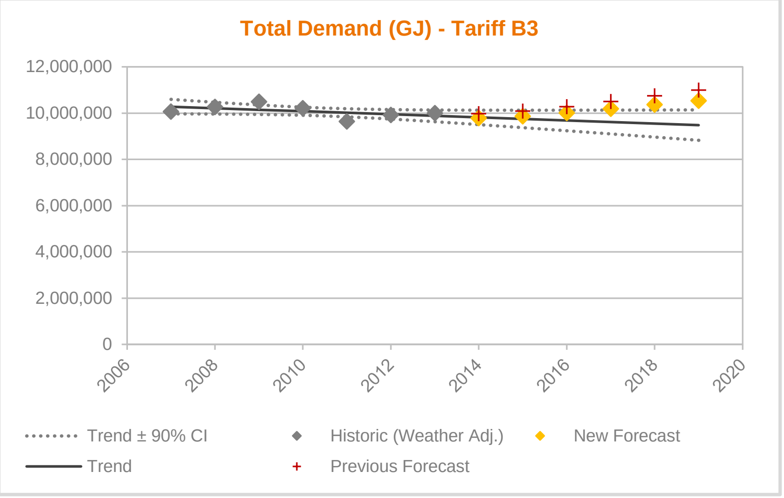


Table 2.13: Total Demand | Original vs. November Refresh Forecasts | GJ

	2014	2015	2016	2017	2018	2019
Original	9,970,563	10,089,375	10,274,990	10,501,759	10,747,244	10,999,195
Revised	9,785,209	9,858,722	10,007,804	10,188,283	10,372,812	10,530,472
Difference	(185,354)	(230,653)	(267,186)	(313,476)	(374,432)	(468,723)

Figure 2.14: Connections | Original vs. November Refresh Forecasts | No.

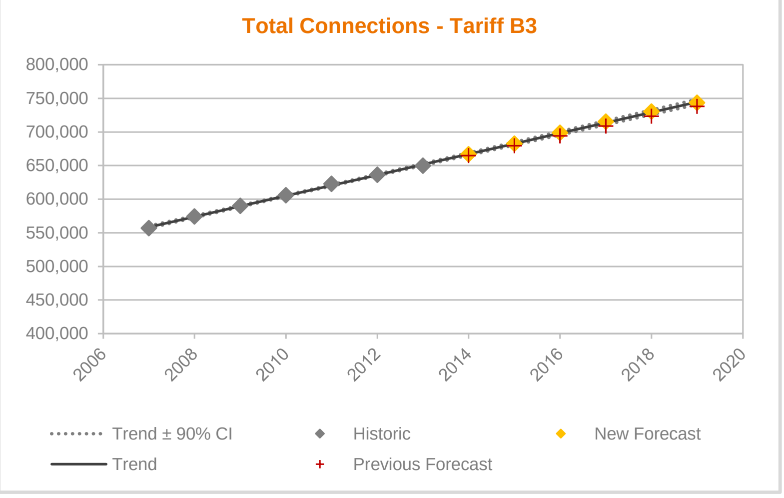


Table 2.14: Connections | Original vs. November Refresh Forecasts | No.

	2014	2015	2016	2017	2018	2019
Original	664,763	679,549	694,284	708,948	723,542	738,065
Revised	666,795	682,402	698,689	715,147	730,154	743,578
Difference	2,032	2,852	4,405	6,199	6,612	5,513

Figure 2.15: Demand per Connection | Original vs. November Refresh Forecasts | GJ

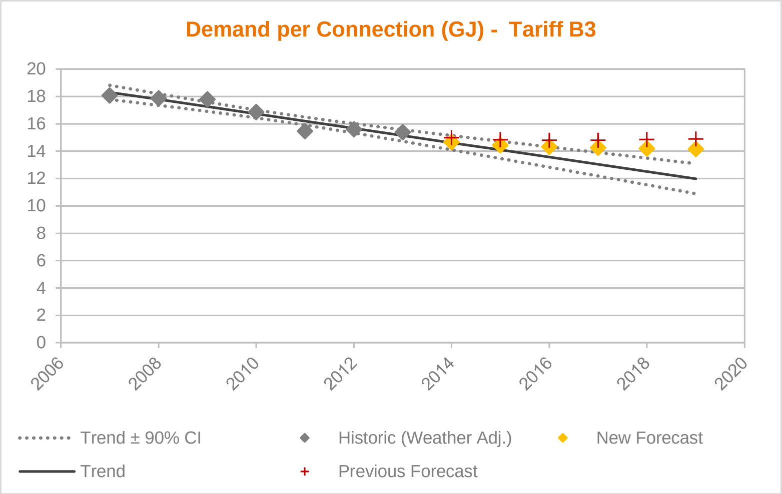


Table 2.15: Demand per Connection | Original vs. November Refresh Forecasts | GJ

	2014	2015	2016	2017	2018	2019
Original	15.00	14.85	14.80	14.81	14.85	14.90
Revised	14.67	14.45	14.32	14.25	14.21	14.16
Difference	(0.3)	(0.4)	(0.5)	(0.6)	(0.6)	(0.7)

2.1.2. Results | Exclusive of Marketing Impact

Figure 2.16 to 2.30 provide graphical representations of the historical trend of gas demand (± 90% CI), originally submitted demand forecasts and the revised gas demand forecasts for each tariff class, exclusive of marketing impact. Meanwhile, the data in Table 2.16 to Table 2.30: presents a comparison of original gas demand forecasts against revised demand forecasts for each tariff class, exclusive of marketing impact.

Tariff A1

Figure 2.16: Total Demand | Original vs. November Refresh Forecasts | GJ

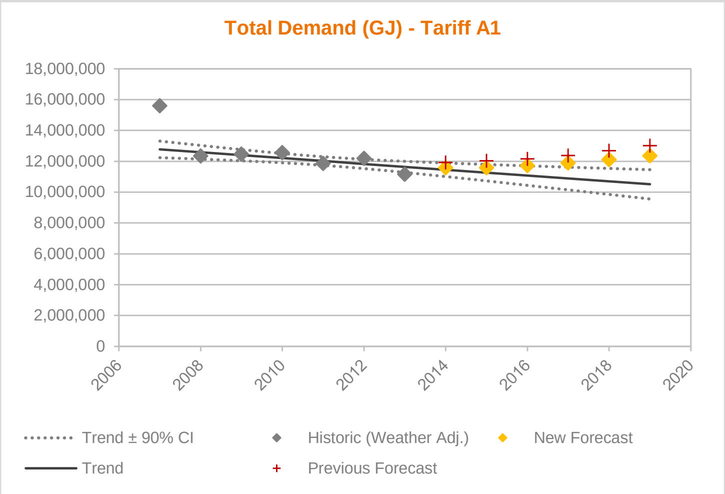


Table 2.16: Total Demand | Original vs. November Refresh Forecasts | GJ

	014	2015	2016	2017	2018	2019
Original	11,922,065	12,029,555	12,143,688	12,370,908	12,673,841	13,008,602
Revised	11,571,022	11,572,769	11,720,093	11,883,212	12,105,157	12,350,313
Difference	(351,044)	(456,787)	(423,595)	(487,696)	(568,684)	(658,289)

Figure 2.17: Connections | Original vs. November Refresh Forecasts | No.

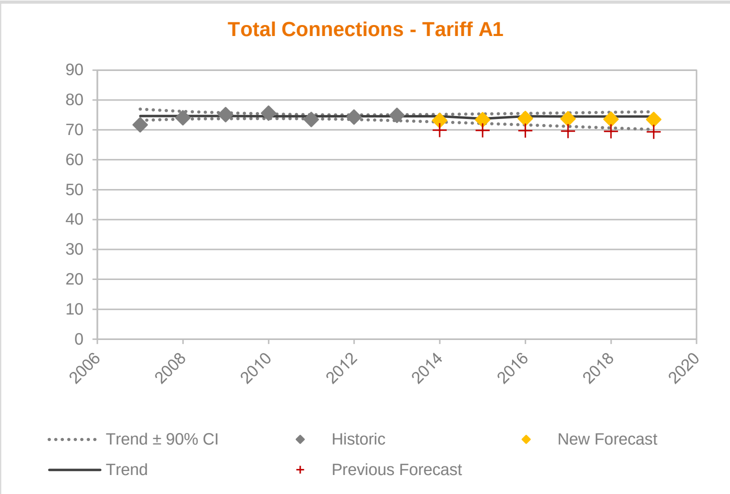


Table 2.17: Connections | Original vs. November Refresh Forecasts | No.

	2014	2015	2016	2017	2018	2019
Original	70	70	70	70	70	69
Revised	73	73	74	74	74	74
Difference	3	4	4	4	4	4

Figure 2.18: Demand per Connection | Original vs. November Refresh Forecasts | GJ

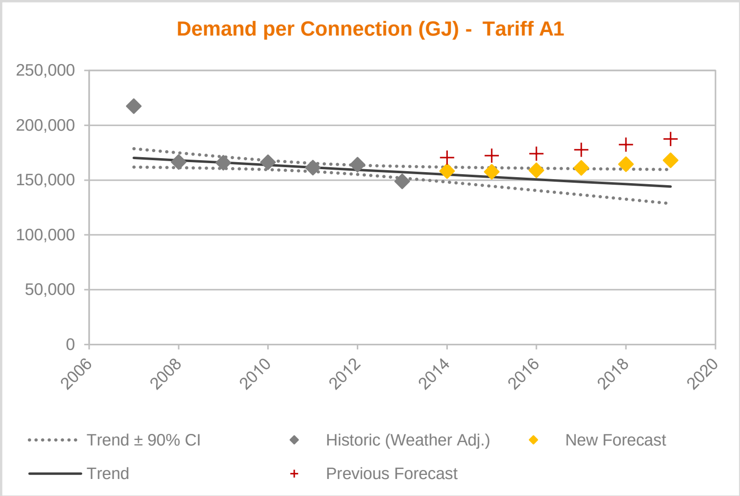


Table 2.18: Demand per Connection | Original vs. November Refresh Forecasts | GJ

	2014	2015	2016	2017	2018	2019
Original	170,406	172,218	174,132	177,675	182,318	187,435
Revised	158,146	157,570	158,732	161,180	164,434	168,013
Difference	(12,260)	(14,648)	(15,399)	(16,495)	(17,884)	(19,421)

Tariff A2

Figure 2.19: Total Demand | Original vs. November Refresh Forecasts | GJ

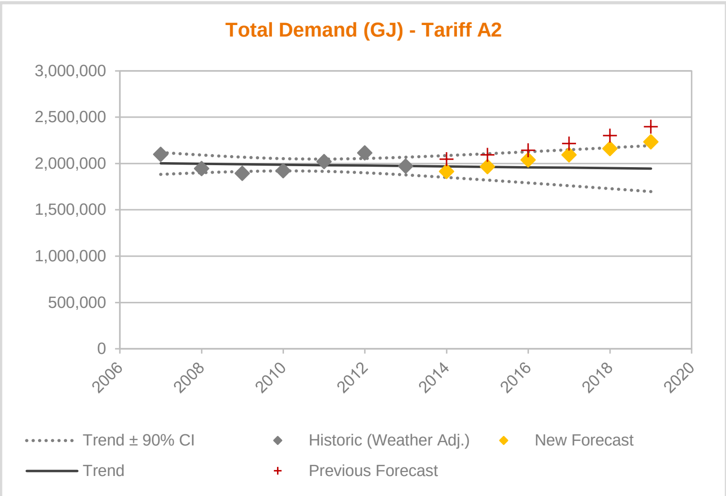


Table 2.19: Total Demand | Original vs. November Refresh Forecasts | GJ

	2014	2015	2016	2017	2018	2019
Original	2,046,327	2,093,980	2,143,355	2,214,748	2,302,082	2,397,526
Revised	1,914,907	1,964,815	2,038,598	2,093,755	2,160,501	2,232,868
Difference	(131,419)	(129,165)	(104,757)	(120,993)	(141,581)	(164,657)

Figure 2.20: Connections | Original vs. November Refresh Forecasts | No.

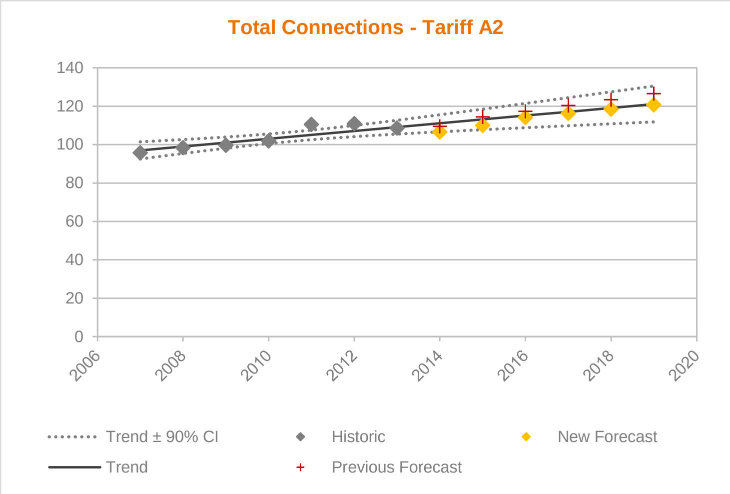


Table 2.20: Connections | Original vs. November Refresh Forecasts | No.

	2014	2015	2016	2017	2018	2019
Original	109	114	117	120	123	127
Revised	107	110	114	116	118	121
Difference	(3)	(4)	(3)	(4)	(5)	(6)

Figure 2.21: Demand per Connection | Original vs. November Refresh Forecasts | GJ

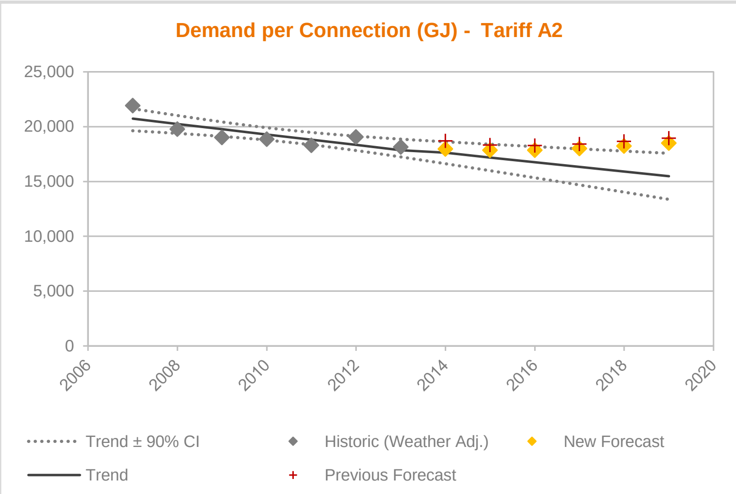


Table 2.21: Demand per Connection | Original vs. November Refresh Forecasts | GJ

	2014	2015	2016	2017	2018	2019
Original	18,690	18,312	18,274	18,409	18,656	18,942
Revised	17,966	17,855	17,859	18,004	18,234	18,497
Difference	(724)	(457)	(415)	(406)	(421)	(446)

Tariff B1

Figure 2.22: Total Demand | Original vs. November Refresh Forecasts | GJ

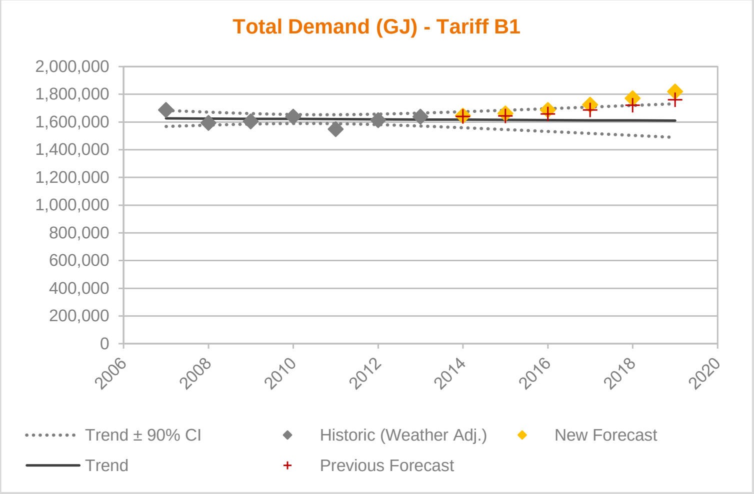


Table 2.22: Total Demand | Original vs. November Refresh Forecasts | GJ

	2014	2015	2016	2017	2018	2019
Original	1,640,745	1,644,734	1,658,705	1,686,646	1,722,159	1,760,601
Revised	1,646,743	1,662,033	1,687,385	1,725,834	1,771,171	1,819,523
Difference	5,998	17,299	28,681	39,188	49,012	58,922

Figure 2.23: Connections | Original vs. November Refresh Forecasts | No.

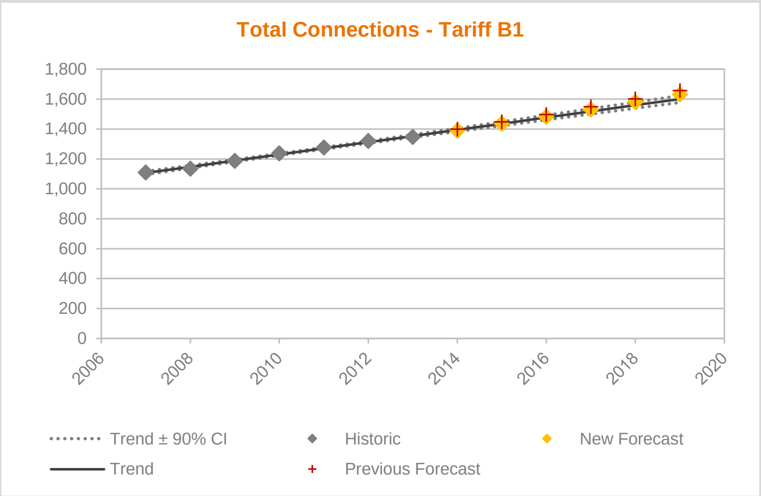


Table 2.23: Connections | Original vs. November Refresh Forecasts | No.

	2014	2015	2016	2017	2018	2019
Original	1,400	1,448	1,498	1,549	1,602	1,657
Revised	1,389	1,436	1,483	1,531	1,581	1,632
Difference	(11)	(12)	(15)	(18)	(21)	(25)

Figure 2.24: Demand per Connection | Original vs. November Refresh Forecasts | GJ

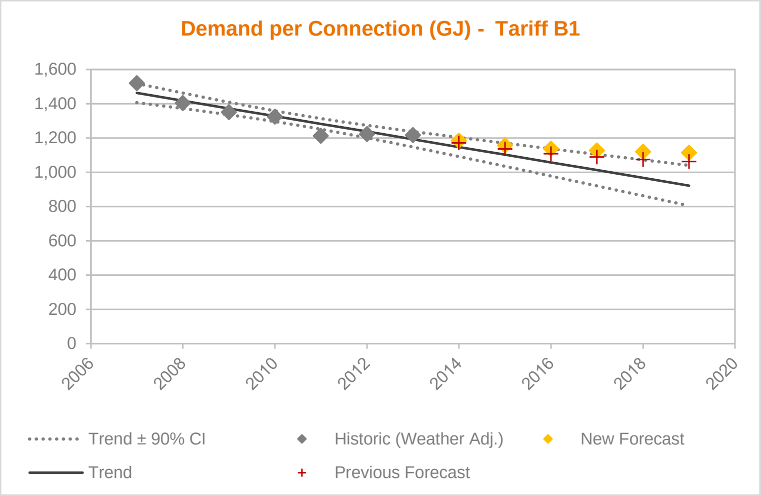


Table 2.24: Demand per Connection | Original vs. November Refresh Forecasts | GJ

	2014	2015	2016	2017	2018	2019
Original	1,172	1,136	1,108	1,089	1,075	1,062
Revised	1,185	1,157	1,138	1,127	1,120	1,115
Difference	13	21	30	38	45	52

Tariff B2

Figure 2.25: Total Demand | Original vs. November Refresh Forecasts | GJ

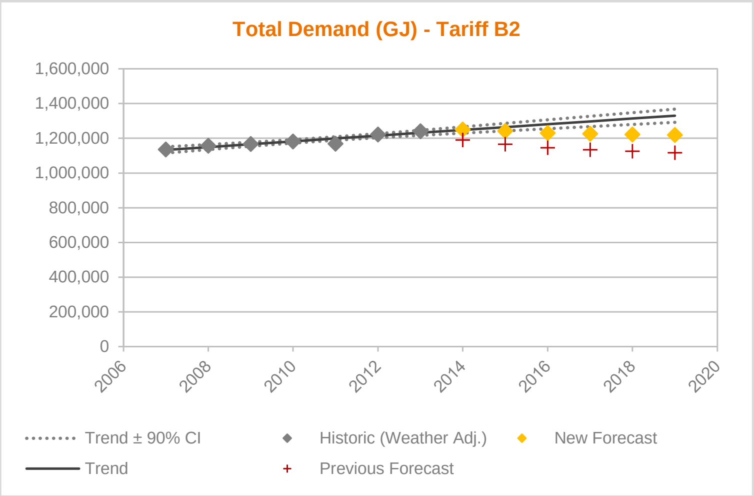


Table 2.25: Total Demand | Original vs. November Refresh Forecasts | GJ

	2014	2015	2016	2017	2018	2019
Original	1,190,274	1,165,422	1,146,135	1,134,801	1,126,438	1,117,689
Revised	1,251,134	1,242,503	1,230,679	1,225,760	1,222,733	1,218,670
Difference	60,859	77,082	84,545	90,959	96,295	100,981

Figure 2.26: Connections | Original vs. November Refresh Forecasts | No.

