Gas Demand Forecast

ActewAGL Distribution Access Arrangement | 2017 to 2021

CORE ENERGY GROUP

FINAL

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Glossary

AAR	ActewAGL Retail
ACQ	Annual Contract Quantity
ACT	Australian Capital Territory
ActewAGL Distribution	ActewAGL Distribution Gas Networks
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AIC	Akaike Information Criterion
AUD	Australian Dollar
CAGR	Compound Annual Growth Rate
D/C	Demand per Connection
DD	Degree Day
DWP	Dalton Watson Pipeline
E to G	Electricity to Gas Connection
EBITDA	Earnings before interest, taxes, depreciation and amortization.
EDD	Effective Degree Day
EGP	Eastern Gas Pipeline
ERA	Economic Regulation Authority
FRC	Full Retail Contestability
FY	Financial Year
GAAR	Gas Access Arrangement
GJ	Gigajoule
GSP	Gross State Product
HDD	Heating Degree Day
HFT	Hoskinstown to Fyshwick Trunkline
HIA	Housing Industry Australia
IPART	Independent Pricing and Regulatory Tribunal
JCC	Japan Crude Cocktail
LF	Load Factor
LNG	Liquefied Natural Gas
LRMC	Long Run Marginal Cost
MDQ	Maximum Daily Quantity
MSP	Moomba Sydney Pipeline
NGR	National Gas Rules
NSW	New South Wales
p.a.	Per Annum
R^2	Residual Sum of Squares
RMSE	Root Mean Square Error

SFD	State Final Demand
T	Average 8 Three Hourly Temperature
TJ	Terajoules

1. Interpretation

References to “Tariff customers” or “Tariff V” customers refer to “volume customers”. Volume customers are delivery points with annual consumption reasonably expected to be less than 10TJ per annum. Currently there is a single service available to volume customers.

References to “Non-Tariff customers” or “Tariff D” customers refer to “demand customers”. Demand customers are delivery points with annual consumption reasonably expected to be equal to or greater than 10TJ per annum. Currently, there are a number of services available to demand customers including capacity reservation, managed capacity, throughput and multiple delivery point.

References to “2011-2014” refer to the period 1 July 2010 to 30 June 2014.

References to “2015-2021” refer to the period 1 July 2014 to 30 June 2021.

References to “2017-2021” or “Review Period” refer to the period 1 July 2016 to 30 June 2021.

Further, all data is reported in financial years unless otherwise specified.

2. Executive Summary

2.1. Scope of Report

This report has been prepared by Core Energy Group Pty Ltd ("**Core**") for the purpose of providing ActewAGL Distribution Gas Networks ("**ActewAGL Distribution**") with an independent forecast of gas customers and demand relating to the company's natural gas distribution network in Australian Capital Territory ("**ACT**"), Queanbeyan and Palerang for the five financial year period from 1 July 2016 to 30 June 2021 ("**Review Period**").

Core notes that this report (and related forecasting models[1]) will form part of ActewAGL Distribution's Gas Access Arrangement Review ("**GAAR**") submission to the Australian Energy Regulator ("**AER**").

Core acknowledges that the derivation of mid to longer range forecasts generally, and this customer and demand forecast specifically, involves a significant degree of uncertainty. Accordingly, Core has taken all reasonable steps to ensure this report, and the approach to deriving the forecasts referred to within the report, comply with Division 2 of the National Gas Rules ("**NGR**") "*Access arrangement information relevant to price and revenue regulation*", and in particular parts 74 and 75 as referenced below.

> *"74. Forecasts and estimates*
>
> *(1) Information in the nature of a forecast or estimate must be supported by a statement of the basis of the forecast or estimate.*
>
> *(2) A forecast or estimate:*
>
> *(a) must be arrived at on a reasonable basis; and*
>
> *(b) must represent the best forecast or estimate possible in the circumstances.*
>
> *75. Inferred or derivative information*
>
> *Information in the nature of an extrapolation or inference must be supported by the primary information on which the extrapolation or inference is based."* [2]

[1] The forecast models are confidential and an application will be sought for disclosure to be suppressed in accordance with NGR part 43 (2) (b).
[2] NGR dated April 2014 and accessed from AEMC website.

2.2. Methodology

Core’s approach to forecasting gas consumption favours a time-series approach, which focuses on those factors which are expected to materially impact future normalised consumption and connections relative to the historic growth rate.

Core's approach to deriving demand forecasts involves two elements, which are based on best practice standards:

- Forecasting principles which establish the principles to be observed in defining the forecasting methodology
- Forecasting methodology which defines the specific steps taken by Core to derive a forecast of demand for volume customers (residential and business) and demand customers.

2.2.1. Forecasting Principles

Core’s forecasting methodology is guided by the following principles.

- **Disciplined approach** – Core continually targets best practice approaches and analysis, consistent with international quality management standards. In the area of demand forecasting, Core maintains a continuous review of relevant domestic and international forecasting analysis and precedents. This includes review of analysis and methodologies adopted by the Australian Energy Market Operator (“**AEMO**”), AER and Economic Regulation Authority (“**ERA**”) access arrangement decisions, including expert submissions, as well as by the US Department of Energy and International Energy Agency.
- **Evaluate key drivers** – Core’s approach involves a rigorous analysis of the key drivers (both direct and indirect) of gas consumption. In accordance with best practice, Core adopts a balance of top down and bottom up analysis, including consideration of the following factors:
  - Connections: population, housing stock, construction trends, third party forecasts
  - Consumption per connection: energy efficiency, appliance trends, dwelling type, energy substitution.

  To the extent that forecasts of underlying drivers are expected to follow a similar pattern to that observed historically, or there is no reasonable basis to quantify an adjustment, then future gas consumption has been assumed to conform to a historical time trend – for example, appliance efficiency and energy substitution.

  Where Core identified material changes in those drivers to historical growth rate, it has made an adjustment accordingly. For example, an adjustment was made during the analysis of own price and cross price elasticity, due to a material change in forecast prices as validated by independent third party analysis.
- **Remove bias –** Core’s forecast avoids bias — that is, careful data screening excludes data which consistently over or under-predicts outcomes. Specifically, Core applied a rigorous approach to normalise demand for weather, analysed historical trends to observe any changes in trend, ensured data sourced from third parties was independent, reviewed apparent outliers in a data series, and used widely accepted best practice methodologies to conduct statistical analysis.
- **Use accurate and up-to-date data –** Core forecasts are based on most recent data available, and data sources and outcomes are validated, via independent third party analysis, and where this is not reasonably available, extensive literature review.
- **Model rigour, transparency and validation –** Core adopts best practice in the design and development of models and data books used to support forecasts. All inputs, calculations and outputs are clearly set out in a transparent manner and validation processes are consistently applied. Core takes care to ensure all models and data books can be subject

to review and revision in an efficient and consistent manner. Examples include clear model documentation, highlighting of key variables, and formatting of output table summaries and detailed underlying data.

2.2.2. Forecasting Methodology

An outline of the forecasting methodology adopted by Core to derive a customer and demand forecast for volume and demand customers is summarised in Figure 2.1 and Figure 2.2 below.

Figure 2.1 Volume Customers Demand Forecast Methodology Overview

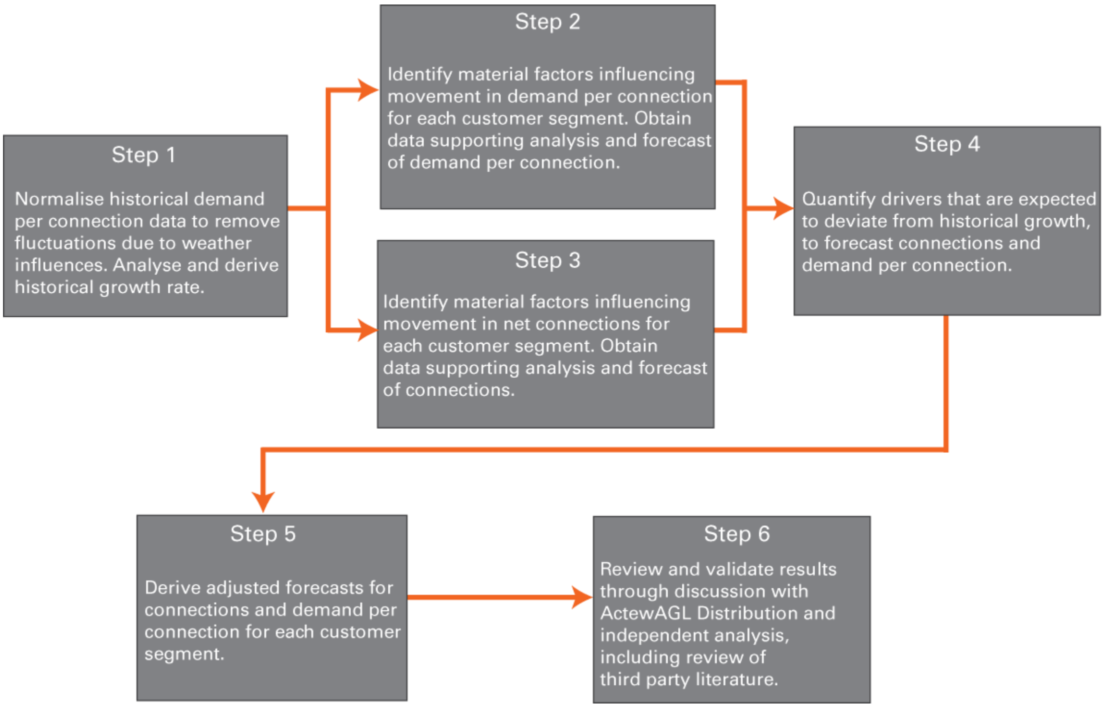
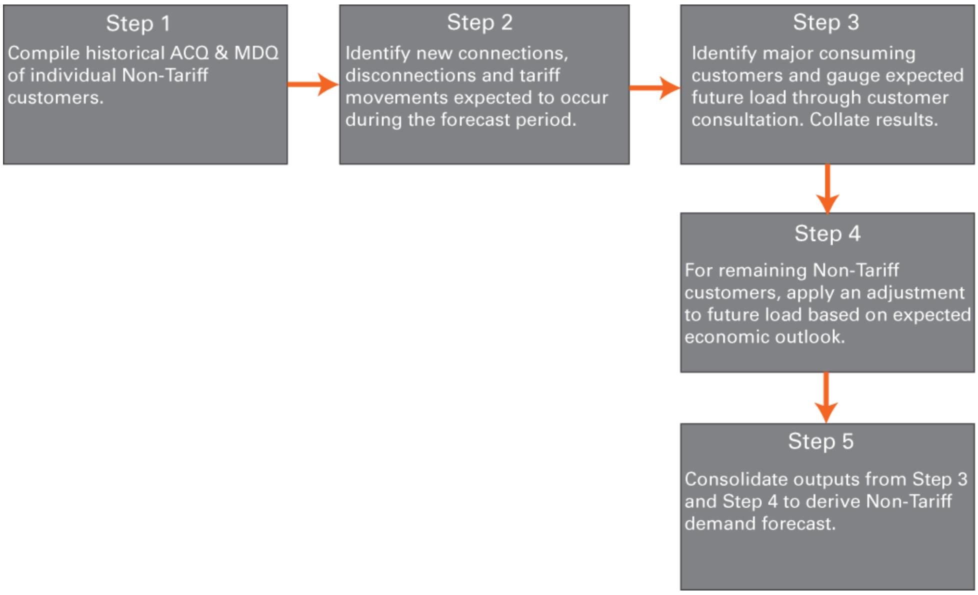


Figure 2.2 Demand Customers Demand Forecast Methodology Overview



2.3. Historical Connections and Demand

2.3.1. Volume Customers

Residential demand has fallen by 0.47% and business demand has fallen by 0.65% over the 2011-2014 period. Demand is principally determined by the number of connections and demand per connection, both of which are described further below. While residential and business customer connections have increased, demand per connection has declined leading to an overall decline in demand over the period between 2011-2014.

Table 2.1 summarises the historical average annual growth rates for volume customer demand for the 2011-2014 period.

Table 2.1 Historical Volume Customer Demand | GJ

Demand	2014	Average Annual Growth | %
		2011-2014
Residential	5,110,704	-0.47%
Business	1,566,260	-0.65%
Total	**6,676,963**	**-0.51%**

Table 2.2 summarises historical average annual growth rates for volume customer connections in the 2011-2014 period. This table highlights that residential and business connections have increased by 3.66% over this period.

Table 2.2 Historical Volume Customer Connections | No.

Connections	2014	Average Annual Growth | %
		2011-2014
Residential	130,818	3.66%
Business	3,416	3.66%

Table 2.3 summarises historical average annual growth rates for volume customer demand per connection for the 2011-2014 period. This table highlights that residential demand has fallen by 3.98% over the period and business demand has fallen by 4.16% over this period.

Table 2.3 Historical Volume Customer Demand per Existing Connection | GJ

Demand per Connection	2014	Average Annual Growth | %
		2011-2014
Residential | Existing	39.07	-3.98%
Business | Existing	458.56	-4.16%

2.3.2. Demand Customers

The annual consumption quantity ("**ACQ"**) and maximum daily quantity ("**MDQ**") for demand customers have increased by 2.17% and 6.52% respectively over the 2011-2014 period.

Table 2.4 summarises the historical average annual growth rates for demand customer demand on an ACQ and MDQ basis for the 2011-2014 period.

Table 2.4 Historical Demand Customer ACQ and MDQ | GJ

Load	2014	Average Annual Growth | % 2011-2014
ACQ | GJ	1,155,040	2.17%
MDQ | GJ	8,242	6.52%

2.4. Forecast Connections and Demand

2.4.1. Volume Customers

2.4.1.1 Volume Customer Demand

Residential demand is forecast to fall by 2.15%, while business demand is forecast to increase by 0.12% over the Review Period. This forecast is influenced by two principal forces – the number of connections and demand per connection, both of which are described in the following sections.

Residential demand is forecast to decline over the Review Period due to declining demand per connection despite increasing residential customer connections. Due to a greater forecast demand per connection for new connections, business demand is forecast to increase over the Review Period. This is despite lower connections rate in comparison to historical rates.

Table 2.5, Table 2.6, Figure 2.3 and Figure 2.4 summarise forecast annual movements in volume customer demand for the 2015-2021 period.

Table 2.5 Volume Customer Demand Forecast | GJ

Total Demand	2015	2016	2017	2018	2019	2020	2021
Residential	4,981,429	4,867,580	4,769,776	4,638,499	4,531,286	4,447,063	4,367,126
Business	1,494,158	1,510,783	1,526,442	1,521,632	1,508,357	1,509,095	1,519,631
Total	**6,475,587**	**6,378,363**	**6,296,219**	**6,160,131**	**6,039,643**	**5,956,158**	**5,886,757**

Table 2.6 Volume Customer Demand Average Annual Growth | %

Total Demand	Average Annual Growth | % 2011-2014	Average Annual Growth | % 2017-2021
Residential	-0.47%	-2.15%
Business	-0.65%	0.12%
Total	**-0.51%**	**-1.59%**

Figure 2.3 Volume Customer Residential Demand Forecast | GJ

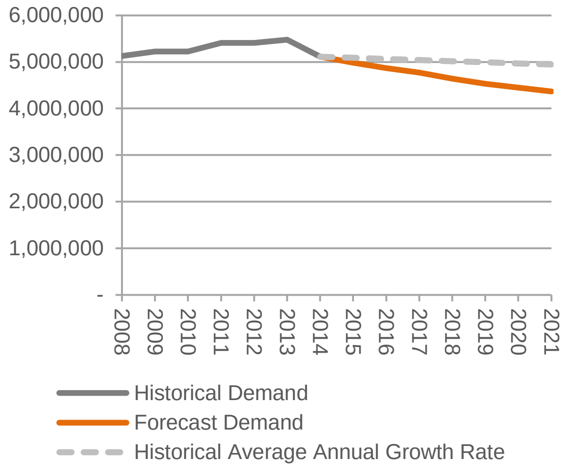
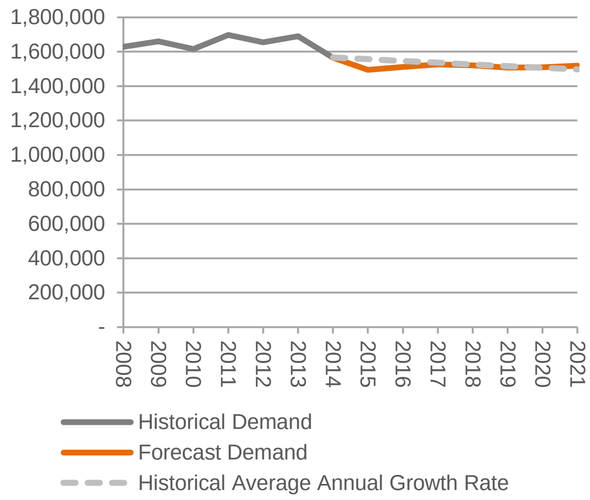


Figure 2.4 Volume Customer Business Demand Forecast | GJ



2.4.1.2 Volume Customer Connections

Residential connections are forecast to increase by 2.49%, while business connections are forecast to increase by 3.04% over the Review Period.

The residential connections forecast has primarily been determined by:

- the existing residential connections;
- the forecast number of new estates and new medium/high density forecast connections over the Review Period based on Housing Industry Association ("**HIA**") new dwelling forecasts[3] (refer Annexure 5);
- the forecast number of new electricity to gas ("**E to G**") connections over the Review Period; and
- the number of forecast disconnections over the Review Period.

The business connections forecast has primarily been determined by:

- the existing business connections;
- the continuing historical growth over the Review Period;
- the forecast growth in Gross State Product ("**GSP**") over the Review Period (refer Annexure 6); and
- the number of forecast disconnections over the Review Period.

Table 2.7, Table 2.8, Figure 2.7 and Figure 2.8 summarise forecast annual movements in volume customer connections for the 2015-2021 period.

Table 2.7 Volume Customer Connections Forecast | No.

Total Connections	2015	2016	2017	2018	2019	2020	2021
Residential	134,568	137,974	141,337	144,966	148,575	152,471	156,039
Business	3,449	3,554	3,661	3,773	3,887	4,005	4,127
Total	**138,017**	**141,528**	**144,998**	**148,739**	**152,463**	**156,476**	**160,166**

Table 2.8 Volume Customer Connections Annual Average Growth | %

Total Connections	Average Annual Growth | % 2011-2014	Average Annual Growth | % 2017-2021
Residential	3.66%	2.49%
Business	3.66%	3.04%
Total	**3.66%**	**2.51%**

[3] Housing Industry Australia, Housing Forecasts, February 2015 <http://hia.com.au/en/BusinessInfo/economicInfo/housingForecasts.aspx>

Figure 2.5 Volume Customer Residential Connections Forecast | No.

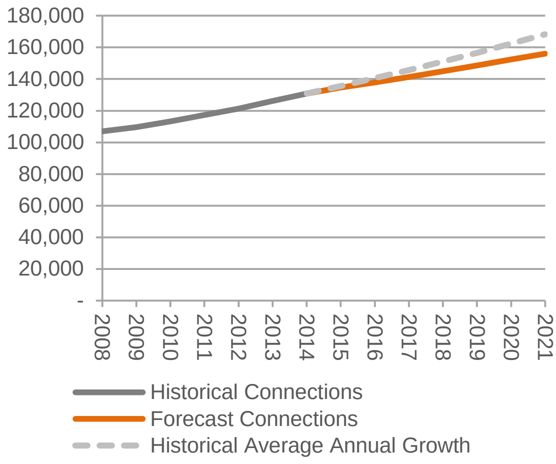
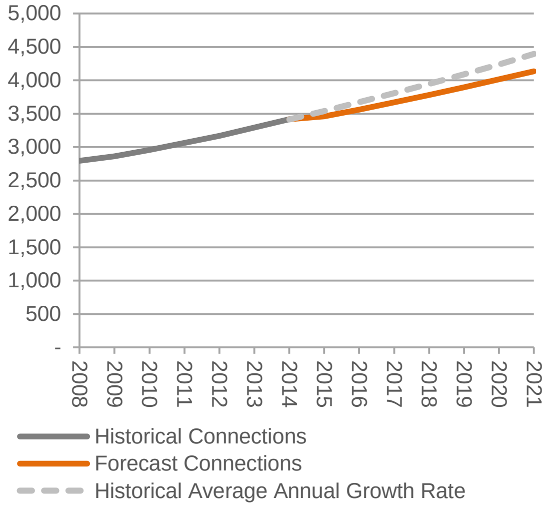


Figure 2.6 Volume Customer Business Connections Forecast | No.



2.4.1.3 Demand per Connection

Residential demand per connection is forecast to fall by 4.52%, while business demand per connection is forecast to fall by 2.83% (2.83% post Tariff D movements) over the Review Period.

The forecast decline in residential demand per connection is influenced by a number of factors, including:

- the continuation of influences observed in historical growth rate;
- customer demand response to gas and electricity price movements (refer Annexure 4);
- the greater availability and affordability of energy efficient appliances (refer Annexure 7);
- the impacts of the Gas Services and Installation Rules Code and Gas Network Boundary Code Amendments on gas connections and demand for high rise developments (refer Annexure 7);
- the changing housing density mix, in particular, the increasing number of high rise developments compared to other dwelling types (refer Annexure 5);
- greater customer preference for clean energy sources (following feedback from customers in ActewAGL/Jemena engagement sessions); and
- the ongoing impact of the *Climate Change and Greenhouse Gas Reduction Act 2010* (ACT), in particular, the ACT's government's directive to achieve a renewable energy target of 90% in the ACT by 2020 (refer Annexure 7).

The forecast decline in business demand per connection is influenced by a number of factors, including:

- the continuation of influences observed in the historical growth rate;
- customer demand response to increased gas price rises (refer Annexure 4);
- greater customer preference for clean energy sources (following feedback from customers in our engagement sessions); and
- the ongoing impact of the *Climate Change and Greenhouse Gas Reduction Act 2010* (ACT), in particular, the renewable energy target of 90% by 2020 (Annexure 7).

Table 2.9, Table 2.10, Figure 2.7 and Figure 2.8 summarise forecast annual movements in volume customer demand per connection for the 2015-2021 period.

Table 2.9 Volume Customer Demand per Connection Forecast | GJ

Demand per Connection	2015	2016	2017	2018	2019	2020	2021
Residential							
Existing	37.5	36.1	34.8	33.4	32.2	31.1	30.1
New Estate	33.6	32.3	31.2	29.9	28.8	27.8	26.9
New M/H Density	14.4	13.8	13.4	12.8	12.3	11.9	11.5
New E to G	25.5	24.5	23.7	22.7	21.9	21.1	20.5
Weighted Average	**37.0**	**35.3**	**33.7**	**32.0**	**30.5**	**29.2**	**28.0**
Business							
Existing	439	427	414	398	380	366	355
New Business	559	543	528	506	483	466	452
Weighted Average | Pre Demand Customer to Volume Customer Movement	**440**	**432**	**424**	**410**	**394**	**383**	**374**
Weighted Average | Post Demand Customers to Volume Customer Movement	**433**	**425**	**417**	**403**	**388**	**377**	**368**

Table 2.10 Volume Customer Demand per Connection Annual Average Growth | %

Total Demand per Connection	Average Annual Growth | % 2011-2014	Average Annual Growth | % 2015-2021	Average Annual Growth | % 2017-2021
Residential			
Existing	-3.98%	-3.67%	-3.57%
New Estate		-3.67%	-3.57%
New M/H Density		-3.67%	-3.57%
New E to G		-3.67%	-3.57%
Weighted Average		**-4.65%***	**-4.52%***
Business			
Existing	-4.16%	-3.60%	-3.62%
New Business		-3.60%	-3.62%
Weighted Average | Pre Demand to Volume Customer Movements		**-2.86%**	**-2.83%**
Weighted Average | Post Demand to Volume Customer Movements			**-2.83%**

*The weighted average annual growth is lower than the average annual growth of the individual connection types due to the change in proportion of existing connections to new connections. The proportion of lower consuming new connections increases during the forecast period, resulting in a lower weighted average demand per connection by 2021 than if the mix of connections remained constant.