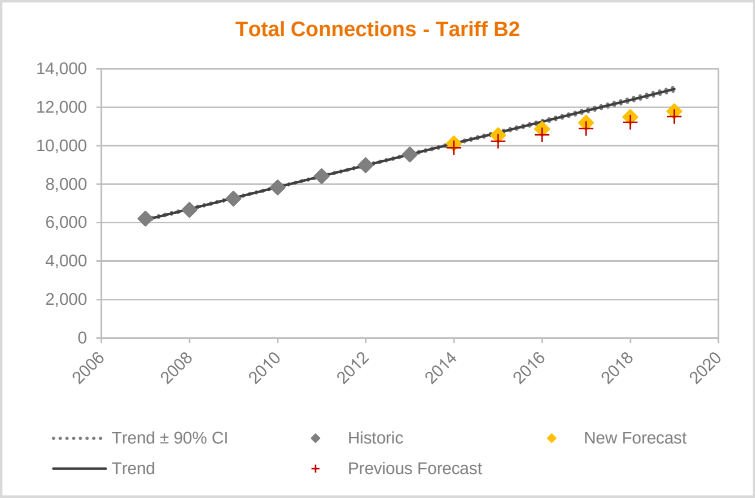


Table 2.26: Connections | Original vs. November Refresh Forecasts | No.

	2014	2015	2016	2017	2018	2019
Original	9,897	10,239	10,573	10,900	11,217	11,523
Revised	10,118	10,542	10,873	11,193	11,500	11,793
Difference	221	303	300	293	283	270

Figure 2.27: Demand per Connection | Original vs. November Refresh Forecasts | GJ

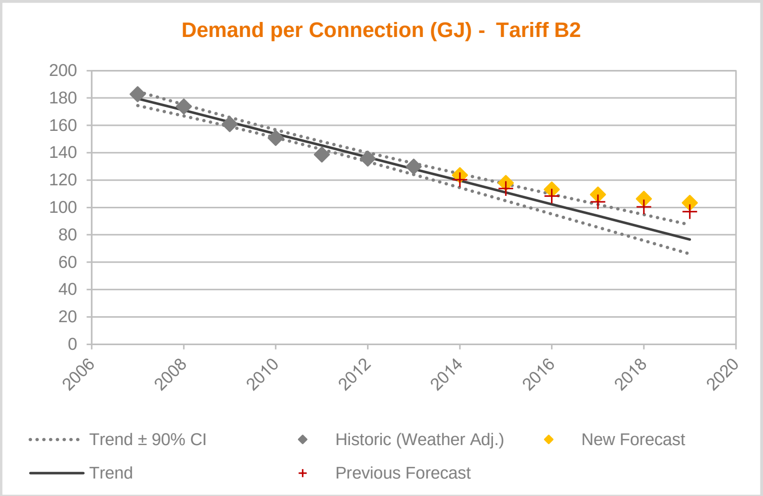


Table 2.27: Demand per Connection | Original vs. November Refresh Forecasts | GJ

	2014	2015	2016	2017	2018	2019
Original	120	114	108	104	100	97
Revised	124	118	113	110	106	103
Difference	3	4	5	5	6	6

Tariff B3

Figure 2.28: Total Demand | Original vs. November Refresh Forecasts | GJ

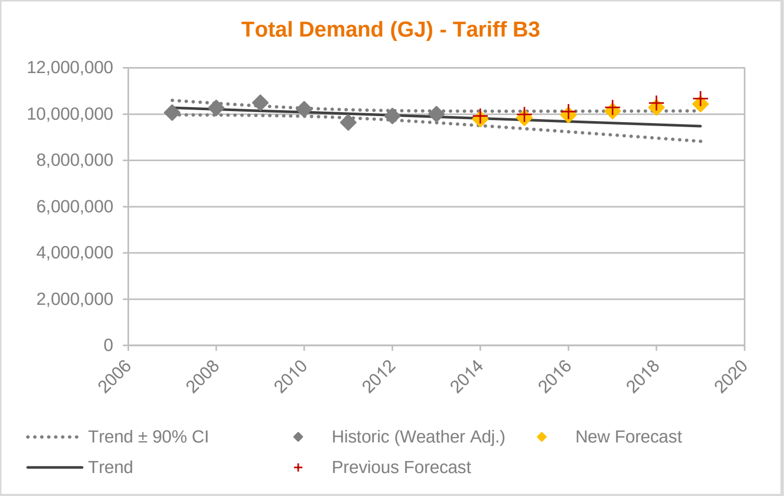


Table 2.28: Total Demand | Original vs. November Refresh Forecasts | GJ

	2014	2015	2016	2017	2018	2019
Original	9,916,297	9,981,695	10,114,651	10,287,810	10,478,177	10,673,561
Revised	9,785,209	9,845,779	9,969,056	10,132,051	10,291,692	10,431,445
Difference	(131,087)	(135,916)	(145,595)	(155,759)	(186,485)	(242,116)

Figure 2.29: Connections | Original vs. November Refresh Forecasts | No.

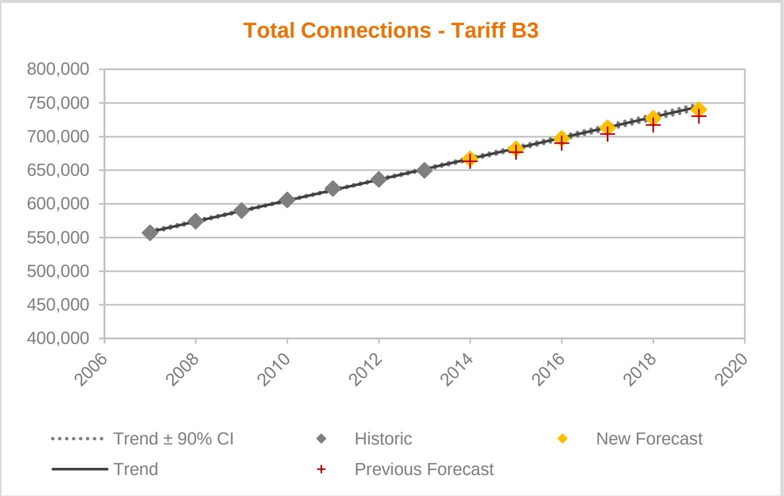


Table 2.29: Connections | Original vs. November Refresh Forecasts | No.

	2014	2015	2016	2017	2018	2019
Original	663,248	676,651	690,161	703,649	717,072	730,431
Revised	666,795	681,905	697,319	713,026	727,285	739,964
Difference	3,547	5,254	7,158	9,376	10,213	9,533

Figure 2.30: \Demand per Connection | Original vs. November Refresh Forecasts | GJ

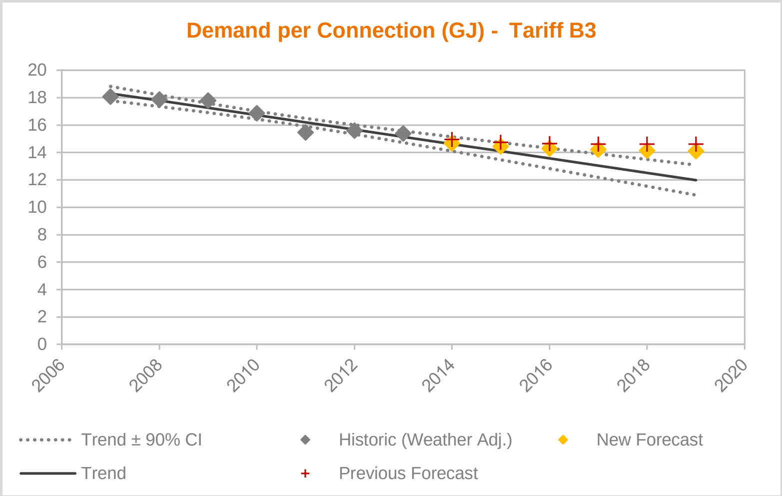


Table 2.30: Demand per Connection | Original vs. November Refresh Forecasts | GJ

	2014	2015	2016	2017	2018	2019
Original	14.95	14.75	14.66	14.62	14.61	14.61
Revised	14.67	14.44	14.30	14.21	14.15	14.10
Difference	(0.3)	(0.3)	(0.4)	(0.4)	(0.5)	(0.5)

2.2. Impact of Marketing on Gas Demand Forecasts

The following sections compares the impact of marketing on the original gas demand forecasts submitted to the ERA, and the revised demand forecasts that form the basis of this submission.

2.2.1. Original Gas Demand Forecasts | Submitted to the ERA

Figure 2.31: Comparison of Tariff A1 Forecasts | With and Without Marketing Impact

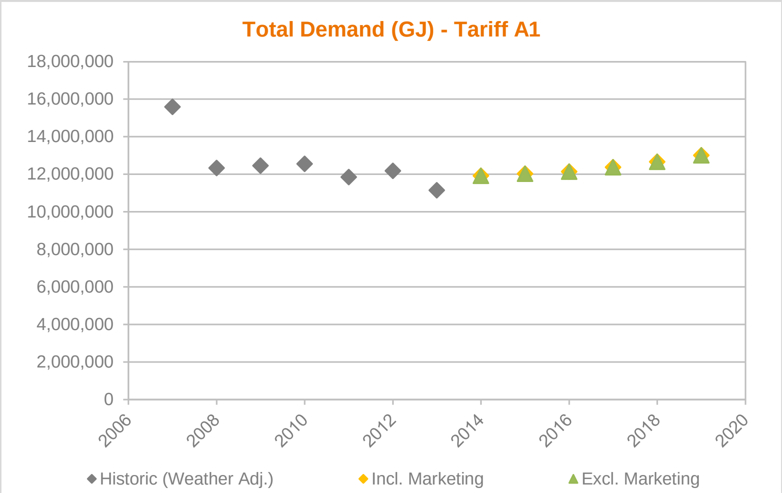


Table 2.31: Comparison of Tariff A1 Forecasts | With and Without Marketing Impact

	2014	2015	2016	2017	2018	2019
Incl. Marketing	11,922,065	12,029,555	12,143,688	12,370,908	12,673,841	13,008,602
Excl. Marketing	11,922,065	12,029,555	12,143,688	12,370,908	12,673,841	13,008,602
Impact of Marketing	-	-	-	-	-	-

Figure 2.32: Comparison of Tariff A2 Forecasts | With and Without Marketing Impact

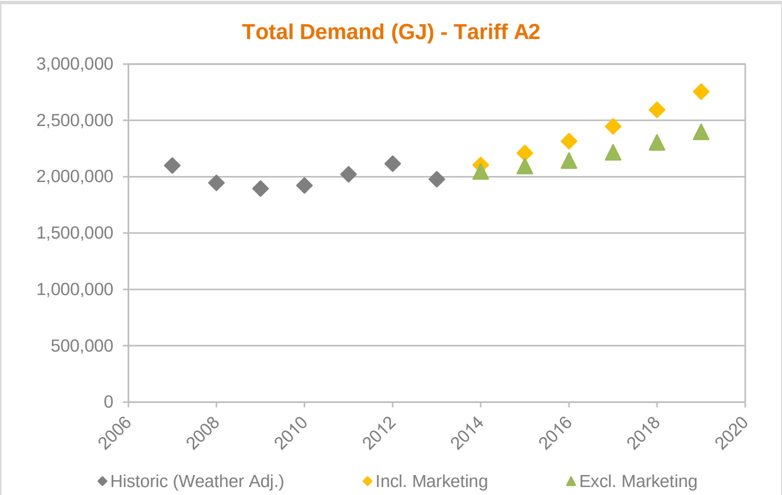


Table 2.32: Comparison of Tariff A2 Forecasts | With and Without Marketing Impact

	2014	2015	2016	2017	2018	2019
Incl. Marketing	2,103,786	2,208,644	2,315,018	2,445,268	2,593,941	2,752,930
Excl. Marketing	2,046,327	2,093,980	2,143,355	2,214,748	2,302,082	2,397,526
Impact of Marketing	57,459	114,664	171,663	230,520	291,859	355,405

Figure 2.33: Comparison of Tariff B1 Forecasts | With and Without Marketing Impact

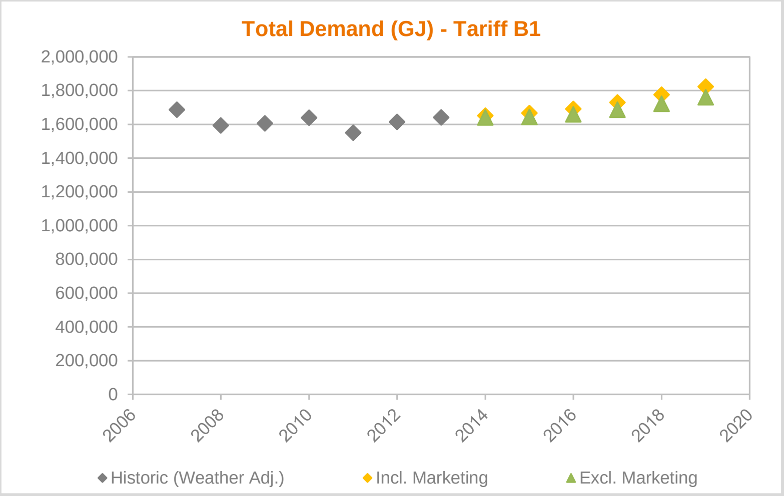


Table 2.33: Comparison of Tariff B1 Forecasts | With and Without Marketing Impact

	2014	2015	2016	2017	2018	2019
Incl. Marketing	1,652,379	1,667,284	1,691,685	1,729,881	1,775,516	1,823,895
Excl. Marketing	1,640,745	1,644,734	1,658,705	1,686,646	1,722,159	1,760,601
Impact of Marketing	11,634	22,550	32,981	43,235	53,357	63,295

Figure 2.34: Comparison of Tariff B2 Forecasts | With and Without Marketing Impact

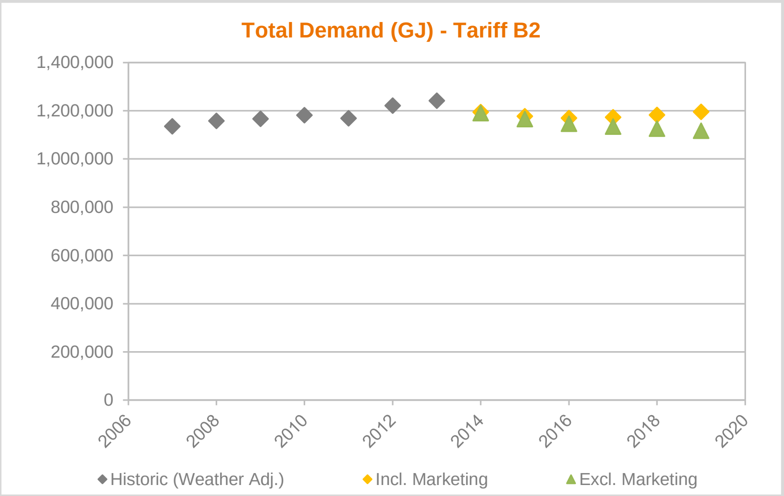


Table 2.34: Comparison of Tariff B2 Forecasts | With and Without Marketing Impact

	2014	2015	2016	2017	2018	2019
Incl. Marketing	1,194,484	1,177,612	1,169,788	1,173,334	1,183,114	1,195,512
Excl. Marketing	1,190,274	1,165,422	1,146,135	1,134,801	1,126,438	1,117,689
Impact of Marketing	4,209	12,190	23,653	38,533	56,676	77,824

Figure 2.35: Comparison of Tariff B3 Forecasts | With and Without Marketing Impact

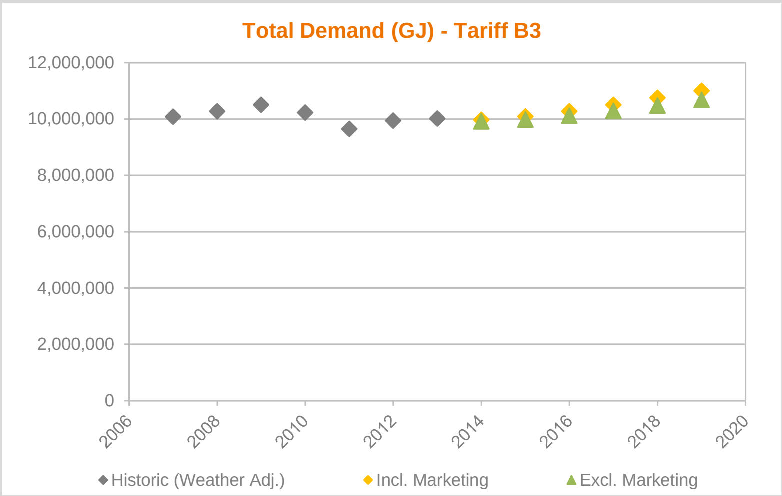


Table 2.35: Comparison of Tariff B3 Forecasts | With and Without Marketing Impact

	2014	2015	2016	2017	2018	2019
Incl. Marketing	9,970,563	10,089,375	10,274,990	10,501,759	10,747,244	10,999,195
Excl. Marketing	9,916,297	9,981,695	10,114,651	10,287,810	10,478,177	10,673,561
Impact of Marketing	54,267	107,679	160,339	213,949	269,067	325,634

2.2.2. Revised Gas Demand Forecasts

Figure 2.36: Comparison of Tariff A1 Forecasts | With and Without Marketing Impact

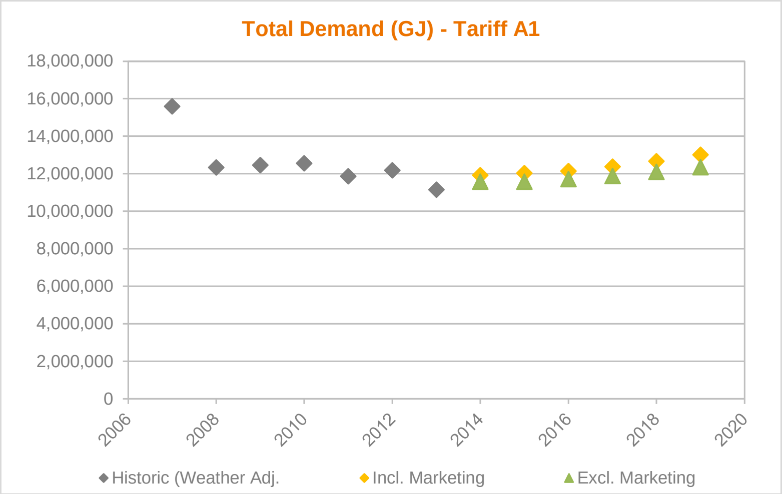


Table 2.36: Comparison of Tariff A1 Forecasts | With and Without Marketing Impact

	2014	2015	2016	2017	2018	2019
Incl. Marketing	11,571,022	11,572,769	11,720,093	11,883,212	12,105,157	12,350,313
Excl. Marketing	11,571,022	11,572,769	11,720,093	11,883,212	12,105,157	12,350,313
Impact of Marketing	-	-	-	-	-	-

Figure 2.37: Comparison of Tariff A2 Forecasts | With and Without Marketing Impact

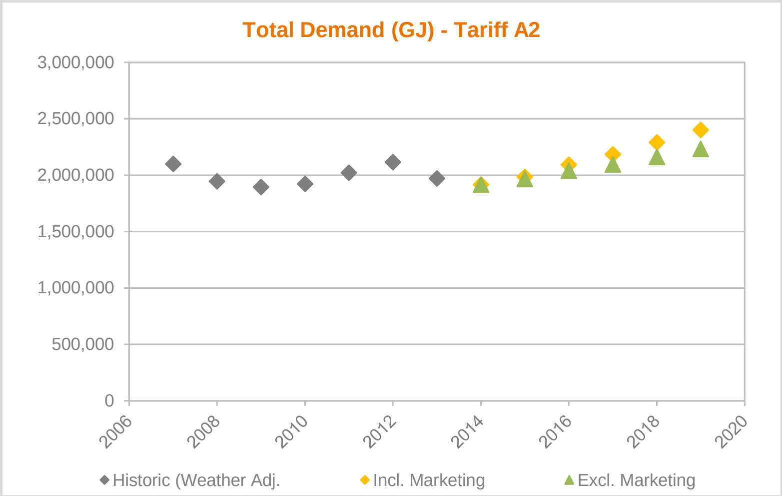


Table 2.37: Comparison of Tariff A2 Forecasts | With and Without Marketing Impact

	2014	2015	2016	2017	2018	2019
Incl. Marketing	1,914,907	1,982,745	2,092,394	2,184,157	2,288,724	2,400,155
Excl. Marketing	1,914,907	1,964,815	2,038,598	2,093,755	2,160,501	2,232,868
Impact of Marketing	-	17,931	53,796	90,402	128,223	167,286

Figure 2.38: Comparison of Tariff B1 Forecasts | With and Without Marketing Impact

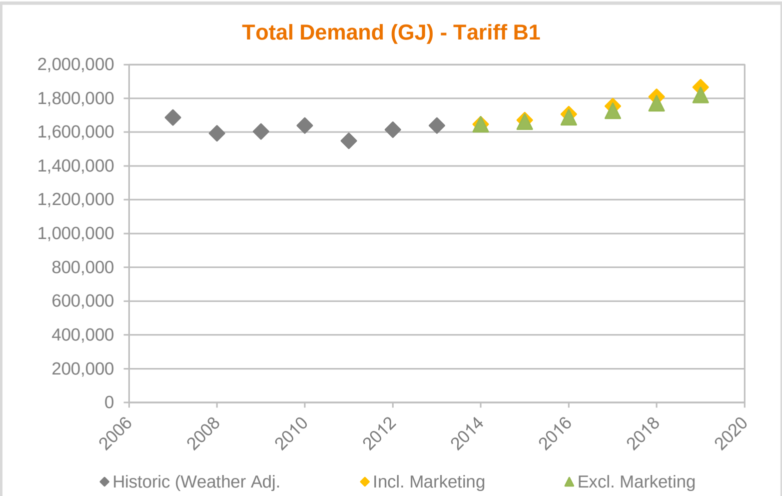


Table 2.38: Comparison of Tariff B1 Forecasts | With and Without Marketing Impact

	2014	2015	2016	2017	2018	2019
Incl. Marketing	1,646,743	1,671,627	1,706,345	1,754,091	1,808,694	1,866,278
Excl. Marketing	1,646,743	1,662,033	1,687,385	1,725,834	1,771,171	1,819,523
Impact of Marketing	-	9,594	18,960	28,257	37,523	46,755

Figure 2.39: Comparison of Tariff B2 Forecasts | With and Without Marketing Impact

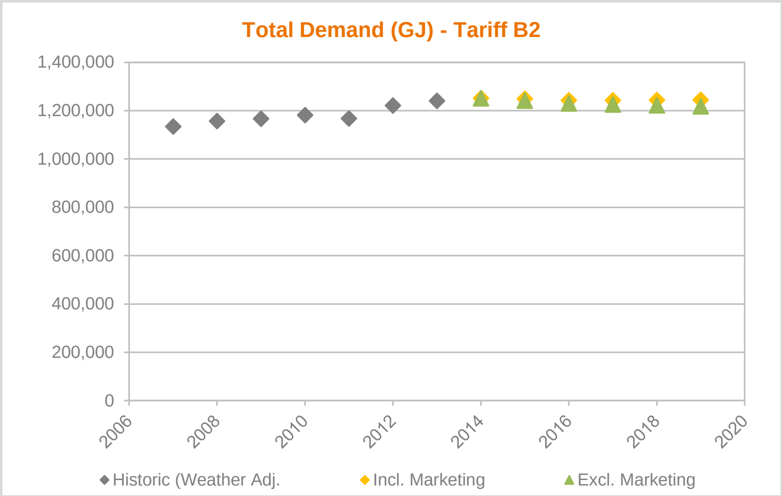
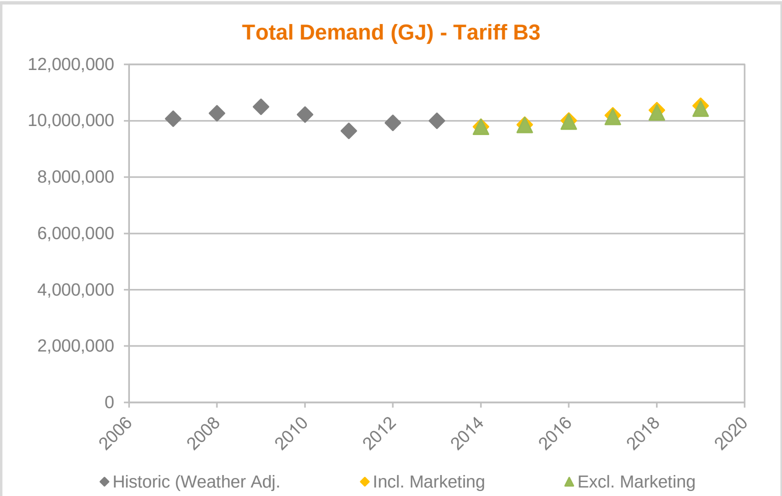


Table 2.39: Comparison of Tariff B2 Forecasts | With and Without Marketing Impact

	2014	2015	2016	2017	2018	2019
Incl. Marketing	1,251,134	1,249,783	1,242,812	1,242,746	1,244,572	1,245,362
Excl. Marketing	1,251,134	1,242,503	1,230,679	1,225,760	1,222,733	1,218,670
Impact of Marketing	-	7,280	12,133	16,986	21,839	26,692

Figure 2.40: Comparison of Tariff B3 Forecasts | With and Without Marketing Impact



6

Table 2.40: Comparison of Tariff B3 Forecasts | With and Without Marketing Impact

	2014	2015	2016	2017	2018	2019
Incl. Marketing	9,785,209	9,858,722	10,007,804	10,188,283	10,372,812	10,530,472
Excl. Marketing	9,785,209	9,845,779	9,969,056	10,132,051	10,291,692	10,431,445
Impact of Marketing	-	12,943	38,748	56,232	81,120	99,027

2.2.3. Impact of Marketing on Demand | Original vs. Revised Forecasts

Table 2.41: Comparison of the Impact of Marketing between Original and Revised Demand Forecasts | Tariff A1 | GJ

	2014	2015	2016	2017	2018	2019
Original Impact of Marketing	-	-	-	-	-	-
Revised Impact of Marketing	-	-	-	-	-	-

Table 2.42: Comparison of the Impact of Marketing between Original and Revised Demand Forecasts | Tariff A2 | GJ

	2014	2015	2016	2017	2018	2019
Original Impact of Marketing	57,459	114,664	171,663	230,520	291,859	355,405
Revised Impact of Marketing	-	17,931	53,796	90,402	128,223	167,286

Table 2.43: Comparison of the Impact of Marketing between Original and Revised Demand Forecasts | Tariff B1 | GJ

	2014	2015	2016	2017	2018	2019
Original Impact of Marketing	11,634	22,550	32,981	43,235	53,357	63,295
Revised Impact of Marketing	-	9,594	18,960	28,257	37,523	46,755

Table 2.44: Comparison of the Impact of Marketing between Original and Revised Forecasts | Tariff B2

	2014	2015	2016	2017	2018	2019
Original Impact of Marketing	4,209	12,190	23,653	38,533	56,676	77,824
Revised Impact of Marketing	-	7,280	12,133	16,986	21,839	26,692

Table 2.45: Comparison of the Impact of Marketing between Original and Revised Demand Forecasts | Tariff B3 | GJ

	2014	2015	2016	2017	2018	2019
Original Impact of Marketing	54,267	107,679	160,339	213,949	269,067	325,634
Revised Impact of Marketing	-	12,943	38,748	56,232	81,120	99,027

3. Executive Summary

3.1. Scope

This report has been prepared by Core Energy Group Pty Ltd ("**Core**") for the purpose of providing ATCO Gas Australia ("**ATCO**") with an independent forecast of gas demand for the Mid-West and South-West Gas Distribution System ("**MWSWGDS**"), for the calendar year period 2015 to 2019. The 2015 year forecasts have been provided on a half-yearly basis to allow for transition from financial year to calendar year reporting.

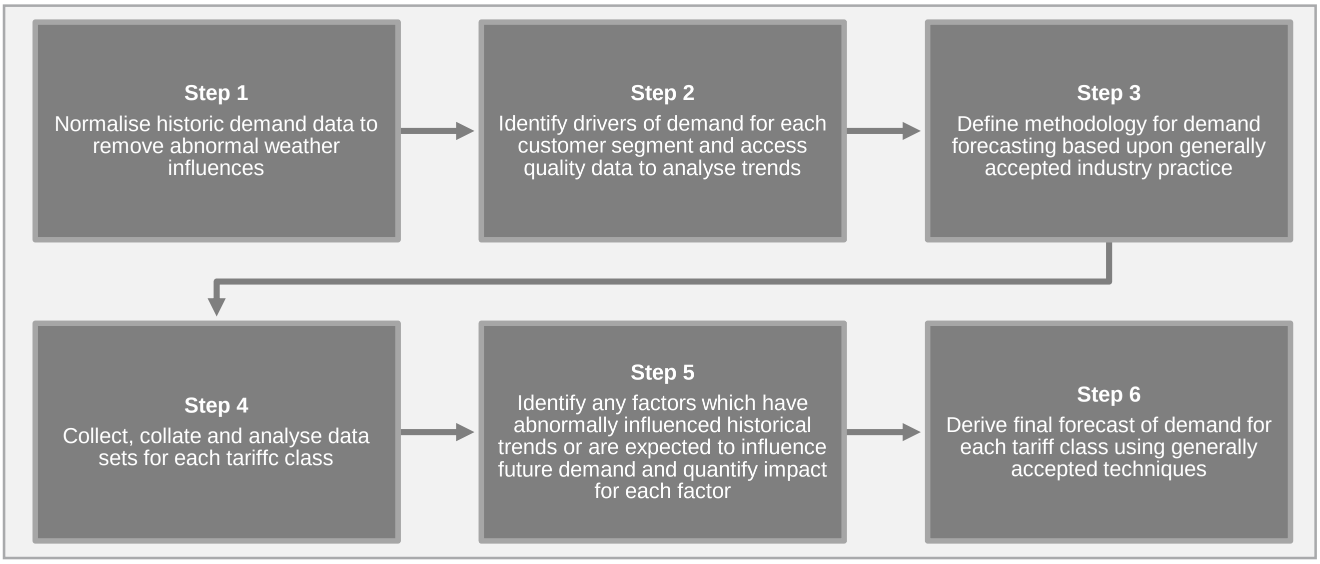
Core understands that this forecast (including this report and the associated model) has been prepared as part of ATCO's Gas Access Arrangement Review ("**GAAR**") for the calendar years 2015 to 2019 ("**Review Period**") and may be submitted to the Economic Regulatory Authority ("**ERA**").

3.2. Methodology

3.2.1. Overview

An overview of the methodology used by Core Energy is provided in Figure 3.1 and further details of our analysis for each reference tariff are provided in Section 4.

Figure 3.1: Core Methodology.



Source: Core Energy Group; 2014.

3.2.2. Demand Forecast for Customer Segments and Reference Tariffs

In broad terms, forecast demand for the Review Period, for a particular customer segment and reference tariff, is a function of the forecast number of gas connections and the forecast gas demand per connection.

Further information regarding the derivation of forecast connections and demand per connection for each customer segment is provided in the following paragraphs.

3.2.3. Residential Demand

The forecast for residential customer demand applies to tariff class B3.

The methodology used to derive a forecast of residential customer demand incorporates the following broad steps:

1. Adjust historical residential demand trends for weather and other abnormal influences;
2. Determine future trend in residential connections by reference to historical trends and the expected impact of any new factors, not reflected in historical trend; and
3. Derive a forecast using the results of 1 and 2.

Key findings in relation to Core Energy's forecast of residential demand for the forecast period include:

- Increase in total connections – at a compound annual growth rate ("**CAGR**") rate of 2.2 percent;
- Decrease in demand per connection – at a CAGR of 0.7 percent;
- Increase in total demand – at a CAGR of 1.5 percent.

3.2.4. Commercial Demand

The forecast of commercial customer gas demand relates to tariff classes B1 and B2.

The methodology used to derive a forecast of commercial customer demand incorporates the following broad steps:

1. Adjust historical commercial demand trends for weather and other abnormal influences;
2. Determine future trend in commercial connections by reference to historical trends and the expected impact of any new factors, not reflected in historical trend; and
3. Derive a forecast using the results of 1 and 2.

Key findings in relation to Core Energy's forecast of commercial demand, tariff class B1 for the forecast period include:

- Increase in total connections – at a CAGR of 3.5 percent;
- Decrease in demand per connection – at a CAGR rate of 0.94 percent; and
- Increase in total demand – at a CAGR of 2.5 percent.

Key findings in relation to Core Energy's forecast of commercial demand, tariff class B2 for the forecast period include:

- Increase in total connections – at a CAGR of 4.4 percent;
- Decrease in demand per connection – at a CAGR of 3.1 percent; and
- Decrease in total demand – at an average rate of 0.09 percent.

3.2.5. Industrial Demand

The forecast of industrial customer demand relates to reference tariffs A1 and A2.

The methodology used to derive a forecast of industrial customer demand incorporated the following broad steps:

1. Adjust historical industrial demand trends for weather and other abnormal influences;
2. Determine future trend in industrial connections by reference to historical trends and expected new customer load; and
3. Derive a forecast using the results of 1 and 2.

Key findings in relation to Core Energy's forecast of A1 demand for the forecast period include:

- Increase in total connections – at a CAGR of 0.09 percent;
- Increase in demand per connection – at a CAGR of 1.2 percent; and
- Increase in total demand – at a CAGR of 1.3 percent.

Key findings in relation to Core Energy's forecast of A2 demand for the forecast period include:

- Increase in total connections – at a CAGR of 4.0 percent;
- Increase in demand per connection – at a CAGR of 0.59 percent; and
- Increase in total demand – at a CAGR 4.6 percent.

3.3. Results

3.3.1. Summary

Table 3.1: summarises Core Energy's total demand forecast by tariff class for the calendar year period 2015 to 2019.

Actual historical values for 2014 were recorded until October 31 at the time of this forecast. To annualise data for the 2014 full year for each reference tariff, demand for November and December was calculated based on total load in these months historically, while customer numbers were extrapolated in line with the historic monthly trend in customer numbers.

The forecast for the year 2015 has been split into a first half ("**H1**") and second half ("**H2**") in order to allow for the transition from ATCO's existing Access Arrangement in financial years to its future Access Arrangement in calendar years. The historical average share of demand per half-year period was calculated for each tariff (see Table 3.2:) and applied to the 2015 full year forecast demand to arrive at a figure for H1 2015 demand.

The H2 2015 forecast was taken as the midpoint between H1 2015 demand and 2016 demand for each tariff.

Table 3.1: Total Demand.

Total Demand (GJ)	H1 2015	H2 2015	2015	2016	2017	2018	2019
Industrial							
Tariff A1	5,711,223	5,861,546	11,572,769	11,720,093	11,883,212	12,105,157	12,350,313
Tariff A2	951,992	1,030,753	1,982,745	2,092,394	2,184,157	2,288,724	2,400,155
Commercial							
Tariff B1	759,306	912,320	1,646,743	1,671,627	1,706,345	1,754,091	1,808,694
Tariff B2	581,560	668,223	1,251,134	1,249,783	1,242,812	1,242,746	1,244,572
Residential							
Tariff B3	4,278,385	5,580,336	9,858,722	10,007,804	10,188,283	10,372,812	10,530,472

Source: Core Energy Group; 2014.
Note: "**GJ**" Gigajoule.

Table 3.2: Historical Half-Yearly Share of Demand.

Tariff	H1 Demand (Percentage of Total)	H2 Demand (Percentage of Total)
Industrial		
Tariff A1	49.4%	50.6%
Tariff A2	48.0%	52.0%
Commercial		
Tariff B1	45.4%	54.6%
Tariff B2	46.5%	53.5%
Residential		
Tariff B3	43.4%	56.6%

Source: Core Energy Group; 2014.

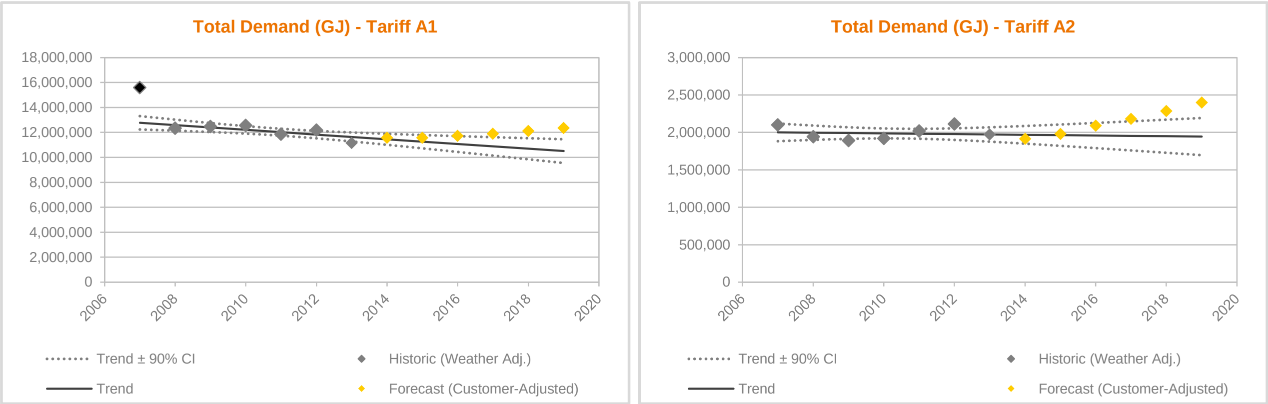
3.3.2. Statistical Validation

Core Energy has undertaken statistical analysis to determine the extent to which demand forecasts fall within an acceptable confidence interval of the historical trend.

Figure 3.2 to Figure 3.4 below show that some forecasts fall outside the historic trend in later years. This is attributed to the expected demand impact of:

- New marketing initiatives to be implemented by ATCO which will not have been recognised in the historical demand figures;
- Known customer adjustments in 2014 which were known to ATCO at the time of this analysis, with expected demand per connection which is significantly greater than the historic average as some of these customers were not using any gas; and
- In the case of B2, a slowing rate of connection growth caused by the introduction of "AL10" metering (discussed in Section 0).

Figure 3.2: Total Industrial Demand - Tariff A1 and A2.

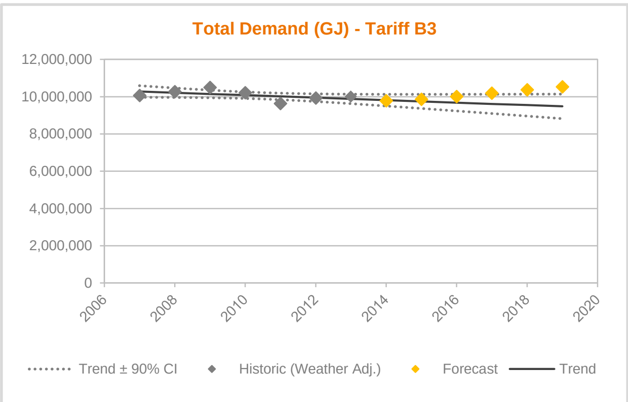


Source: Core Energy Group; 2014.

Figure 3.3: Total Commercial Demand - Tariff B1 and B2.

Source: Core Energy Group; 2014.

Figure 3.4: Total Demand - Tariff B3.



Source: Core Energy Group; 2014.

4. Methodology

The purpose of this Section of the Report is to describe the methodology used by Core Energy to develop a forecast of gas demand for each customer segment and tariff class. The resultant demand forecasts for each segment and tariff class are addressed in Section 8.

4.1. Overview

The MWSWGDS has three customer segments and five reference tariffs, outlined in Table 4.1 below. It should be noted that the classification between industrial / commercial / residential is based on general characteristics of customers within each reference tariff, however in practice the reference tariff a customer will be a function of actual usage. For example, a commercial customer which uses a low level of gas may fall into a residential/B3 reference tariff.