Figure 2.7 Residential Demand per Existing Connection | GJ

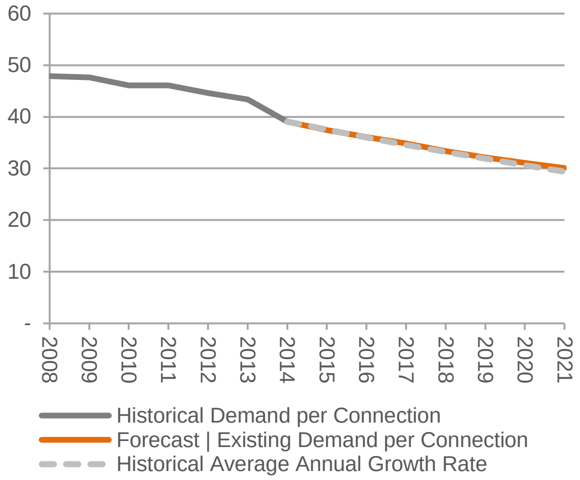
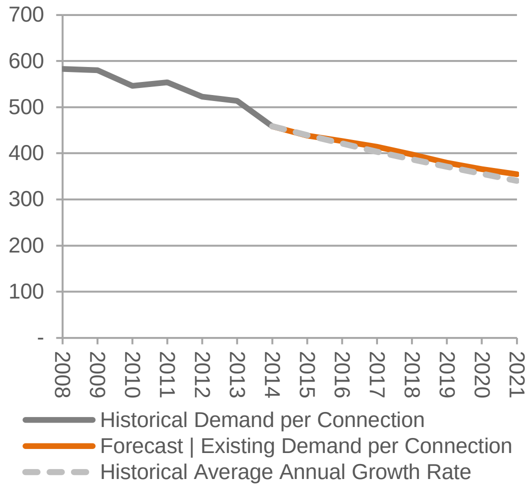


Figure 2.8 Business Demand per Existing Connection | GJ



2.4.2. Demand Customers

ACQ and MDQ are projected to increase over the Review Period by 0.52% and 0.47% respectively. The main contributing factor is that no new demand customer connections are forecast for the Review Period and this sits in contrast with what occurred during the 2011-2014 period. This was based on information provided by ActewAGL Distribution following its engagement with retailers and major customers. In 2011-2014, there were a number of new demand customer connections including [redacted], [redacted], [redacted] and [redacted], [redacted], and [redacted].

Table 2.11, Table 2.12, Figure 2.9 and Figure 2.10 summarise forecast average annual growth rates for demand customer consumption on an ACQ and MDQ basis, for the 2015-2021 period.

Table 2.11 Forecast of Demand Customer MDQ & ACQ | GJ

Demand	2015	2016	2017	2018	2019	2020	2021
MDQ | GJ	8,140	8,025	7,951	7,956	8,201	8,206	8,211
ACQ | GJ	1,224,102	1,201,836	1,185,399	1,185,769	1,231,356	1,231,764	1,232,191

Table 2.12 Comparison of Historical and Forecast Average Annual Growth in Demand Customer Demand | %

	Average Annual Growth | % 2011-2014	Average Annual Growth | % 2017-2021
MDQ	6.52%	0.47%
ACQ	2.17%	0.52%

Figure 2.9 Demand Customer ACQ | GJ

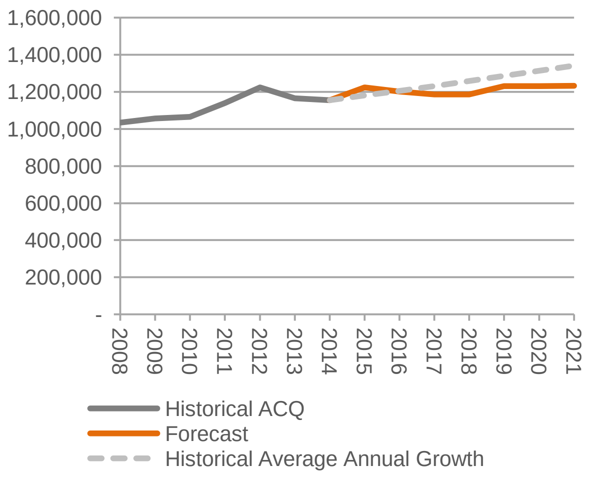
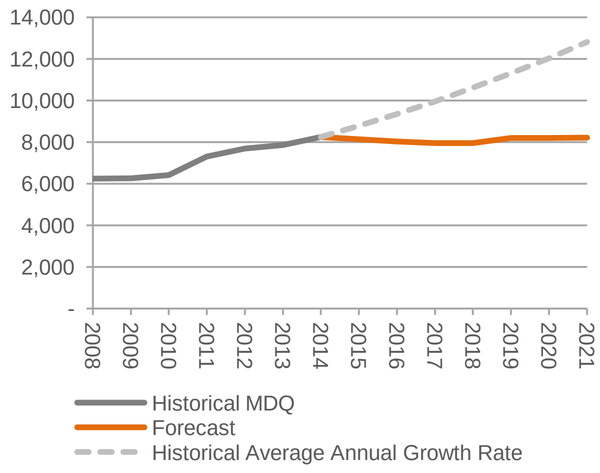


Figure 2.10 Demand Customer MDQ | GJ



3. Methodology

3.1. Introduction

The methodology adopted by Core to derive a forecast of gas connections and gas demand for the ActewAGL Distribution network, involves three primary elements:

> An approach to normalising historical demand to remove the abnormal impact of weather (Section 3.2).

> An approach to deriving a forecast of volume customer demand (Section 3.3).

> An approach to deriving a forecast demand customer demand (Section 3.4).

Prior to formulating the methodology for each of the above elements, Core completed a review of all recent access arrangement proposals and draft and final decisions. This revealed any potential improvements to Core methodology and ensured that all requirements of the NGR were strictly complied with.

The Core methodology favours a highly transparent approach. This includes a demand forecast model which focuses on those factors which are expected to materially impact future normalised demand and connections, having regard to historical annual average growth analysis and forecast changes in certain trends and demand drivers, to derive final forecasts. This model and associated documents set out all underlying facts and assumptions which are relied upon to derive the forecasts.

Core is of the opinion that the methodology described herein provides a basis for the best forecasts available given the specific circumstances; utilising quality data and information, including primary source data where it is reasonably available to Core.

3.2. Weather Normalisation

Gas demand, particularly in the residential sector, is materially influenced by weather. The weather impact on historical gas demand was therefore normalised to provide an appropriate and consistent basis for demand forecasting.

Core adopts a weather normalisation methodology based on AEMO's "*2012 Weather Standards for Gas Forecasting*" guidelines, which involves the calculation of Effective Degree Days ("**EDD**").

Core notes that the prior ACT submissions to the AER applied a Heating Degree Day ("**HDD**") methodology. Nonetheless, Core considers an EDD_{312} approach to be the preferred approach for weather normalisation in ActewAGL Distribution's ACT gas demand network. In comparing HDD and EDD, EDD accounts for additional climatic factors such as sunshine, wind chill and seasonality. The coefficient of determination also shows that EDD has a stronger relationship with gas demand than HDD. Further, the Akaike Information Criterion ("**AIC**") also supports the use of EDD instead of HDD as an index of weather fluctuations. For these reasons, Core used EDD as the preferred approach for weather normalisation.

Core's weather normalised demand approach involves the following steps:

EDD calculation

1. Develop an EDD Index Model that calculates the EDD index coefficients – this model is included as a supporting document to this report.
2. Obtain EDD Index coefficients through regression between daily gas demand and climate data (temperature, wind speed, sunshine hours) from Canberra Airport Comparison Station (Station ID 70014) from 01/07/2007 to 28/02/2010 and the Canberra Airport Station (Station ID 70351) from 01/03/2010 to 05/12/2012. It should be noted that in instances where data was unavailable, Core has interpolated to estimate a data point. The average daily temperature and wind speed data were estimated using two approaches; the average of 8x3-hourly data points between 3.00a.m. and 12.00a.m., and the average of same day maximum and minimum data. Core compared the regression results and selected the regression with the best fit, based on the sum squared residual. In this case, the 8x3-hourly data was selected.
3. Using the Weather Normalised Demand Model and EDD Index coefficients, the EDD was calculated. The weather normalisation model is included as a supporting document to this report.

Weather Normalisation Regression Model Development and Selection

1. In determining the appropriate estimate for weather normalised demand, the following models were examined. Please note that the sunshine hours data between 05/12/2012 and 30/06/2014 used to calculate EDD was estimated using sunshine exposure data from the BOM, as the actual dataset is unavailable.

   Model 1 $Dem\ per\ Conn = \beta_0 + \beta_1 EDD$

   Model 2 $Dem\ per\ Conn = \beta_0 + \beta_1 EDD + \beta_2 (Dem\ per\ Conn)_{\ t-1}$

   Model 3 $\Delta(Dem\ per\ Conn) = \beta_0 + \beta_1 \Delta(EDD)$

   Model 4 $Dem\ per\ Conn = \beta_0 + \beta_1 \Delta(EDD) + \beta_2 (Dem\ per\ Conn)_{\ t-1}$

   Where t-1 is indicative of the previous month's demand per connection
2. The preferred weather normalisation model (Model 2) was used to normalise demand per connection for each customer type, on an annual basis. For each observation, the required adjustment for weather normalisation was calculated as the deviation in EDD from the sample average, multiplied by β_1.

Below are the coefficients of EDD which provide the best fit to daily demand, defined by the following model:

Daily demand per connection = $b_0 + b_1$*EDD + b_2*Friday + b_3*Saturday +b_4*Sunday.

EDD = DD (temperature effect)

+ **0.0163** x DD x average wind speed (wind chill factor)

- **0.1326** x sunshine hours (warming effect of sunshine)

+ max(**3.128** *2* Cos $\left(\frac{2\pi(\text{day}-196)}{365}\right)$,0) (seasonal factor)[4]

[4] Please note the AEMO EDD_{312} standards do not include the max function or 3.128 coefficient for the seasonality factor. The addition of this coefficient is to optimise the relationship between EDD and the seasonality factor, while the max function is used as it is irrational to have a resulting negative demand per connection.

Where:

DD is the degree day (see calculation below);

DD = **14.6** – T if T < 14.6

0 if T > 14.6:

T is the average of 8x3-hourly Canberra temperature readings (in degrees Celsius) from 3.00am to 12.00am the following day inclusive, as measured at the Canberra Airport Comparison Station and Canberra Airport Weather Station. 14.6 degrees Celsius represents the threshold temperature for ACT gas heating. Friday, Saturday and Sunday are dummy variables for those days of the week, consistent with the AEMO EDD_{312} methodology.

Demand per connection is equal to total volume customer daily demand divided by estimated total volume customer daily customer numbers (using year-end customer numbers and interpolating for each day of the year). Given the network's historically stable rate of customer growth, Core believes this to be a reasonable estimate of daily customer numbers.

Core has reviewed the use of EDD for weather normalisation in prior access arrangements, including responses from the AER in relation to the Envestra VIC 2013-17 Draft Decision. The methodology detailed above demonstrates that Core has applied a weather normalisation process using EDD that is broadly consistent with AEMO's "*2012 Review of Weather Standards for Gas Forecasting*" method; daily EDD values have been calculated through regression of historical data rather than being based on projected figures. Core considers this process to be compliant with 74 (2) of the *National Gas Rules*; EDD values are arrived at on a reasonable basis, representing the best forecasts possible in the circumstances.

3.2.1. Weather Normalised Demand Model

Table 3.1 and Table 3.2 summarise the regression results for the models.

The EDD coefficients are used to normalise demand per connection.

Table 3.1 Residential Demand per Connection Regression Outputs

	Model 1	Model 2	Model 3	Model 4
Dependent Variable	Residential D/C	Residential D/C	Δ Residential D/C	Residential D/C
EDD Coefficient	0.00917***	0.00763***		
Residential D/C Lag(-1) Coefficient		0.737***		1.113***
EDD_fDif			0.00711**	0.00934***
constant	2.12***	-0.395*	-0.0279	-0.447
No. of observations	84	83	83	83
R^2	0.38	0.913	0.22	0.71
Adj R^2	0.37	0.910	0.21	0.71
AIC	374	216	312	307
RMSE	2.20	0.838	1.5	1.52

Note: *** represents significance of 0.01% or below, ** represents significance of 1% or below
* represents significance of 5% or below

Table 3.2 Business Demand per Connection Regression Outputs

	Model 1	Model 2	Model 3	Model 4
Dependent Variable	Residential D/C	Residential D/C	Δ Residential D/C	Residential D/C
EDD Coefficient	0.116***	0.0818***		
Business D/C Lag(-1) Coefficient		0.483***		1.0639***
EDD_fDif			0.0929***	0.1013***
constant	24.0***	8.42***	-0.212	-3.074
No. of observations	84	83	83	83
R^2	0.76	0.92	0.46	0.8
Adj R^2	0.76	0.92	0.45	.79
AIC	668	560	646	642
RMSE	12.4	6.9	11.4	11.39

The selected models for residential and business demand take the following factors into consideration.

- The explanatory variables are significant at the 5% confidence level.
- The explanatory variables have logical signs (positive or negative).
- The explanatory variables have a high explanatory power (R-Square).
- The AIC score is low compared to other models.

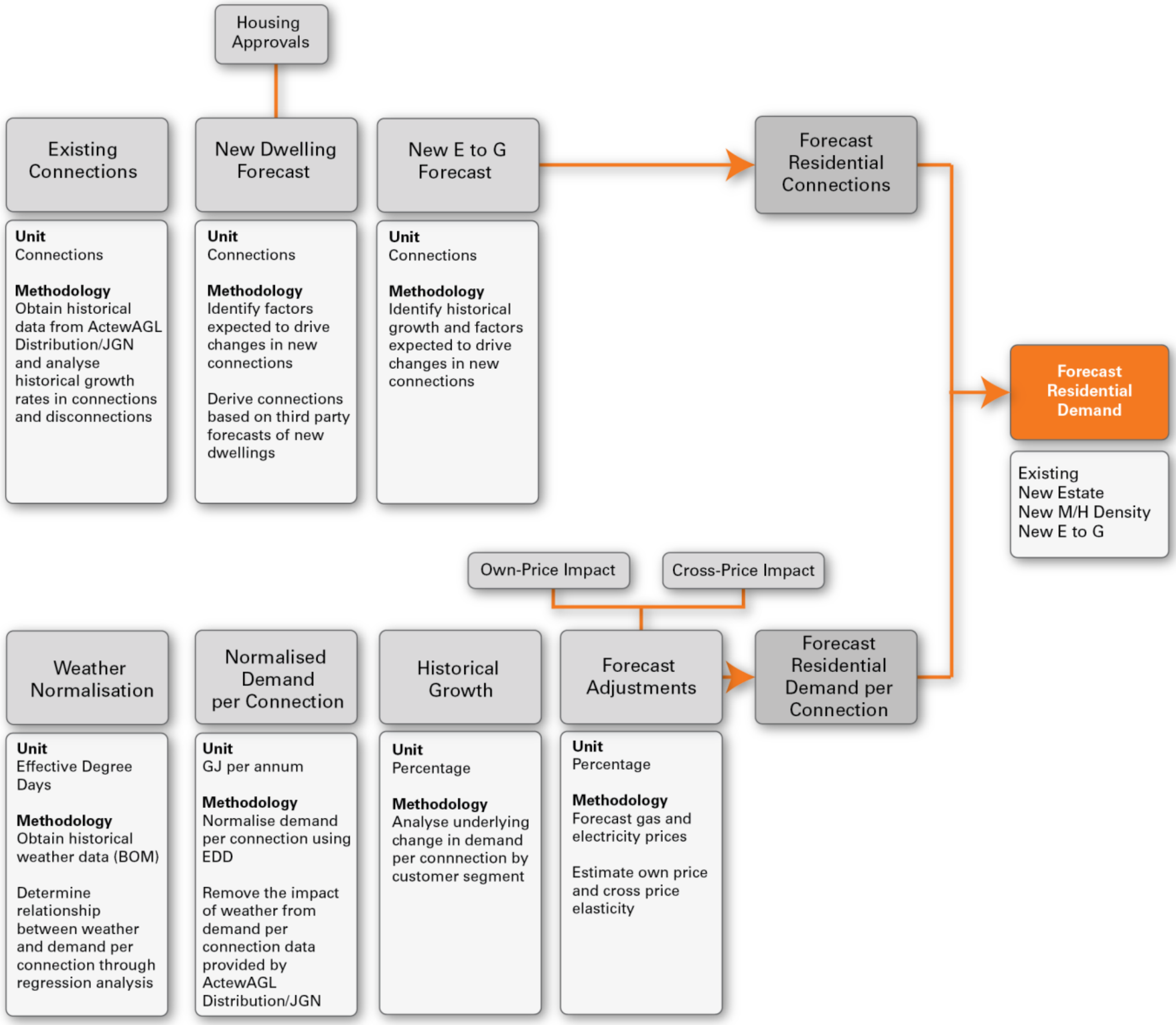
Model 2 is chosen to normalise demand per connection for both the residential and business sector. Model 2 has the lowest AIC and strongest R^2.

3.3. Volume Customer Demand

3.3.1. Volume Customers | Residential

Figure 3.1 provides a diagrammatic representation of the approach Core has adopted to derive a forecast of volume customer residential demand, including a forecast of connections and demand per connection.

Figure 3.1 Volume Customer Residential Demand Forecast Methodology



The derivation of forecast connections and demand per connection is discussed in further detail below.

3.3.1.1 Connections

Core has determined that a bottom-up approach, which assesses the impact of each driver that is expected to have a material influence on connections (with appropriate rigour and data quality), to be the best approach under the review circumstances. The following steps were undertaken to derive a forecast for different categories of residential connections.

Existing Connections

1. Opening residential connection numbers between 2007 and 2014 were compiled based on data obtained from Jemena/ActewAGL Distribution.[5]
2. Disconnections between 2011 and 2014 were also obtained from Jemena/ActewAGL Distribution.[6] Disconnection numbers were provided as a total for both residential and business segments. To determine the number of disconnections for the residential segment, the historical proportion of residential connections to total connections was applied.
3. Estimate the number of disconnections as an average percentage of annual disconnections between 2010 and 2014.
4. Derive the existing connections forecast in the forecast period 2015-2021 using the closing number of connections in 2014 and the disconnections in the forecast year.
5. Incorporate additional disconnections to the existing connections forecast during 2017 and 2019, to account for the Mr Fluffy buy-back scheme, which involves demolishing homes contaminated with "Mr Fluffy" loose fill asbestos. Further detail on the Mr Fluffy buy-back scheme, and its impact on connections, is provided in Annexure 7.

New Dwelling Connections

1. Obtain the Housing Industry Association Housing Starts forecast[7] for ACT, reported as of February 2015. Upscale the new dwellings forecast to reflect additional new dwellings to be built in Queanbeyan and Palerang.
2. Determine a forecast of the reach of the ActewAGL distribution network across this population (assumed to be 100%), based on information provided by ActewAGL Distribution. Apply this network reach to new dwellings forecast to derive new dwellings within the ActewAGL network region.
3. Derive a forecast of future new gas connections by multiplying the number of new dwelling connections, by a penetration rate provided by ActewAGL Distribution (90%). It is assumed that the impact of the current dwelling stock surplus in ACT on new dwelling connections is included in HIA's forecast of new dwellings.
4. Allocate the new connections forecast by dwelling type (New Estate vs. Medium/High Density) based on HIA data. This data was released in February 2015, and forecasts 52% of future dwellings between 2015 and 2021 to be new estates and the remaining 48% to be medium/high density dwellings. The percentage of total dwellings to be connected in a given forecast year is also determined based on the forecasts provided by HIA.
5. Additional new dwelling connections are applied to the new dwelling connections forecast during 2018 and 2020, to account for the new homes built as part of the My Fluffy buy-back scheme. Further detail on the Mr Fluffy buy-back scheme, and its impact on connections, is provided in Annexure 7.

[5] Jemena/ActewAGL Distribution, ACT historical Customer Numbers.xls, Tab: Customer Numbers
[6] Jemena/ActewAGL Distribution, Copy of 18 11 2014 ACT disconnections historicals.xls, Tab: Sheet 1
[7] Housing Industry Australia, Housing Forecasts, February 2015 <http://hia.com.au/en/BusinessInfo/economicInfo/housingForecasts.aspx>

Electricity to Gas ("E to G") Connections

1. Historical new E to G connections data was provided by Jemena/ActewAGL Distribution[8] for the period between 2008 and 2014.
2. Core calculated the average number of connections and assumed that this level would remain constant throughout the Review Period based on:
    a. Information provided by ActewAGL Distribution that there are plans to continue seeking the same AER approved marketing operating expenditure allowance as its 2010-2015 access arrangement; and
    b. Research conducted by Core to assess whether there are any known policy impacts which may influence E to G connections.

Core has assumed that there is no change in impact on the E to G connections.

3.3.1.2 Demand per Connection

Core has undertaken an assessment of the alternative methodologies which are widely accepted as a basis for deriving a forecast of demand per connection for the residential segment of the ActewAGL Distribution Network. Core has determined that an approach which analyses the average historical growth and adjusts for the impact of each material factor which is reasonably expected to influence demand per connection (with appropriate rigour and data quality), to be the best available approach under the review circumstances. Accordingly, Core has adopted this approach, ensuring analysis is set out in a transparent fashion, using a model which clearly sets out assumptions/inputs, calculations and results.

The steps taken to arrive at forecast demand per connection are as follows:

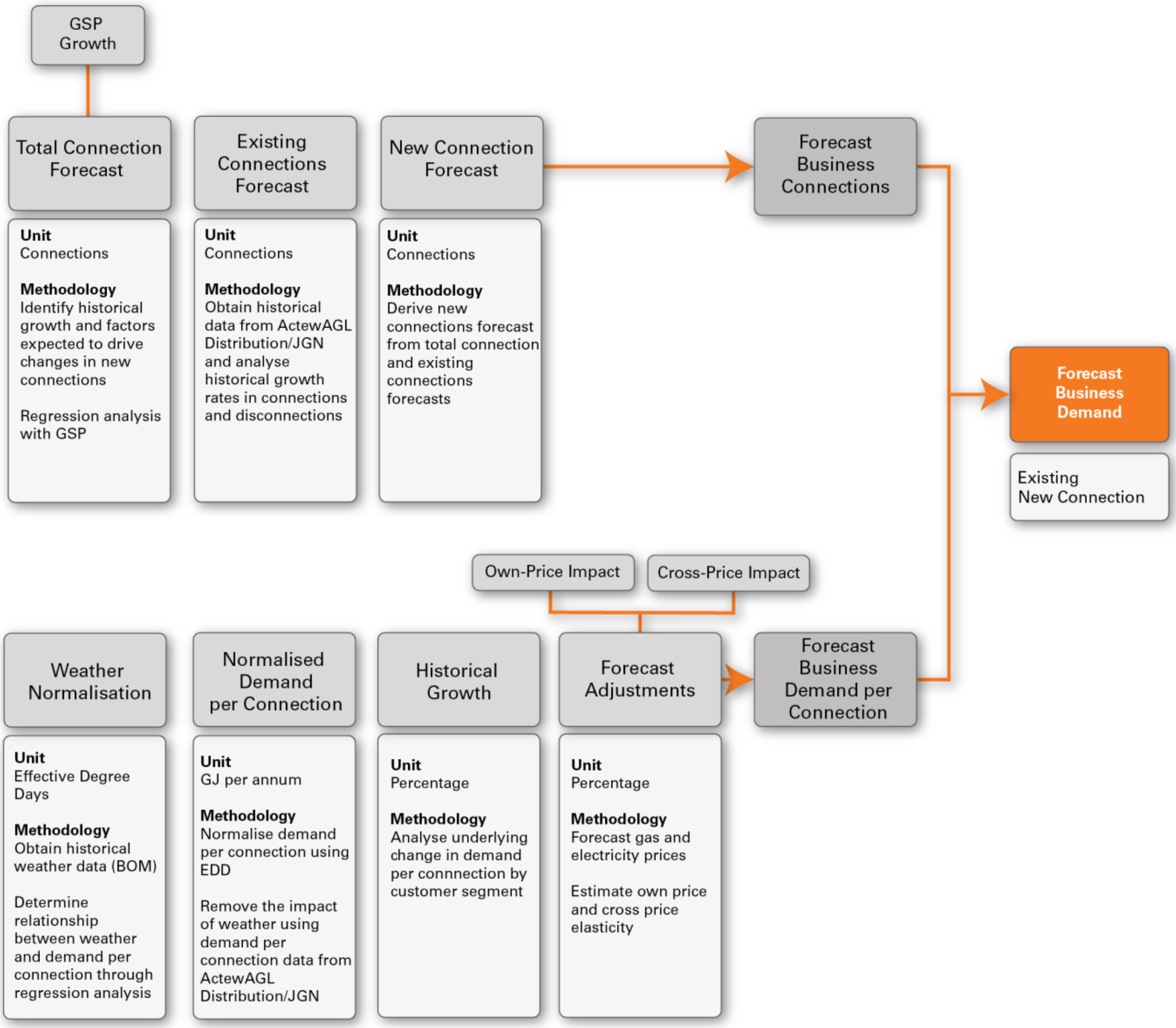
1. Normalise demand per connection and demand for the effects of weather using the methodology discussed in Section 3.2.
2. Divide normalised historical demand by number of connections to determine demand per connection.
3. Derive the average historical growth in demand per connection based on demand per connection between 2008 and 2014 for existing connections.
4. Adjust normalised historical annual average growth in demand per connection to remove historical impact of own and cross price elasticity.
5. Derive a forecast of demand per connection, having regard to major factors which have the potential to influence demand per connection.

[8] Jemena/ActewAGL Distribution, ACT new connection history.xls, Tab:

3.3.2. Volume Customers | Business

Figure 3.2 provides a diagrammatic representation of the approach Core used to derive a forecast of volume customer business demand, including a forecast of connections and demand per connection.

Figure 3.2 Volume Customers Business Demand Forecast Methodology



3.3.2.1 Connections

Core has determined that a bottom-up approach, which assesses the impact of each material factor that is reasonably expected to influence connections (with appropriate rigour and data quality), to be the best approach under the circumstances.

The following steps were undertaken to derive a forecast for the two categories of business connections.