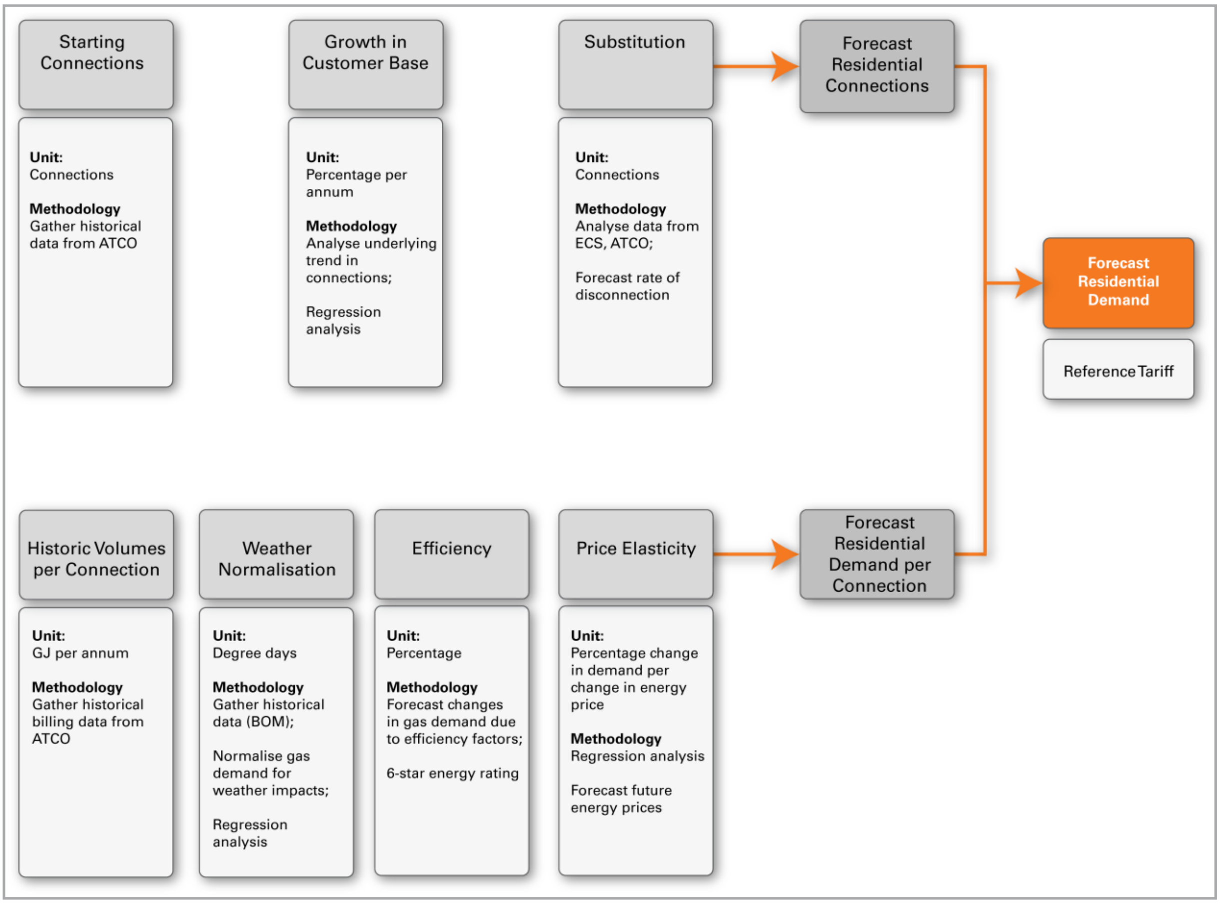
Table 4.1: MWSWGDS Overview.

Industrial	Commercial	Residential
▪ Tariff A1 ▪ Tariff A2	▪ Tariff B1 ▪ Tariff B2	▪ Tariff B3

Source: Core Energy Group; 2014.

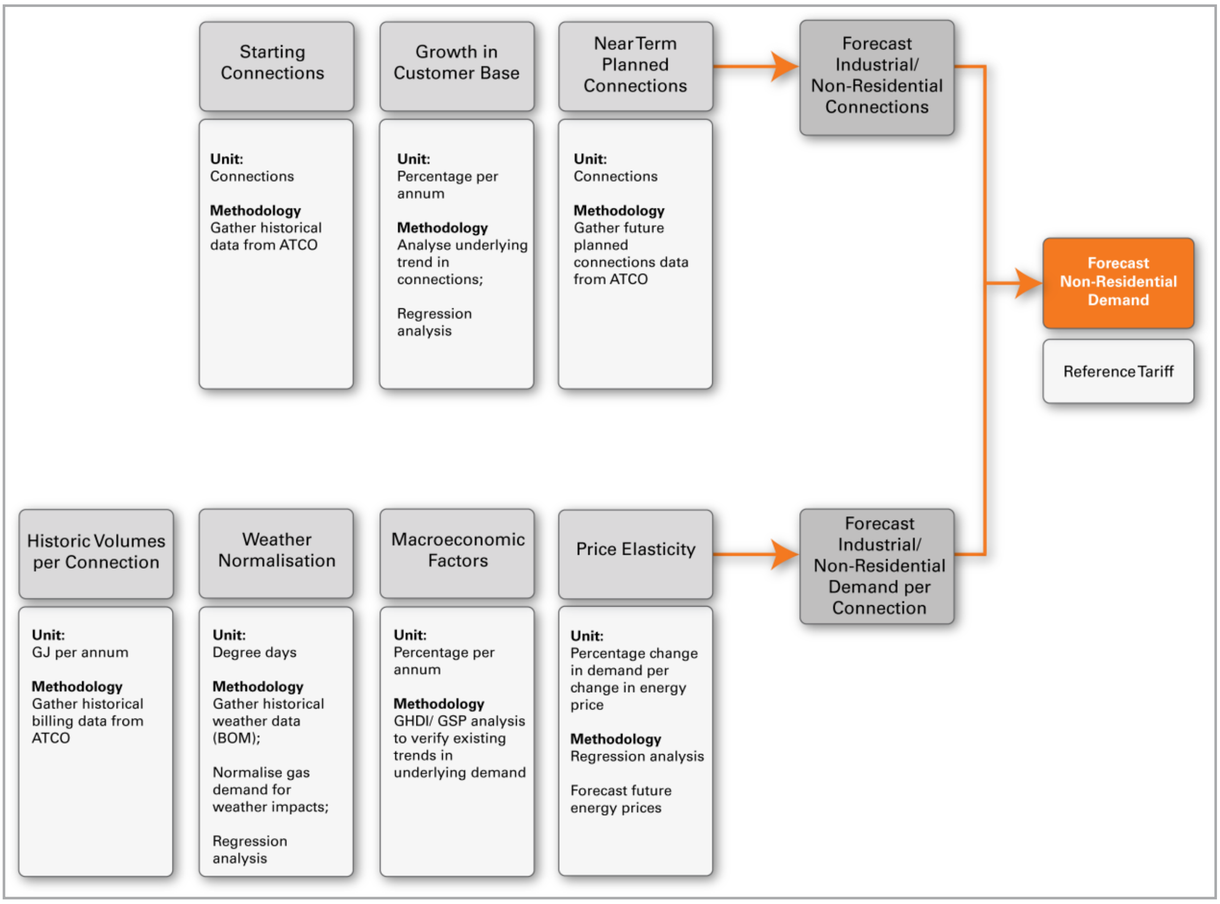
To derive a forecast of demand for each reference tariff, Core has identified those factors which are expected to influence demand during the forecast period. The resultant relationship “map” of the drivers of gas demand is presented at Figure 4.1 for the residential segment and at Figure 4.2 for the commercial and industrial segments, which have been combined for illustration purposes only, given common demand drivers for these segments.

Figure 4.1: Residential Demand Drivers.



Source: Core Energy Group; 2014.

Figure 4.2: Commercial / Industrial Demand Drivers.



Source: Core Energy Group; 2014.

The following paragraphs provide an explanation of key elements of this methodology.

4.2. Residential Gas Demand

The forecast for residential customers applies to reference tariff class B3.

4.2.1. Average Residential Connections

The methodology adopted to arrive at forecast of residential connections includes the following steps:

1. Obtain historical connection trend from data provided by ATCO;
2. Obtain forecasts of new connections prepared by ECS in its document titled '*ATCO Gas Australia Connections Forecast*';
3. Determine the historic disconnection rate using data provided by ATCO;
4. Forecast connections by applying new connection forecasts and the historic disconnection rate to average connection trend; and
5. Adjust connections for the impact of new planned marketing initiatives and the impact of new "AL10" metering classifications.

4.2.2. Demand per Residential Connection

The methodology adopted to arrive at forecast demand per residential connection includes the following steps:

1. Normalise total demand for the effects of weather using the methodology discussed in Section 4.5;
2. Divide total demand by average connections to determine demand per connection;
3. Adjust demand per connection for the effect of historical price increases which impacted particular years only;
4. Use regression analysis to determine the historic trend in demand per connection;
5. Forecast demand per connection by applying the historic trend to existing demand per connection;
6. Adjust demand per connection forecasts for factors not present in the historic trend, which include:

> The lagged effect of historic increases in retail gas prices, as well as any future changes in price resulting from:
  - the introduction of a price on carbon in July 2012;
  - the repeal of the carbon tax in July 2014 and;
  - forecast wholesale gas price increases;

> The effect of 6-Star Building Standards – introduced in May 2012, but not accounted for in the historic trend; and

> New planned marketing initiatives.

4.3. Commercial Gas Demand

The forecast of demand for commercial customers applies to reference tariffs B1 and B2.

4.3.1. Forecast Total Demand

Forecast total demand is the product of average connections and demand per connection.

- Total Demand and Connections are further adjusted in forecast year 2014 to account for any new known connections and disconnections (and their associated gas volumes) as provided by ATCO.

4.3.2. Average Commercial Connections

The methodology adopted to arrive at forecast of average commercial connections includes the following steps:

1. Historical average connections were calculated using data provided by ATCO;
2. Use regression analysis to determine the historic trend in connection growth;
3. Forecast average connections by applying the historic trend in connection growth; and
4. Adjust connections for the impact of new planned marketing initiatives.

4.3.3. Demand per Connection

The methodology adopted to arrive at forecast demand per commercial connection includes the following steps:

1. Normalise total demand for the effects of weather using the methodology discussed in Section 4.5;

2. Divide total demand by average connections to determine demand per connection;
3. Adjust historical demand per connection for the effect of historical price increases which impacted particular years only;
4. Use regression analysis to determine the historic trend in demand per connection;
5. Forecast demand per connection by applying the historic trend to existing demand per connection;
6. Adjust demand per connection forecast for factors not present in the historic trend, including:
   - The lagged effect of historic increases in retail gas prices, as well as any future changes in price resulting from:
     - the introduction of a price on carbon in July 2012;
     - the repeal of the carbon tax in July 2014 and;
     - forecast increases in wholesale gas price.

4.4. Industrial Gas Demand

The forecast for industrial customers applies to reference tariffs A1 and A2.

4.4.1. Forecast Total Demand

Forecast total demand is the product of average connections and demand per connection.

- Total Demand and Connections are further adjusted in forecast year 2015 to account for new known connections and disconnections (and their associated gas volumes) as provided by ATCO.

4.4.2. Average Connections

The methodology adopted to arrive at forecast average connections follows:

1. Historical average connections were calculated based upon monthly connection data provided by ATCO.
2. Use regression analysis to determine the historic trend in connection growth.
3. Forecast average connections by applying the historic trend in connection growth to average connections; and
4. Adjust connections for the impact of new planned marketing initiatives.

4.4.3. Demand per Connection

The methodology adopted to arrive at forecast demand per connection was:

1. Normalise total demand for the effects of weather using the methodology discussed in Section 4.5;
2. Divide total demand by average connections to determine demand per connection;
3. Adjust historical demand per connection for the effect of increases in gas price which impacted particular years only;
4. Use regression analysis to determine the historic trend in demand per connection;
5. Forecast demand per connection by applying the historic trend to existing demand per connection;
6. Adjust demand per connection forecasts for factors not present in the historic trend, including:
   - The lagged effect of historic increases in retail gas prices, as well as any future changes in price resulting from:

  - the introduction of a price on carbon in July 2012;
  - the repeal of the carbon tax in July 2014 and;
  - forecast increases in wholesale gas price.

> The impact of new planned marketing initiatives.

4.5. Weather Normalisation

To remove the bias of abnormal weather movements on historical demand, Core Energy has applied a technique known as weather normalisation, to arrive at a normalised historical gas demand data series for the MWSWGDS.

The methodology used is as follows:

1. Obtain historical weather data for the Perth Airport Weather Station - 009021 from the Bureau of Meteorology ("**BOM**");
2. Use regression analysis consistent with the methodology used by the Australian Energy Market Operator ("**AEMO**") in its '*2012 Review of the Weather Standards for Gas Forecasting*' to develop an EDD index which best represents gas demand in the MWSWGDS;
3. Use regression analysis to identify an appropriate normalised set of EDD;
4. Calculate abnormal EDD by comparing actual and normalised EDD;
5. Use regression analysis to estimate the sensitivity of each reference tariff to EDD; and
6. Multiply abnormal EDD by the sensitivity factor to determine abnormal gas demand due to weather.

Further detail regarding the application of the weather normalisation process is provided in Section 4.5.

4.6. Gas Price Sensitivity

To determine the impact of historical and forecast movements in gas price on demand forecasts, Core has used the following gas sensitivity methodology:

- Identify long-term sensitivity factors accepted in relevant gas price regulatory decisions;
- Validate long-term factors against a derivation of short-term sensitivity factors;
- Apply sensitivity factor against historical data series and future forecasts, having regard to the lagged effect of price increases on demand.

Core's final gas demand forecast has adopted a long-term price elasticity factor which is consistent with previous regulatory submissions by gas distribution networks in Eastern Australia, which have been accepted by the Australian Energy Regulator ("**AER**")[1].

In order to validate the long-run price elasticity estimates, Core conducted a short-run price elasticity analysis. The specification used in determining short-run price elasticity follows.

[1] Refer to p.103 of AER; Final Decision Envestra Limited Access Arrangement Proposal For The SA Gas Network 1 July 2011 – 30 June 2016, June 2011 and p.35-37 of ACIL Tasman; Review of Demand Forecasts for Envestra Victoria; August 2012.

$\text{Log (Demand per Connection}_t) = b_0 + b_1 \times \text{Log (Price}_t)$

Where:

- Demand per Connection is the gas demand per connection for a given year;
- Price is the typical gas bill as provided by the Western Australia Council of Social Service ("**WACOSS**") in its 'Information Sheet – Utility Price Rises 2006-11' for a household consuming 14.6 units per day;
- t is the year of historic data;
- b_0 is the intercept term; and
- b_1 is the price elasticity coefficient.

Further detail regarding the application of the price sensitivity based adjustment process is provided in Section 0.

5. Data Sources

- This Section sets out primary data sources relied upon by Core.
- Core has identified a list of factors which have a material influence gas demand and developed a dataset comprising relevant historic and forecast data available in relation to each driver, including data provided by ATCO.
- Data sources were identified by the modelling team as being the most appropriate, having regard to strict selection criteria including generally accepted, simple, fact-based and repeatable.

5.1. Data Sources

The following table sets out the nature of historic and forecast data relied upon by Core in deriving demand forecasts.

Table 5.1: Data Sources.

Data Description	Source	Data Description
Historic Data		
Gas demand by reference tariff	ATCO	▪ Daily demand by reference tariff - from 2007 to October 2014.
Connections by reference tariff	ATCO	▪ Total connections by reference tariff - from 2007 to October 2014.
Temperature	BOM; 009021 - Perth Airport Weather Station	▪ Average of 8 x 3-hourly temperature readings – from 1993 to October 2014
Wind	BOM; 009021 - Perth Airport Weather Station	▪ Average of 8 x 3-hourly wind readings – from 1993 to October 2014
Sunshine	BOM; 009021 - Perth Airport Weather Station	▪ Number of hours of sunshine above a standard intensity for a specific day – from 1993 to October 2014
Gas Prices	WACOSS	▪ Gas price increase for a household consuming 14.6 units per day – from 2006 to 2011.
Gas Tariffs	Energy Coordination (Gas Tariffs) Regulations	▪ Changes to WA gas tariffs – from 1 July 2003 to 21 May 2013.
Carbon price impact on retail gas prices	Alinta Energy Clean Energy Charge 1 July 2012 and 21 May 2013	▪ Alinta Energy Tariff increase for residential and business customers effective 1 July 2012 and 21 May 2013.
Carbon price impact on retail gas prices	Alinta Energy Substantiation Statement 18 August 2014	▪ Alinta Energy Tariff decrease for residential and business customers due to the repeal of the carbon tax, effective 1 July 2014.
Forecast Data		
New connections for Tariff B3	ECS	▪ New connections Tariff B3 - from 2014 to 2019.

Data Description	Source	Data Description
Effect of 6-Star Building Standard	CIE; Final Regulation Impact Statement for residential buildings (class 1, 2, 4 and 10 buildings), Table 6.2 p.80 ; December 2009	▪ CIE estimates of the effect on gas usage of a move from 5 to 6-Star Building Standards in VIC.
Network price	ATCO	▪ Estimate of increase by ATCO.
Wholesale gas prices	Core Energy Group	▪ Annual forecast of the real change in wholesale gas prices - from 2014 to 2019.
Price elasticity of gas demand	AER; Final Decision Envestra Limited Access Arrangement Proposal For The SA Gas Network 1 July 2011 – 30 June 2016	▪ Long-run price elasticity of gas demand.
Retail gas price components	Core Energy Group, public estimates of gas price elements.	▪ Analysis of gas value chain elements to derive share of total retail gas price.

Source: Core Energy Group; 2014.

6. Quantitative Analysis

- Consistent with the methodology described in Section 4, the objective of this section is to set out the key elements of quantitative analysis undertaken to derive final forecasts of gas demand.
- Core Energy's quantitative analysis has involved use of a customised Excel spreadsheet which includes a comprehensive set of assumptions, calculation logic and outputs. The Excel workbook is titled '*AA-Forecast-2015-to-2019 18.11.2014_Final_ERA_Version'* and should be read in conjunction with this report.

6.1. Introduction

The major elements of quantitative analysis undertaken by Core include:

- weather normalisation of historical gas demand (refer to Section 6.2)
- regression analysis to provide a statistical trend to provide a basis for demand forecasts (refer to Section 6.3)
- gas price sensitivity analysis to adjust demand for the impact of gas price influences (refer to Section 6.4)
- adjustment for expected impact of 6 Star rating standard (refer to Section 6.5)

In addition, ATCO engaged ECS to develop a forecast of new connections for Tariff B3. These forecasts, as summarised in Table 6.1, have been used by Core in developing a forecast of average connections for Tariff B3.

Table 6.1: New Connections – Tariff B3.

Economic Assumption	2015	2016	2017	2018	2019
New connections – Tariff B3	18,353	18,758	18,815	15,980	15,760

Source: ECS.

To above projections include the impact of ATCO's new planned marketing initiatives. To separate the marketing impact from these figures, ATCO's estimates of the marketing contribution to new B3 connections is shown in Table 6.2 below.

Table 6.2: New Connections – Tariff B3 (Marketing Split).

Economic Assumption	2015	2016	2017	2018	2019
B3 connections – Non-Marketing	17,359	18,002	18,059	15,224	15,004
B3 connections – Marketing	994	756	756	756	756
Total	18,353	18,758	18,815	15,980	15,760

Source: ATCO, ECS.

6.2. Weather Normalisation

This Section is to be read in conjunction with Core's additional paper entitled "The Use of EDD in Weather Normalisation".

To normalise historical demand trends for the impact of weather, an EDD index has been applied in accordance with the formula presented in Figure 6.1.

Figure 6.1: EDD Index.

Daily demand = $a + b_1$ * **EDD** + b_2 * **Friday** + b_3 * **Saturday** + b_4 * **Sunday**,

Where **EDD** =

Temperature		MAX(**Threshold** - **Temperature**, 0)
Wind Chill	*plus*	**Wind Chill Coefficient** * MAX(**Threshold** - **Temperature**, 0) * **Wind**
Insolation	*minus*	**Insolation Coefficient** * **Sunshine Hours**
Seasonality	*plus*	**Seasonality Coefficient** * Cosine(2π(**Day** - **Seasonality Factor**)/365)

Where:

- **Threshold** equals **22.36** degrees Celsius, as determined through regression analysis.
- **Wind Chill Coefficient** equals **0.024**, as determined through regression analysis.
- **Insolation Coefficient** equals **0.196**, as determined through regression analysis.
- **Seasonality Coefficient** equals **4.98**, as determined through regression analysis.
- **Seasonality Factor** equals **205**, as determined through regression analysis.
- **Temperature** is the average of eight three-hourly temperature readings in degrees Celsius as measured at the Perth Airport weather station.
- **Wind** is the average of eight three-hourly temperature readings in km per hour as measured at the Perth Airport weather station.
- **Sunshine** is the number of hours of sunshine on a gas day above a standard intensity as measured at the Perth Airport weather station.
- **Day** is the day of the year. Friday, Saturday and Sunday are dummy variables to model the change in base load for Fridays, Saturdays and Sundays relative to Monday to Thursday base load respectively.

Source: Core Energy Group; 2014.

Core's analysis indicates that no statistically significant trend in EDD exists during the period 1993 to 2013[2]; therefore the average of historic EDD has been used as a proxy for normal weather conditions.

Table 6.3 summarises key variables used together with results of the weather normalisation process.

[2] Sunshine data for the Perth Airport Weather Station – 009021 is only available from 1993.

Table 6.3: Weather Normalisation of Gas Demand (Calendar Years).

Weather Normalisation	Units	2007	2008	2009	2010	2011	2012	2013	2014
Effective Degree Days	(EDD)	2,494	2,556	2,439	2,464	2,236	2,339	2,298	2,203
Normalised	(EDD)	2,403	2,403	2,403	2,403	2,403	2,403	2,403	2,403
Abnormal Weather	(EDD)	92	153	36	61	(167)	(64)	(104)	(200)
Tariff A1									
Sensitivity factor	(GJ/EDD)	1.2670	1.2670	1.2670	1.2670	1.2670	1.2670	1.2670	1.2670
Average connections	(no.)	72	74	75	76	74	74	75	73
Abnormal demand	(GJ)	8,327	14,405	3,446	5,833	(15,508)	(5,989)	(9,911)	(18,503)
Abnormal percentage	(%)	0.1%	0.1%	0.0%	0.0%	-0.1%	0.0%	-0.1%	-0.2%
Actual total demand	(GJ)	15,598,230	12,346,218	12,468,626	12,565,313	11,844,817	12,180,788	11,141,986	11,552,518
Normalised total demand	(GJ)	15,589,902	12,331,813	12,465,179	12,559,480	11,860,326	12,186,777	11,151,897	11,571,022
Actual demand per connection	(GJ)	217,397	166,653	165,880	166,244	161,154	163,867	148,725	157,893
Normalised demand per connection	(GJ)	**217,281**	**166,459**	**165,834**	**166,167**	**161,365**	**163,948**	**148,857**	**158,146**
Tariff A2									
Sensitivity factor	(GJ/EDD)	0.5018	0.5018	0.5018	0.5018	0.5018	0.5018	0.5018	0.5018
Average connections	(no.)	96	98	100	102	111	111	109	107
Abnormal demand	(GJ)	4,401	7,579	1,810	3,115	(9,234)	(3,539)	(5,689)	(10,676)
Abnormal percentage	(%)	0.2%	0.4%	0.1%	0.2%	-0.5%	-0.2%	-0.3%	-0.6%
Actual total demand	(GJ)	2,102,575	1,952,502	1,895,698	1,924,409	2,011,649	2,110,137	1,965,183	1,904,232
Normalised total demand	(GJ)	2,098,174	1,944,923	1,893,888	1,921,294	2,020,883	2,113,676	1,970,872	1,914,907
Actual demand per connection	(GJ)	21,959	19,839	19,020	18,882	18,205	19,025	18,098	17,866
Normalised demand per connection	(GJ)	**21,913**	**19,762**	**19,002**	**18,852**	**18,289**	**19,056**	**18,151**	**17,966**
Tariff B1									
Sensitivity factor	(GJ/EDD)	0.0776	0.0776	0.0776	0.0776	0.0776	0.0776	0.0776	0.0776
Average connections	(no.)	1,110	1,135	1,187	1,237	1,277	1,321	1,348	1,389
Abnormal demand	(GJ)	7,890	13,521	3,335	5,851	(16,511)	(6,519)	(10,922)	(21,526)
Abnormal percentage	(%)	0.5%	0.8%	0.2%	0.4%	-1.1%	-0.4%	-0.7%	-1.3%
Actual total demand	(GJ)	1,694,774	1,606,857	1,607,679	1,644,214	1,532,391	1,607,901	1,628,203	1,625,217
Normalised total demand	(GJ)	1,686,884	1,593,336	1,604,344	1,638,363	1,548,902	1,614,421	1,639,125	1,646,743
Actual demand per connection	(GJ)	1,527	1,416	1,354	1,329	1,200	1,217	1,208	1,170
Normalised demand per connection	(GJ)	**1,520**	**1,404**	**1,351**	**1,324**	**1,213**	**1,222**	**1,216**	**1,185**
Tariff B2									
Sensitivity factor	(GJ/EDD)	0.0040	0.0040	0.0040	0.0040	0.0040	0.0040	0.0040	0.0040
Average connections	(no.)	6,212	6,661	7,250	7,833	8,417	8,993	9,554	10,118
Abnormal demand	(GJ)	2,300	4,131	1,060	1,928	(5,664)	(2,311)	(4,032)	(8,161)
Abnormal percentage	(%)	0.2%	0.4%	0.1%	0.2%	-0.5%	-0.2%	-0.3%	-0.7%
Actual total demand	(GJ)	1,137,422	1,161,746	1,168,145	1,183,588	1,162,513	1,219,321	1,236,823	1,242,972
Normalised total demand	(GJ)	1,135,122	1,157,614	1,167,085	1,181,660	1,168,178	1,221,632	1,240,855	1,251,134
Actual demand per connection	(GJ)	183	174	161	151	138	136	129	123
Normalised demand per connection	(GJ)	**183**	**174**	**161**	**151**	**139**	**136**	**130**	**124**

Weather Normalisation	Units	2007	2008	2009	2010	2011	2012	2013	2014
Tariff B3									
Sensitivity factor	(GJ/EDD)	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022
Average connections	(no.)	556,833	574,250	589,880	605,832	622,663	636,417	649,837	666,795
Abnormal demand	(GJ)	110,461	190,853	46,227	79,912	(224,558)	(87,642)	(146,944)	(288,226)
Abnormal percentage	(%)	1.1%	1.9%	0.4%	0.8%	-2.3%	-0.9%	-1.5%	-2.9%
Actual total demand	(GJ)	10,179,506	10,455,396	10,539,649	10,295,438	9,410,070	9,837,109	9,853,191	9,508,525
Normalised total demand	(GJ)	10,069,045	10,264,544	10,493,422	10,215,526	9,634,628	9,924,751	10,000,135	9,796,751
Actual demand per connection	(GJ)	18.28	18.21	17.87	16.99	15.11	15.46	15.16	14.26
Normalised demand per connection	(GJ)	**18.08**	**17.87**	**17.79**	**16.86**	**15.47**	**15.59**	**15.39**	**14.69**

Source: Core Energy Group; 2014.[3]

The weather normalised forecasts above show the following reductions in demand per connection during the period 2007 to 2014 – on a compound average growth rate ("**CAGR**") basis.

- Tariff A1 demand per connection decreased at a CAGR of 4.5 percent.
- Tariff A2 demand per connection decreased at a CAGR of 2.9 percent.
- Tariff B1 demand per connection decreased at a CAGR of 3.7 percent.
- Tariff B2 demand per connection decreased at a CAGR of 5.5 percent.
- Tariff B3 demand per connection decreased at a CAGR of 3.5 percent.

Core notes that while prior submissions to the AER (eastern Australian states) use a threshold temperature of 18 degrees Celsius, regression analysis of WA specific data under the methodology consistent with AEMO in its "2012 Weather Standards for Gas Forecasting" has provided evidence that the threshold temperature is approximately 22.36 degrees. Due to the statistically higher level of fit with actual demand Core has relied upon the WA specific threshold temperature of 22.36 degrees for modelling weather normalised demand.

Table 6.4 compares the historical normalised demand under Core's EDD index using a 22.36 degrees threshold versus an 18 degree threshold. The normalised demand under both methods aligns closely, normalising actual demand in the same direction for all Reference Tariffs in all years of data.

[3] For November and December 2013 where climate data was not yet available, Core assumed these daily values to be the average of those calendar days historically from 1993 to 2012. As no trend in weather is apparent, Core believes this assumption is reasonable.

Table 6.4: Normalised Demand – 18 Degree Threshold vs 22.36 Degrees

Source: Core Energy Group, 2014.

Historical Demand (GJ)	2007	2008	2009	2010	2011	2012	2013	2014
Tariff A1								
Actual	15,598,230	12,346,218	12,468,626	12,565,313	11,844,817	12,180,788	11,141,986	11,552,518
Normalised (18 Degree EDD)	15,599,419	12,337,715	12,464,594	12,555,467	11,859,562	12,187,054	11,146,699	11,568,394
Normalised (22.36 Degree EDD)	15,589,902	12,331,813	12,465,179	12,559,480	11,860,326	12,186,777	11,151,897	11,571,022
Tariff A2								
Actual	2,102,575	1,952,502	1,895,698	1,924,409	2,011,649	2,110,137	1,965,183	1,904,232
Normalised (18 Degree EDD)	2,103,217	1,947,939	1,893,538	1,919,045	2,020,605	2,113,914	1,967,942	1,913,575
Normalised (22.36 Degree EDD)	2,098,174	1,944,923	1,893,888	1,921,294	2,020,883	2,113,676	1,970,872	1,914,907
Tariff B1								
Actual	1,694,774	1,606,857	1,607,679	1,644,214	1,532,391	1,607,901	1,628,203	1,625,217
Normalised (18 Degree EDD)	1,696,038	1,597,908	1,603,304	1,633,138	1,549,995	1,615,550	1,634,027	1,645,928
Normalised (22.36 Degree EDD)	1,686,884	1,593,336	1,604,344	1,638,363	1,548,902	1,614,421	1,639,125	1,646,743
Tariff B2								
Actual	1,137,422	1,161,746	1,168,145	1,183,588	1,162,513	1,219,321	1,236,823	1,242,972
Normalised (18 Degree EDD)	1,137,807	1,158,881	1,166,688	1,179,765	1,168,839	1,222,161	1,239,075	1,251,197
Normalised (22.36 Degree EDD)	1,135,122	1,157,614	1,167,085	1,181,660	1,168,178	1,221,632	1,240,855	1,251,134
Tariff B3								
Actual	10,179,506	10,455,396	10,539,649	10,295,438	9,410,070	9,837,109	9,853,191	9,508,525
Normalised (18 Degree EDD)	10,196,657	10,332,892	10,480,837	10,148,739	9,642,247	9,936,823	9,929,180	9,777,448
Normalised (22.36 Degree EDD)	10,069,045	10,264,544	10,493,422	10,215,526	9,634,628	9,924,751	10,000,135	9,796,751

6.3. Regression Analysis

In arriving at the preferred methodology for deriving a reasonable forecast of gas demand, Core has considered options which meet the following simple criteria - generally accepted, simple, fact-based and repeatable. Further Core has considered those constraints which render certain options inapplicable. These constraints include, but are not limited to:

- Availability of only six full years of actual gas demand observations compared to a forecast requirement of at least eight to ten years;
- A significant outlier event in 2008, being the Varanus Island incident, which materially impacted gas demand. This has led Core to exclude pre-incident data from the forecast for the large industrial tariff (A1) which is believed to have been materially affected;
- Large historic increase in the retail cost of gas causing a material demand side response – due to limited pricing and demand data, the precise level of this response is not known with certainty;
- Limited availability of information on appliance efficiency, usage and penetration; and
- Limited information on the quantitative impact of government policies.

These constraints have resulted in Core selecting a simple linear trend to forecast gas demand. This methodology assumes that all factors which have affected gas demand historically will continue to affect gas demand in the future. Therefore, specific adjustments must be made prior and post calculation of the statistical trend.

Pre-trend adjustments include:

- normalising historic demand for weather; and
- normalising historic demand for one-off increases in retail gas prices.

Post-trend adjustments include:

- Adding the lagged effect of increases in retail gas prices, as well as any future changes in price resulting from:
  - the introduction of a price on carbon in July 2012; and
  - wholesale gas price increases.
- Adding the effect of 6-Star Building Standards (residential gas demand only) – introduced in May 2011, but not accounted for in the historic trend.
- Adding the impact of new planned marketing initiatives which would not have been accounted for in the historic trend; and
- Changes in metering classification which impact on connections (i.e. “AL10” metering discussed in Section 0).

Figure 6.2 summarises the specification used for the regression analysis.

Figure 6.2: Model Specification.

Log (Demand per Connection$_t$) = $b_0 + b_1$ x Trend$_t$

Where:

- Demand per Connection is the gas demand per connection for a given year;
- Trend is the year, i.e. 2007, 2008, 2009 etc.;
- t is the year of historic data;
- b_0 is the intercept term;
- b_1 is the coefficient on the trend.

Source: Core Energy Group.

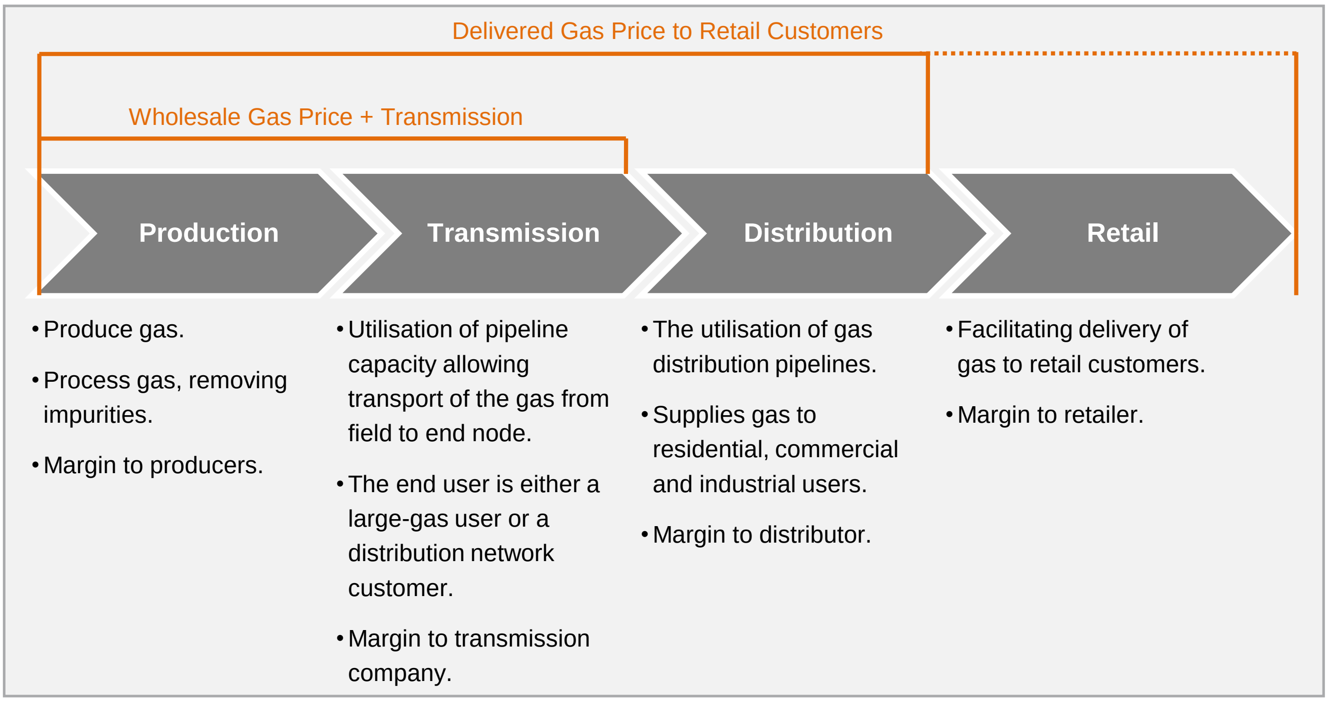
Further detail relating to the regression analysis undertaken for this process is available within the Excel workbook which accompanies this report, titled *'AA-Forecast-2015-to-2019 18.11.2014_Final_ERA_Version'*.

For Tariff B3 demand Core has not relied upon regression analysis. Core has observed a fundamental change in B3 demand over recent years and the use of longer dated regression results would, in Core's opinion, provide a result which is not the best estimate available. Core has relied upon an average of the 2011 to 2014 demand per connection as a basis for the 2015 to 2019 forecasts.

6.4. Gas Price Sensitivity

From a customer perspective, a movement in gas price includes increases in all elements of the gas value chain as illustrated in Figure 6.3.

Figure 6.3: Delivered Retail Gas Price Components



Source: Core Energy Group; 2014.

Core has undertaken an analysis of the share of each of these elements in terms of the total retail price for each tariff class and these findings are presented in Table 6.5.

Table 6.5: Retail Gas Price Components.

Retail Gas Price Components	Tariff A1	Tariff A2	Tariff B1	Tariff B2	Tariff B3
Distribution	5%	5%	30%	30%	40%
Retail	5%	5%	10%	10%	10%
Production and Transmission	90%	90%	60%	60%	50%
Total Retail Gas Cost	**100%**	**100%**	**100%**	**100%**	**100%**

Source: Core Energy Group; 2014.

In addition to the above, there is also a cost of carbon to consider. The introduction of the Clean Energy Bill 2011 into law prescribes an initial cost of carbon emissions at Australian Dollars (“**AUD**”) 23 per tonne. In the case of the gas industry, the carbon emission cost obligations will be passed onto gas customers.

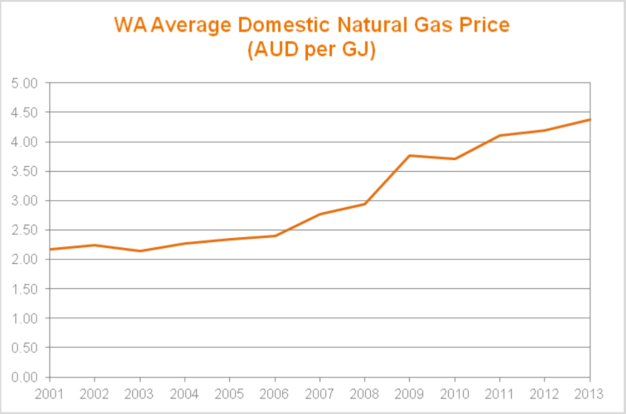
Core has undertaken an analysis of each of the above referenced price elements over the historical and future time periods to arrive at a forecast of future gas price increases for each tariff class. The two elements of price increase include wholesale prices and carbon price.

6.4.2. Wholesale Gas Price Increase

Historical Prices

Figure 6.4 summarises historic weighted average wholesale domestic gas prices in WA. The figure indicates that the weighted average real price of all domestic gas contracts in WA doubled from approximately AUD2.17 in 2001 to 4.37 per GJ in 2013.

Figure 6.4: Historic WA Domestic Average Gas Price.



Source: 2012-13 WA Mineral and Petroleum Statistics Digest.

These prices are used as a basis to derive annual price increases against which a price sensitivity factor is applied[4].

Historical Retail Gas Tariffs

Historical changes in residential and non-residential gas tariffs were sourced from official releases from the Energy Coordination (Gas Tariffs) Regulations. Annual changes in these tariffs are weighted according to the time of the year in which they are implemented.

Forecast Prices

Over the forecast period, Core is of the opinion that the combined influence of lagged historical wholesale gas price increases and additional future increases will continue to materially impact gas demand. These increases are attributable to:

- increasing wholesale gas production costs;
- expiration of lower priced legacy contracts gas contracts, which have been renegotiated at significantly higher prices; and
- changes in supply/ demand dynamics of the WA gas market, including linkages to the Asian Liquefied Natural Gas (“**LNG**”) export market.

[4] Note: Data for the year ending 2012-13 has been used as the average price for 2013.

A literature review undertaken by Core confirms that recent domestic prices have materially exceeded the weighted average price:

- Finding 10 of the Economic and Industry Standing Committee inquiry into WA domestic gas prices reports a range of AUD5.55 to 9.25 per GJ for new domestic gas contracts[5];
- The DomGas Alliance reports that wholesale gas prices are in the range of AUD7.00 to 8.00 per GJ, and as high as AUD10.00 to 12.00 per GJ[6];

Core expects wholesale future contract prices to fall within the range of AUD7.50 to 8.50 per GJ.

A price of AUD7.50 per GJ is used to forecast the impact of price increases, by applying a sensitivity factor against the assumed increase.

[5] WA Economics and Industry Standing Committee; Inquiry Into Domestic Gas Prices; 2011.
[6] DomGas Alliance; The Facts On Domestic Gas; 2011.

Timing of Future Price Increases

To determine the estimated timing of new gas contracts and prices, Core has analysed the considered the two dominant gas retailers operating in the MWSWGDS, which are:

- Alinta Energy – Supplies all B3 and a portion of A1, A2, B1 and B2 customers; and
- Synergy – Supplies A1, A2, B1 and B2 customers.

As at March 2013, Kleenheat Gas have entered the residential gas market in WA, offering a 10 percent discount on gas usage charges for customers transferring on a 24 month contract from Alinta Energy. While this may have an impact on residential retailer market share in the future, Core believes this is extremely difficult to quantify at present.

Core understands that the majority of Alinta's gas supply comes from its North West Shelf gas contract signed in 2005 for a period of 15 years (taken from the Government of Western Australia - Energy in WA Report 2003), with a price review scheduled around 2014.

Core's understanding is that Synergy is currently purchasing gas from the North West Shelf and that in 2015 this contract will have a price review. At the same time, new gas supply is likely to begin from the Gorgon gas project.

The total wholesale price changes for each tariff were weighted within the forecasting model based on Core's assumption of Alinta and Synergy's share of gas supply.

6.4.3. Carbon Price Increase

As of 1 July 2012, Alinta introduced a Clean Energy Charge of AUD0.006098 per unit for residential customers and AUD0.005742 per unit for non-residential customers to recover expected costs related to the Federal Government's Carbon Pricing Mechanism. This equates to a 4.77 percent price increase for residential customers and a 4.92 percent increase for non-residential customers, later increased in September 2013 to AUD0.006138 per unit for residential customers and AUD0.005782 per unit for non-residential customers (a 0.66 percent increase for residential and 0.70 percent increase for non-residential). These price increases are modelled as a step-change price increase in 2012 and 2013 and thus will have shown little impact historically; a large component of the carbon price impact will be felt in future years as a result of price elasticity assumptions outlined in Section 6.4.4.

The retail gas price of gas is reduced by 1.04% in 2015 to reflect the repeal of the carbon tax in 2014. This percentage is based on Alinta Energy Retail Supply Charges, an average residential customer demand of 12.95 units per day and proposed cost saving of AUD1.58/GJ as stated in Alinta Energy's Substantiation Statement[7] (Refer Assumptions Tab of the AA Forecast Model).