Existing Connections

1. Compiled opening annual business connection numbers between 2008 and 2014 based on data obtained from Jemena/ActewAGL Distribution.[9]
2. Derived a forecast of disconnections for the Review Period based on the average disconnections per annum between 2011 and 2014.
3. Derived a forecast of existing connections between 2015 and 2021 based on opening connections less disconnections in each year.

New Connections

1. Derived a forecast of new connections by finding the difference between total business connections and existing connections.
2. Derived a forecast of total business connections using regression analysis.
   > The regression analysis undertaken indicates a strong relationship (R^2 value of 0.996) between historical growth in GSP and growth in total business connections. A 1% increase in GSP increases business connections by 1.13%. Further detail of this regression analysis is provided in Annexure 6.
3. The average historical growth of total business connections was normalised with respect to GSP to remove the impact of GSP from historical growth rate.
4. Derived a forecast of total business connections by multiplying the GSP coefficient and ACT GSP growth projection.[10]
5. Derived a forecast of demand per connection, having regard to major factors which have the potential to influence demand per connection.

3.3.2.2 Demand per Connection

As with residential demand per connection, a bottom up approach was undertaken to forecast business demand per connection. This approach analyses the historical growth and adjusts for the impact of each driver which is expected to have a material influence on demand per connection (with appropriate rigour and data quality). Core considers this approach to be the best available approach under the review circumstances.

Specific steps in the process include:

1. Develop models to calculate EDD, normalised demand and forecast of demand per connection (these have been provided to ActewAGL Distribution).
2. Normalise demand and demand per connection for the effects of weather using the methodology discussed in Section 2.1.
3. Divide weather normalised historical demand by number of connections to determine demand per connection.
4. The historical growth in demand per connection was determined based on demand per connection between 2008 and 2014 for existing connections.
5. Normalise the average historical growth with respect to own and cross price to remove historical pricing impacts.

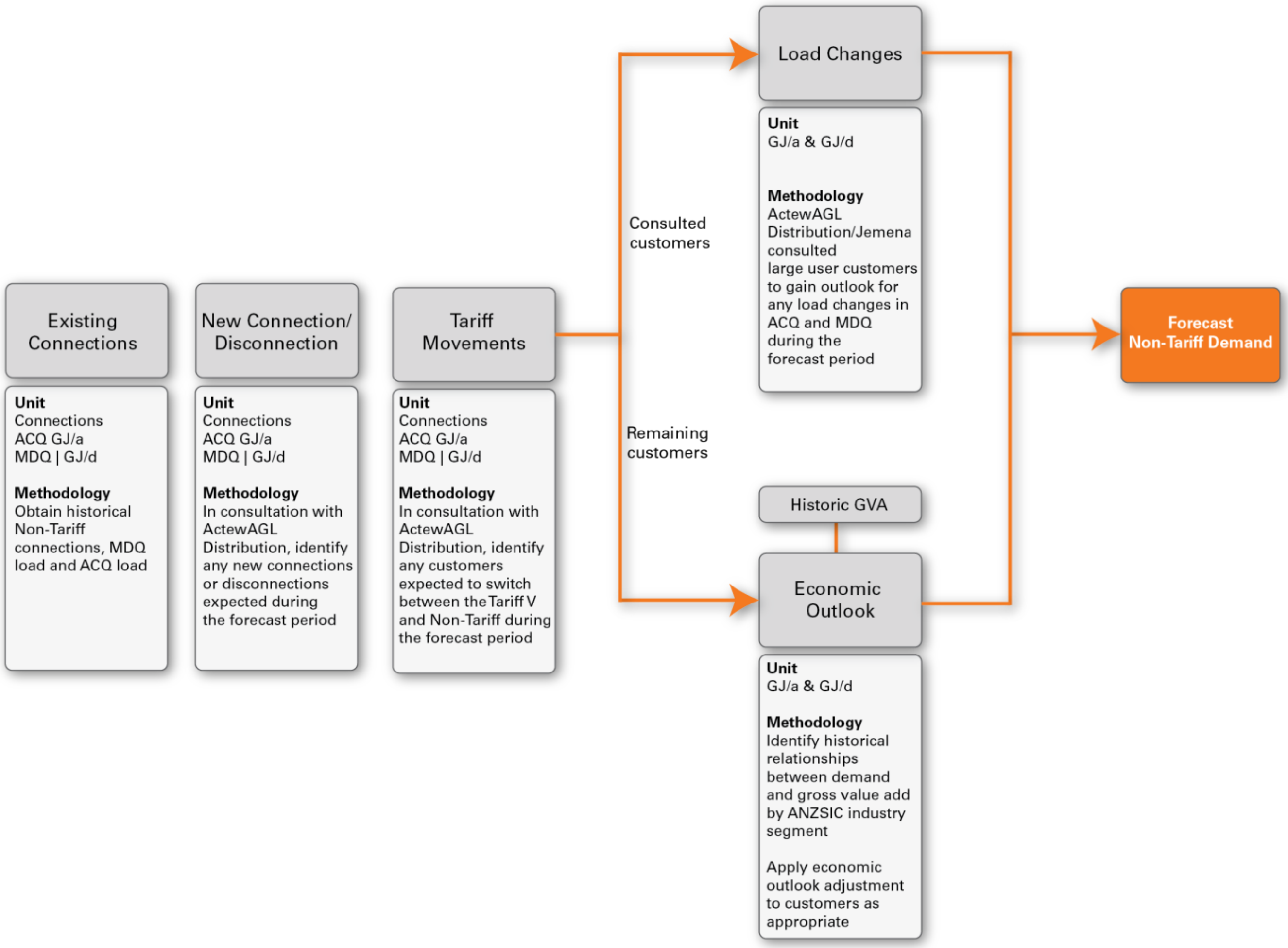
[9] Jemena/ActewAGL Distribution, ACT historical Customer Numbers.xls, Tab: Customer Numbers
[10] Based on 2014-2015 Budget Paper No. 3 (ACT), Tables 1.3.1 and 1.3.2

6. Derive forecast of demand per connection, having regard to major factors which have the potential to influence demand per connection.

3.4. Demand Customer MDQ and ACQ

This section provides a summary of the methodology used to derive a forecast for Tariff D demand. Figure 3.3 provides a diagrammatic representation of the approach Core used to derive a forecast of demand customer ACQ and MDQ.

Figure 3.3 Demand Customer ACQ and MDQ Forecast Methodology



3.4.2. Maximum Daily Quantity

The specific steps taken by Core to arrive at forecast of ACQ and MDQ, for demand customers is as follows:

1. Review list of demand customers at 2014 and allocate these customers according to ANZSIC classification of industry sectors.
2. Adjust for any known closures, new connections, tariff reallocation and expected material load changes. These adjustments were provided by ActewAGL Distribution, based on customer feedback.[11]
3. Adjust demand for remaining customers at an industry segment level based on the economic outlook for each material industry segment. The economic outlook is based on the gross value add of individual ANSZIC industry segments. To assess whether a statistically significant relationship exists between economic activity and sector demand, sector GVA is regressed on gas demand. For those industry segments where a significant relationship exists, Core assessed whether historical growth in GVA is likely to continue into the future. The resulting growth rates are then applied to each customer within the given industry segment. For industry segments which did not demonstrate a statistically significant relationship between economic activity and demand, the MDQ is assumed to remain constant.

[11] A pro forma of the questions posed to Demand Customers is included as Annexure 8.

4. Volume Customer Demand Forecast

4.1. Introduction

Core has derived a best estimate of volume customer demand and connections using an approach which satisfies the requirements of the *NGR*. Details of this analysis and the resultant forecasts are summarised in the following sections.

4.2. Derivation of Weather Normalised Demand

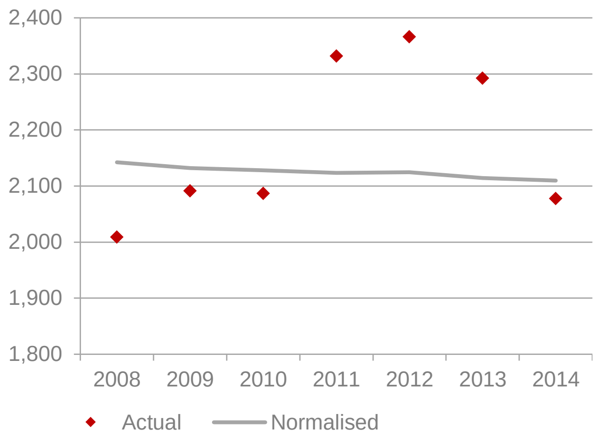
Core's proprietary Excel-based models were used to calculate EDD Index coefficients and to weather normalise demand. The EDD Index Model and Weather Normalised Demand Model, (included as a supporting document to this report) should be read in conjunction with this report. Table 4.1 summarises the results for normalised EDD. Figure 4.1 provides a comparison between the fluctuations in weather, represented by EDD, and the long term trend of EDD (1978 to 2014).

Figure 4.1 illustrates that actual EDD in 2011 to 2013 is greater than long term trend. The colder weather corresponds to higher demand per connection, as more gas is used for heating. The reverse is observed in 2014, when EDD is lower than long term trend. Hotter weather in 2014 reduced demand per connection, as less gas was used for heating. Table 4.2 presents a summary of the weather normalised residential demand per connection and demand for 2008 to 2014. Demand per connection appears to have a declining trend, whereas demand shows a slight upward trend. Table 4.3 presents a summary of the weather normalised business demand per connection and demand. Both demand per connection and total demand demonstrate a fall over the relevant period.

Table 4.1 EDD Index

	2008	2009	2010	2011	2012	2013	2014
Normalised EDD	2,143	2,132	2,128	2,123	2,125	2,114	2,110
Actual EDD	2,009	2,092	2,087	2,332	2,366	2,292	2,078
Difference	(134)	(41)	(41)	209	242	178	(32)

Figure 4.1 EDD Index



Note the normalised trend is based on the longer term trend between 1978 and 2014, with data prior to 2008 not shown.

Table 4.2 Normalised Residential Demand per Connection/Demand

	2008	2009	2010	2011	2012	2013	2014
Normalised Demand per Connection	47.9	47.6	46.1	46.1	44.6	43.4	39.1
Actual Demand per Connection	46.9	47.3	45.8	47.7	46.4	44.8	38.8
Difference	(1.0)	(.3)	(.3)	1.6	1.8	1.4	(0.2)
Normalised Demand	5,127,013	5,220,349	5,222,508	5,407,373	5,406,427	5,474,051	5,110,704
Actual Demand	5,017,750	5,186,426	5,187,059	5,594,205	5,629,865	5,645,222	5,078,401
Difference	(109,263)	(33,923)	(35,449)	186,831	223,438	171,171	(32,302)

Figure 4.2 Residential Demand per Connection | GJ

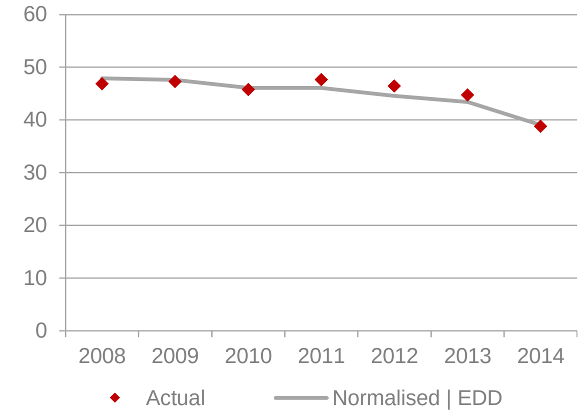


Figure 4.3 Residential Demand | GJ

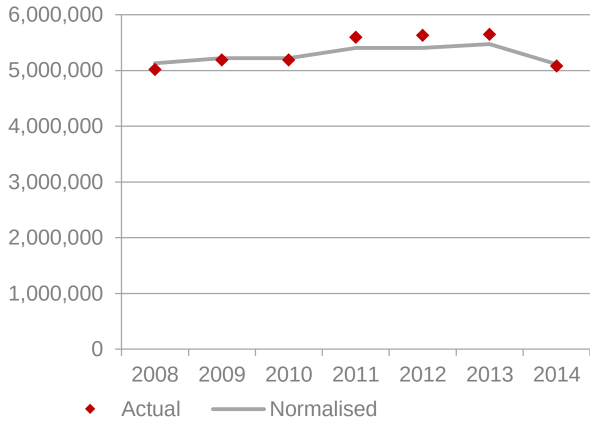


Table 4.3 Normalised Business Demand per Connection/Demand | GJ

	2008	2009	2010	2011	2012	2013	2014
Normalised Demand per Connection	583	580	546	554	522	513	459
Actual Demand per Connection	572	577	543	571	542	528	456
Difference	(11)	(3)	(3)	17	20	15	(3)
Normalised Demand	1,628,307	1,660,124	1,614,942	1,697,385	1,654,013	1,690,605	1,566,260
Actual Demand	1,597,706	1,650,623	1,605,014	1,749,710	1,716,589	1,738,544	1,557,213
Difference	(30,600)	(9,500)	(9,928)	52,324	62,576	47,938	(9,047)

Figure 4.4 Business Demand per Connection | GJ

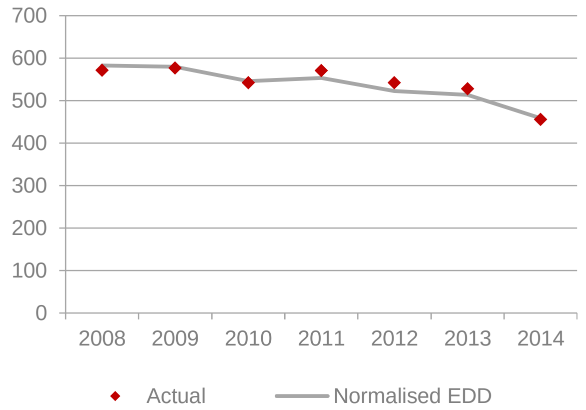
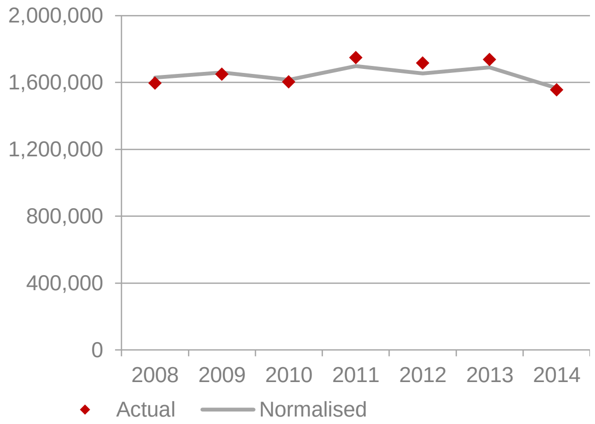


Figure 4.5 Business Demand | GJ



4.3. Overview of Volume Customer Connections and Demand Forecast.

The objective of this section of the report is to explain the derivation of the Core forecast of connections and demand per connection for volume customers. This report should be read in conjunction with the accompanying proprietary model[12] which was utilised by Core in developing the forecast. The model sets out a comprehensive logic and a transparent set of assumptions.

4.3.1. Overview of Volume Customer Demand Forecast

Total volume customer demand is forecast to decline from 6,378,363GJ to 5,886,757GJ at an average annual growth of -1.59% over the Review Period. Table 4.4 provides a summary of the volume customer demand forecast and Table 4.5 compares the historical average annual growth of demand against the forecast across the Review Period.

Table 4.4 Volume Customer Demand Forecast | GJ

Total Demand	2015	2016	2017	2018	2019	2020	2021
Residential	4,981,429	4,867,580	4,769,776	4,638,499	4,531,286	4,447,063	4,367,126
Business	1,494,158	1,510,783	1,526,442	1,521,632	1,508,357	1,509,095	1,519,631
Total	**6,475,587**	**6,378,363**	**6,296,219**	**6,160,131**	**6,039,643**	**5,956,158**	**5,886,757**

Table 4.5 Volume Customer Demand Average Annual Growth | %

Total Demand	Average Annual Growth | % 2011-2014	Average Annual Growth | % 2017-2021
Residential	-0.47%	-2.15%
Business	-0.65%	0.12%
Total	**-0.51%**	**-1.59%**

The demand forecast is the product of forecast connections and forecast demand per connection. A summary of these forecasts is set out in the following sections.

[12] ActewAGL Distribution GAAR Gas Demand Forecast Model

4.3.2. Overview of Volume Customer Connections Forecast

Total volume customer connections are forecast to increase from 141,528 to 160,166 at an average annual growth of 2.51% over the Review Period.

Table 4.6 provides a summary of the volume customer connections forecast derived by Core and Table 4.7 provides a comparison of historical and forecast average annual growth in connections.

Table 4.6 Volume Customer Connections Forecast | No.

Total Connections	2015	2016	2017	2018	2019	2020	2021
Residential	134,568	137,974	141,337	144,966	148,575	152,471	156,039
Business	3,449	3,554	3,661	3,773	3,887	4,005	4,127
Total	138,017	141,528	144,998	148,739	152,463	156,476	160,166

Table 4.7 Volume Customer Connections Average Annual Growth | %

Total Demand	Average Annual Growth | % 2011-2014	Average Annual Growth | % 2017-2021
Residential	3.66%	2.49%
Business	3.66%	3.04%
Total	3.66%	2.51%

4.3.3. Overview of Volume Customer Demand per Connection Forecast

Volume customer demand per connection is forecast to fall by 4.52% for residential customers and 2.83% (post demand customer movements) for business customers over the Review Period.

Table 4.8 provides a summary of the volume customer demand per connection forecast which has been derived by Core, while Table 4.9 provides a comparison of historical and forecast average annual growth in demand per connection.

Table 4.8 Volume Customer Demand per Connection Forecast | GJ

Demand per Connection	2015	2016	2017	2018	2019	2020	2021
Residential							
Existing	37.5	36.1	34.8	33.4	32.2	31.1	30.1
New Estate	33.6	32.3	31.2	29.9	28.8	27.8	26.9
New M/H Density	14.4	13.8	13.4	12.8	12.3	11.9	11.5
New E to G	25.5	24.5	23.7	22.7	21.9	21.1	20.5
Weighted Average	**37.0**	**35.3**	**33.7**	**32.0**	**30.5**	**29.2**	**28.0**
Business							
Existing	439	427	414	398	380	366	355
New Business	559	543	528	506	483	466	452
Weighted Average | Pre Demand Customers Movements	**440**	**432**	**424**	**410**	**394**	**383**	**374**
Weighted Average | Post Demand Customers Movements	**433**	**425**	**417**	**403**	**388**	**377**	**368**

Table 4.9 Volume Customer Demand per Connection Average Annual Growth | %

Total Demand per Connection	Average Annual Growth | % 2011-2014	Average Annual Growth | % 2015-2021	Average Annual Growth | % 2017-2021
Residential			
Existing	-3.98%	-3.67%	-3.57%
New Estate		-3.67%	-3.57%
New M/H Density		-3.67%	-3.57%
New E to G		-3.67%	-3.57%
Weighted Average		**-4.65%***	**-4.52%***
Business			
Existing	-4.16%	-3.60%	-3.62%
New Business		-3.60%	-3.62%
Weighted Average | Pre Demand Customer to Volume Customer Movements		**-2.86%**	**-2.83%**
Weighted Average | Post Demand Customer to Volume Customer Movements			**-2.83%**

*The weighted average annual growth is lower than the average annual growth of the individual connection types due to the change in proportion of existing connections to new connections. The proportion of lower consuming new connections increases during the forecast period, resulting in a lower weighted average demand per connection by 2021 than if the mix of connections remained constant.

The following sections of this report address the derivation of the Core forecast for each volume customer segment.

4.4. Derivation of Volume Customer Demand and Connections Forecast | Residential Segment

4.4.1. Derivation of Residential Demand

Residential demand comprises two segments:

- Existing connections
- New Connections
  - New Electricity to Gas (“**E to G**”)
  - New Estates
  - New Medium/High Density (“**M/H Density**”)

Total residential demand is forecast to decrease from 4,867,580 to 4,367,126GJ, a decline in average annual growth of 2.15% over the Review Period. The contribution of each residential segment to total forecast growth is set out in Table 4.10.

Table 4.10 Residential Demand Forecast | GJ

Total Demand	2015	2016	2017	2018	2019	2020	2021
Existing	4,875,220	4,665,308	4,469,503	4,247,001	4,054,368	3,890,008	3,741,052
New Estates	58,095	115,866	177,650	232,481	283,813	331,967	371,950
New M/H Density	28,197	48,069	67,072	88,036	107,660	126,067	142,274
New E to G	19,917	38,337	55,551	70,981	85,445	99,020	111,851
Total	**4,981,429**	**4,867,580**	**4,769,776**	**4,638,499**	**4,531,286**	**4,447,063**	**4,367,126**

Table 4.11 Residential Demand Average Annual Growth | %

Demand	Average Annual Growth | % 2011-2014	Average Annual Growth | % 2017-2021
Total Demand	-2.22%	-2.15%

4.4.2. Derivation of Volume Customer Connection Forecast | Residential Segment

Total residential connections are forecast to increase from 137,974 to 156,039, an average annual growth rate of 2.49% over the Review Period. The forecast of each residential connection type is presented in Table 4.12.

Table 4.12 Residential Connections Forecast | No.

Total Connections	2015	2016	2017	2018	2019	2020	2021
Existing	130,097	129,355	128,288	127,202	126,097	125,278	124,437
New Estate	1,730	1,856	2,106	2,081	2,081	2,081	1,876
New Medium/High Density	1,960	1,512	1,543	1,853	1,853	1,853	1,751
New E to G	781	781	781	781	781	781	781
Cumulative New Estate	1,730	3,586	5,692	7,772	9,853	11,933	13,810
Cumulative New Medium/High Density	1,960	3,471	5,014	6,867	8,721	10,574	12,325
Cumulative New E to G	781	1,562	2,343	3,124	3,905	4,686	5,467
Total	**134,568**	**137,974**	**141,337**	**144,966**	**148,575**	**152,471**	**156,039**

Table 4.13 Residential Connections Average Annual Growth | %

Demand	Average Annual Growth | % 2011-2014	Average Annual Growth | % 2015-2021	Average Annual Growth | % 2017-2021
Total Demand	3.66%	2.55%	2.49%

4.4.2.1 Derivation of Existing Residential Connection Forecast

Core has derived a forecast of net existing connections by subtracting forecast disconnections in each year from opening connections of each year. The forecast of disconnections is based on the disconnections as an average percentage of opening connections between 2010 and 2014 (expressed as a percentage, namely 0.55%). Existing connections are forecast to decline from 129,355 to 124,437 between 2017 and 2021. The forecast for existing connections and disconnections is presented in Table 4.14. The additional disconnections resulting from Mr. Fluffy is also included in Table 4.14. More detailed description on Mr. Fluffy can be found in Annexure 7.

Table 4.14 Existing Connections Forecast | No.

Connections	2014	2015	2016	2017	2018	2019	2020	2021
Existing Connections	130,818							
Disconnections		721.30	741.97	760.75	779.29	799.30	819.20	840.68
Mr Fluffy				306.30	306.30	306.30		
Existing Connections Forecast		130,097	129,355	128,288	127,202	126,097	125,278	124,437

4.4.2.2 Derivation of New E to G Connection Forecast

The average number of E to G connections between 2010 and 2014, calculated to be 781, is used as a basis to forecast the annual number of E to G connections during the Review Period. The average number was used rather than an average growth rate due to a high level of observed volatility during the historical period.

The summary of the E to G connections forecast is provided in Table 4.15.

Table 4.15 New E to G Connections Forecast | No.

Connections	2014	2015	2016	2017	2018	2019	2020	2021
2014 New E to G Connections	624							
Historical Annual Average	781							
New E to G Connections Forecast		781	781	781	781	781	781	781

4.4.2.3 Derivation of New Estates & Medium/High Density Connection Forecast

The forecast of New Estate & Medium/High Density connections is based on a new dwellings forecast reported by HIA.[13] Further detail is provided in Annexure 5. The forecast of new dwellings within the ActewAGL Distribution network is provided in Table 4.16.

Table 4.16 New Dwelling Connections Forecast | No.

	2015	2016	2017	2018	2019	2020	2021
HIA Forecast	3,540	3,230	3,500	3,480	3,480	3,480	3,480
HIA Forecasts Scaled to Include Queanbeyan and Palerang	4,100	3,741	4,054	4,031	4,031	4,031	4,031

Assuming a new gas connection rate of 90% during the Review Period, results in the following forecast of new residential connections (refer Table 4.17).

Table 4.17 New Estate & Medium/High Density Connections Forecast | No.

	2015	2016	2017	2018	2019	2020	2021
New Dwelling Forecast	4,100	3,741	4,054	4,031	4,031	4,031	4,031
Gas connection rate	90%	90%	90%	90%	90%	90%	90%
Total New Connections	3,690	3,367	3,648	3,628	3,628	3,628	3,628
% New Estate Connections	6.86%	7.36%	8.35%	7.44%	7.44%	7.44%	7.44%
% Medium/High Density Connections	7.77%	5.99%	6.12%	6.95%	6.95%	6.95%	6.95%
New Estate Connections	1,730	1,856	2,106	1,876	1,876	1,876	1,876
Medium/High Density Connections	1,960	1,512	1,543	1,751	1,751	1,751	1,751

An additional 306 new dwellings per annum are forecast to be built between 2018 and 2020 to account for homes demolished as part of the Mr Fluffy buy back scheme. It is assumed that 90% of the 1,021 (919) new dwellings built will reconnect to the gas network, with a third of the dwellings built to be MD/HR dwellings and the remaining two thirds to be new estates The resultant forecast for new M/H density and new estate connections, inclusive of additional Mr Fluffy buy back scheme related dwellings, is provided in Table 4.18 and Table 4.19. Further detail on the impact of the Mr Fluffy buy back scheme on the forecast of connections is provided in Annexure 7.