6.4.4. Adjustment for Price Elasticity

In order to adjust forecast demand for the lagged impact of historical and future price increases, Core has used the following approach:

- Determine the timing and extent of historical and future price increases (all elements including carbon price);
- Determine the timing and extent of demand response to price increases (demand sensitivity); and

[7] Alinta Energy "Carbon Repeal Substantiation Statement", 18 August 2014, < https://alintaenergy.com.au/Alinta/media/Documents/140818-Substantiation-Statement-Alinta-Sales-gas-2.pdf>

- Deduct the estimated demand response from the demand per connection for each tariff class.

Core's final gas demand forecasting model has adopted a long-term price elasticity factor calculated from previous regulatory submissions by gas distribution networks in eastern Australia which have been accepted by the AER[8].

Table 6.6 summarises the price elasticity of gas demand factors used for each reference tariff in the final model.

Table 6.6: Price Elasticity Factors - AER.

Long-run Price Elasticity	Elasticity (%)
Residential	-0.30
Commercial	-0.35
Industrial	-0.35

Source: AER; Final Decision Envestra Limited Access Arrangement Proposal for the SA Gas Network 1 July 2011 – 30 June 2016.

The above factors have been modelled by taking into consideration the lagged effect of the increases as shown in Table 6.7. In essence, the price elasticity is experienced over a four year period.

Table 6.7: Price Elasticity Factors - AER.

Lagged Effect	Elasticity (%)		
	Residential	Commercial	Industrial
Immediate: $\Delta p(t)$	-0.13	-0.06	-0.06
One Year: $\Delta p(t-1)$	-0.08	-0.16	-0.16
Two Years: $\Delta p(t-2)$	-0.05	-0.09	-0.09
Three Years: $\Delta p(t-3)$	-0.03	-0.03	-0.03
Four Years: $\Delta p(t-4)$	-0.01	-0.01	-0.01
Total	**-0.30**	**-0.35**	**-0.35**

Source: AER; Final Decision Envestra Limited Access Arrangement Proposal for the SA Gas Network 1 July 2011 – 30 June 2016.

In order to cross-check the long-run price elasticity estimates Core has conducted a short-run price elasticity analysis. The specification used in determining short-run price elasticity follows.

$$\text{Log (Demand per Connection}_t) = b_0 + b_1 \times \text{Log (Price}_t)$$

Where:

- Demand per Connection is the gas demand per connection for a given year;
- Price is the typical gas bill as provided by the Western Australia Council of Social Service ("**WACOSS**") in its 'Information Sheet – Utility Price Rises 2006-11' for a household consuming 14.6 units per day;
- t is the year of historic data;
- b_0 is the intercept term; and
- b_1 is the price elasticity coefficient.

Core's short-run price elasticity based on the above specification for each individual tariff category is summarised in Table 6.8 below. These results provide a cross-check only and are not used directly in Core's demand modelling.

Table 6.8: Short-Run Price Elasticity.

Tariff	Short-Run Price Elasticity (%)
Tariff A1 (Industrial)	N/A*

[8] Refer to p.103 of AER; Final Decision Envestra Limited Access Arrangement Proposal For The SA Gas Network 1 July 2011 – 30 June 2016, June 2011 and p.35-37 of ACIL Tasman; Review of Demand Forecasts for Envestra Victoria; August 2012

Tariff	Short-Run Price Elasticity (%)
Tariff A2 (Industrial)	N/A*
Tariff B1 (Commercial)	-0.41
Tariff B2 (Commercial)	-0.70
Tariff B3 (Residential)	-0.31

Source: Core Energy Group; 2014.
* No price elasticity estimates have been calculated for Tariff A1 and A2 due to a lack of reliable price data.Forecast Total Gas Price Increases

The forecast for total nominal price increases (i.e. before price sensitivity factors are applied) for each reference tariff is shown in Table 6.9 below.

Table 6.9: Tariff A1 Retail Gas Price Impact.

Tariff	2014	2015	2016	2017	2018	2019
Tariff A1 (Industrial)	4.08%	7.75%				
Tariff A2 (Industrial)	3.98%	7.89%				
Tariff B1 (Commercial)	3.09%	4.62%				
Tariff B2 (Commercial)	3.09%	4.62%				
Tariff B3 (Residential)	4.00%					

Source: Core Energy Group; 2014.

6.5. Impact of Introduction of 6 Star Energy Rating

Table 6.10 provides estimates of the reduction in gas demand for new dwellings which is expected to result from an introduction of a 6-Star building standard in WA.

Table 6.10: Impact of 6-Star Building Standard on the Gas Demand of New Dwellings in WA.

Dwelling Type	% of Total Dwellings	Reduction in Demand
House	81.7%	1.090 GJ
Townhouse	8.8%	0.511 GJ
Flat	9.5%	1.709 GJ
	Weighted Average	**1.098 GJ**

Source: CIE; Final Regulation Impact Statement for Residential Buildings (class 1, 2, 4 and 10 buildings); December 2009 and 2011 dwelling make-up as reported by ABS; 4602.0.55.001 - Environmental Issues: Energy Use and Conservation; Mar 2011

New customer demand per connection is derived by deducting the weighted average 6 star impact of 1.098GJ from the weighted average demand for all connections as summarised in Table 6.11.

Table 6.11: Demand per Connection | Average of All Connections vs. New Connections

Connection Type	2014	2015	2016	2017	2018	2019
Weighted Average Usage (All Connections)	14.67	14.45	14.32	14.25	14.21	14.16
Average usage of new connections with impact of 6 star rating	13.57	13.35	13.23	13.15	13.11	13.06

Demand per connection has been analysed on a weighted average basis by determining the percentage of new and existing connections and applying these percentages against the respective demand per connection, as summarised above. For example, in 2015 there are 18,603 new connections, which is equivalent to 2.7% of all connections. The 18,603 connections have forecast demand per connection value of 13.35 GJ, which will dilute the demand per connection of all connections by 0.03 GJ (2.7% multiplied by 1.098GJ reduction). This method has been applied consistently throughout the forecast period, as set out in Tab Tariff_B3, Rows 56 to 63 of the gas demand forecast model.

It should also be noted that this analysis does not take into consideration the recent switch from flued to non-flued gas heaters arising from the implementation of the 6-star standard. Core literature review indicates that non-flued heaters are as high as 20 percent more energy efficient and thus reduce gas demand.

6.6. Impact of Future Marketing

ATCO has developed estimates of increases in average load and/or customer numbers directly attributable to new planned marketing initiatives across its network, based on its estimated marketing expenditure allowance over the Review Period. These initiatives may include programs such as rebates on gas hot water systems to increase residential connections. Core has accounted for future marketing as a post-forecast adjustment to average demand and customer numbers beyond the existing trend in demand, as the impact of these initiatives will not have been seen in the historic trend.

The expected impact of ATCO's marketing initiatives on demand and connections is shown in annual terms in Table 6.12.

Table 6.12: ATCO Marketing Impact on Demand and Connections as of 13 November 2014 | Annual

Reference Tariff	2015	2016	2017	2018	2019
A2					
A2 Demand increase due to marketing	-	-	-	-	-
A2 Connections increase due to marketing	2	2	2	2	2
B1					
B1 Connections increase due to marketing	4	4	4	4	4
B1 Demand increase due to marketing	7,280	12,133	16,986	21,839	26,692
B2					
B2 Demand increase due to marketing	7,280	12,133	16,986	21,839	26,692
B3					
B3 Connections - Non-Marketing	17,359	18,002	18,059	15,224	15,004
B3 Connections - Marketing	994	756	756	756	756
Impact of marketing on usage per connection	0.01	0.03	0.04	0.06	0.07

6.7. Impact of AL10 Meter

ATCO's planned introduction of a new residential "AL10" meter is expected to marginally affect the manner in which new connections between the B2 and B3 reference tariffs are recognised. It is expected that some connections using the AL10 meter that would normally be classified as part of the B2 reference tariff will fall into the B3 reference tariff, therefore lowering the growth in B2 connections that has been seen historically. ATCO's estimates of the connections adjustment for the B2 and B3 reference tariffs based on this new meter are that 250 new B2 connections per year will be recognised as B3 connections, as shown below.

Table 6.13: B2 and B3 Connections Adjustment Due to AL10 Meter.

Adjustment to Total New Connections	2015	2016	2017	2018	2019
B2	-250	-250	-250	-250	-250
B3	250	250	250	250	250

Source: ATCO.

7. Qualitative Analysis

- The purpose of this section of the report is to provide a quantitative analysis of a range of factors which are expected to influence demand for one or more customer segments and tariff classes. The primary focus is on the residential segment.
- Core believes it is impractical to quantify the impact of these factors on future demand, unless otherwise stated. Rather the analysis serves to provide further support to the quantitative analysis presented in Section 6.

7.1. Macro Factors

For the purpose of this report Macro Factors are defined as those factors which are expected to have an impact on multiple demand segments and tariff classes. Segment-specific factors are addressed separately in earlier Sections of this report.

7.1.1. Energy Policy

There are a range of Federal and State Government initiatives in place that are expected to have an impact on future gas demand. These include but are not limited to:

- the 6 star building standard;
- the National Strategy on Energy Efficiency;
- the introduction of a carbon price; and
- various rebate and incentive schemes favouring renewable energy and energy efficiency.

Core has performed a qualitative assessment of these factors.

Although it is possible to determine whether a specific policy is expected to increase, decrease or have no effect on gas demand in a qualitative sense, quantifying the effect poses a significant challenge due to the lack of adequate and consistent data. As a result, the following section focuses on a qualitative assessment of the impact of energy policy initiatives.

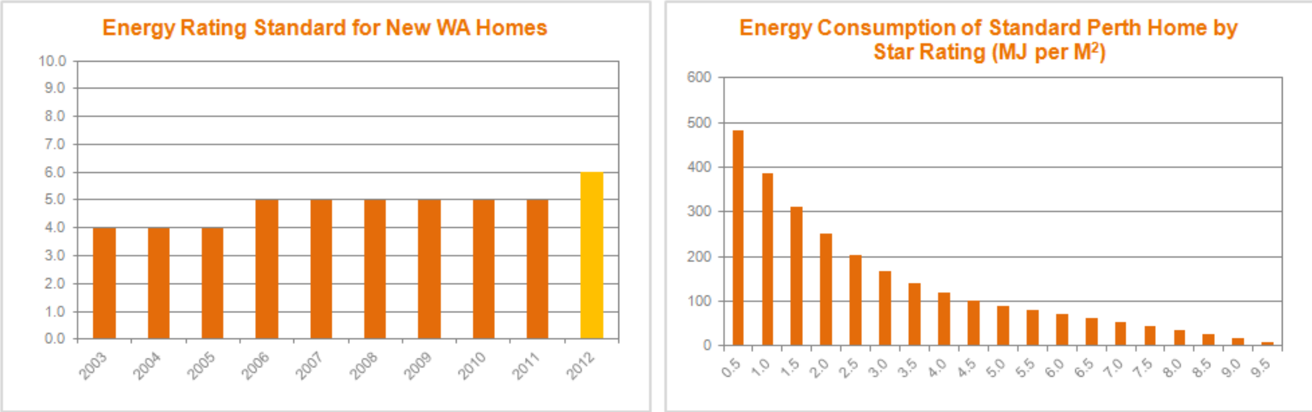
The 6-Star Building Standard

The Government mandated an increase in Star Rating of new buildings in WA from 4 during 2003 to 2005 to 5 during 2006 to 2011 (see Figure 7.1). As of 1 May 2012, a further increase Star Rating to 6[9] has been mandated, with potential to reach up to 7 or 8 by the end of the forecast period.

Based on Nathers Starbands analysis, a standard Perth home is expected to use 21.3 percent less energy for temperature control when moving from a Star Rating of 5 to 6 (see Figure 7.1). This implies a significant reduction in the gas demand of new homes during the forecast period.

[9] WA Building Commission

Figure 7.1: Historical Energy Rating Standards and Energy Consumption by Rating.



Source: WA Building Commission, Nathers; Starbands.
Note: MJ refers to Megajoules.

Whilst energy rating requirements have been in place historically, and WA builders are likely to have responded to the emergence of the 6-star building standard prior to its implementation, Core is of the opinion that the impact of a move to 6-Star building requirements (introduced on 1 May 2012) has not been fully reflected in the underlying historical demand trend. Therefore, Core has modelled the expected impact of improvements in household energy efficiency on residential gas demand per connection (see Section 6.5).

National Strategy on Energy Efficiency; July 2009

In October 2008, the Council of Australian Governments ("**COAG**") agreed to develop a National Strategy on Energy Efficiency ("**NSEE**") to accelerate energy efficiency efforts, streamline roles and responsibilities across levels of governments, and help households and businesses prepare for the introduction of a carbon price. The official NSEE was released in July 2009 and initiatives relevant to an assessment of gas demand are summarised in the following table.

Table 7.1: National Strategy on Energy Efficiency Gas Sensitive Outcomes.

Initiative	Key Elements	Impact
Minimum Energy Performance Standards ("**MEPS**") and Greenhouse and Energy Minimum Standards ("**GEMS**")	▪ Establishment of national legislation for MEPS and labelling, and over time, a move to add GEMS. ▪ Acceleration and expansion of the current MEPS and labelling program.	Gas appliances to become more efficient, reducing gas demand.
Phase-out of inefficient and greenhouse-intensive hot water systems	▪ A set of measures (including energy efficiency standards) to phase-out conventional electric resistance water heaters (except where the greenhouse intensity of the public electricity supply is low) and increase efficiency of other systems. ▪ MEPS to regulate remaining technologies. ▪ The 10-year framework provides a staged approach to transition to low-emission water heaters, with the first phase focused on the phase-out of electric resistance water heaters commencing in 2010. The strategy includes further phases (in 2015 and 2020) where the minimum performance standard is strengthened, subject to regulatory impact analysis processes.	Phase-out of electric water heaters provides some scope to increase penetration of gas water heaters or substitutes. Any increase in gas system penetration could increase gas demand.

Initiative	Key Elements	Impact
Building Energy Efficiency Standard	▪ All jurisdictions will work together to develop a consistent outcomes-based national building energy standard setting, assessment and rating framework for driving significant improvement in the energy efficiency of Australia's building stock. To be implemented in 2011. ▪ This measure will be used to increase the energy efficiency of new residential and commercial buildings and major renovations, with minimum standards to be reviewed and increased periodically, for example every three years.	Increased energy efficiency of homes expected to cause demand for space heating to fall, reducing energy, including gas demand.
Increased energy efficiency of commercial buildings	▪ Significantly increase over time the stringency of energy efficiency provisions for all commercial buildings (Class three, and five to nine) in the Building Code of Australia ("**BCA**") – starting with the 2010 version of the BCA. ▪ A package of energy efficiency measures for implementation in 2010 – for new buildings and major new work in existing buildings, which meets a benefit to cost ratio of 2:1. Note the last BCA update included a package of commercial buildings energy efficiency measures with a benefit to cost ratio of 5:1. Tightening the energy efficiency measures such that the regulatory impact analysis of the energy efficiency package comes in at 2:1 represents a significant strengthening of standards. ▪ New efficiency provisions for heating, ventilation and air-conditioning systems and for artificial lighting.	Increased energy efficiency of commercial buildings expected to cause demand for gas space heating to fall, reducing energy, including gas demand.
Mandatory disclosure of energy efficiency of commercial buildings	▪ Phase-in from 2010 the mandatory disclosure of the energy efficiency of commercial buildings. ▪ Phase one: implement a national mandatory disclosure scheme for large commercial office buildings (2,000 square metres or larger). ▪ Phase two: consideration of expanding mandatory disclosure to other building types, including hotels, retail, schools and hospitals.	Mandatory disclosure of commercial building energy efficiency is expected to create greater awareness and encourage further upgrades in efficiency, reducing energy, including gas demand.
Increased energy efficiency of residential buildings	▪ Significantly increase the stringency of energy efficiency provisions for all new residential buildings in the BCA and broaden coverage of efficiency requirements. ▪ Minimum energy efficiency standards upgraded to 6-stars, or equivalent, nationally in the 2010 update of the BCA –implemented by May 2011 and reviewed regularly for potential upgrade thereafter. For example, 3-yearly from 2012.	Increased energy efficiency of residential buildings is expected to cause demand for space heating to fall, reducing energy, including gas demand.
Mandatory disclosure of energy efficiency of residential buildings	▪ Phase in mandatory disclosure of residential building energy, greenhouse and water performance at the time of sale or lease, commencing with energy efficiency by May 2011. ▪ Credible and meaningful information is to be publicly and readily available to market participants to assist them in making lease/purchase decisions.	Mandatory disclosure of residential building energy efficiency is expected to encourage owners to upgrade efficiency in order to maximise their sale/lease income – reducing energy, including gas demand.

Initiative	Key Elements	Impact
Energy efficiency audits of public housing	▪ States and territories to audit the energy efficiency of public housing stocks. ▪ All states and territories will conduct and make publicly available an independent audit of the energy efficiency performance of their public housing stocks. ▪ States and territories to consider implementing cost-effective upgrades.	Energy audits of public housing are expected to create greater awareness and opportunity to improve efficiency, reducing energy, including gas demand.
Incentives to undertake energy efficiency improvements in residential buildings	▪ Provide incentives for residential building owners to undertake energy efficiency improvements. ▪ Australian Government's Energy Efficient Homes Package including the Low Emission Assistance Plan for Renters, the Homeowner Insulation Program, and the Solar Hot Water Rebate. ▪ Range of state and territory programs designed to improve the energy efficiency of existing residential housing stock.	Increased energy efficiency of residential buildings expected to cause demand for space heating to fall reducing energy, including gas demand

Source: Core Energy Group with data from the National Strategy on Energy Efficiency; July 2009

Rebate and Incentive Schemes

Table 7.2: summarises Australia-wide rebate and incentive schemes which have the potential to affect gas demand.

Table 7.2: Australia-Wide Rebate and Incentive Schemes.

Scheme	Description	Impact
Renewable power incentives	Households across Australia installing; a small scale solar, wind or hydro renewable electricity system or a solar or heat pump hot water system may be eligible for a benefit via Small-scale Technology Certificates and Solar Credits.	Solar and heat pump systems favoured over gas hot water systems, reducing gas demand.
Solar hot water or heat pump rebate	Households across Australia that replace an existing electric storage hot water system may be eligible for rebates of AUD1,000 for a solar hot water system or AUD600 for a heat pump hot water system under the Renewable Energy Bonus Scheme.	Electric storage hot water systems to be displaced by solar and heat pump – no effect on gas demand.
Commonwealth's Renewable Energy Target ("**RET**") scheme	The RET scheme provides support to households and businesses to install small-scale solar, wind and hydro-electricity systems through Solar Credits. Households and businesses can also receive support under the RET when they install a solar hot water system. Most installers will provide a discount based on the estimated output of the solar hot water system.	Solar hot water systems favoured over gas hot water systems, decreasing gas demand.
Energy Efficiency Opportunities program	Encourages large energy-using businesses to improve their energy efficiency by requiring businesses to identify, evaluate and report publicly on cost effective energy savings opportunities. Participation in Energy Efficiency Opportunities is mandatory for corporations that use more than 0.5 PJ of energy per year. There are more than 220 corporations (incorporating around 1200 subsidiaries) registered for the Energy Efficiency Opportunities program.	Encourages industrial gas users to continually improve the efficiency, decreasing energy, including gas demand.

Source: Core Energy Group; 2014.

Table 7.3: summarises Western Australia specific rebate and incentive schemes with potential to affect gas demand.

Table 7.3: WA Rebate and Incentive Schemes.

Scheme	Description	Effect
Air Conditioning Rebate - Electricity	This rebate subsidises the cost of operating an air conditioner for eligible households in areas of high heat discomfort. The amount of the subsidy varies with location.	Increased penetration of reverse-cycle air conditioners provides a substitute to gas space heating, – decreasing gas demand

Scheme	Description	Effect
6-star energy efficiency	From 1 May 2012, 6-star building requirements are mandatory.	Improved energy efficiency of buildings will reduce demand for space heating and water heating – reducing gas demand
Electricity feed-in tariff	The WA government roll-out of a residential feed-in tariff on renewable energy generation for SWIS customers benefits households, small businesses, community organisations and schools that install a solar photovoltaic, wind turbine or hydro renewable energy generation system by paying them for the excess electricity they generate.	Favours renewable power for space and water heating over gas, reducing gas demand
Solar hot water rebate	The Solar Hot Water Heater Subsidy Scheme provides rebates from AUD500 to 700 to WA households installing environmentally friendly, gas-boosted solar water heaters. Despite solar water heating being gas boosted, the net result of the rebate will lead to declining gas demand as stand-alone gas water heating is replaced.	Gas-boosted solar water heating to replace stand-alone gas water heating, reducing gas demand
Renewable power incentives	Households across Australia installing; a small scale solar, wind or hydro renewable electricity system or a solar or heat pump hot water system may be eligible for a benefit via Small-scale Technology Certificates and Solar Credits.	Favours renewable power for space and water heating over gas, reducing gas demand
Showerhead exchange	The Showerhead Swap program helps households in the Perth metropolitan area to swap old inefficient showerheads for new 3-star rated water-efficient showerheads.	Efficient showerheads will reduce use of hot water – reducing gas demand

Source: Core Energy Group; 2014.