[13] Housing Industry Australia, Housing Forecasts, February 2015 <http://hia.com.au/en/BusinessInfo/economicInfo/housingForecasts.aspx>

Table 4.18 New Estate Connections Forecast | No.

	2015	2016	2017	2018	2019	2020	2021
New Estate Connections	1,730	1,856	2,106	1,876	1,876	1,876	1,876
Mr Fluffy Connections	-	-	-	204	204	204	-
Total New Estate Connections	**1,730**	**1,856**	**2,106**	**2,081**	**2,081**	**2,081**	**1,876**

Table 4.19 Medium/High Density Connections Forecast | No.

	2015	2016	2017	2018	2019	2020	2021
Medium/High Density Connections	1,960	1,512	1,543	1,751	1,751	1,751	1,751
Mr Fluffy Connections	-	-	-	102	102	102	-
Total Medium/High Density Connections	**1,960**	**1,512**	**1,543**	**1,853**	**1,853**	**1,853**	**1,751**

4.4.3. Derivation of Demand per Connection Forecast | Residential Segment

Table 4.20 provides a summary of the residential demand per connection forecast derived by Core. Weighted average residential demand per connection (weighted by connection type) is forecast to fall from 35.3GJ to 28.0GJ over the Review Period. This is equivalent to an average annual growth rate of -4.52%.

Table 4.20 Residential Demand per Connection Forecast | GJ

Demand per Connection	2015	2016	2017	2018	2019	2020	2021
Existing	37.5	36.1	34.8	33.4	32.2	31.1	30.1
New E to G	33.6	32.3	31.2	29.9	28.8	27.8	26.9
New Medium/High Density	14.4	13.8	13.4	12.8	12.3	11.9	11.5
New Estate	25.5	24.5	23.7	22.7	21.9	21.1	20.5
Weighted Average	**37.0**	**35.3**	**33.7**	**32.0**	**30.5**	**29.2**	**28.0**

Table 4.21 Residential Demand per Connection Average Annual Growth | %

Total Demand per Connection	Average Annual Growth | % 2015-2021	Average Annual Growth | % 2017-2021
Weighted Average	-4.65%	-4.52%

The following section provides an explanation of the factors driving demand per connection. The methodology adopted to derive a forecast for demand per connection for residential connections is summarised in Section 3.3.1.2. Our approach involved the compilation of historic demand per connection data to derive an average annual growth in demand per connection for each connection type. This average annual growth was analysed by Core to determine the influence of:

- Factors present in the historic average annual growth which were expected to exert an influence during the Review Period (see Annexure 7);
- Factors present in the historic average annual growth which were unlikely to exert an influence during the Review Period; and
- Factors that are expected to influence future demand which were not observed in the historic average annual growth rate.

The major drivers to the forecast decline in demand per connection, across each connection type, relative to the historic average annual growth include:

- the continuation of influences observed in historical growth rates; including continued trends in gas use efficiency and energy substitution;
- the influence of future gas and electricity prices (not evident in historic average annual growth);
- an increase in the number of new dwellings connected to lower gas usage levels, including high rise developments; and
- existing policy impacts on appliance trends.

4.4.3.1 Factors Continuing to Impact Demand per Connection

Appliance Trends

History has shown that there are two significant influences on the level of gas consumption attributable to appliance use. The first relates to a continuing trend in improved energy efficiency. The second relates to a continuing trend in substitution of alternative energy sources in the water and room heating segments. The two largest uses of gas for ACT households are space heating and water heating. However, households are substituting their gas appliances at a significant rate as revealed by the ABS in their Australian Energy Use data for the three years leading up to 2014. This showed that electricity had increased its market share by over 35% when it comes to heating homes in the ACT. Accordingly, 22% of ACT households that were using gas as their main heating source in 2011, switched away from gas heating by 2014. In addition to the substitution of gas heating appliances, gas hot water appliances have also been under threat from solar water heating systems. Over the same period, solar water heaters increased their market share by just under 30%. Data and further explanation can be found in Annexure 7. Core research believes that the significant efficiency gains and lower running costs from reverse cycle air conditioning and solar water heating are being pursued by a substantial number of households in the ACT. This is expected to increase during the forthcoming Review Period and this will help to sustain the continued decline in demand per residential connection.

The Impact of E3 and MEPS

The latest impact study for the E3 program was recently released and it shows a considerable increase in gas savings. The E3 program incorporates several key efficiency initiatives such as the Minimum Energy Performance Standards ("**MEPS**"). Between 2000 and 2013, it is estimated that the E3 program saved 6.1PJ of gas. However, over a quarter of this was achieved in 2013 alone, the final year of the review study. Given the implementation of new policies under E3 and the strengthening of existing policies, the study forecasted that on average, three times the 2013 gas savings will be achieved each year until 2020. This was somewhat of a conservative estimate based on a scenario with slower policy implementation. The E3 program has been strengthened at the end of 2012 with new legislation and a national framework that extends to the ACT. Increased reporting and compliance (e.g. financial penalties) will ensure that gas demand per connection will continue to fall over the Review Period.

Other Efficiency Trends and Policy Impacts

Two policies that are predicted to have a material impact over the Review Period include the Gas Service and Installation Rules Code and Gas Network Boundary Code. These Codes were introduced in 2013 and drive down gas consumption for Medium & High Density connections. The impact of this policy in the ACT has helped to lower the forecast of annual demand per connection in these dwellings by over 30%.There has been a multitude of policies, programs and initiatives that are driving efficiency gains in the ACT. These primarily target household appliances or building efficiency. In addition to the appliance substitution discussed above, these policies will continue to reduce average gas usage due to superior building design (e.g. insulation), or by promoting household appliances that operate using less energy.

Energy efficient appliances are becoming more widely available and affordable to residential customers. As more customers move to energy efficient appliances, demand per customer is forecast to decline. This is further promoted through ActewAGL Distribution’s marketing campaigns which incentivise customers who are seeking to replace their existing gas heating appliance by providing rebates for more energy efficient appliances (potentially, if this marketing campaign is not implemented, ActewAGL Distribution could lose this heating gas demand to an alternative energy source).

A qualitative survey also reveals that Australians assess the environmental impact of their energy use and then use this to make decisions that reduce energy.[14] In the survey, approximately half of Australian households that reduced their energy use were influenced by the environmental aspects of doing so. Over 60% of these households cited a new awareness of the potential efficiency and cost advantages. This reinforces that all the policies, campaigns and even fact sheets will continue to lower demand per connection during the Review Period.

Climatic Trend

Long term trend in weather indicates that a warming trend will continue across the Review Period. Core believes it is reasonable to assume that this trend observed in the historic annual average growth will continue during the Review Period. Core is of the opinion that deviation from the warming trend is unlikely in the forecast period. A warming trend for the ACT during the Review Period is also expected by AEMO.[15] This was made clear in a forecasting report for New South Wales and the ACT. Core accepts this warming trend.

Economic Activity

Core’s analysis concludes that the relationship between certain economic variables and residential demand is unreliable and not statistically significant. This is also consistent with expected household behaviour in that an increase in income will tend to lead to more spending on discretionary goods, as opposed to necessity goods such as

[14] Fielding, K. Et al., Environmental Sustainability: understanding the attitudes and behaviour of Australian households, Australian Housing and Urban Research Institute, October 2010
[15] AEMO, National Gas Forecasting Report 2014, see page 28.

gas and electricity (heating and cooking).Therefore, an economic variable was not included in the forecasting model. Further analysis of the relationship between residential demand and economic activity is presented in Annexure 6

4.4.3.2 Factors with a New Impact on Demand per Connection

Own Price Elasticity

The own price elasticity captures the impact of gas prices on demand per connection, accounting for not only the current year impact but also four years of lagged impacts. Table 4.22 provides the forecast of own price impacts on demand per connection. Further detail on the gas price forecast and price elasticity is presented in Annexure 4.

Table 4.22 Own Price Impacts | %

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
% Change in Gas Price	3.3%	5.2%	11.1%	4.5%	-2.5%	0.0%	5.0%	6.9%	0.0%	0.0%	0.0%
Own Price Impact	-2.02%	-1.80%	-2.35%	-1.89%	-0.77%	-0.41%	-0.77%	-1.26%	-0.78%	-0.49%	-0.26%

Cross Price Elasticity

Cross price elasticity addresses the impact of electricity prices on demand per gas connection. For example, when the relative prices of gas and electricity change, cross price elasticity captures the change in gas usage by consumers who have both gas heating and reverse cycle air conditioning. Relatively lower electricity prices make it more attractive to use electricity based heating appliances. Further detail on the electricity price forecast and cross price elasticity impact is presented in Annexure 4. Table 4.23 summarises Core's assessment of historical and forecast cross price impacts.

Table 4.23 Cross Price Impacts | %

	2015	2016	2017	2018	2019	2020	2021
% Change in Electricity Price	-6.2%	-5.9%	1.7%	0.0%	0.0%	0.0%	0.0%
Cross Price[16] Impact	-0.6%	-0.6%	0.2%	0.0%	0.0%	0.0%	0.0%

4.4.3.3 Derivation of Demand per Connection Forecast | Residential Segment – Existing Customers

Core's approach ultimately takes three drivers into consideration when forecasting existing demand per connection for existing customers:

- Historical average annual change
- Own price elasticity
- Cross price elasticity

[16] Historical electricity prices are based ABS data, which could be a blend of standing and market offer prices, whereas Core developed forecasts on a standing offer basis.

Historical average annual change in demand per connection is -3.98% over the 2011 to 2014 prior to any adjustments. Core has adjusted historical annual change by removing the impact of own and cross price, to derive an adjusted value of -2.7%.

The impact of gas and electricity price movements on demand per connection in the forecast period are reflected in the price elasticity of demand as set out in further detail in Annexure 4. The impact of these three drivers is applied to the 2014 historical demand per connection to derive a forecast. Table 4.24 summarises the forecast annual movement in demand per connection and the average annual forecast of demand per connection presented in Table 4.25.

Table 4.24 Demand per Connection | Existing Connections | %

Demand per Connection	2014	2015	2016	2017	2018	2019	2020	2021
Average Annual Growth		-2.7%	-2.7%	-2.7%	-2.7%	-2.7%	-2.7%	-2.7%
Own Price Elasticity		-0.8%	-0.4%	-0.8%	-1.3%	-0.8%	-0.5%	-0.3%
Cross Price Elasticity		-0.6%	-0.6%	0.2%	0.0%	0.0%	0.0%	0.0%
Total Impact		**-4.1%**	**-3.7%**	**-3.3%**	**-4.0%**	**-3.5%**	**-3.2%**	**-2.9%**

Table 4.25 Demand per Connection | Existing Connections | GJ

Demand per Connection	2014	2015	2016	2017	2018	2019	2020	2021
Existing 2014	39.1							
Average Annual Growth		-1.05	-1.02	-0.99	-0.97	-0.94	-0.92	-0.89
Own Price Elasticity		-0.30	-0.16	-0.30	-0.48	-0.29	-0.19	-0.10
Cross Price Elasticity		-0.24	-0.23	0.07	0.00	0.00	0.00	0.00
Total Impact		-1.59	-1.41	-1.23	-1.45	-1.23	-1.10	-0.99
Forecast		37.5	36.1	34.8	33.4	32.2	31.1	30.1

Table 4.26 Demand per Connection Average Annual Growth | %

Total Demand per Connection	Average Annual Growth | % 2011-2014	Average Annual Growth | % 2017-2021
Existing	-3.98%	-3.6%

4.4.3.4 Derivation of Demand per Connection Forecast | Residential Segment – New E to G

The forecast of demand per connection for E to G customers is derived from the average demand per connection in 2014 (26.6 GJ) by applying the impact of historical average annual growth of existing connections, and the impact of forecast movement in demand due to a response to gas and electricity prices (refer Annexure 4). Table 4.27 summarises the forecast annual movement in demand per connection in percentage terms and the average annual forecast of demand per connection is presented Table 4.28.

Table 4.27 Demand per Connection | New E to G Connections | %

Demand per Connection	2014	2015	2016	2017	2018	2019	2020	2021
Average Annual Growth		-2.7%	-2.7%	-2.7%	-2.7%	-2.7%	-2.7%	-2.7%
Own Price Elasticity		-0.8%	-0.4%	-0.8%	-1.3%	-0.8%	-0.5%	-0.3%
Cross Price Elasticity		-0.6%	-0.6%	0.2%	0.0%	0.0%	0.0%	0.0%
Total Impacts		**-4.1%**	**-3.7%**	**-3.3%**	**-4.0%**	**-3.5%**	**-3.2%**	**-2.9%**

Table 4.28 Demand per Connection | New E to G Connections | GJ

Demand per Connection	2014	2015	2016	2017	2018	2019	2020	2021
2014 Demand per Connection	26.6							
Average Annual Growth		-0.71	-0.70	-0.68	-0.66	-0.64	-0.62	-0.61
Own Price Elasticity		-0.21	-0.11	-0.20	-0.33	-0.20	-0.13	-0.07
Cross Price Elasticity		-0.16	-0.16	0.04	0.00	0.00	0.00	0.00
Total Impact		**-1.08**	**-0.96**	**-0.83**	**-0.99**	**-0.84**	**-0.75**	**-0.67**
Forecast		**25.5**	**24.5**	**23.7**	**22.7**	**21.9**	**21.1**	**20.5**

Table 4.29 Demand per Connection Average Annual Growth | %

Total Demand per Connection	Average Annual Growth | % 2011-2014	Average Annual Growth | % 2017-2021
New E To G	N/A	-3.6%

4.4.3.5 Derivation of Demand per Connection Forecast | Residential Segment – New Estate

As for E to G customers, the forecast of demand per connection for New Estate customers is derived from the average demand per connection in 2014 (35 GJ) by applying the impact of historical average annual growth of existing connections, and the impact of gas and electricity prices (refer Annexure 4). Table 4.30 summarises the forecast annual movement in demand per connection in percentage terms and the average annual forecast of demand per connection is presented in Table 4.30.

Table 4.30 Demand per Connection | New Estate Connections | %

Demand per Connection	2014	2015	2016	2017	2018	2019	2020	2021
Average Annual Growth		-2.7%	-2.7%	-2.7%	-2.7%	-2.7%	-2.7%	-2.7%
Own Price Elasticity		-0.8%	-0.4%	-0.8%	-1.3%	-0.8%	-0.5%	-0.3%
Cross Price Elasticity		-0.6%	-0.6%	0.2%	0.0%	0.0%	0.0%	0.0%
Total Impacts		**-4.1%**	**-3.7%**	**-3.3%**	**-4.0%**	**-3.5%**	**-3.2%**	**-2.9%**

Table 4.31 Demand per Connection | New Estate Connections | GJ

Demand per Connection	2014	2015	2016	2017	2018	2019	2020	2021
2014 Demand per Connection	35.0							
Average Annual Growth		-0.94	-0.92	-0.89	-0.87	-0.84	-0.82	-0.80
Own Price Elasticity		-0.27	-0.14	-0.27	-0.43	-0.26	-0.17	-0.09
Cross Price Elasticity		-0.22	-0.21	0.06	0.00	0.00	0.00	0.00
Total Impact		**-1.43**	**-1.26**	**-1.10**	**-1.30**	**-1.11**	**-0.99**	**-0.88**
Forecast		**33.6**	**32.3**	**31.2**	**29.9**	**28.8**	**27.8**	**26.9**

Table 4.32 Demand per Connection Average Annual Growth | %

Total Demand per Connection	Average Annual Growth | % 2011-2014	Average Annual Growth | % 2017-2021
New Estate	N/A	-3.6%

4.4.3.6 Derivation of Demand per Connection Forecast | Residential Segment - New Medium/High Density

The forecast of demand per connection for new M/H Density customers is derived from the average new M/H density demand per connection in 2014 (15 GJ) by adjusting for:

- Historical average annual growth, derived from the historical demand per connection for existing connections.
- Forecast movement in demand due to a response to prices (refer Annexure 4).

Core has assumed the continuation of the Gas Network Boundary Code Amendment (implemented in 2013) impact on appliance trend in New M/H Density connections. More details on the policy can be found in Annexure 7.

Table 4.33 summarises the forecast annual movement in demand per connection in percentage terms and the average annual forecast of demand per connection is presented in Table 4.34.

Table 4.33 Demand per Connection | New M/H Density Connections | %

Demand per Connection	2014	2015	2016	2017	2018	2019	2020	2021
Average Annual Growth		-2.7%	-2.7%	-2.7%	-2.7%	-2.7%	-2.7%	-2.7%
Own Price Elasticity		-0.8%	-0.4%	-0.8%	-1.3%	-0.8%	-0.5%	-0.3%
Cross Price Elasticity		-0.6%	-0.6%	0.2%	0.0%	0.0%	0.0%	0.0%
Total Impacts		**-4.1%**	**-3.7%**	**-3.3%**	**-4.0%**	**-3.5%**	**-3.2%**	**-2.9%**

Table 4.34 Demand per Connection | New M/H Density Connections | GJ

Demand per Connection	2014	2015	2016	2017	2018	2019	2020	2021
2014 Demand per Connection	15.0							
Average Annual Growth		-0.40	-0.39	-0.38	-0.37	-0.36	-0.35	-0.34
Own Price Elasticity		-0.12	-0.06	-0.11	-0.19	-0.11	-0.07	-0.04
Cross Price Elasticity		-0.09	-0.09	0.03	0.00	0.00	0.00	0.00
Total Impact		**-0.61**	**-0.54**	**-0.47**	**-0.56**	**-0.47**	**-0.42**	**-0.38**
Forecast		**14.4**	**13.8**	**13.4**	**12.8**	**12.3**	**11.9**	**11.5**

Table 4.35 Demand per Connection Average Annual Growth | %

Total Demand per Connection	Average Annual Growth | % 2011-2014	Average Annual Growth | % 2017-2021
New M/H D	N/A	-3.6%

4.5. Derivation of Volume Customer Demand and Connections Forecast | Business Segment

4.5.1. Business Demand

Business demand comprises two segments:

- Existing Connections
- New Connections

Table 4.36 and Table 4.37 provide a summary of Core's business demand forecast together with a historical comparison.

Total business demand is forecast to increase by 0.12% on an average annual growth basis over the Review Period. This increase is attributable primarily to forecast growth in new connections, offset partially by a reduction in demand per connection.

Table 4.36 Business Demand Forecast | GJ

Total Demand	2015	2016	2017	2018	2019	2020	2021
Existing	1,490,883	1,442,087	1,394,363	1,330,933	1,263,814	1,211,421	1,168,950
New	28,719	94,140	157,524	216,143	269,987	323,118	376,125
Tariff to Non-Tariff Movements	49,517	49,517	49,517	49,517	49,517	49,517	49,517
Non-Tariff to Tariff Movements	24,073	24,073	24,073	24,073	24,073	24,073	24,073
Total	**1,494,158**	**1,510,783**	**1,526,442**	**1,521,632**	**1,508,357**	**1,509,095**	**1,519,631**

Table 4.37 Volume Customer Demand Average Annual Growth | %

Total Demand	Average Annual Growth | % 2011-2014	Average Annual Growth | % 2017-2021
Business	-0.65%	0.12%

4.5.2. Business Connections

Table 4.38 provides a summary of Core's business connections forecast together with a historical comparison. Total business connections are forecast to increase by 3.03% at an average annual growth basis over the Review Period compared to a historical growth rate of 3.66%. This fall is attributable to a forecast reduction in GSP.

Table 4.38 Business Connections Forecast | No.

Total Connections	2015	2016	2017	2018	2019	2020	2021
Existing	3,398	3,381	3,364	3,347	3,330	3,312	3,295
New (Annual)	51	122	125	128	132	135	139
New (Cumulative)	51	173	298	427	559	694	833
Tariff to Non-Tariff Movements	(4)	(4)	(4)	(4)	(4)	(4)	(4)
Non-Tariff to Tariff Movements	3	3	3	3	3	3	3
Total	**3,449**	**3,554**	**3,661**	**3,773**	**3,887**	**4,005**	**4,127**

Table 4.39 Business Connections Average Annual Growth | %

Total Connections	Average Annual Growth | % 2011-2014	Average Annual Growth | % 2017-2021
Business	3.66%	3.04%

The derivation of this forecast is addressed in the following sections.

4.5.2.1 Existing Connections

The forecast of existing connections for each year is derived by deducting forecast disconnections from year-opening connections, commencing with actual connections in 2014.

The forecast of per annum disconnections during the Review Period is based on the average number of disconnections during the historical period 2011 to 2014.

The forecast for existing connections and disconnections is presented in Table 4.40.

Table 4.40 Existing Connections Forecast | No.

Connections	2014	2015	2016	2017	2018	2019	2020	2021
Existing Connections	3,416							
Disconnections	18	17	17	17	17	17	17	17
Existing Connections Forecast		3,398	3,381	3,364	3,347	3,330	3,312	3,295

4.5.2.2 New Connections

The forecast of new connections is determined by the difference between forecast total connections (prior to any movements between volume and demand customers) and forecast existing connections.

Table 4.41 provides a summary of forecast new business connections.

Table 4.41 New Connections Forecast | No.

Connections	2015	2016	2017	2018	2019	2020	2021
New	51	122	125	128	132	135	139
Cumulative New	51	173	298	427	559	694	833

Total connections is forecast by adjusting the average historical growth rate by the impact of a forecast movement in GSP (refer Annexure 6).

- Historical average annual growth is 0.21% which has been adjusted to remove the historical impact of GSP.
- Based on regression analysis a 1% increase in GSP[17] is assumed to increase business connections by 1.13% as summarised in the following table.

Table 4.42 GSP Forecast & GSP Impact | %

	2014	2015	2016	2017	2018	2019	2020	2021
ACT GSP Forecast	0.7%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
GSP Coefficient		1.13	1.13	1.13	1.13	1.13	1.13	1.13
GSP Impact		0.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%

Table 4.43 Total Connections Forecast (prior to reallocation between Demand and Volume customers) | No.

Connections	2014	2015	2016	2017	2018	2019	2020	2021
Total Connections	3,416							
Average Annual Growth		7	7	7	8	8	8	8
GSP Impact		27	97	100	103	107	110	113
Total Impact		34	105	108	111	115	118	122
Total Connections Forecast		3,450	3,555	3,662	3,774	3,888	4,006	4,128

4.5.3. Business Demand per Connection

Table 4.44 provides a summary of the business demand per connection forecast derived by Core and the related annual growth rate assumption is presented in Table 4.45.

Weighted average of existing and new commercial demand per connection is forecasted to over the 2017 to 2021 period.

[17] GSP forecasts are obtained from ACT 2014/15 Budget Paper No.3.

Table 4.44 Business Demand per Connection Forecast | GJ

Demand per Connection	2015	2016	2017	2018	2019	2020	2021
Existing	439	427	414	398	380	366	355
New E to G	559	543	528	506	483	466	452
Weighted Average | Pre Demand Customer to Volume Customer Movements	440	432	424	410	394	383	374
Weighted Average | Post Demand Customers to Volume Customer Movements	433	425	417	403	388	377	368

Table 4.45 Demand per Connection Average Annual Growth | %

Total Demand per Connection	Average Annual Growth | % 2017-2021
Weighted Average | Pre Demand Customer to Volume Customer Movements	-2.83%
Weighted Average | Post Demand Customer to Volume Customer Movements	-2.83%

4.5.3.1 Demand per Connection Drivers

The methodology adopted to derive a forecast for demand per connection for business connections is summarised in Section 3.3.2.2.

Our approach involved the compilation of historic demand per connection data to derive a historical average annual growth in demand per connection for each connection type. The average annual growth between 2010 and 2014 was used as the basis for forecasting historical business demand per connection. A historical trend was not adopted as a linear trend in historical demand per connection data was not observed. This historical average annual growth was analysed by Core to determine the influence of:

- Factors present in the historical average annual growth which were expected to exert an influence during the Review Period (see Annexure 7);
- Factors present in the historical average annual growth which were unlikely to exert an influence during the Review Period; and
- Factors that are reasonably expected to influence future demand which were not observed in the historic average annual growth rate.

The major drivers to the forecast decline in demand per connection across each connection type is the future gas and electricity price movements (not evident in historic average annual growth).

A summary of each driver impacting business demand per connections is provided below.

Historical Average Annual Growth

The historical average annual growth captures existing impacts on demand per connection due to climatic trend, appliance trend, energy efficiency trend, and policy.

Climatic Trend

Long term trend in weather indicates a warming trend will continue across the access arrangement period. Core believes it is reasonable to assume that this trend observed in the historic annual average growth will continue during the access arrangement period. Core is of the opinion that deviation from the warming trend is unlikely in the forecast period. Further detail on the climatic trend is included in Annexure 7.

Own Price Elasticity

The following table summarises Core's assessment of historical and forecast own price elasticity of demand. Further detail regarding the non-residential gas price forecast is provided in Annexure 2 and further detail regarding own price elasticity is included in Annexure 4.

Table 4.46 Own Price Impacts | %

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
% Change in Gas Price	3.3%	5.2%	11.1%	4.5%	-2.9%	0.0%	5.9%	8.1%	0.0%	0.0%	0.0%
Own Price Impact	-2.9%	-2.0%	-2.2%	-2.7%	-1.7%	-0.3%	-0.4%	-1.4%	-1.8%	-0.9%	-0.3%

Cross Price Elasticity

Table 4.47 summarises Core's assessment of historical and forecast cross price elasticity of demand. Further detail regarding forecast electricity prices and cross price elasticity is included in Annexure 3 and 4.

Table 4.47 Cross Price Impacts | %

	2015	2016	2017	2018	2019	2020	2021
% Change in Electricity Price	-1.6%	0.5%	0.7%	0.0%	0.0%	0.0%	0.0%
Cross Price Impact	-0.16%	0.05%	0.07%	0.00%	0.00%	0.00%	0.00%

Economic Activity

Regression analysis was undertaken to determine whether economic activity should be used as a basis for forecasting business demand per connection. Core found the relationship to be unreliable and not statistically significant. On this basis, an economic variable was not used to forecast business demand per connection. Further detail on the regression analysis can be found in Annexure 6.

4.5.3.2 Derivation of Demand per Connection Forecast | Business Segment – Existing Connections

Forecast demand per connection was derived by relying on four assumptions:

- an average opening demand per connection of 459 GJ, based on information presented by ActewAGL Distribution;
- an average historical growth rate of - 4.16% prior to an adjustment for price impact, -2.45% subsequent to such adjustment;
- an own price adjustment as set out below; and
- a cross price adjustment as set out below.

The derivation of price impacts is explained in further detail in Annexure 4.

Table 4.48 summarises the impact of each driver and the resulting demand per connection change for existing connections.

Table 4.48 Demand per Connection | Existing Connections | GJ

Demand per Connection	2014	2015	2016	2017	2018	2019	2020	2021
Average Annual Growth		-2.5%	-2.5%	-2.5%	-2.5%	-2.5%	-2.5%	-2.5%
Own Price Elasticity		-1.7%	-0.3%	-0.4%	-1.4%	-1.8%	-0.9%	-0.3%
Cross Price Elasticity		-0.2%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%
Total Impacts		**-4.3%**	**-2.7%**	**-2.7%**	**-3.9%**	**-4.2%**	**-3.4%**	**-2.8%**

Table 4.49 Demand per Connection | Existing Connections | GJ

Demand per Connection	2014	2015	2016	2017	2018	2019	2020	2021
2014 Demand per Connection	459							
Average Annual Growth		-11.2	-11.0	-10.7	-10.4	-10.2	-9.9	-9.7
Own Price Elasticity		-7.9	-1.5	-1.7	-6.4	-7.9	-3.9	-1.3
Cross Price Elasticity		-0.8	0.2	0.3	0.0	0.0	0.0	0.0
Total Impacts		**-19.9**	**-12.2**	**-12.0**	**-16.8**	**-18.1**	**-13.8**	**-11.0**
Forecast		**439**	**427**	**414**	**398**	**380**	**366**	**355**

Table 4.50 Demand per Connection Average Annual Growth | %

Demand per Connection	Average Annual Growth | % 2011-2014	Average Annual Growth | % 2015-2021	Average Annual Growth | % 2017-2021
Existing	-4.16%	-3.60%	-3.62%

4.5.3.3 Derivation of Demand per Connection Forecast | Business Segment – New Customers

Forecast demand per connection for new customers was derived by relying on four assumptions:

- an average opening annual demand per connection of 584 GJ, based on information presented by ActewAGL Distribution;
- historical annual average growth of existing connections
- an own price adjustment as set out below; and
- a cross price adjustment as set out below.

The derivation of price impacts is explained in further detail in Annexure 4.

Table 4.51 summarises the impact of each driver and Table 4.50 summarises the resulting demand per connection for new connections.

Table 4.51 Demand per Connection | New Connections | %

Demand per Connection	2014	2015	2016	2017	2018	2019	2020	2021
Average Annual Growth		-2.5%	-2.5%	-2.5%	-2.5%	-2.5%	-2.5%	-2.5%
Own Price Elasticity		-1.7%	-0.3%	-0.4%	-1.4%	-1.8%	-0.9%	-0.3%
Cross Price Elasticity		-0.2%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%
Total Impacts		**-4.3%**	**-2.7%**	**-2.7%**	**-3.9%**	**-4.2%**	**-3.4%**	**-2.8%**

Table 4.52 Demand per Connection | New Connections | GJ

Demand per Connection	2014	2015	2016	2017	2018	2019	2020	2021
2014 Demand per Connection	584							
Average Annual Growth		-14.3	-13.9	-13.6	-13.3	-12.9	-12.6	-12.3
Own Price Elasticity		-10.0	-1.9	-2.1	-8.1	-10.1	-5.0	-1.6
Cross Price Elasticity		-1.0	0.3	0.4	0.0	0.0	0.0	0.0
Total Impacts		**-25.3**	**-15.5**	**-15.3**	**-21.4**	**-23.1**	**-17.6**	**-14.0**
Forecast		**559**	**543**	**528**	**506**	**483**	**466**	**452**

Table 4.53 Demand per Connection Average Annual Growth | %

Demand per Connection	Average Annual Growth | % 2011-2014	Average Annual Growth | % 2017-2021
Existing	N/A	-3.62%

5. Demand Customer Forecast

5.1. Introduction

As at the end of 2014, ActewAGL Distribution had a total of 48 customers that were charged on a capacity (MDQ) basis and classified as demand customers. The objective of this section of the report is to present Core's forecast of demand customer MDQ, including an explanation of movements between existing and forecast demand.

ACQ is also forecast to ensure an understanding of any movement between the relationship of ACQ and MDQ.

The ACQ and MDQ forecast for demand customers is based upon analysis of the following:

- existing ACQ and MDQ by customer at the end of 2014;
- reallocations between demand customer and volume customer categories;
- known load changes, disconnections and new connections; and
- economic outlook.

5.2. Forecast

A summary of the ACQ and MDQ forecast for demand customers is provided in Table 5.1. MDQ is forecast to increase from 8,025GJ to 8,211GJ during the Review Period. This is equivalent to an average annual growth of 0.47% as presented in Table 5.2.

Table 5.1 Forecast of Demand Customer MDQ & ACQ | GJ

Demand	2015	2016	2017	2018	2019	2020	2021
MDQ | GJ	8,140	8,025	7,951	7,956	8,201	8,206	8,211
ACQ | GJ	1,224,102	1,201,836	1,185,399	1,185,769	1,231,356	1,231,764	1,232,191

Table 5.2 Comparison of Historical and Forecast Average Annual Growth in Demand | %

Average Growth	Average Annual Growth | % 2011-2014	Average Annual Growth | % 2015-2021	Average Annual Growth | % 2017-2021
MDQ	6.52%	-0.04%	0.47%
ACQ	2.17%	0.96%	0.52%

The components of MDQ and ACQ load movements during the Review Period are outlined in Table 5.3 and Table 5.4, respectively. A significant proportion of the load reduction stems from known load changes for existing customers, which are addressed in paragraph 5.4.

Table 5.3 Forecast Change in MDQ | GJ

Demand	2015	2016	2017	2018	2019	2020	2021
Existing Connections | Load Changes	-70	-120	-78	0	240	0	0
New Connections	0	0	0	0	0	0	0
Disconnections	0	0	0	0	0	0	0
Economic Outlook	4	5	5	5	5	5	5
Demand Customer Demand to Volume Customer Movements	194						
Volume Customer to Demand Customer Demand Movements	-230						
Total	**-102**	**-115**	**-73**	**5**	**245**	**5**	**5**

Table 5.4 Forecast Change in ACQ | GJ

Connections	2015	2016	2017	2018	2019	2020	2021
Existing Connections | Load Changes	42,798	-23,103	-17,292	-504	44,695	-504	-504
New Connections	0	0	0	0	0	0	0
Disconnections	0	0	0	0	0	0	0
Economic Outlook	820	837	855	873	892	912	931
Demand Customer to Volume Customer Movements	49,517	0	0	0	0	0	0
Volume Customer to Demand Customer Movements	-24,073	0	0	0	0	0	0
Total	**69,061**	**- 22,266**	**-16,437**	**370**	**45,587**	**408**	**427**

Demand customer connections are forecast to remain at 40 during the Review Period. The demand forecasting methodology for demand customers does not rely upon use of any form of average ACQ or MDQ per customer. The connection or customer number statistic for demand customers is deemed to be immaterial as a basis for deriving a capacity demand forecast.

Table 5.5 Forecast Change in Customers | No.

Connections	2015	2016	2017	2018	2019	2020	2021
Existing Connections	36	36	36	36	36	36	36
New Connections	-	-	-	-	-	-	-
Disconnections	-	-	-	-	-	-	-
Demand Customer to Volume Customer Movements	3	3	3	3	3	3	3
Volume Customer to Demand Customer Movements	4	4	4	4	4	4	4
Total	**40**	**40**	**40**	**40**	**40**	**40**	**40**

5.3. Disconnections & New Connections

There are no disconnections or new connections forecast for the Review Period.

5.4. Known Load Changes

Following consultation with Core, Jemena/ActewAGL Distribution held one-on-one consultations with a number of demand customers, to gain information on the outlook for demand over the Review Period. The customers consulted were either:

a) large users (relative to the rest of the ACT market); or

b) identified as customers with the potential to change future demand; or

c) customers who displayed a recent change in their consumption pattern.

The consultation questions are included in Annexure 8. In total, Jemena/ActewAGL Distribution consulted 11 demand customers.

The demand adjustments due to known load changes in summarised in Table 5.6.

Table 5.6 Known ACQ and MDQ Load Changes | GJ

Existing Customers	2015	2016	2017	2018	2019	2020	2021
ACQ | GJ	42,798	- 23,103	- 17,292	- 504	44,695	-504	-504
MDQ | GJ	- 70	- 120	- 78	-	240	-	-

The significant movement is attributed to the [redacted] undergoing renovation over the next five years. The demolition of [redacted] will allow for their replacement by [redacted]. A 50% drop in ACQ and MDQ load in 2016 and 2017 is forecast to reflect these renovations. This drop in ACQ and MDQ load is forecast to be online in 2019. In addition, [redacted] is forecast to drop 10% of ACQ per annum to reflect expected decreases due to improved energy efficiencies from new buildings (knock-downs and re-builds to replace [redacted] with new buildings). It is assumed no change in MDQ load would result from the efficiency gains at [redacted].

5.5. Economic Activity

The forecast change in ACQ and MDQ which is attributable to economic activity is summarised in Table 5.7. ACQ and MDQ are forecast to increase by 4,464GJ and 24GJ, respectively, over the Review Period.

Table 5.7 Change in ACQ and MDQ load due to Economic Outlook | GJ

Existing Customers	2015	2016	2017	2018	2019	2020	2021
ACQ | GJ	820	837	855	873	892	912	931
MDQ | GJ	4	5	5	5	5	5	5

The measure of economic activity relied upon is the gross value add (**"GVA"**) of individual ANSZIC industry segments. Historical values were regressed against gas demand to identify whether a significant relationship exists for each segment. From this regression, it was determined that the following industry segments have a significant relationship with gas demand historically. For more detail on the regression output, please see Annexure 9.

- Accommodation and Food Services
- Education and Training
- Professional, Scientific and Technical Services

For these sectors, a forecast growth in each GVA was used to derive an estimate for growth in demand. The results are summarised in Table 5.8.

Table 5.8 Growth in Demand due to Growth in GVA | %

Industry Segment	%
Accommodation and Food Services	0.3
Education and Training	2.5
Professional, Scientific and Technical Services	0.1

5.6. Demand Customer to Volume Customer Movements

Three customers are forecast to move from a demand customer to a volume customer group in 2015, they are [redacted], [redacted] and [redacted]. The resultant change to demand customer ACQ and MDQ is summarised in Table 5.9 below.

Table 5.9 Demand Customer to Volume Customer Movements | GJ

Existing Customers	2015	2016	2017	2018	2019	2020	2021
ACQ | GJ	-24,073	-	-	-	-	-	-
MDQ | GJ	-230						

5.7. Volume Customer to Demand Customer Movements

In 2015, four customers have planned to move from the volume customer to the demand customer group - [redacted], [redacted], [redacted] and [redacted]. The resultant change to demand customer ACQ and MDQ is summarised in Table 5.10 below.

Table 5.10 Volume Customer to Demand Customer Movements | GJ

Existing Customers	2015	2016	2017	2018	2019	2020	2021
ACQ | GJ	49,517	-	-	-	-	-	-
MDQ | GJ	194						

6. Conclusion | Demand and Customer Forecasts

Core considers that the methodology adopted for this review and the forecasts presented comply with the requirements of the NGR and provide the best estimate of gas demand and customer numbers for the ActewAGL Distribution network during the Access Arrangement period.

Presented below are Core's final forecast of demand and connections for volume customers by customer segment and ACQ and MDQ for the demand customer segment. Core is of the opinion that the following forecasts represent the best estimate of demand and customer numbers for ActewAGL Distribution for the 2017 to 2021 period, based on the specific circumstances of this review.

6.1. Volume Customer Demand

Table 6.1 Residential Demand Forecast | GJ

Total Demand	2015	2016	2017	2018	2019	2020	2021
Existing	4,875,220	4,665,308	4,469,503	4,247,001	4,054,368	3,890,008	3,741,052
New Estates	58,095	115,866	177,650	232,481	283,813	331,967	371,950
New M/H Density	28,197	48,069	67,072	88,036	107,660	126,067	142,274
New E to G	19,917	38,337	55,551	70,981	85,445	99,020	111,851
Total	**4,981,429**	**4,867,580**	**4,769,776**	**4,638,499**	**4,531,286**	**4,447,063**	**4,367,126**

Table 6.2 Business Demand Forecast | GJ

Total Demand	2015	2016	2017	2018	2019	2020	2021
Existing	1,490,883	1,442,087	1,394,363	1,330,933	1,263,814	1,211,421	1,168,950
New	28,719	94,140	157,524	216,143	269,987	323,118	376,125
Tariff to Non-Tariff Movements	49,517	49,517	49,517	49,517	49,517	49,517	49,517
Non-Tariff to Tariff Movements	24,073	24,073	24,073	24,073	24,073	24,073	24,073
Total	**1,494,158**	**1,510,783**	**1,526,442**	**1,521,632**	**1,508,357**	**1,509,095**	**1,519,631**

Figure 6.1 Volume Customer Demand Forecast | GJ

6.1.2. Volume Customer Connections

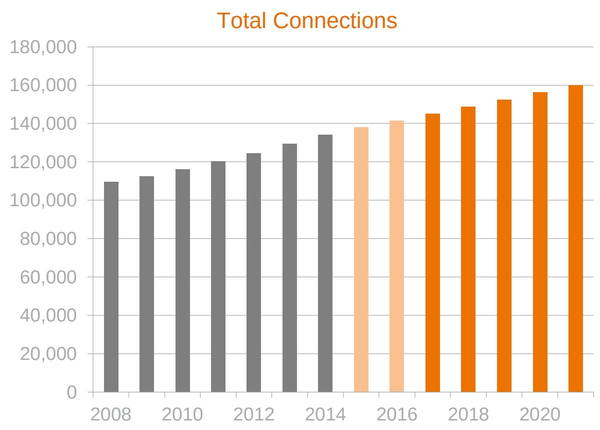
Table 6.3 Residential Connections Forecast | No.

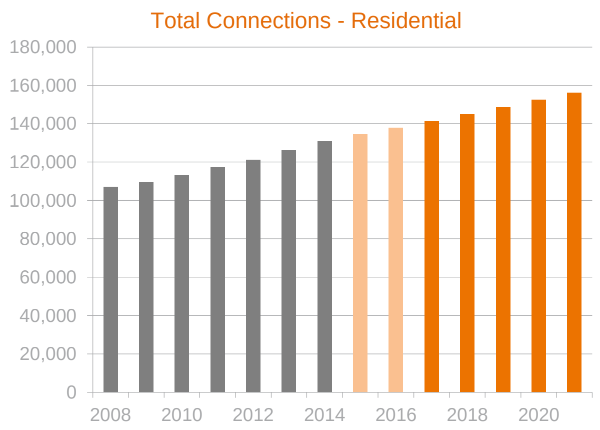
Total Connections	2015	2016	2017	2018	2019	2020	2021
Existing	130,097	129,355	128,288	127,202	126,097	125,278	124,437
New Estate	1,730	1,856	2,106	2,081	2,081	2,081	1,876
New Medium/High Density	1,960	1,512	1,543	1,853	1,853	1,853	1,751
New E to G	781	781	781	781	781	781	781
Cumulative New Estate	1,730	3,586	5,692	7,772	9,853	11,933	13,810
Cumulative New Medium/High Density	1,960	3,471	5,014	6,867	8,721	10,574	12,325
Cumulative New E to G	781	1,562	2,343	3,124	3,905	4,686	5,467
Total	**134,568**	**137,974**	**141,337**	**144,966**	**148,575**	**152,471**	**156,039**

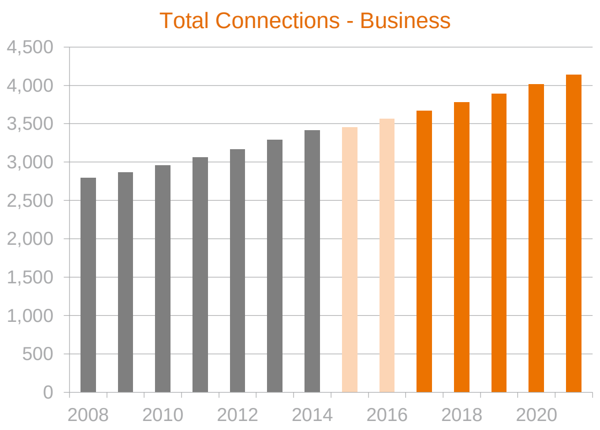
Table 6.4 Business Connections Forecast | No.

Total Connections	2015	2016	2017	2018	2019	2020	2021
Existing	3,398	3,381	3,364	3,347	3,330	3,312	3,295
New	51	122	125	128	132	135	139
Cumulative New	51	173	298	427	559	694	833
Tariff to Non-Tariff Movements	(4)	(4)	(4)	(4)	(4)	(4)	(4)
Non-Tariff to Tariff Movements	3	3	3	3	3	3	3
Total	**3,449**	**3,554**	**3,661**	**3,773**	**3,887**	**4,005**	**4,127**

Figure 6.2 Volume Customer Connections Forecast | No.





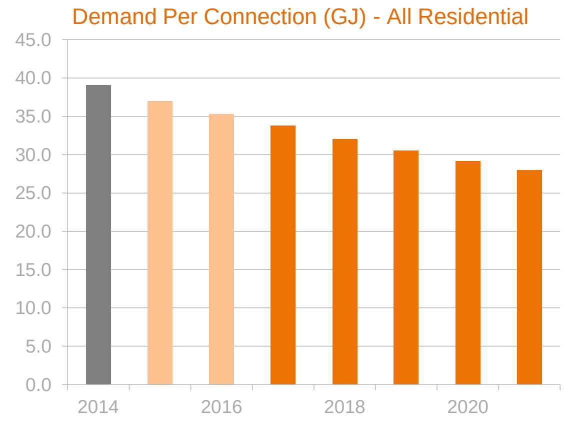


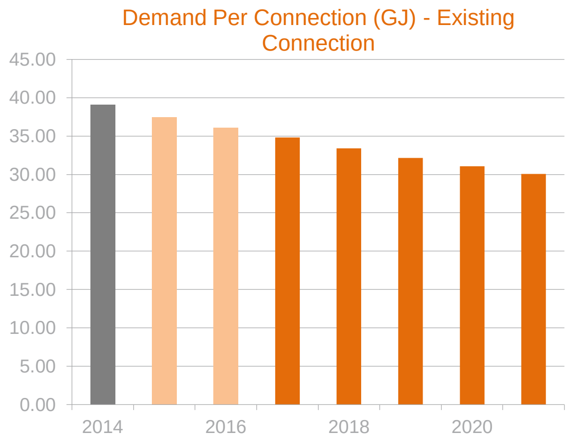
6.1.3. Volume Customer Demand per Connection

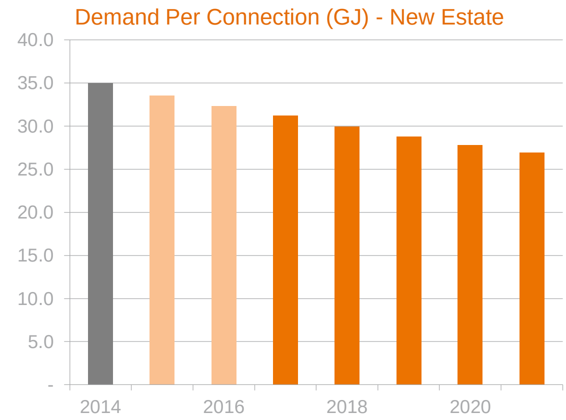
Table 6.5 Volume Customer Demand per Connection Forecast | GJ

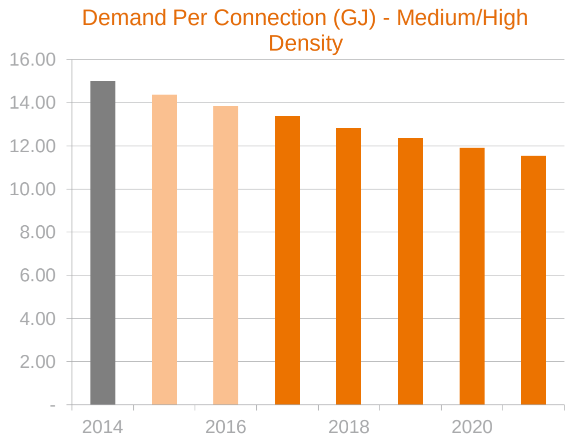
Demand per Connection	2015	2016	2017	2018	2019	2020	2021
Residential							
Existing	37.5	36.1	34.8	33.4	32.2	31.1	30.1
New Estate	33.6	32.3	31.2	29.9	28.8	27.8	26.9
New M/H Density	14.4	13.8	13.4	12.8	12.3	11.9	11.5
New E to G	25.5	24.5	23.7	22.7	21.9	21.1	20.5
Weighted Average	37.0	35.3	33.7	32.0	30.5	29.2	28.0
Business							
Existing	439	427	414	398	380	366	355
New Business	559	543	528	506	483	466	452
Weighted Average | Pre Demand to Volume Customer Movements	440	432	424	410	394	383	374
Weighted Average | Post Demand to Volume Customer Movements	433	425	417	403	388	377	368

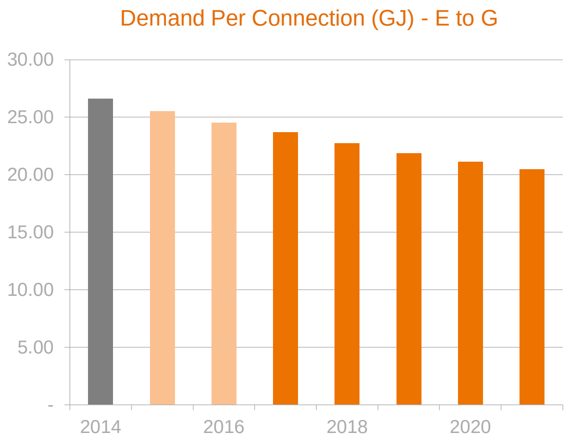
Figure 6.3 Volume Customer Demand per Connection Forecast | GJ[18]



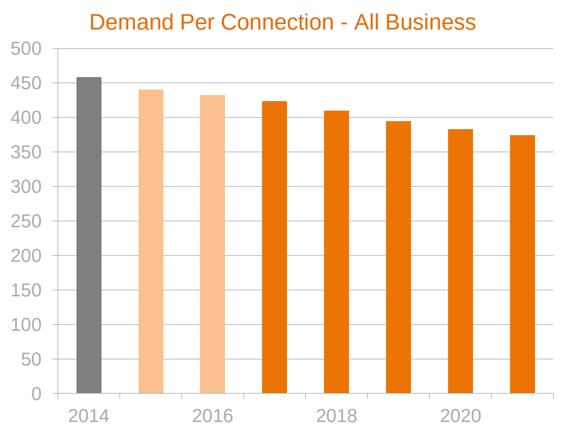


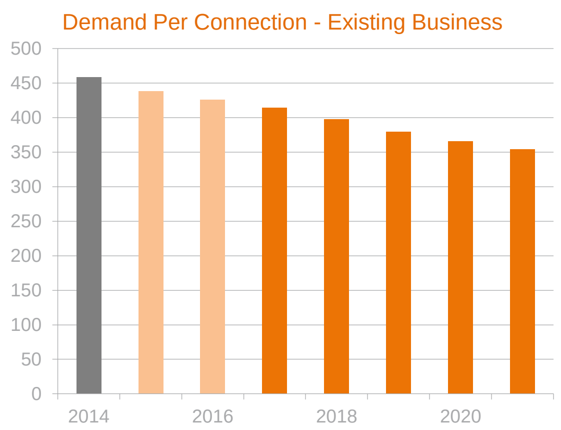


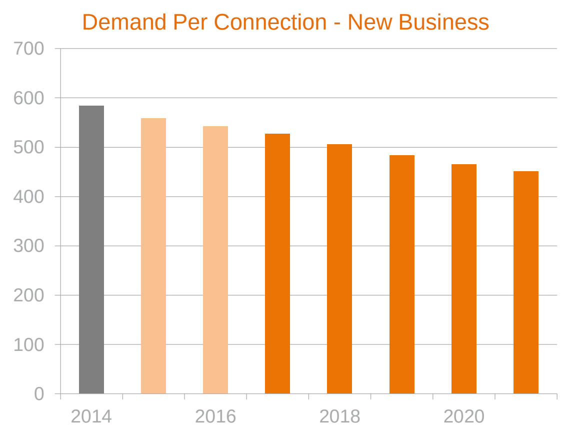




[18] The existing demand per connection is the weighted average of demand per connection in 2014.