7.2. Residential Demand

The level of residential gas demand per connection is largely a function of the following factors:

- gas space heating demand per household;
- gas water heating demand per household ; and to a lesser extent
- gas cooking demand per household.

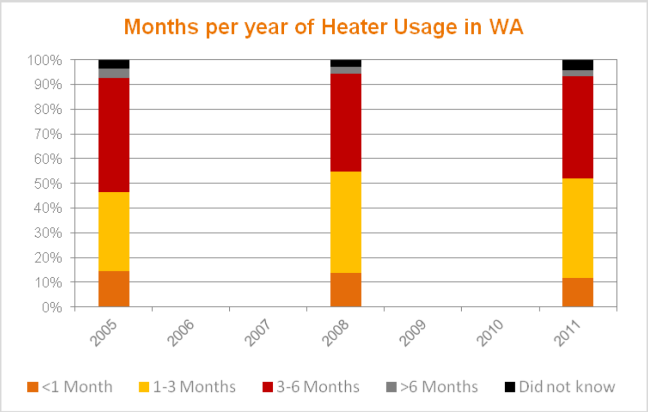
The following paragraphs present an historical analysis of these factors. Core acknowledges that the ATCO distribution system is centred on the Perth region and refers to statistics for Perth where available. Where standalone Perth statistics are not available, data relating to total WA are relied upon.

7.2.1. Space Heating

Reduction in Overall Space Heating Use

The length of time WA households use space heating throughout the year (from all fuel sources) has reduced from 2005 to 2011. Figure 7.2 illustrates that 46 percent of households used heaters for 3-6 months per year in 2005, reducing to 41 percent in 2011.

Figure 7.2: Months per Year of Heater Usage in WA.

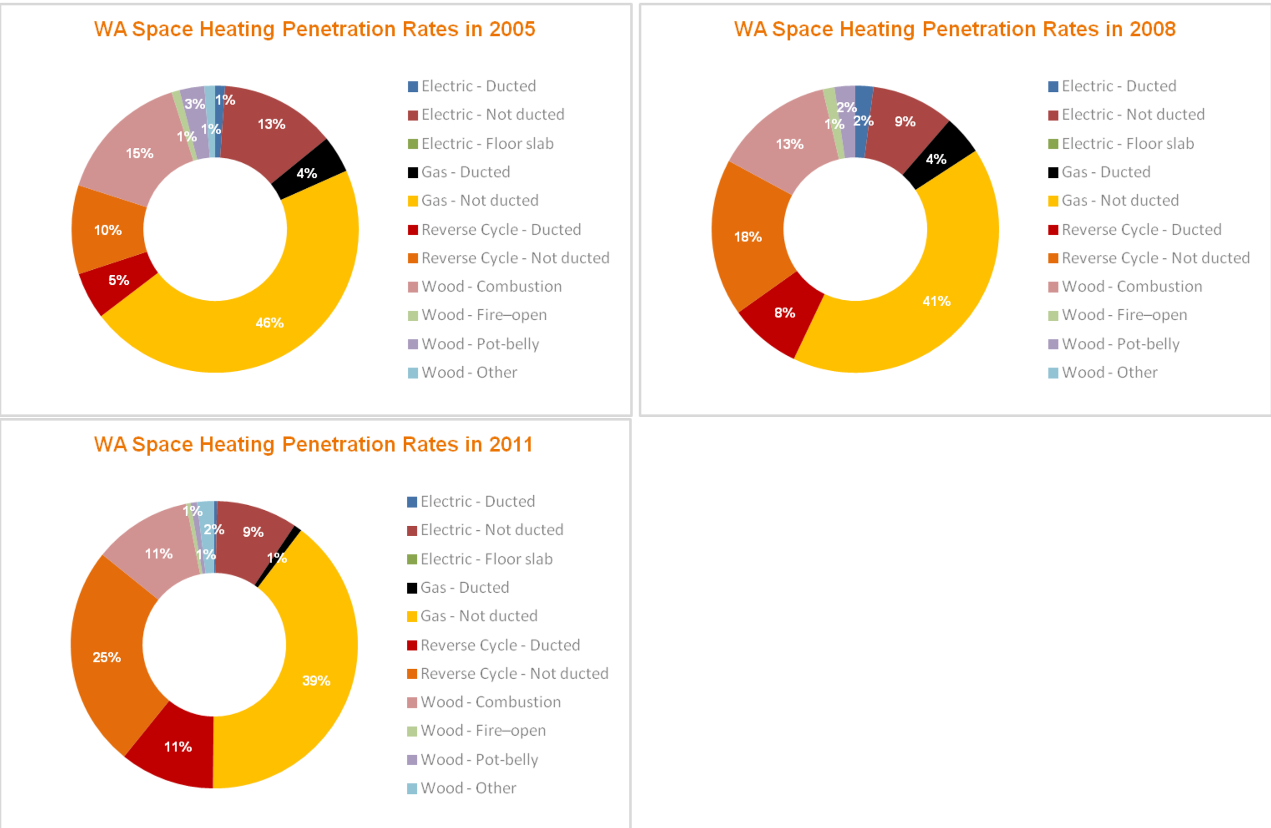


Source: ABS; 4602.0.55.001 - Environmental Issues: Energy Use and Conservation; March 2011.

Decline in Gas Heating Penetration

Penetration of gas space heating in WA has declined from 2005 to 2011, in favour of reverse cycle heating as seen in Figure 7.3. Gas penetration rates have declined from 50 percent in 2005 (both ducted and non-ducted) to 40 percent in 2011, with reverse cycle penetration rising significantly from 15 percent in 2005 (both ducted and non-ducted) to 36 percent in 2011.

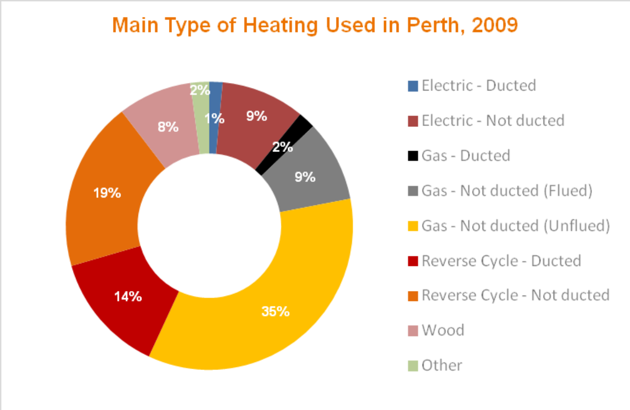
Figure 7.3: Space Heating Penetration Rates in WA, 2005 to 2011.



Source: ABS; 4602.0.55.001 - Environmental Issues: Energy Use and Conservation; March 2011.

Similar data is available for the Perth region alone. This data shows that in 2009 (note 2011 data not available) the gas penetration rate was approximately 44 percent, similar to 45 percent for total WA in 2008 (see Figure 7.4). Reverse cycle penetration however was significantly higher in the Perth region at 33 percent, compared to 26 percent for all WA in 2008.

Figure 7.4: Main Type of Heating Used in Perth, 2009.



Source: ABS; 4656.5.001 – Household Choices Related to Water and Energy; October 2009.

Core notes that the charts presented above reflect the most used heating type in each household. It is important to note that approximately 19.2 percent of households (total WA) with heaters have reverse cycle units, but do not use this unit as the primary source of heating (see Table 7.4). The barrier for this 19.2 percent to switch heating source to reverse cycle is very low as the unit is already installed in the household. This is a risk for future gas demand.

Table 7.4: Core Calculation of ABS Reverse Cycle Data.

Australian Bureau of Statistics (“ABS”) Data	Calculation
The ABS reports 775,000 households with heaters in WA in 2011.	775,000
Of these, 35.1 percent use reverse cycle as their primary heating source.	272,025
The ABS also reports 420,800 households in WA use reverse cycle as their primary cooling source.	420,800
This implies 148,775 households have reverse cycle units which are not used as a primary source of heating. As a proportion of the 775,000 WA households with heaters, this equates to:	19.2 percent

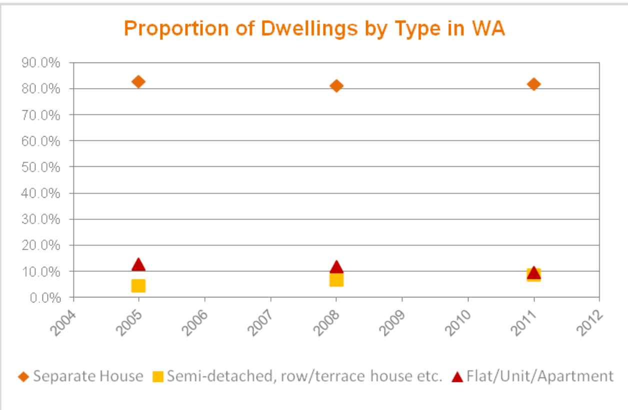
Source: Tables 7, 8 and 16 of ABS; 4602.0.55.001 - Environmental Issues: Energy Use and Conservation; March 2011.

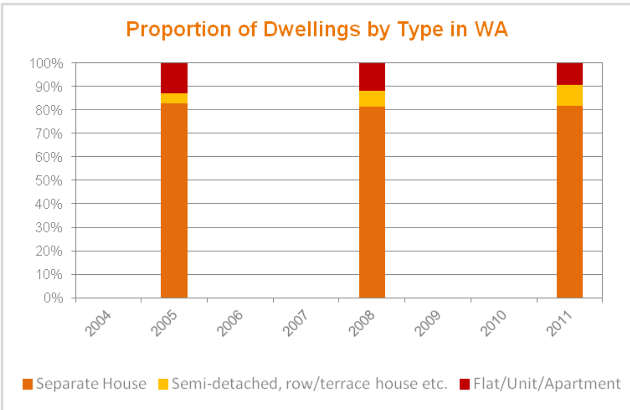
The proportion of dwellings classified as ‘Separate Houses’ has been relatively flat from 2005 to 2011, whilst Semi-detached/Row/Terrace houses have increased (see Figure 7.5).

Semi-detached etc. dwellings typically do not have an individual gas connection, and those that do have a connection tend to use less gas for space heating than other dwelling types as they have a significantly smaller floor area.

Furthermore, improvements in energy efficiency e.g. 6 star building standards are reducing the level of space heating generally, including gas.

Figure 7.5: Dwelling by Type WA.



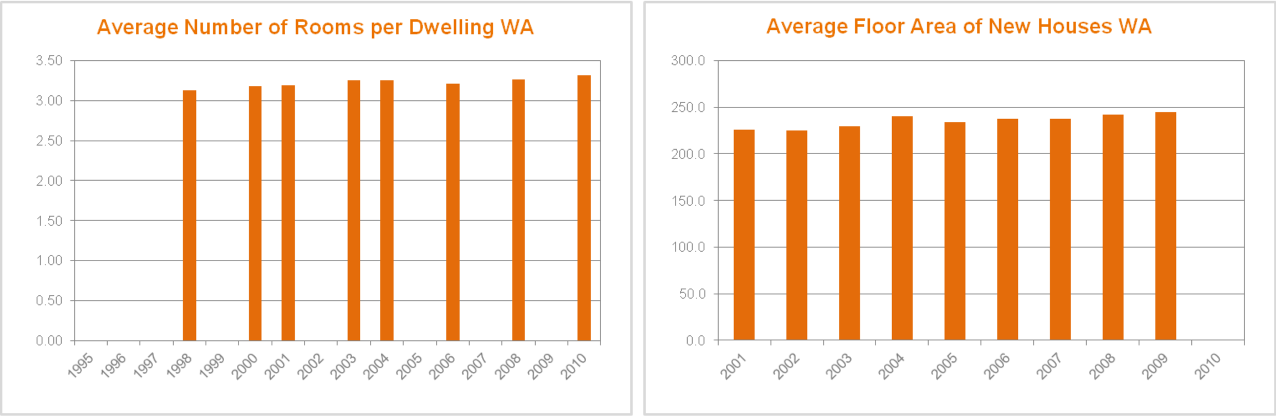


Source: ABS; 4602.0.55.001 - Environmental Issues: Energy Use and Conservation; March 2011.

Energy Efficiency Offsetting Impact of Increased Floor Area

The average number of rooms per dwelling has increased from 3.13 to 3.32 from 1998 to 2010, while the average floor area has increased from 226.0 square meters (“**m²**”) to 244.4 m^2 from 2001 to 2009 (see Figure 7.6). Given that larger homes generally require additional gas space heating relative to smaller homes, this would be expected to result in an increase in the average gas demand of households. However, the emergence of newer, more efficient heating systems not only improve energy efficiency but enable residents to only heat certain areas of a home, vs the whole home, leading to a higher proportion of single room heating, and lower gas usage.

Figure 7.6: Average Number of Rooms per Dwelling and Average Floor Area of New Houses in WA.



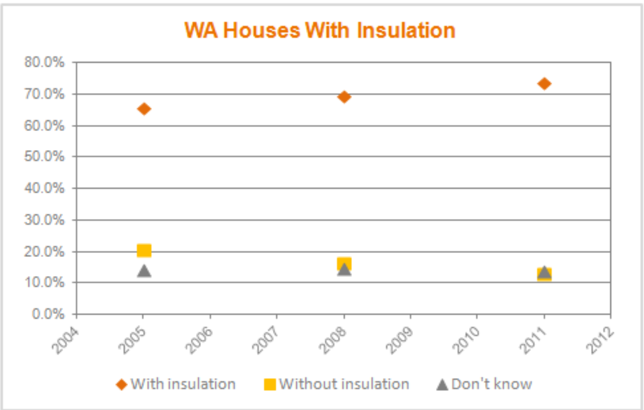
Source: ABS; Cat. No. 4102.0, Australian Social Trends, Data Cube - Housing; 14 December 2011, ABS; 8731.0 - Building Approvals, Australia, February 2010; Feature Article: Average Floor Area of New Residential Dwellings.

Increased Use of Insulation

The number of WA homes with insulation has increased from 65.6 to 73.7 percent from 2005 to 2011 (Refer Figure 7.7). Homes with insulation typically require less space heating in colder months to maintain desired temperatures.

A continuation of this insulation trend is expected to reduce gas space heating requirements of households.

Figure 7.7: WA Houses with Insulation.



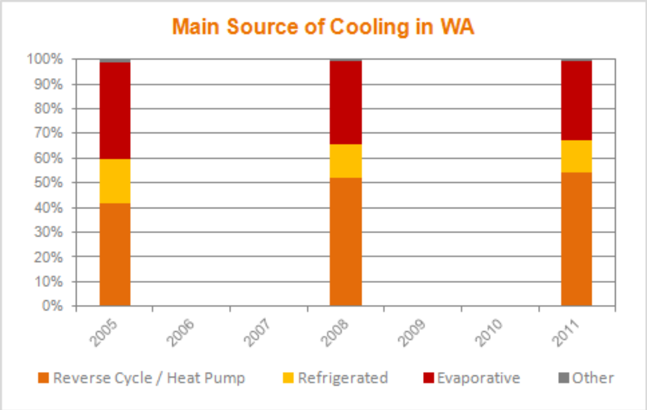
Source: ABS; 4602.0.55.001 - Environmental Issues: Energy Use and Conservation; March 2011.

Higher Penetration of Reverse Cycle Systems

The penetration of Reverse Cycle / Heat Pump cooling has increased from 42 to 54 percent from 2005 to 2011 (Refer Figure 7.8). These systems provide cooling and heating capacity.

A continuation of this trend is expected reduce demand for gas space heating.

Figure 7.8: Space Cooling Penetration WA.



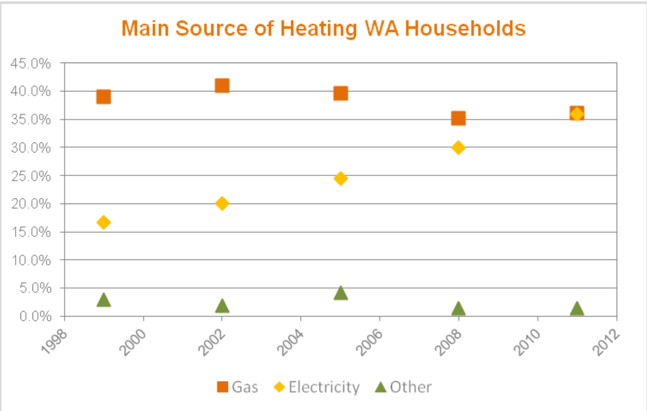
Source: ABS; 4602.0.55.001 - Environmental Issues: Energy Use and Conservation; March 2011.

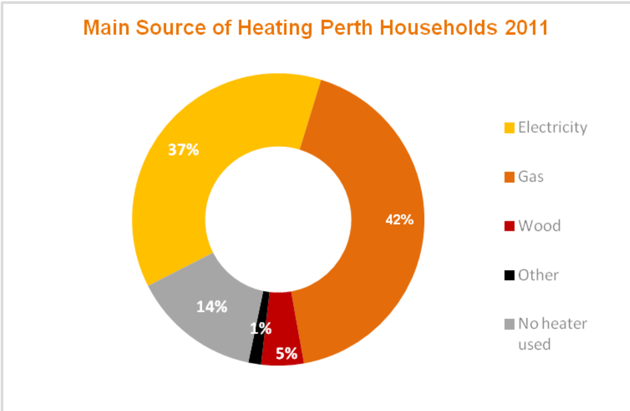
Decline in Gas as Main Source of Heating

Gas as the main source of space heating in WA has fallen from 39.0 to 36.0 percent from 1999 to 2011, while electricity as the main source of space heating has increased from 16.6 percent to 35.9 percent (refer to Figure 7.9). A continuation of this trend is expected to reduce gas demand.

Data for Perth in 2011 shows a higher penetration of gas for space heating relative to WA at 42 percent.

Figure 7.9: Main Source of Heating in WA and Perth Households.





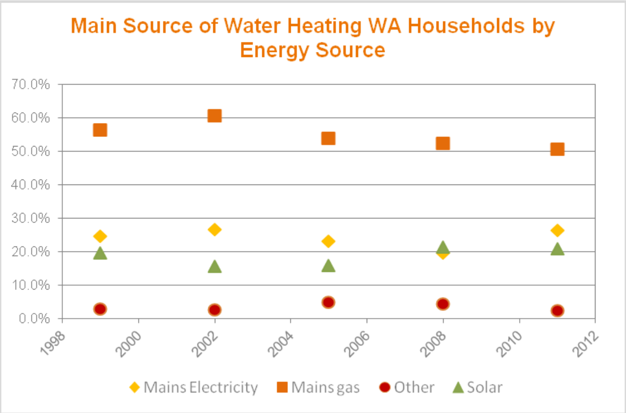
Source: ABS; 4602.0.55.001 - Environmental Issues: Energy Use and Conservation; March 2011.

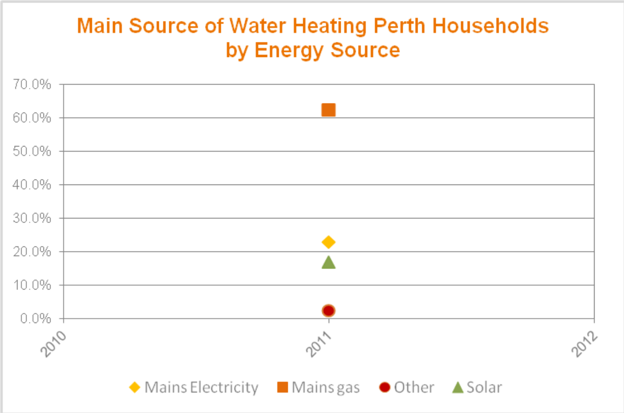
7.2.2. Water Heating

Decline in Gas Water Heating

Gas water heating in WA has declined from 60.5 to 50.7 percent from 2002 to 2011 (Refer Figure 7.10). The same data for Perth in 2011 reveals a higher penetration of gas water heating than total WA at 62.2 percent.

Figure 7.10: Main Source of Water Heating in WA and Perth.



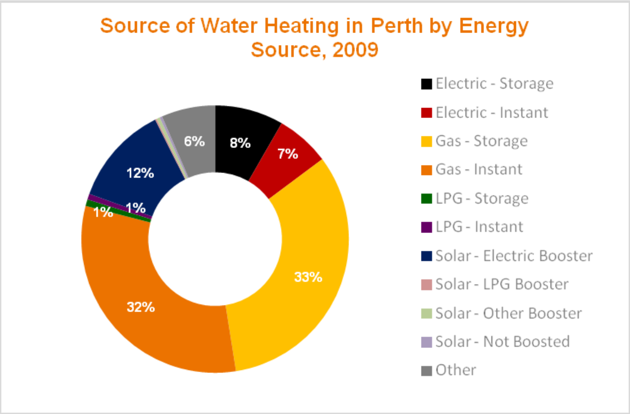


Source: ABS; 4602.0.55.001 - Environmental Issues: Energy Use and Conservation; March 2011

Significant Share of Instant vs Storage Water Heating

Figure 7.11 illustrates the significant share of instant vs storage units which are more energy efficient and thus consume less gas.

Figure 7.11: Source of Water Heating by Energy Source in WA 2009.