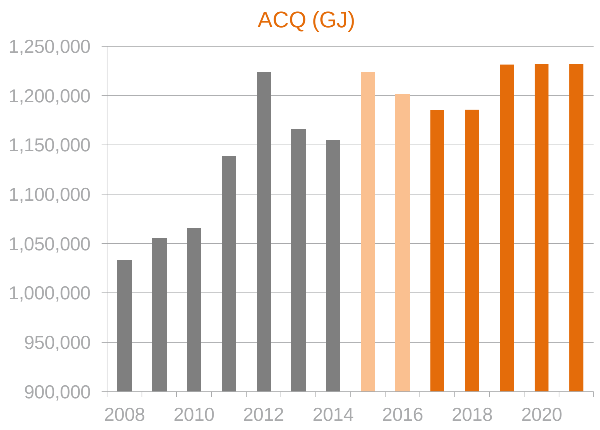


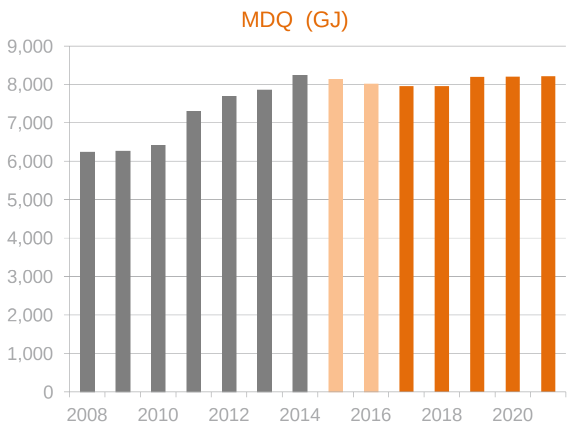
6.2. Demand Customer Demand | ACQ and MDQ

Table 6.6 Forecast of Demand Customer MDQ & ACQ | GJ

Demand	2015	2016	2017	2018	2019	2020	2021
MDQ | GJ	8,140	8,025	7,951	7,956	8,201	8,206	8,211
ACQ | GJ	1,224,102	1,201,836	1,185,399	1,185,769	1,231,356	1,231,764	1,232,191

Figure 6.4 Demand Customer ACQ and MDQ Forecast





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13. NSW Government, Planning and Environment, Population and housing projections – 2013, < http://www.planning.nsw.gov.au/population-and-housing-projections>, June 2013

Annexure 1 | Terms of Reference

This is an independent forecast of the quantitative impact (both positive and negative) of each of the following contributing factors during the period 2013/14 to 2020/21 upon annual gas consumption of ActewAGL Distribution's existing residential, business and large industrial customers:

- annual gas consumption of new residential, business and large industrial customers;
- daily demand for business and large industrial customers using more than 10 terajoules (TJ) per annum; and
- annual gas consumption and customer numbers for specific sub market segments.

The contributing factors are:

- market trends affecting the installation of existing gas appliances;
- government energy efficiency policies;
- implementation of the Federal Government's climate change policies;
- forecast economic factors and market trends in industries relevant to ActewAGL Distribution's customer base; and
- forecast environmental factors such as weather warming trends and urban heat island effects and the relationship to gas usage by customer segment.

The expert is required to provide outputs in two parts:

- a final set of worksheets which set out forecast customer numbers and gas demand forecasts
- final written report.

In its final written report, the expert should:

- clearly set out all their findings;
- justify the methodology applied;
- explain how and why the forecast is fit for submission to the AER including an assessment that the model complies with the NGR; and
- explain all the assumptions made to provide the forecast.

Annexure 2 | Retail Gas Price Forecast

The retail gas price consists of the cost components outlined in Table A 2.1.

Table A 2.1 Cost Components of Retail Gas Price

Cost Component	Units	Description
Variable Cost		
Wholesale	AUD/GJ	The market price achieved by the supplier to produce and deliver gas into the transmission pipeline. This is for flat load gas production.
MDQ	AUD/GJ	The cost of production to deliver maximum daily supply capacity to meet peak customer demand during the winter heating season.
Transmission	AUD/GJ	Cost of transporting gas along the transmission pipeline from the supply source to the distribution network. This includes base load and an additional load factor for maximum daily quantity ("**MDQ**") capacity allowance.
Distribution	AUD/GJ	Cost of transporting gas though the distribution network to the customer.
Carbon	AUD/GJ	Additional cost due to carbon emissions tax.
Retail Margin	AUD/GJ	Retailer profit margin (% **EBITDA**)
Market Charges	AUD/GJ	Cost to cover Australian Energy Market Operator ("**AEMO**") market participant fees.
Fixed Cost		
Fixed Retail Supply Charge	AUD p.a.	Annual fixed charge per customer per annum to cover defined costs of pipeline and retail operations.

Residential

Historical Gas Prices

To determine the historical change in residential gas prices between 2009 and 2013, Core has assumed that there was no change to the Wholesale, MDQ, Transmission and Market Charge cost components of Total Variable Cost prior to 2014. The Distribution cost component of Total Variable Cost was determined based on the tariff schedule outlined in ActewAGL Distribution's Access Arrangement for the period between 2011 and 2015. The Distribution cost components for 2009 and 2010 are determined based on the tariff schedule outlined in ActewAGL Distribution's Access Arrangement for the period between 2005 and 2010. The cost of carbon included from July 2012 onwards accords with ActewAGL Retail's ("**AAR**") "Carbon Component of Gas Retail Prices from 1 July 2012" report. The historical change in residential gas prices between 2010 and 2013 is summarised in Table A 2.2.

Table A 2.2 Historical Change in Residential Gas Price

	Units	2010	2011	2012	2013
Change in Retail Bill	%	-0.2%	2.6%	7.6%	3.3%

Gas Price Forecast Summary

The forecast of each cost component of retail gas prices from 2014 to 2021 is outlined in Table A 2.3. below.

Table A 2.3 Cost Components of Retail Gas Price Forecasts | Real 2014 AUD

Cost Component	Units	2014	2015	2016	2017	2018	2019	2020	2021
Variable Cost									
Wholesale	AUD/GJ	5.20	6.20	6.20	7.20	9.20	9.20	9.20	9.20
MDQ	AUD/GJ	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80
Transmission	AUD/GJ	2.40	2.40	2.40	2.79	2.79	2.79	2.79	2.79
Distribution	AUD/GJ	11.20	11.20	11.20	11.20	11.20	11.20	11.20	11.20
Carbon	AUD/GJ	1.70	-	-	-	-	-	-	-
Retail Margin	AUD/GJ	1.60	1.60	1.60	1.60	1.60	1.60	1.60	1.60
Market Charges	AUD/GJ	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Total Variable Cost	AUD/GJ	23.93	23.21	23.21	24.60	26.60	26.60	26.60	26.60
Fixed Cost									
Fixed Retail Supply Charge	AUD	212.39	212.39	212.39	212.39	212.39	212.39	212.39	212.39

Assuming gas usage of an average Australian Capital Territory ("**ACT**") household of 47.5 GJ p.a.[19], gives rise to the following retail gas price forecast to 2021.

Table A 2.4 Retail gas price forecast to 2021 | Real 2014 AUD

	Units	2014	2015	2016	2017	2018	2019	2020	2021
Retail Bill	AUD	1349.23	1314.91	1314.89	1380.94	1475.94	1475.96	1475.96	1475.96
Change in Retail Bill	AUD	27.37	-34.32	-0.02	66.05	95.00	0.02	0.00	0.00
Change in Retail Bill	%	1.7%	-2.5%	0.0%	5.0%	6.9%	0.0%	0.0%	0.0%

Determination of Cost Components

The forecast of Wholesale and MDQ cost components are based on Core intelligence and extensive market research. Forecasts for Transmission, Carbon, Retail, Market Charges, Total Variable Cost and Fixed Retail Supply Charge cost components are derived from publicly available third party data, predominately from the retail arm of ActewAGL ("**AAR**"), the Independent Competition and Regulatory Commission ("**ICRC**"), AEMO and the Australian Energy Market Commission ("**AEMC**"). The Distribution cost component is calculated as the balance of the Total Variable Cost minus the known cost components.

Wholesale

Core Energy estimates that ex-field wholesale gas prices will move from an existing weighted average price of AUD5.20/GJ towards AUD9.20/GJ. Core Energy has undertaken extensive analysis of the outlook for wholesale gas prices, having regard to two primary forces:

- the increasing cost of gas extraction due to increasing geological complexity and increased engineering costs; and
- the impact of the emerging LNG sector in terms of volume of gas required and pricing.

Core analysis indicates that ex-field gas prices are likely to increase toward AUD9.20/GJ in real 2014 terms over the period 2016-2021.

[19] AAR, 'Pricing frequently asked questions – Natural Gas'', accessed October 2014, <http://www.actewagl.com.au/Product-and-services/Offers-and-prices/Prices/Pricing-faq.aspx>

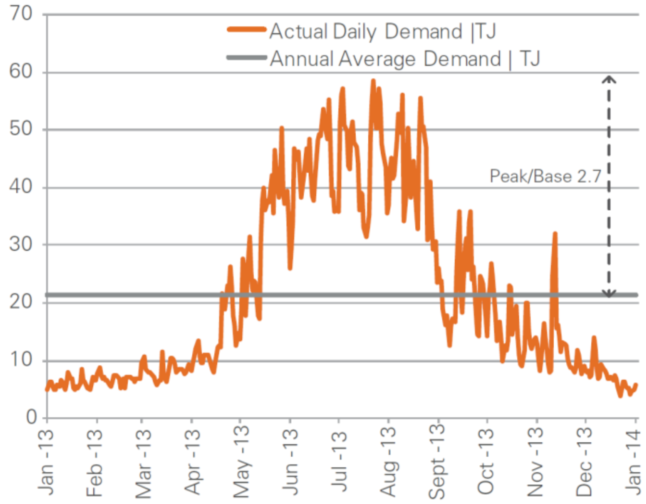
The key price influences are:

- the field netback price of LNG at Wallumbilla;
- the estimated transmission costs from the North (Wallumbilla) to ACT; and
- the cost of competitive new supplies which are expected to be above AUD8.00/ GJ.

MDQ

MDQ is the maximum daily volume of gas that a gas customer is able to draw upon under a gas contract to meet peak demand. MDQ is usually defined as some multiple of ACQ. For the purpose of this analysis, MDQ is assumed to be 125% of ACQ (based on Core experience/intelligence). If an average annual demand of 5PJ is used to derive average daily demand (5/365), the ACQ is 21TJ and the MDQ (59) /ACQ (21) = 2.7. This is demonstrated in Figure A 2.1 below.

Figure A 2.1 Actual Daily and Annual Average Demand | TJ



With the Cooper Basin and Gippsland Basin contracts maturing in 2016/17, and the level of MDQ capacity available under new contracts expected to be lower, retailers are looking at alternative peak supply sources. For example, AGL is developing a peaking facility in Newcastle for a cost of over AUD300 million. This flexibility clearly has a value to retailers to meet customer requirements and a cost to producers to maintain the capacity.

Core uses the following formula to derive the cost of MDQ:

- Cost _MDQ = MDQC/365 x LF where:
- Cost_MDQ is cost of MDQ
- MDQC (MDQ cost) is AUD 240 per GJ/MDQ/year[20]
- LF is load factor expressed as % AQ; and
- AQ is annual quantity.

MDQC/365 = 240/365 = AUD0.66

For a total peak of 2.7 this would equate to 2.7 x AUD0.66 = AUD1.80/GJ.

[20] Refer Table 3.4 Extracts from ACIL Tasman “Cost of gas for the 2013 to 2017 regulatory period” pp. 30- 33.

Table A 2.5 Extracts from ACIL Tasman "Cost of gas for the 2013 to 2017 regulatory period" pp. 30-33

Topic	Commentary
MDQ Cost Benchmarks	*We consider a number of MDQ cost benchmarks based on gas storage, and then develop additional non-storage benchmarks based on the prospects of interrupting and alternatively providing excess gas at a discounted price to gas-fired power generation. For comparative purposes, we also estimate an MDQ cost based on daily gas spot prices at the Sydney Hub observed during 2012.*
Underground Gas Storage (Iona)	*This storage facility was previously referred to as Western Underground Storage (WUGS). According to EnergyAustralia (EnergyAustralia), "the Iona site is located above a depleted gas field that was originally used to supply the Western System. Gas is stored in three underground storage reservoirs – Iona and the remote reservoirs of North Paaratte and Wallaby Creek. The plant includes two gas processing trains and compression equipment to process gas from the storage reservoirs and the offshore Casino development. Compressed gas can be injected into the South West Pipeline to supply Melbourne, the SEA Gas Pipeline to supply Adelaide, or into the storage reservoirs for later withdrawal."* *EnergyAustralia explains further that "Iona provides energy retailers and wholesalers the ability to shape supply contracts to meet peak requirements and provides a hedge against spikes in the spot market price. Storage might also appeal to gas producers because it allows production to remain flat whilst allowing deliverability to match demand."* *According to EnergyAustralia, "gas storage fees consist of a fixed capacity charge for MHQ and storage volume, and variable charges per gigajoule of plant throughput. Storage contracts are available until 30 September for the following reservoir year (1 October to 30 September). The minimum contracting level is typically 10TJ per day of storage withdrawal capacity."* *Previously, when operated by TXU, WUGS rates were published and constituted a publicly available source of information on the market cost of MDQ. We understand that EnergyAustralia, the current owners and operators of the gas storage, no longer publish rates publicly but invite commercial enquiries. Origin Energy (submission 2002) refers to a rate of $150 per GJ/MDQ from October 2003. For the previous review a range of MDQ costs based on WUGS published rates was $160 to $240 per GJ MDQ /year. In the previous review MMA expressed its view that the cost of MDQ for retailers was at the lower end of this range.*
Newcastle Gas Storage Facility	*According to an AGL media release of 11 May 2012, AGL is constructing the Newcastle Gas Storage Facility at Tomago. The total project investment cost is cited by AGL to be around $310 million. It is expected to be completed in 2015 and will incorporate a processing plant to treat and liquefy natural gas, LNG storage tank capable of 1.5PJ capacity and a re-gasification unit to convert the LNG back into natural gas. According to AGL it will have peaking capacity of 120 TJ/day (AGL, 27 February 2013). Ignoring any operating costs, estimates for the cost of providing MDQ at this facility can be made on the basis of its cited project development cost and peaking capacity. Assuming a thirty year asset life, annual capital recovery factors corresponding to post-tax real weighted average costs of capital of 6% and 8% are 7.26% and 8.88% respectively. Multiplying the project development cost by the annual capital recovery factor and dividing by the peak capacity expressed in GJ, gives an MDQ cost in the range of $188 to $229 GJ MDQ/year.*
Dandenong LNG Storage Facility	*According to APA Group, with a fully contracted capacity of approximately 12,000 tonnes (or 0.7 PJ), the Dandenong LNG storage facility provides peak shaving and security of supply services for the Victorian Principal Transmission System (PTS). This facility injects gas into the PTS to meet peak winter demands as well as providing a truck loading station for LNG tankers. The Dandenong LNG Facility is not subject to regulation under the National Gas Code. We understand that APA Group makes the associated peak shaving services available through a tender process, the details of which, including outcomes are not generally disclosed.*
Mondarra Gas Storage Facility	*In a media release of 26 May 2011, APA Group cited a cost of $140M to expand its Mondarra gas storage facility located on the Parmelia Gas Pipeline near Dongara in Western Australia. According to the Australian Pipeliner, October 2011, "a significant increase in the daily injection and withdrawal rates into and out of the facility will be another result of the expansion, with the current 15 TJ/d injection and withdrawal rates to increase to rates of 70 TJ/d for injection and 150 TJ/d for withdrawal." This information suggests that an additional 135TJ/day withdrawal capacity is achieved at a cost of $140M. Amortising the project development cost at 10% provides an MDQ cost estimate for this facility of $104 per GJ MDQ per year.*

Topic	Commentary
Non Storage Benchmarks	*Electricity spot prices are typically more volatile is summer than in winter. This suggests that there might be a case for sourcing MDQ by interrupting gas-fired power generators in the winter season (quarters 2 and 3) when retail gas demand is higher. Assuming a heat rate of 11 GJ/MWh, and valuing the MDQ at the cost of an electricity cap contract, the equivalent value would be $200 per GJ MDQ/year for a $1/MWh cap premium. Winter season caps are currently traded at around $3/MWh, implying a potentially very high MDQ cost of $600 per GJ MDQ/year. This assumes that the generator is unable to produce electricity if its gas supply is interrupted.* *If the gas-fired power generator has the ability to switch from gas to liquid fuel it will retain its ability to generate against potentially high electricity prices. SKM MMA has estimated recently for Western Australia's Independent Market Operator (IMO), the capital cost of providing a 160MW open cycle gas turbine installation with liquid fuel capability (SKM MMA, January 2013). The cost is around $6.5M or $650,000 annually if amortised at 10%. Assuming that the use of liquid fuel results in a variable generation cost of $300/MWh (SKM MMA cites an estimated cost of diesel fuel of $23.62 per GJ), and that the generator is interrupted 1% of the time, the annual cost of interruption (in fuel terms) will be 0.01 x 8760 x 160 x $300 = $4.2M. The total cost of the interrupt service would be $4.85M. If the interruption is for 12 hours and the heat rate of the OCGT is assumed to be 11 GJ/MWh, the available MDQ is 12 x 160 x 11 = 21,120GJ. The cost is then $230 per GJ MDQ/year. It will be noted that this estimate is highly sensitive to assumptions, particularly the assumption regarding the time the generator is to be interrupted. As a result the cost estimate has a potentially wide range.* *Another approach is for the retailer to contract additional annual quantity and to sell excess gas at a discount to gas-fired power generators. For example if a retailer has a customer load factor of 33% and contracts for an annual quantity three times its demand, and it is assumed that it sells excess gas at a $1 per GJ discount, it will make a loss of $2 per GJ for every GJ sold to its customers. This "additional deliverability" cost of $2 per GJ corresponds to an MDQ cost of $360 per GJ MDQ/year. In this approach it is assumed that there is adequate spare gas-fired generation capacity to make use of the retailer's excess gas. This is likely to be problematic for a retailer with a relatively large customer demand.* *Finally, it possible to arrive at an estimate of MDQ cost from gas spot price and system withdrawal data published by AEMO. We base our estimate on daily data published for 2012 for the Sydney hub. This estimate can be regarded as an implied MDQ cost.* *Analysis of daily system withdrawals gives an average withdrawal of 236TJ and a maximum withdrawal of 334TJ – a load factor of 71%. The difference between the system withdrawal weighted spot price and the time-weighted spot price ($5.06 - $4.77 = $0.29 per GJ) represents the cost of additional deliverability. This is the additional cost of supplying a 71% load factor demand over a 100% load factor demand. Rearranging the formula used previously to calculate the additional cost of MDQ, we have MDQC = 365 x AC_MDQ x CLF = $75.15 per GJ MDQ/year.* *The cited range of MDQ costs of $160 to $240 per GJ MDQ/year represents a multiple of 2 to 3 of this value. However this is not dissimilar to the electricity market where cap contracts trade at similar or even higher multiples to value based on spot prices.*
Conclusion	*There are a number of approaches to estimating the cost of MDQ. The application of these gives rise to a large range in estimated value from less than $100 per GJ/MDQ/year based on analysis of daily gas spot prices to possibly in excess of $300 per GJ/MDQ based on opportunities to interrupt gas-fired power generators or provide them with additional gas at a discounted price. We consider the most relevant benchmark cost to be that based on AGL's Newcastle gas storage facility. Our reasoning is that this is a facility currently under construction in New South Wales which is well suited to providing the additional deliverability service and for which the estimated cost and delivery capacity are known.* *We note further that our estimate of the MDQ cost at this facility ($188 to $229/ GJ MDQ/year) is within the range previously quoted for the underground storage facility in Victoria ($160 to $240 GJ MDQ /year). Finally we note that our estimate of MDQ cost of $230 per GJ MDQ/year based on interrupting a gas-fired power generator fitted with the capability to switch to liquid fuel is also within this range. However we note that this particular estimate depends on a number of assumptions.*

Transmission

Pipeline transportation tariffs form the basis of the transmission cost component of Total Variable Cost. Gas to ACT is supplied by two main gas pipelines; the Eastern Gas Pipeline ("**EGP**") and the Moomba-Sydney Pipeline ("**MSP**"). Two laterals transport gas from the main lines to the distribution network of ACT and surrounding regions; the Hoskinstown to Fyshwick Trunkline ("**HFT**"), which receives gas from the EGP, and Dalton to Watson Lateral ("**DWP**"), which receives gas from the MSP. Each of these pipelines has a different tariff structure, and it is the combination of these tariffs that gives rise to the overall transmission cost. The tariff structure of each pipeline is outlined in Table A

2.6 and Table A 2.7 each adjusted with a load factor of 2, to account for additional fee for the provision of peak load capacity.

Table A 2.6 Jemena Eastern Gas Pipeline | Real 2014 AUD

Firm Forward Haulage Service	AUD/GJ
Effective 1 January 2013	1.19
Effective 1 January 2014	1.21
Average | Tariff for 13/14	1.20
Load Adjusted Tariff	2.40

Table A 2.7 APA Group Moomba to Sydney | Real 2014 AUD

Throughput Tariff	AUD/km per GJ	Distance | km	AUD/GJ
Capacity Tariff | Effective 1 July 2014	0.0000375	1,135	0.04
Throughput Tariff | Effective 1 July 2014	0.0006681	1,135	0.76
Total Tariff | Effective 1 July 2014	-	-	0.80
Load Adjusted Tariff	-	-	1.60

To estimate an average transmission cost per GJ, it is assumed that approximately 50% of ACT and surrounding region's gas is supplied via the EGP/ HFT supply path, to 2017. The remaining 50% is assumed to be supplied via the MSP/ DWP supply path, to 2017. Post 2017, it is assumed that 99% of the gas is transported via the EGP/HFT supply path. The remaining 1% is expected to be supplied via the MSP/DWP supply path. The average transmission tariff weighted by supply volume is provided, per annum, in Table A 2.8. This currently assumes that the tariff for the two lateral pipelines, HFT and DWP, will each charge AUD0.40/GJ.

Table A 2.8 Weighted Average Transmission and Lateral Tariffs | Real 2014 AUD

Pipeline	2014	2015	2016	2017	2018	2019	2020	2021
Transmission	2.00	2.00	2.00	2.39	2.39	2.39	2.39	2.39
Lateral	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40
Total	2.40	2.40	2.40	2.79	2.79	2.79	2.79	2.79

Distribution

The distribution cost component is calculated as the balance of the Total Variable Cost minus the known cost components. This is calculated to be AUD11.20/GJ in 2014. It is assumed that the distribution costs are regulated and maintained constant between 2015 and 2021.

Carbon

A carbon cost of AUD1.66/GJ for 2013 is outlined in AAR's '*Proposed Impact of Carbon on Gas Retail Prices'*. This cost has been escalated by 2.5% to AUD1.72/GJ, to give an estimate for the cost of carbon of in 2014.The carbon tax was repealed as of 1 July 2014. As such, the cost of carbon is removed from the Total Variable Cost of gas from 2014 onwards.

Retail Margin

The AAR's retail margin for 1 July 2013 to 30 June 2016 was reviewed and approved by IPART in June 2013. The reasonable range for the retail margin was set between 6.7% and 7.34% EBITDA[21]. Based on the lower end of 6.7% EBITDA, and total variable cost of AUD23.93, this is equivalent to AUD1.60 per GJ of the Total Variable Cost.

AEMO Market Charge

AEMO's market charges participants in the NSW/ACT Full Retail Contestability (FRC) gas markets, with fees published in "NSW/ACT FRC Gas Final Budget and Fees: 2014-2015". AEMO fees consist of two elements; Consumer Advocacy Panel Requirements Fees and Gas Statement of Opportunities Fees. Forecasts for Consumer Advocacy Panel Requirements Fees are provided for 2014 and 2015. Meanwhile Forecasts for Gas Statement of Opportunities Fees are provided until 2019. It is assumed that there is no change in the fees between 2019 and 2021. A summary of the AEMO markets fees are provided in Table A 2.9 and Table A 2.10.

Table A 2.9 AEMO Consumer Advocacy Panel Requirements[22]

CAP Fees	2014	2014
Gas ($ per customer supply point per month)	0.0191	0.0110
Gas ($ per customer supply point per annum)	0.2292	0.1320

Table A 2.10 AEMO Gas Statement of Opportunities Projected Fees | Real 2014 AUD[23]

Fees	2014	2015	2016	2017	2018	2019	2020	2021
Gas ($ per customer supply point per month)	0.0298	0.0283	0.0269	0.0296	0.0296	0.0311	0.0311	0.0311
Gas ($ per customer supply point per annum)	0.3575	0.3396	0.3227	0.3557	0.3557	0.3734	0.3734	0.3734

Based on an average annual consumption of 47.5GJ p.a. for residential customers and 184GJ/p.a. for business customers, fees were calculated on a per GJ basis for each demand segment.

Table A 2.11 AEMO Market Fees | Real 2014 AUD

Fees	2014	2015	2016	2017	2018	2019	2020	2021
Residential | AUD/GJ	0.0130	0.0105	0.0101	0.0108	0.0108	0.0112	0.0112	0.0112
Business | AUD/GJ	0.0032	0.0026	0.0025	0.0027	0.0027	0.0027	0.0027	0.0027

Total Variable Cost

The total variable cost for 2014 is calculated based on the usage rates published in AAR's '*Our ACT Natural Gas Prices*' Schedule of charges from 1 July 2013[24]. A summary of these usage rates in provided in Table A 2.12.

[21] IPART, 'Review of regulated retail prices and charges for gas From 1 July 2013 to 30 June 2013', June 2013, page 39.< http://www.ipart.nsw.gov.au/Home/Industries/Gas/Reviews/Retail_Pricing/Review_of_regulated_gas_retail_prices_2013_to_2016/17_Jun_2013_-_Final_Report/Final_Report_-_Review_of_regulated_retail_prices_and_charges_for_gas_-_June_2013>
[22] AEMO, 'NSW/ACT FRC Gas Final Budget and Fees: 2014-2015, May 2014 < https://www.google.com.au/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&cad=rja&uact=8&ved=0CB8QFjAA&url=http%3A%2F%2Fwww.aemo.com.au%2FAbout-AEMO%2FCorporate-Publications%2F~%2Fmedia%2FFiles%2FOther%2Fbudget%2F14-15%2F2014_15%2520FINAL%2FFINAL_1415_NSW_ACT_FRC_Gas_stakeholder_report.ashx&ei=fEYOVPvQJIe_uASn5IH4Dw&usg=AFQjCNFrUoxZPL7ffrrOWDGfW-lpZF0UgA&sig2=DYVj9xfn6Gf4MyKtpALwtA&bvm=bv.74649129,d.c2E>
[23] ibid
[24] AAR, '*Our ACT natural gas prices Schedule of charges from 1 July 2013*', July 2013 <http://www.actewagl.com.au/~/media/ActewAGL/ActewAGL-Files/Products-and-services/Retail-prices/Natural-gas-retail-prices/ACT-gas-retail-brochure-2013-14.ashx>

Table A 2.12 AAR ACT Gas Usage Rates | Real 2014 AUD

Usage Rate	2014 GST-exclusive rate	
	¢/MJ	AUD/GJ
First 41.0959 MJ/day | 15 GJ equiv.	2.524	25.24
Next 2,704.1096 MJ/day | 987 GJ equiv.	2.328	23.28
Next 10,964.3836 | 4,002 GJ equiv.	2.270	22.70
Thereafter	2.075	20.75

An average household in ACT is assumed to consume 47.5 GJ p.a. of gas.[25] As such, Total Variable Cost for an average retail bill in the ACT would be equivalent to AUD 23.93 per GJ:

$$\left(\frac{15\ \text{GJ}}{47.5\ \text{GJ}}\ \text{x}\frac{\text{AUD25.24}}{\text{GJ}}\right)+\left(\frac{32.5\ \text{GJ}}{47.5\ \text{GJ}}\ \text{x}\frac{\text{AUD23.28}}{\text{GJ}}\right)=\frac{\text{AUD23.93}}{\text{GJ}}$$

Fixed Retail Supply Charge

A fixed supply fee of 58.19 cents per day is outlined in AAR's "*Our ACT Natural Gas Prices*" Schedule of charges from 1 July 2013[26]. This is equivalent to AUD212.39 p.a.

[25] AAR Retail, 'Pricing frequently asked questions – Natural Gas'', accessed October 2014, <http://www.actewagl.com.au/Product-and-services/Offers-and-prices/Prices/Pricing-faq.aspx>
26 AAR, 'Our ACT natural gas prices Schedule of charges from 1 July 2013', July 2013 <http://www.actewagl.com.au/~/media/ActewAGL/ActewAGL-Files/Products-and-services/Retail-prices/Natural-gas-retail-prices/ACT-gas-retail-brochure-2013-14.ashx>

Business

Historical Gas Prices

A similar approach to derivation of historical movement in residential gas prices was undertaken to determine the historical change in business gas price. The historical change in business gas prices between 2009 and 2013 is summarised in Table A 2.13.

Table A 2.13 Historical Change in Business Gas Price | %

	Units	2010	2011	2012	2013
Change in Retail Bill	%	-0.1%	7.1%	8.4%	4.0%

Gas Price Forecast Summary

The forecast of each cost component of retail gas prices from 2014 to 2021 is outlined in Table A 2.14 below.

Table A 2.14 Cost Components of Retail Gas Price Forecasts | Real 2014 AUD

Cost Component	Units	2014	2015	2016	2017	2018	2019	2020	2021
Variable Cost									
Wholesale	AUD/GJ	5.20	6.20	6.20	7.20	9.20	9.20	9.20	9.20
MDQ	AUD/GJ	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80
Transmission	AUD/GJ	2.40	2.40	2.40	2.79	2.79	2.79	2.79	2.79
Distribution	AUD/GJ	9.41	9.41	9.41	9.41	9.41	9.41	9.41	9.41
Carbon	AUD/GJ	1.70	-	-	-	-	-	-	-
Retail Margin	AUD/GJ	1.47	1.47	1.47	1.47	1.47	1.47	1.47	1.47
Market Charges	AUD/GJ	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
Total Variable Cost	AUD/GJ	21.99	21.29	21.29	22.68	24.68	24.68	24.68	24.68
Fixed Cost									
Fixed Retail Supply Charge	AUD	389.05	389.05	389.05	389.05	389.05	389.05	389.05	389.05

Assuming the gas usage of an average ACT business is 184 GJ p.a.[27], this gives rise to the following retail gas price forecast to 2021.

Table A 2.15 Retail gas price forecast to 2021 | Real 2014 AUD

	Units	2014	2015	2016	2017	2018	2019	2020	2021
Retail Bill	AUD	4,435	4,306	4,306	4,562	4,930	4,930	4,930	4,930
Change in Retail Bill	AUD	163.37	-128.92	-0.02	255.77	368.00	0.02	0.00	0.00
Change in Retail Bill	%	3.8%	-2.9%	0.0%	5.9%	8.1%	0.0%	0.0%	0.0%

Determination of Cost Components

The same approach as residential gas price was used to determine the cost components of business gas price. It was assumed that there would be no difference in wholesale, MDQ, transmission and distribution costs between the residential and business segments. The main cost component differences between the two segments is the

[27] IPART, 'Review of regulated retail prices and charges for Gas', February 2014, page 39 <http://www.ipart.nsw.gov.au/Home/Industries/Gas/Reviews/Retail_Pricing/Changes_in_regulated_gas_retail_prices_from_1_July_2014>

distribution cost and retail margin cost, which drives the difference between the total variable cost, as well as the fixed supply charge.

Distribution Cost

The Distribution cost component is calculated as the balance of the Total Variable Cost minus the known cost components. This is calculated to be AUD9.41/GJ in 2014. It is assumed that the distribution costs remain constant between 2015 and 2021.

Retail Margin

The AAR's retail margin for 1 July 2013 to 30 June 2016 was reviewed and approved by IPART in June 2013. The reasonable range for the retail margin was set between 6.7% and 7.34% EBITDA.[28] Based on the lower end of 6.7% EBITDA, and a total variable cost of AUD21.99, this is equivalent to AUD1.47 per GJ of the Total Variable Cost.

Total Variable Cost

The total variable cost for 2014 is calculated based on the usage rates published in AAR's *Our ACT Natural Gas Prices*" schedule of charges from 1 July 2013[29]. A summary of these usage rates in provided in Table A 2.16

Table A 2.16 AAR ACT Gas Usage Rates | Real 2014 AUD

Usage Rate	2013-14 GST-exclusive rate	
	¢/MJ	AUD/GJ
First 41.0959 MJ/day	2.379	23.79
Next 2,704.1096 MJ/day	2.183	21.83
Next 10,964.38.36 MJ/day	2.108	21.08
Thereafter	1.909	19.09

An average business in ACT is assumed to consume 184 GJ p.a. of gas.[30] Therefore, the variable component of a retail bill for an average ACT household would be equivalent to AUD21.99 per GJ:

$$\left(\frac{15\ \text{GJ}}{184\ \text{GJ}}\ \text{x}\frac{\text{AUD23.79}}{\text{GJ}}\right)+\left(\frac{169\ \text{GJ}}{184\ \text{GJ}}\ \text{x}\frac{\text{AUD21.83}}{\text{GJ}}\right)=\frac{\text{AUD21.99}}{\text{GJ}}$$

Fixed Retail Supply Charge

A fixed supply fee of 106.59 cents per day is outlined in AAR '*Our ACT Natural Gas Prices*' Schedule of charges from 1 July 2013.[31] This is equivalent to AUD389.05 p.a.

[28] IPART, 'Review of regulated retail prices and charges for gas From 1 July 2013 to 30 June 2013', June 2013, page 39.< http://www.ipart.nsw.gov.au/Home/Industries/Gas/Reviews/Retail_Pricing/Review_of_regulated_gas_retail_prices_2013_to_2016/17_Jun_2013_-_Final_Report/Final_Report_-_Review_of_regulated_retail_prices_and_charges_for_gas_-_June_2013>

[29] AAR, '*Our ACT natural gas prices Schedule of charges from 1 July 2013*', July 2013 <http://www.actewagl.com.au/~/media/ActewAGL/ActewAGL-Files/Products-and-services/Retail-prices/Natural-gas-retail-prices/ACT-gas-retail-brochure-2013-14.ashx>

[30] IPART, 'Review of regulated retail prices and charges for Gas', February 2014, page 39 <http://www.ipart.nsw.gov.au/Home/Industries/Gas/Reviews/Retail_Pricing/Changes_in_regulated_gas_retail_prices_from_1_July_2014>

[31] AAR, '*Our ACT natural gas prices Schedule of charges from 1 July 2013*', July 2013 <http://www.actewagl.com.au/~/media/ActewAGL/ActewAGL-Files/Products-and-services/Retail-prices/Natural-gas-retail-prices/ACT-gas-retail-brochure-2013-14.ashx>

Annexure 3 | Retail Electricity Price Forecast

Retail electricity prices are assumed to consist of the cost components outlined in Table A 3.1.

Table A 3.1 Cost Components of Retail Electricity Price

Cost Component	Units	Description
Variable Cost		
Wholesale	¢/kWh	The market price achieved to produce and dispatch electricity.
Retail	¢/kWh	The costs of the retail sale of electricity.
Transmission	¢/kWh	Cost of transporting electricity along transmission lines from the generator to the distribution network.
Distribution	¢/kWh	Cost of transporting gas through the distribution network to the customer.
Carbon	¢/kWh	Additional cost due to carbon emissions tax.
LRET	¢/kWh	Cost to comply with obligations under the Federal Government's Small-scale Renewable Energy Scheme (SRES) and Large-scale Renewable Energy Target (LRET)
SRES	¢/kWh	Refer above.
Feed In Tariff	¢/kWh	Additional charge to offset the cost of premium feed-in-tariff schemes.
Energy Efficiency Improvements Scheme ("**EEIS**")	¢/kWh	Additional charge to offset the cost of complying with the EEIS.
Fixed Cost		
Fixed Supply Charge	AUD p.a.	Annual fixed charge per customer per annum to cover some of the costs of retail operations.

Summary of Retail Electricity Price Forecasts

Table A 3.2 Summary of Residential Retail Electricity Price Forecast | AUD/GJ

Cost Component	Unit	2015	2016	2017	2018	2019	2020	2021
Competitive Market Cost Component | Real 2014 AUD		10.09	10.32	10.65	10.65	10.65	10.65	10.65
Transmission Cost		2.20	2.17	2.06	2.06	2.06	2.06	2.06
Distribution Cost		5.54	3.89	4.10	4.10	4.10	4.10	4.10
Regulated Networks Cost Component | Real 2014 AUD		7.74	6.06	6.16	6.16	6.16	6.16	6.16
Carbon								
LRET & SRES		1.07	1.19	1.40	1.40	1.40	1.40	1.40
Feed in Tariffs | Small Scale		0.75	0.91	0.91	0.91	0.91	0.91	0.91
EEIS		0.49	0.25	0.00				
Environmental Cost Component | Real 2014 AUD		2.31	2.35	2.31	2.31	2.31	2.31	2.31
Total Variable Cost | Real 2014 AUD		20.14	18.73	19.12	19.12	19.12	19.12	19.12
Fixed Supply Charge | Real 2014 AUD		$ 251.49	$ 251.49	$ 251.49	$ 251.49	$ 251.49	$ 251.49	$ 251.49
Average residential electricity usage per annum		7,000	7,000	7,000	7,000	7,000	7,000	7,000
Retail Bill | Real 2014 AUD		1,661	1,563	1,590	1,590	1,590	1,590	1,590
Change in Retail Bill | Real 2014 AUD		-109.90	-98.70	27.30	0.00	0.00	0.00	0.00
Change in Retail Price | Real 2014 AUD		-6.2%	-5.9%	1.7%	0.0%	0.0%	0.0%	0.0%

Table A 3.3 Summary of Business Retail Electricity Price Forecast | AUD/GJ

Cost Component	Unit	2015	2016	2017	2018	2019	2020	2021
Competitive Market Cost Component | Real 2014 AUD		10.09	10.32	10.65	10.65	10.65	10.65	10.65
Transmission Cost		2.20	2.17	2.06	2.06	2.06	2.06	2.06
Distribution Cost		8.13	8.00	8.00	8.00	7.99	7.99	7.98
Regulated Networks Cost Component | Real 2014 AUD		10.33	10.17	10.06	10.06	10.05	10.05	10.04
Carbon								
LRET & SRES		1.07	1.19	1.40	1.40	1.40	1.40	1.40
Feed in Tariffs | Small Scale		0.75	0.91	0.91	0.91	0.91	0.91	0.91
EEIS		0.49	0.25	0.00				
Environmental Cost Component | Real 2014 AUD		2.31	2.35	2.31	2.31	2.31	2.31	2.31
Total Variable Cost | Real 2014 AUD		22.73	22.84	23.02	23.02	23.01	23.01	23.00
Fixed Supply Charge | Real 2014 AUD		$ 361.35	$ 361.35	$ 361.35	$ 361.35	$ 361.35	$ 361.35	$ 361.35
Average business electricity usage per annum		30,000	30,000	30,000	30,000	30,000	30,000	30,000
Retail Bill | Real 2014 AUD		7,181	7,215	7,267	7,267	7,265	7,263	7,262
Change in Retail Bill | Real 2014 AUD		-119.55	33.83	52.36	-0.35	-1.83	-1.50	-1.50
Change in Retail Price | Real 2014 AUD		-1.64%	0.47%	0.73%	0.00%	-0.03%	-0.02%	-0.02%

Residential

Total Variable Cost

The Total Variable Cost of retail electricity was sourced from the Australian Energy Market Commission 2014 Residential Electricity Price Trends report[32] to Council of Australian Governments ("**COAG**") Energy Council, released on 5 December 2014. This report provides the forecast for the total variable cost of residential electricity to 2017/18. It was assumed that the total variable cost of electricity would remain constant post 2017/18.

Fixed Supply Change

The fixed supply charge was derived from ActewAGL "Our ACT electricity prices" Fact Sheets for 2015. The supply charge is listed for 2015 as 68.90c per day. It was assumed the fixed supply charge would not change during the access arrangement period.

Retail Bill

The retail bill was calculated from the Total Variable Cost and Fixed Supply Charge, based on an average annual household electricity consumption of 7,000kWh.[33]

Business

Total Variable Cost

It was assumed that the total variable cost for business electricity supply would be the same as residential electricity supply.

Fixed Supply Change

The fixed supply charge was derived from ActewAGL "Our ACT electricity prices" Fact Sheets for 2015. The supply charge is listed for 2015 as 99.00c per day. It was assumed the fixed supply charge would not change during the Access Arrangement period.

Retail Bill

The retail was calculated from the Total Variable Cost and Fixed Supply Charge, based on an average annual business electricity consumption of 30,000kWh.[34]

[32] Australian Energy Market Commission, '2014 Residential Electricity Price Trends TO COAG Energy Council', 5 December 2014, < http://www.aemc.gov.au/getattachment/ae5d0665-7300-4a0d-b3b2-bd42d82cf737/2014-Residential-Electricity-Price-Trends-report.aspx>
[33] ActewAGL Distribution, 2014/2015 Network Pricing Proposal, page vi
[34] ibid

Annexure 4 | Elasticity of Demand Analysis

Introduction

This Annexure describes the approach adopted by Core to derive a forecast of the impact that a projected material movement in ACT retail gas and electricity prices is likely to have on ActewAGL Distribution gas demand.

Background

Price elasticity of demand is a widely recognised concept that will impact gas demand in the ActewAGL distribution network. To capture the predicted changes to gas and electricity prices in the forecast period, Core has derived an appropriate own and cross price elasticity factor. Core is of the opinion, supported by broad-based expert third party analysis, that ACT wholesale and retail gas prices, measured in real 2014 terms, will increase materially during the Review Period (refer Annexure 2). Further, Core is of the opinion, supported by third party expert analysis, that ACT wholesale and retail electricity prices, measured in 2014 real terms, will fall materially during the Review Period (refer Annexure 3).

Core notes that it is well recognised, nationally and internationally, that a material movement in the price of a good or service, including gas and electricity, is likely to cause some degree of movement in the level of demand for that good or service (own price elasticity of demand). Further, Core notes that it is well recognised that a material movement in the price of one substitute good or service (electricity) is likely to cause some degree of movement in the level of demand for a close substitute good or service (gas) – (cross price elasticity of demand).

For the above reasons, Core has derived a forecast of both own price and cross price elasticity of demand for gas in the ActewAGL Distribution over the Review Period.

Approach

Core has undertaken an assessment of the alternative approaches available to derive an estimate of the price elasticity of gas demand within ActewAGL Distribution, including broad-based research of approaches adopted nationally and internationally. Core is of the opinion that the preferred approach would involve an observation of actual demand response to actual price movements over a statistically relevant period. However, the specific circumstances of this review involve a likely material price movement in both gas and electricity prices in the future (from 2016). Therefore, it is not possible to apply such an approach. Core is of the opinion that the best estimate, under the circumstances, will be derived by applying a rigorously determined elasticity factor against a rigorous assessment of future gas and electricity prices in ACT during the Review Period. This is the approach adopted for this review.

Core has undertaken an extensive review of historical GAAR's and empirical studies, relating to price elasticity of demand generally and in relation to gas and electricity more specifically.

The two price elasticity factors Core has quantified are:

- own price elasticity (the change in gas demand resulting from a change in the price of gas); and
- cross price elasticity (the change in gas demand resulting from a change in the price of a substitute energy source such as electricity).

Core's analysis has considered:

- the results of third party analysis via an international literature review regarding price elasticity factors; and
- the range of price elasticity factors previously accepted by the AER in prior GAAR's.

Core is of the opinion that the listing of own-price and cross-price elasticity factors, which are summarised in Table A 4.1 and Table A 4.2 provide a reasonable basis for deriving an estimate of the price elasticity of demand for gas in the ActewAGL Distribution Network.

In the literature research, cross price elasticity is in the range of 0.011 to 1.24. Core has arrived at a cross price elasticity of 0.1 based on the literature research in Table A 4.1. Nilsen et al found cross price elasticity under 0.1 in the UK. However, in the same study cross price elasticity in several other European countries is above 0.1. Most of the literature found the range of cross price elasticity to be between 0.1 and 0.15. Thus, Core has adopted a conservative view, arriving at cross price elasticity of 0.1.

Table A 4.1 Price Elasticity of Gas Demand – Literature Review.

Year Published	Study	Country	Author / Source	Own Price Elasticity of Gas Demand	Cross Price Elasticity of Gas Demand
1987	Residential gas consumption	US	Herbert	-0.30 (short run)	0.10 (short run)
1999	Gas demand forecast and transmission and distribution tariffs	Australia	Harman et al	-0.54 (Short run) -0.65 (Long run)	N/A
2001	Residential gas consumption	Australia	Akmal and Stern		0.870 (Long run)
2004	The ex post impact of an energy tax on household energy demand	Netherlands	Berkhout et al	-0.19 (Short run) -0.44 (Long run)	N/A
2005	Residential gas consumption	Europe	Nilsen et al		Austria 0.484, 0.525 (short run) 0.758, 0.891 (long run) UK 0.011, 0.031 (short run) 0.024, 0.064 (long run) Netherlands 0.152 (short run) 0.226 (long run)
2005	Regional differences in the price-elasticity of demand for energy	US	Bernstein, Griffin	-0.12 (Short run) -0.36 (Long run)	0.11 (electricity price of previous year)
2010	Residential consumption of gas and electricity in the US	US	Alberini et al	-0.552 (Short run) -0.693 (Long run)	0.15 (Long run)
2011	Residential gas consumption	US	Payne, Loomis, Wilson	-0.264 (Long run)	0.123 (Long run)
2014	Residential gas consumption Commercial gas consumption	US	US Energy Information Administration		Residential: 0.13 Commercial: 1.24

Source: Third Party expert reports and analysis

Table A 4.2 Price Elasticity of Gas Demand – Prior AER Submissions.

Period	Network	Source	Own Price Elasticity of Demand	Cross Price Elasticity of Demand
2013-17	Multinet (VIC)	NIEIR	-0.28 (all customer segments)	N/A
2011-16	Envestra (SA)	NIEIR	-0.30 (Residential, long-run) -0.35 (Industrial, long-run)	N/A
2013-17	SP Ausnet (VIC)	CIE	-0.17 (Residential, long-run) -0.77 (Commercial, long-run)	N/A
2013-17	Envestra (VIC, Albury)	Core	-0.30 (Residential, long-run) -0.35 (Non-residential, long-run)	N/A

Source: Access Arrangement demand forecast submissions.

Own Price Elasticity

To derive a forecast of the impact of forecast gas price movements on demand per connection, Core has adopted a long-term price elasticity factor which is consistent with Envestra's 2011-16 regulatory submission for South Australia, as prepared by NIEIR and accepted by the AER. This elasticity falls within the AER's accepted range as outlined in its Final Decision:

"*NIEIR's assumed long run price elasticity appears to be consistent with those produced by other studies. However, the AER acknowledges the limitations of this comparative analysis due to geographical factors and time differences. For this reason it has performed a regression analysis to estimate price elasticity based on historical average residential consumption data, the real retail gas price index, and ABS real household disposable income per capita data to compare against NIEIR's estimate. The regression analysis produced an indicative estimate for long run price elasticity of -0.41, with a 95 per cent confidence interval for the estimate range from -0.23 to -0.58. As NIEIR's estimate is broadly in line with the range of the estimates obtained in other studies and the AER's own indicative estimate, the AER considers that the assumed long run residential price elasticity of -0.30 is reasonable and represents the best estimate possible in the circumstances.*[35]*.*"

Core has used reference values of -0.30 (residential) and -0.35 (non-residential) as long-run elasticity factors in its final demand forecast model.

Table A 4.3 Own Price Elasticity.

Market Type	Reference
Residential	-0.30
Non Residential	-0.35

Source: AER Final Decision, Envestra Limited Access Arrangement Proposal, SA Gas Network 2011 –16.

The interpretation of these elasticity factors is that for every percentage increase in retail gas price, gas demand will decrease by 0.3 percent (0.35 percent for non-residential customers).

These long-run elasticity factors are a summation of the individual short-run elasticity factors which are applied as shown in Table A4.4 below. Demand impacts are highest in the year of the price change (for residential) and the year after the price change (non-residential).

[35] AER, Final Decision, Envestra Limited Access Arrangement Proposal for the SA Gas Network 1 July 2011 – 30 June 2016, June 2011, p103.

Table A 4.4 Short-Run Price Elasticity Factors.

Elasticity	Residential	Non-Residential
Δp(t)	-0.13	-0.06
Δp(t-1)	-0.08	-0.16
Δp(t-2)	-0.05	-0.09
Δp(t-3)	-0.03	-0.03
Δp(t-4)	-0.01	-0.01
Total	**-0.30**	**-0.35**

Source: Core Energy Group.

These short-run elasticity factors are applied to the annual real increase in gas prices in Table A4.5 to arrive at the own price elasticity impact in each year, for each customer segment, as summarised below.