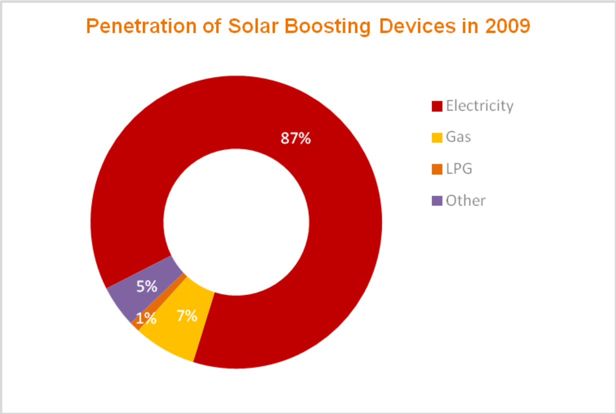


Source: ABS; 4656.5.001 – Household Choices Related to Water and Energy; October 2009.

Low Level of Gas Boosted Solar Water Heating

With a significant growth in solar water heating, it is noteworthy that solar booster units in Western Australia are mainly electric powered, with an 87 percent penetration in 2009, as shown in Figure 7.12. Gas powered solar boosters made up a lower 7 percent of the solar boosting market.

Figure 7.12: Penetration of Solar Boosting Devices in WA 2009.

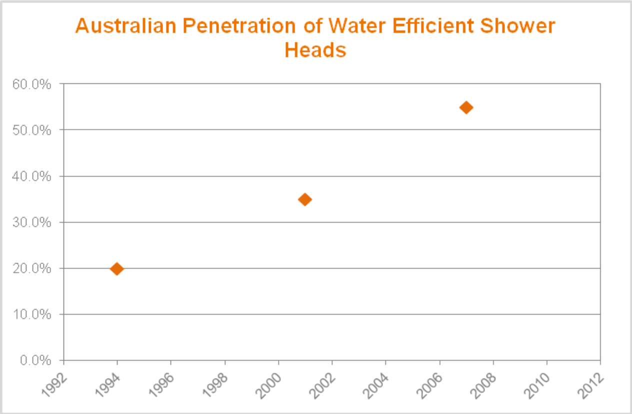


Source: ABS; 4656.5.001 – Household Choices Related to Water and Energy; October 2009.

Penetration of Water Efficient Showerheads

The penetration of water efficient showerheads has increased from 20 to 55 percent from 1994 to 2007 (Refer Figure 7.13). A continuation of this trend is likely to reduce household gas water heating demand.

Figure 7.13: Penetration of Water Efficient Shower Heads in Australia.

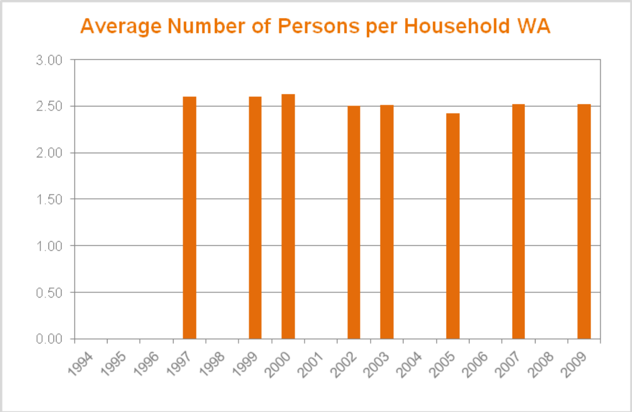


Source: ABS; 4613.0 - Australia's Environment: Issues and Trends, January 2010.

Reduced Household Density

The average number of persons per dwelling has decreased from 2.60 to 2.52 from 1998 to 2010 (see Figure 7.14). A continuation of this trend is expected to result in some reduction in demand for hot water.

Figure 7.14: Average Number of Persons per Household WA.



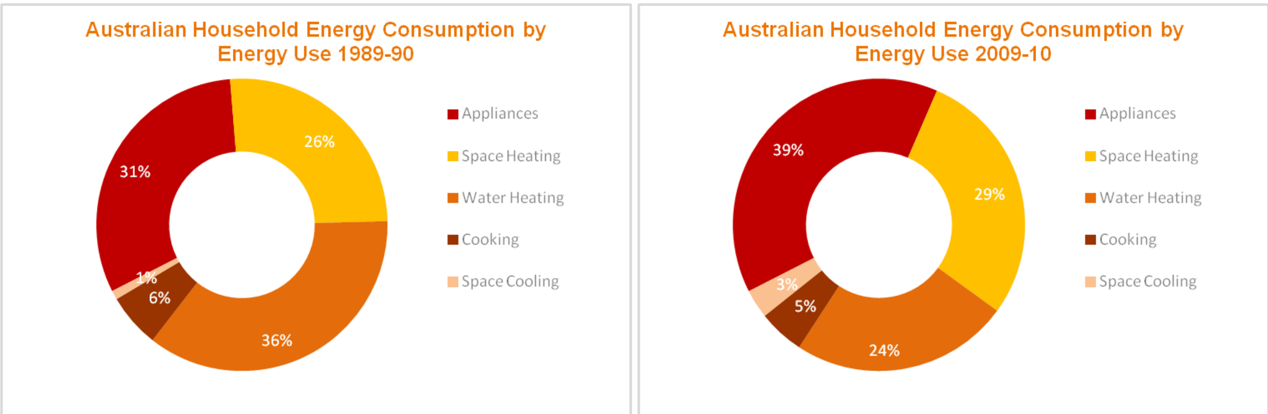
Source: ABS; cat. no. 4102.0, Australian Social Trends, Data Cube - Housing; 14 December 2011.

Cooking

As previously stated, three uses make up the vast majority of overall gas demand in residential the sector - space heating/ water heating and cooking. Of the three cooking accounts for a minor share of total gas usage. For this reason, together with the fact that there is limited quality information available; Core has not undertaken qualitative analysis for this area.

It is noteworthy that in the last twenty years, the overall energy share of cooking appliances (cooktops, ovens, microwaves etc) in Australia has fallen from ~6 percent in 1989-90 to ~5 percent in 2009-10 as illustrated in Figure 7.15. Although this data is captured on a national level, Core does not believe the energy share for cooking in WA will differ materially.

Figure 7.15: Australian Household Energy Consumption by Energy Use, 1989-90 to 2009-10.



Source: BREE; Economic Analysis of End-use Energy Intensity in Australia, May 2012.

Demand per Connection

Table 7.5 demonstrates that a dwelling built in 2010 uses approximately 10 to 23 percent less gas than a house built in 2009 and prior. This reduction is attributable to increasing energy efficiency standards, substitution of energy sources reducing gas share of energy mix and increasing efficiency of new appliances which are more prevalent in newer homes.

Table 7.5: Demand per Connection – Tariff B3.

Year of Connection	Weather Normalised Demand per Connection				
	2007	2008	2009	2010	2011
Pre 2008	18.57	18.62	18.83	17.63	17.19
2008			14.82	15.65	15.81
2009				13.62	14.71
2010					13.24

Source: ATCO.

8. Results

- The purpose of this Section of the Report is to summarise the results of Core Energy's demand forecasting process.
- Results are presented in three parts:
  - > Gas demand by reference tariff;
  - > Connections by reference tariff; and
  - > Total demand by reference tariff.
- This report should be read in conjunction with the Core Energy Excel spreadsheet titled '*AA-Forecast-2015-to-2019 18.11.2014_Final_ERA_Version*'.

8.1. Summary

The Core Energy forecast demonstrates a continuation of the historic trend decline in weather adjusted demand per connection (refer to Section 6.2) with the future effect of a carbon price, network price increases, wholesale gas price increases and a 6-Star Building Standard extending this trend decline. Increasing total connections due to population growth provide an offsetting influence.

8.2. Connections Forecast

Table 8.1: summarises connection forecasts by reference tariff for the period 2014 to 2019.

Table 8.1: Forecast Connections by Tariff Class.

Forecast Connections	H1 2015	H2 2015	2015	2016	2017	2018	2019
Industrial							
Tariff A1	73	74	73	74	74	74	74
Tariff A2	109	113	111	117	121	125	130
Commercial							
Tariff B1	1,426	1,451	1,438	1,489	1,541	1,595	1,650
Tariff B2	10,457	10,626	10,542	10,873	11,193	11,500	11,793
Residential							
Tariff B3	678,373	686,430	682,402	698,689	715,147	730,154	743,578

Source: Core Energy Group; 2014.

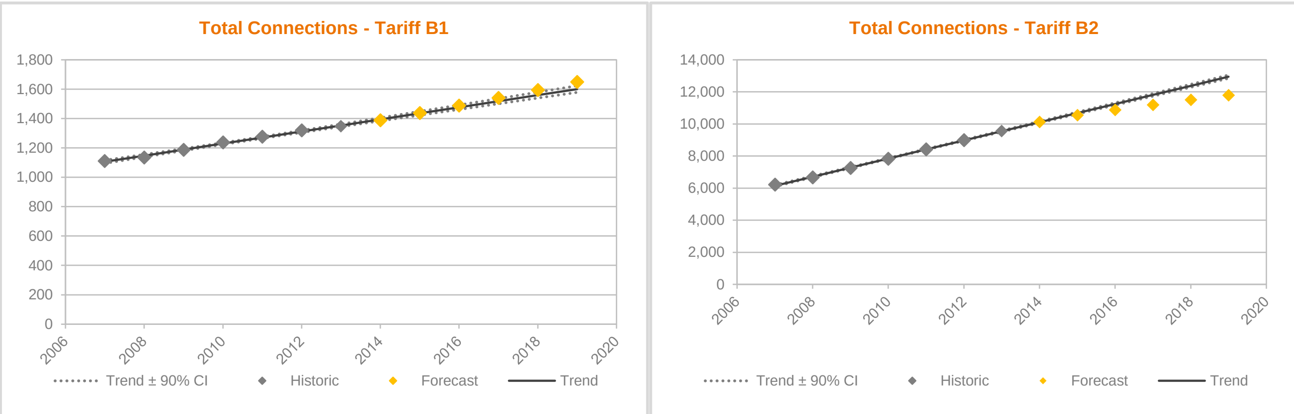
Figure 8.1 to Figure 8.3 compare the above forecasts with the 90 percent confidence interval of the historic trend.

Some forecasts fall outside the historic trend in later years, attributed to the impact of metering reclassification, marketing initiatives and known customer adjustments as previously described in Section 3.2.2.

Figure 8.1: Total Connections Tariff A1 and A2.

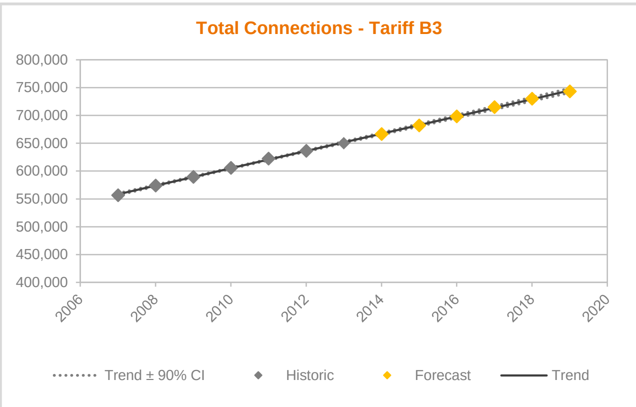
Source: Core Energy Group; 2014.

Figure 8.2: Total Connections Tariff B1 and B2.



Source: Core Energy Group; 2014.

Figure 8.3: Total Connections Tariff B3.



Source: Core Energy Group; 2014.

8.3. Demand per Connection Forecast

Table 8.2 summarises demand per connection forecasts by reference tariff for the period 2015 to 2019.

Figure 8.4 to Figure 8.6 compare the above forecasts with the 90 percent confidence interval of the historic trend.

Some forecasts fall outside the historic trend in later years, attributed to the impact of marketing initiatives and known customer adjustments as previously described in Section 3.2.2.

The B2 tariff lies outside the historic trend due to ATCO revising gas consumption requirements for the B2 reference tariff downwards, resulting in a decline in new connections along with lower demand per connection (as the new connections joining the B2 class were those satisfying these new lower specifications). Figure 8.5 illustrates the declining rate of this trend in the future.

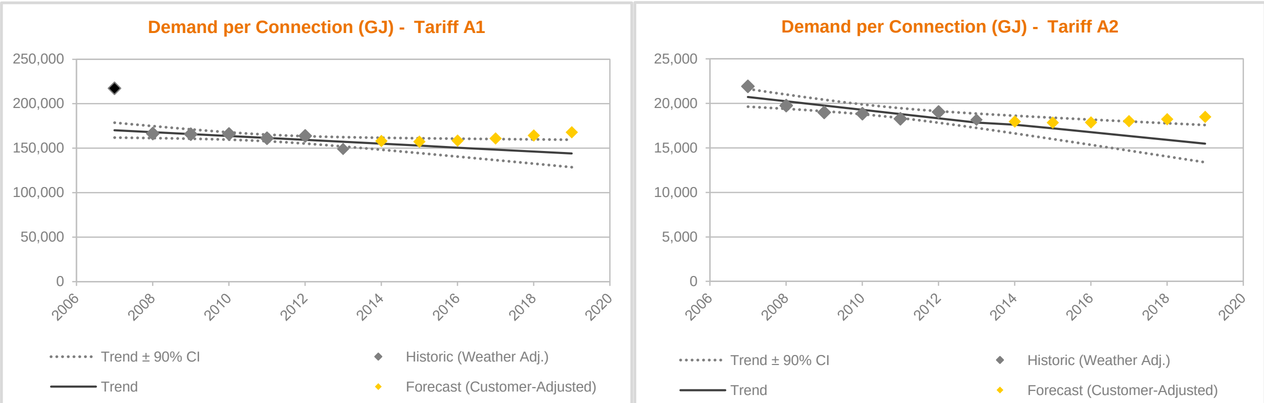
The A1 tariff lies significantly outside the historic trend due to the disconnection of a number of customers in 2014 with no current gas consumption, resulting in a higher future average demand per connection.

Table 8.2: Forecast Demand Per Connection by Tariff Class.

Forecast Demand per Connection (GJ per connection)	H1 2015	H2 2015	2015	2016	2017	2018	2019
Industrial							
Tariff A1	77,998	79,567	157,570	158,732	161,180	164,434	168,013
Tariff A2	8,732	9,117	17,856	17,861	18,007	18,239	18,503
Commercial							
Tariff B1	533	629	1,162	1,146	1,138	1,134	1,131
Tariff B2	56	63	119	114	111	108	106
Residential							
Tariff B3	6.31	8.13	14.45	14.32	14.25	14.21	14.16

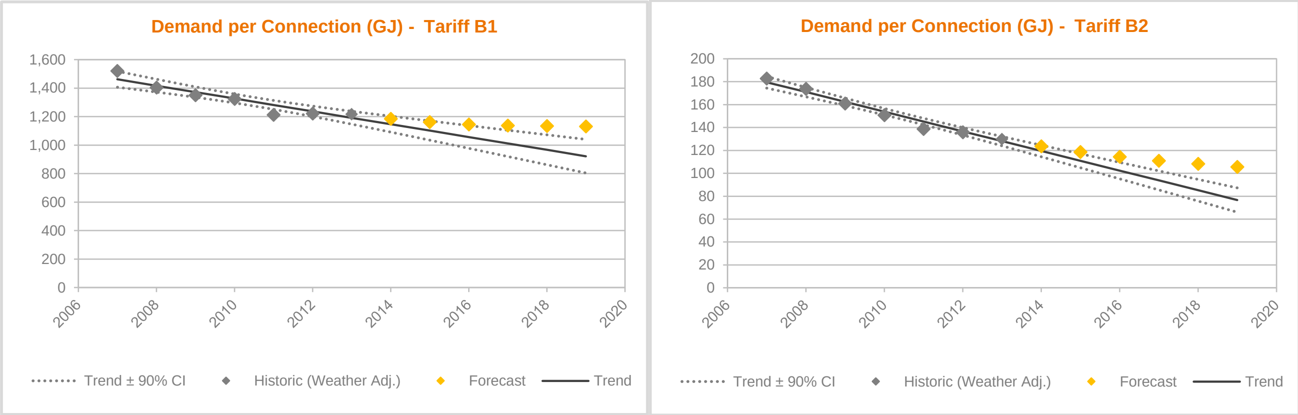
Source: Core Energy Group; 2014.

Figure 8.4: Demand per Connection Tariff A1 and A2.



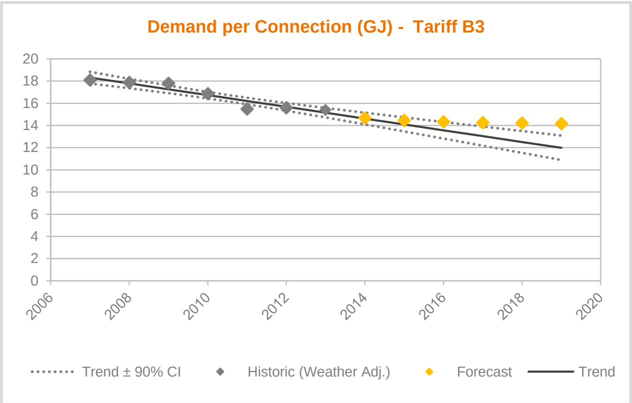
Source: Core Energy Group; 2014.

Figure 8.5: Demand per Connection Tariff B1 and B2.



Source: Core Energy Group; 2014.

Figure 8.6: Demand per Connection Tariff B3.



Source: Core Energy Group; 2014.

8.4. Total Demand Forecast

Table 8.3 summarises total demand forecasts by tariff for the period 2015 to 2019.

Figure 8.7 to Figure 8.9 show that some forecasts fall outside the historic trend in later years. This is attributed to the expected demand impact of:

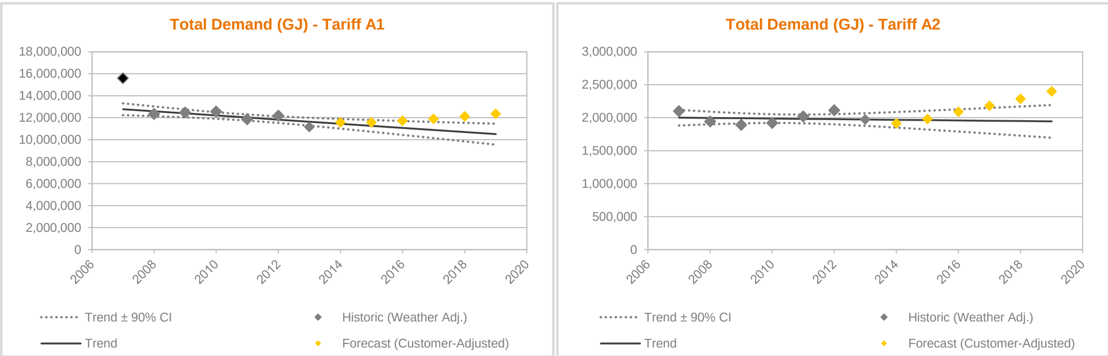
- New marketing initiatives implemented by ATCO which will not have been recognised in the historical demand figures;
- Known customer adjustments in 2015 which were known to ATCO at the time of this analysis, with expected demand per connection which is significantly greater than the historic average as some of these customers were not using any gas; and
- In the case of B2, a slowing rate of connection growth caused by the introduction of “AL10” metering (discussed in Section 4.7).

Table 8.3: Total Demand Forecast by Tariff Class.

Total Demand (GJ)	H1 2015	H2 2015	2015	2016	2017	2018	2019
Industrial							
Tariff A1 (Customer-adjusted)	5,711,223	5,861,546	11,572,769	11,720,093	11,883,212	12,105,157	12,350,313
Tariff A2 (Customer-adjusted)	951,992	1,030,753	1,982,745	2,092,394	2,184,157	2,288,724	2,400,155
Commercial							
Tariff B1	759,306	912,320	1,671,627	1,706,345	1,754,091	1,808,694	1,866,278
Tariff B2	581,560	668,223	1,249,783	1,242,812	1,242,746	1,244,572	1,245,362
Residential							
Tariff B3	4,278,385	5,580,336	9,858,722	10,007,804	10,188,283	10,372,812	10,530,472

Source: Core Energy Group; 2014.

Figure 8.7: Total Demand Tariff A1 and A2.

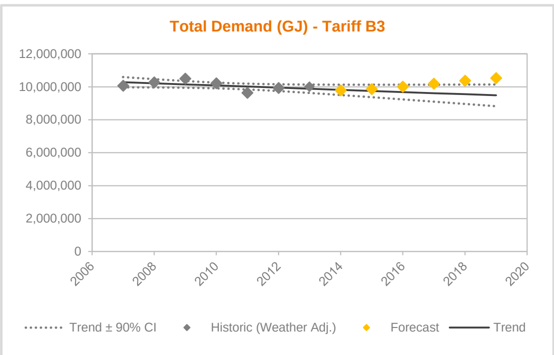


Source: Core Energy Group; 2014.

Figure 8.8: Total Demand Tariff B1 and B2.

Source: Core Energy Group; 2014.

Figure 8.9: Total Demand Tariff B3.



Source: Core Energy Group; 2014.