Table A 4.5 Own Price Elasticity Impact on Demand.| %

Own Price Elasticity Impact on Demand (%)	2014	2015	2016	2017	2018	2019	2020	CAGR (as per Table 1.24)
Residential								
Change in Gas Prices	6.9%	6.8%	-3.4%	1.6%	4.1%	-0.9%	-0.9%	2.1%
Price Elasticity Impact (-0.30)	-2.4%	-2.4%	-0.9%	-0.6%	-0.8%	-0.3%	-0.0%	-0.5%
Non-Residential (Small Business and I&C)								
Change in Gas Prices	6.9%	8.1%	-4.8%	3.7%	7.9%	-0.7%	-0.7%	2.9%
Price Elasticity Impact (-0.35)	-3.3%	-3.0%	-2.1%	-0.5%	-1.0%	-1.5%	-0.6%	-1.1%

Source: Core Energy Group.

Cross Price Elasticity

Core acknowledges that cross price elasticity has not been addressed widely in prior access arrangement reviews.[36] Core believes that this is attributed to the relative prices of gas and electricity historically not being sufficiently different to cause changes in demand over the regulatory time frame under consideration. However, Core is of the opinion that material changes in gas prices relative to electricity price are likely to occur during the Review Period and that it is reasonable to expect a cross-price demand response. Based upon Core's analysis, which is set out in further detail in Annexes 2 and 3, the forecast price movement between gas and electricity prices (from current levels) is expected to exceed 24.26% for residential customers and 16.09% for non-residential customers by 2020 (from end 2013 levels), in favour of electricity, as shown in Table A 4.6.

[36] This matter was addressed in the AER's Draft decision in relation to the Jemena network access arrangement proposal

Table A 4.6 Retail Gas and Electricity Price Projections (Real Percentage Change).| %

Change in Retail Bill	2014	2015	2016	2017	2018	2019	2020
Residential							
Gas	4.50%	-2.54%	0.00%	5.02%	6.88%	0.00%	0.00%
Electricity	0.00%	-6.20%	-5.90%	1.70%	0.00%	0.00%	0.00%
Differential	4.50%	3.66%	5.90%	3.32%	6.88%	0.00%	0.00%
Cumulative Differential	4.50%	8.16%	14.06%	17.38%	24.26%	24.26%	24.26%
Non-Residential							
Gas	4.50%	-2.91%	0.00%	5.94%	8.07%	0.00%	0.00%
Electricity	0.00%	-1.64%	0.47%	0.73%	0.00%	-0.03%	-0.02%
Differential	4.50%	-1.27%	-0.47%	5.21%	8.07%	0.03%	0.02%
Cumulative Differential	4.50%	3.23%	2.76%	7.97%	16.05%	16.07%	16.09%

Source: Core Energy Group.
Source: IPART – Updating Regulated Gas Prices for 1 July 2014, IPART Review of Regulated Electricity Prices 2013-2016.

Based on Core's analysis, an assumed short run elasticity of 0.10 for both residential and non-residential customers is deemed reasonable as shown in Table A 4.7 below. The interpretation of the elasticity factor is that for every percentage increase in retail gas price in a given year, demand for electricity will increase by 0.1 percent in that year. Alternatively, for every percentage increase in electricity price, gas demand will increase by 0.1 per cent. These price elasticity factors are applied to the forecast annual real increase in electricity prices to arrive at the cross price response for each customer segment as summarised below.

Table A 4.7 Cross Price Elasticity Impact on Demand.| %

Cross Price Elasticity Impact on Demand (%)	2014	2015	2016	2017	2018	2019	2020
Residential							
Change in Electricity Prices	-1.58%	-6.20%	-5.90%	1.70%	0.00%	0.00%	0.00%
Price Elasticity Impact (0.10)	-0.16%	-0.62%	-0.59%	0.17%	0.00%	0.00%	0.00%
Non-Residential (Small Business and I&C)							
Change in Electricity Prices	-2.38%	-1.64%	0.47%	0.73%	0.00%	-0.03%	-0.02%
Price Elasticity Impact (0.10)	-0.24%	-0.16%	0.05%	0.07%	0.00%	0.00%	0.00%

Source: Core Energy Group.

Annexure 5 | Volume Customers Residential Connections Forecast

This annexure summarises the approach used by Core Energy to derive the forecast of residential connections for the ActewAGL Distribution network during the access arrangement period from 2016/17 to 2020/2021.

Existing Connections

1. Opening residential connection numbers between 2007 and 2014 were obtained from Jemena/ActewAGL Distribution.
2. Disconnections between 2012 and 2014 were obtained from Jemena/ActewAGL Distribution.[37] Disconnection numbers were provided as a total for both residential and business segments. To estimate the number of historical disconnections for the residential segment, the total number of disconnections was divided based on the proportion of residential connections vs. business connections in 2014.
3. The annual average percentage of disconnections to opening connections was used to forecast disconnections for the access arrangement period.
4. The closing number of connections 2014 and the forecast of disconnections, calculates the number of existing connections from 2014 between 2015 and 2021.

New Dwelling Connections

Core developed a bottom-up forecast of residential connections within the ActewAGL Distribution network, based on the new dwellings forecast reported by HIA as of February 2015[38], as provided in Table A 5.1.

Table A 5.1 HIA Forecast of New Dwellings | No.

Dwelling Type	2015	2016	2017	2018	2019	2020	2021
Houses (New Estates)	1,660	1,780	2,020	1,800	1,800	1,800	1,800
Multi Units (Medium & High Density)	1,880	1,450	1,480	1,680	1,680	1,680	1,680
Total	3,540	3,230	3,500	3,480	3,480	3,480	3,480

As this forecast only refers to new dwellings in the ACT region, the forecast was scaled up by 13.7% to reflect the additional new dwellings forecast for the regions of Queanbeyan and Palerang. The historical change in population in Queanbeyan and Palerang accounts for 13.7% of the total change in population across three regions within the ActewAGL network. The scaled new dwellings forecast is provided in

Table A 5.2 HIA Forecasts of New Dwellings Scaled to Account for Queanbeyan and Palerang | No.

Dwelling Type	2015	2016	2017	2018	2019	2020	2021
Total	4,100	3,741	4,054	4,031	4,031	4,031	4,031

The reach of the ActewAGL Distribution network is assumed to be 100%. To determine the number of new dwelling connections, it is assumed that 90% of households will connect to the ActewAGL Distribution gas network. The number of new connections forecast for the Review Period is 18,159. A summary of the forecast of new connections is provided in Table A5.3

[37] Jemena/ActewAGL Distribution, Copy of 18 11 2014 ACT disconnections historicals.xls, Tab: Sheet 1
[38] Housing Industry Australia, Housing Forecasts, February 2015 <http://hia.com.au/en/BusinessInfo/economicInfo/housingForecasts.aspx>

Table A 5.3 Forecast of New Connections | No.

	2015	2016	2017	2018	2019	2020	2021
New Dwellings in ActewAGL Distribution Region	4,100	3,741	4,054	4,031	4,031	4,031	4,031
Penetration of ActewAGL Distribution Network[39]	90%	90%	90%	90%	90%	90%	90%
New Connections	3,690	3,367	3,648	3,628	3,628	3,628	3,628

To determine the allocation of connections between dwelling type (New Estate vs. Medium/High Density), the forecast of dwelling starts by dwelling type from HIA Housing Forecasts were used. This data was released in November 2014, and forecasts 52% of future dwellings between 2015 and 2021 to be new estates. The remaining 48% will be medium/high density dwellings. The percentage of total dwellings to be connected in a given year was also determined based on the forecasts provided by HIA.

Table A 5.4 Apportionment of New Dwelling Connections by Dwelling Type | %

	2015	2016	2017	2018	2019	2020	2021	Total
% of New Estate Connections of Total New Connections	6.86%	7.36%	8.35%	7.44%	7.44%	7.44%	7.44%	52.34%
% of Medium/High Density Connections of Total New Connections	7.77%	5.99%	6.12%	6.95%	6.95%	6.95%	6.95%	47.66%

These percentages are used to allocate the forecast of new dwelling connections to a given dwelling type, and year.

Table A 5.5 Forecast of New Connections by Dwelling Type | No.

	2015	2016	2017	2018	2019	2020	2021
New Estate	1,730	1,856	2,106	1,876	1,876	1,876	1,876
New MD/HR	1,960	1,512	1,543	1,751	1,751	1,751	1,751
Total	**3,690**	**3,367**	**3,648**	**3,628**	**3,628**	**3,628**	**3,628**

[39] Assumption based on Jemena/ActewAGL Distribution feedback

Annexure 6 | Macroeconomic Variables Analysis

Residential Demand per Connection

Summary

Regression analysis was undertaken in order to examine the impact and statistical significance of macroeconomic variables on demand per connection. Based on the evidence, Core considers that changes in macroeconomic variables do not have a significant impact on demand per connection. This is the expected outcome as it is unlikely that changes in the macro-economy have a significant relationship with individual changes in demand per connection, albeit based on a small statistical sample.

Key Findings

- All univariate regressions generate negative coefficients for the macroeconomic variables.
- Once a price variable is included most models appear to suffer from a high degree of collinearity.
- The lag of GSP per capita is the only statistically significant macroeconomic variable in the multivariate analysis, although the estimate of 2.48% is far above the expected relationship.
- GSP per capita and the lag GSP per capita have coefficients of 2.48% and 1.76% respectively, which are far above the average of 0.32%. In the univariate analysis these variables have the two lowest coefficients.
- The lags of GSP and SFD have negative signs which is not expected.
- The lag price of gas appears to has an average impact of -0.46%.
- GSP per capita has the highest impact of 2.48% compared to -0.998% for the lag of GSP.

Table A 6.1 Univariate Regression Output

	Residential D/C	Residential D/C	Residential D/C	Residential D/C	Residential D/C	Residential D/C	Residential D/C	Residential D/C
LOG(GSP)	-1.012*							
LOG(GSP)t-1		-0.988**						
Log(GSP/Capita)$_t$			-1.786					
Log(GSP/Capita) t-1				-1.910*				
Log(GHDI)					-0.549*			
LOG(GHDI)t-1						-0.481*		
LOG(SFD)							-0.745*	
LOG(SFD)t-1								-0.689*
Constant	14.34**	14.07**	24.01	25.40*	9.351**	8.637**	11.91**	11.28**
N	7	7	7	7	7	7	7	7
R^2	0.714	0.81	0.306	0.624	0.675	0.729	0.673	0.724
Adjusted R^2	0.657	0.772	0.167	0.549	0.61	0.675	0.608	0.669
AIC	-23.15	-26.03	-16.95	-21.25	-22.27	-23.53	-22.22	-23.42
rmse	0.0412	0.0335	0.0641	0.0472	0.0438	0.0401	0.044	0.0404

Note * represents 5% significance level.

Table A 6.2 Multivariate Regression Output

	Residential D/C	Residential D/C	Residential D/C	Residential D/C	Residential D/C	Residential D/C	Residential D/C	Residential D/C
LOG(GSP)	0.43							
LOG(GSP)t-1		-0.998						
Log(GSP/Capita)$_t$			2.4849*					
Log(GSP/Capita) t-1				1.775				
Log(GHDI)					0.51789			
LOG(GHDI)t-1						0.1377141		
LOG(SFD)							.4348	
LOG(SFD)t-1								-0.0556
Log(Price)t-1	-0.514	0.00386	-0.6434*	-0.66227	-0.77158*	-0.51061	-0.56	-0.34
Constant	2.8859	14.14	-19.84787	-11.67644	3.337049	5.807458	2.9632	6.765
N	7	7	7	7	7	7	7	7
R^2	.78	0.81	0.93	0.8148	0.8886	0.7775	0.7886	0.7743
Adjusted R^2	.67	0.72	0.89	0.7222	0.8330	0.6663	0.6829	0.6614
AIC	-22.97	-24.03	-30.97	-24.19	-27.76	-22.916	-23.27	-22.81
rmse	0.04039	0.03747	0.02283	0.03702	0.02871	0.04058	0.03955	0.04087
VIF	23.06	22.76	3.8	13.19	9.16	33.51	15.62	13.26

Note * represents 5% significance level.

Conclusion

Although the univariate regressions suggest the economic variables are statistically significant they produce estimates with signs which are contrary to expectations. The multivariate models do not provide any significant relationships with the exception of GSP per capita. There also appears to be a high degree of volatility in the estimate impact across the univariate and multivariate models. The impact of the economic variables change from negative in the univariate models to positive once a price variable is added. Additionally, most models suffer from a high degree of collinearity which makes the standard errors and statistical significance of the variables unreliable.

Although GSP per capita has the correct sign and is significant without having any collinearity issues, it is much larger than what is reasonably expected. As GSP does not appear to have a statistical relationship with demand per connection, the high degree of significance is most likely due to impact of population. Compared to GSP, per capita GSP has a lower average annual growth rate and has declined in the last two years (2013-2014). Therefore it seems that the impact of increasing population has lowered the growth and variance of GSP per capita, causing it to have a stronger relationship with demand per connection, which has declined in every year since 2007. Overall, the small sample size, lack of statistical significance, high collinearity and volatility do not provide reliable estimates that can be used for the purpose of forecasting. These results confirm that residential demand does not appear to be influenced by broad macroeconomic indicators and there is no reasonable basis for including it in the forecasting model.

Business Demand per Connection

The following economic variables are selected to measure the relationship between business demand per connection and the macro-economy.

Key Findings

- All univariate regressions generate statistically significant relationships with demand per connection.
- All univariate an multivariate regressions have negative coefficients which is not expected.
- Once a price variable is included the coefficients of the economic factors become less negative but are statistically insignificant.

The multivariate models all suffer from a high degree of collinearity which makes the level of significance unreliable.

Table A 6.3 Univariate Regression Output

	Business D/C	Business D/C	Business D/C	Business D/C
LOG(GSP)	-1.247**			
LOG(GSP)t-1		-1.203**		
LOG(SFD)			-0.928*	
LOG(SFD)t-1				-0.845**
Constant	19.26**	18.78***	16.38**	15.45***
N	7	7	7	7
R^2	0.714	0.81	0.675	0.729
Adjusted R^2	0.657	0.772	0.61	0.675
AIC	-23.15	-26.03	-22.27	-23.53
rmse	0.0412	0.0335	0.0438	0.0401

Table A 6.4 Multivariate Regression Output

	Business D/C	Business D/C	Business D/C	Business D/C
LOG(GSP)	-0.035			
LOG(GSP)t-1		-0.585		
LOG(SFD)			-0.00187	
LOG(SFD)t-1				-0.148
Log(Price)t-1	-0.445	-0.245	-0.456	-0.386
Constant	10.43	14.44	10.18	11.17*
N	7	7	7	7
R^2	0.86	0.877	0.86	0.863
Adjusted R^2	0.79	0.815	0.79	0.795
AIC	-23.79	-24.7	-23.78	-23.95
rmse	0.0381	0.0357	0.0381	0.0377
VIF	9.39	11.80	15.62	13.26

Conclusion

The univariate regressions produce negative coefficients which is not expected. When the price variable is added to the models, the macroeconomic variables become less negative but are no longer significant. The multivariate models suffer from a high degree of collinearity which makes the level of significance unreliable. Therefore there is no evidence that changes in the broader economy have a significant impact on business demand per connection. This is consistent with the fact that ACT does not have heavy industry, in the main, where the use of gas may depend on the level of business output. Most industry in the ACT is services, where gas is mainly used for space heating and water heating and this does not vary much with the output or production of the underlying business.

Business Connections

The following economic variables are selected to measure the relationship between business connections and the macro-economy.

- GSP
- State Final Product (SFD)

Given the small sample size of 8 observations, different model and variable specifications are used to confirm, or provide further general intuition, about the relationship. The log transformation of the macroeconomic variables was initially regressed univariate with business connections. The one period lag of the macroeconomic variable is included in the analysis due to potential delay in responses. Then a series of multivariate regressions including gas price and price are generated. The most suitable regression to model the relationship between GSP and Business connections is:

$$Connections = \beta_0 + \beta_1 (LogGSP)_{t-1}$$

Table A 6.5 and Table A 6.6 summarises the statistical regression.

Table A 6.5 Regression Output GSP

	Connections	Connections	Connections	Connections	Connections	Connections
$Log(GSP)_t$	1.24***		0.798	1.038		
LogGSP t-1		1.133***			1.202***	1.84**
Log(Price)			0.168			-0.0213
Log(Price)t-1				0.0773	-0.0287	
Constant	-4.93**	-3.74***	-1.662	-3.403	-4.226*	-4.096
N	8	8	8	8	8	8
R^2	0.98	0.996	0.98	0.997	0.996	0.996
Adjusted R^2	0.97	0.995	0.973	0.996	0.995	0.994
AIC	-43.57	-57.99	-43.25	-41.89	-56.29	-56.1
rmse	0.1429	0.00580	0.0141	0.0153	0.00624	0.00631

Note * represents 5% significance level.

Table A 6.6 Regression Output SFD

	Connections	Connections	Connections	Connections	Connections	Connections
$Log(SFD)_t$	0.918***		0.368	0.462		
Log(SFD) t-1		0.787***			0.521*	0.552
Log(Price)			0.282			0.139
Log(Price)t-1				0.230	0.159	
Constant	--1.96	-0.501	1.718	1.135	1.087	0.903
N	8	8	8	8	8	8
R^2	0.953	0.975	0.976	0.966	0.984	0.978
Adjusted R^2	0.945	0.971	0.966	0.952	0.978	0.969
AIC	-38.26	-43.45	-41.55	-38.79	-44.86	-42.16
rmse	0.0199	0.0144	0.0157	0.0186	0.0127	0.0151

Note * represents 5% significance level.

Conclusion

Generally there is a statistically significant relationship between GSP/SFD and business connections. The inclusion of price variables results in an unacceptable degree of collinearity which makes the estimates and significance levels unreliable. As such, univariate models are preferred in this instance. Model 2 was selected as the preferred model as GSP has a significant impact on connections. The model has a sufficiently high R-square and the lowest AIC. For every 1% increase in GSP, business connections grew by 1.13%.

Annexure 7 | Continued Demand per Connection Drivers

ACT Energy Use Trends (Mar 2014)

The most significant uses of gas for Australian households are heating, hot water heating and cooking. Recent data released by the ABS shows that gas is being substituted for electricity and solar energy when it comes to space heating and water heating.[40] The table below illustrates the substantial increase in ACT households that now use electricity for their heating purposes. This is due mostly to the superior running costs and efficiency of reverse cycle air-conditioners (RCACs) and other forms of electrical heating. In the last three years, the market share of electricity for space heating increased by over 35%. To reinforce this substitution effect, 22% of ACT households that were using gas for heating purposes made the switch to electricity. The data also shows that solar systems are on the rise for hot water heating. Many of these are gas boosted meaning that the household will retain gas as a water heating source but gas will only be used when the solar system cannot provide all the hot water demanded by a household. Therefore, the 3.9% increase in gas water heating could overstate the true increase to gas. More houses can list gas as a water heating source but realistically they will demand only a fraction of gas once solar water heating is installed. The growth of solar water heating was 29% over the three years and this is expected to continue to lower gas demand during the Review Period.

Table 6.7 ACT Energy Use | % of Households

	2011	2014
Electricity main source for heating	33.0	44.7
Gas main source for heating	59.3	46.3
Gas energy for hot water (includes gas boosting)	42.5	46.4
Electricity for hot water (includes solar electricity)	52.3	52.0
Solar used for hot water system	5.5	7.1

A widely sourced study entitled *Are We Still Cooking with Gas?* conducted by the Alternative Technology Association (ATA), and supported by the energy market's Consumer Advocacy panel study found that houses already connected to the gas network could steadily withdraw from using gas for space heating in favour of using reverse-cycle air conditioners, on economic grounds.

Core analysis concludes that solar power will continue to erode the market share of gas both via use of solar water heating and change out of appliance to utilise solar PV based power. Currently, photovoltaics require between 4 and 7 years to recoup their investment. Small-scale Renewable Energy Scheme ("**SRES**") grants households small-scale technology certificates ("**STCs**") which can be sold back to an energy provider or traded. This gives a financial incentive for the installation of solar power systems.12% of eligible households in the ACT are fitted with solar photovoltaics and this represents around 7% of households overall. The large uptake across the whole nation has driven down costs for all consumers so gas users in the ACT network will face increasing incentives to allocate some of their energy requirements to a new solar system. Approximately half of ACT houses are eligible to be fitted with solar photovoltaics but have yet to do so. Households will naturally switch away from using gas and use solar

[40] 4602.0.55.001 - Environmental Issues: Energy Use and Conservation, Mar 2014
http://www.abs.gov.au/ausstats/abs@.nsf/mf/4602.0.55.001

generated electricity instead. Houses will probably retain gas connections for some smaller uses but wherever possible they would be using electricity supplied by their solar photovoltaic systems. In addition to solar photovoltaics, a national ban on the replacement of electric hot water systems from 2012 is expected to boost the solar hot water industry going forward.

Updated E3 program and MEPS

Under the E3 program, Minimum Energy Performance Standards ("**MEPS**") specify the minimum level of energy performance that appliances, lighting and electrical equipment must meet or exceed before they can be offered for sale or used for commercial purposes. MEPS and labelling was implemented for gas appliances in 2009 and 2010 as part of the "Switch on Gas" ten year strategic plan.[41] The aim of the energy rating labelling program is to:

- Encourage consumers to select the appliance that uses the least energy and which meets their energy service needs.
- Enable consumers to understand the approximate running costs of an appliance before buying and to minimise the total life cycle cost of the appliance where possible[42]
- Provide incentives for manufacturers and importers to improve the energy efficiency of the products they supply to the market.

The latest impact study of the E3 program illustrates the underlying fall in demand per connection. Between 2000 and 2013, all E3 programs have saved a combined 6.1PJ of gas, and 1.6PJ or 26.2% of those savings came in 2013 alone.[43] Furthermore, the impact study says that another 0.8PJ could be saved with faster implementation than the current rate. In this way it treats the initial estimate as somewhat of a conservative figure. The E3 program was strengthened in 2012 when the *Greenhouse and Energy Minimum Standards (GEMS) Act 2012* replaced seven separate state and territory energy efficiency regulations. The legislation put into place a national framework for E3. The program now incorporates increased data reporting and compliance measures such as fines. This program is therefore expected to be a continued driver of household efficiency gains.

In addition the Department of Industry's forecast in March of last year indicates that gas savings are expected to total 27.8PJ between 2014 and 2020. This is an annual average saving of 4.5PJ, almost three times the 2013 figure.

[41] "Prevention is Cheaper than Cure", http://www.energyrating.gov.au/wp-content/uploads/Energy_Rating_Documents/Library/Equipment_Energy_Efficiency_Program_%28E3%29/200901-projected-impacts.pdf
[42] Department of Environment, Water, Heritage and the Arts (DEWHA), Energy Use in the Australian Residential Sector 1986 – 2021, 2008
[43] Department of Industry, Impacts of the E3 program: Projected energy, cost and emission savings, March 2014, http://www.energyrating.gov.au/wp-content/uploads/Energy_Rating_Documents/Library/General/Equipment_Energy_Efficiency_Program_(E3)/Impacts-of-the-E3-Program.pdf

Behaviour and Attitudes of Australian households

This section seeks to clarify the incentives and decision making involved with household energy use decisions. A useful way to predict the behavioural patterns of households is to ascertain the motives for their energy usage decisions. A qualitative survey conducted by the Australian Housing and Urban Research Institute, was carried out in two cities of Australia, Brisbane and Melbourne.[44] The table below reports some relevant findings and gives a cross section of households who reduced their energy use over the study period. It shows what reasons were behind decisions that ultimately reduced energy. Note that households could hold multiple reasons for changing their energy usage. 47.1% of Brisbane respondents reduced their energy use due to an appliance or fitting replacement. 38.1% in Melbourne cited the same reason. This is a strong reflection of continuing appliance trends which have also been discussed in this report. Across two cities, almost half of energy use reductions are being driven by new appliances.

Just over 60% of respondents in both cities changed their energy use due to a new awareness of just how to achieve reduced energy use. This suggests that public campaigns and awareness measures do influence household energy use decisions. Public awareness campaigns and climate change discussions have only increased over the last few years, suggesting that such decisions will only increase. The reduced gas demand from increased awareness will be partially captured by the appliance and efficiency trend.

There are further reasons cited which suggest a potential switch-off effect. In addition to growing awareness of energy efficiency, the proportion of households reducing their energy use due to environmental protection centres on 50%. It is reasonable to expect that climate change and public awareness will remain a live issue in Australia over the Review Period. If households are motivated by environmental protection it suggests that it isn't just energy cost savings that drive these decisions. It suggests that households may even switch off or assign a higher threshold of discomfort before using gas. In addition to more efficient appliances, it is feasible that many households will make conscientious efforts to take shorter showers or perhaps wear a jumper rather than heat their house for prolonged periods. This switch-off effect would be in addition to the impact of appliance substitution and efficiency trends.

Table 6.8 % of respondents who cited the following reasons as responsible for a change in their energy use behavior | %

Reason	Brisbane respondents	Melbourne respondents
Commitment to protecting the environment	45.1%	52.1%
Awareness of ways to save energy	61.5%	62.3%
Changes in fittings and appliances	47.1%	38.1%

[44] Fielding, K. Et al., Environmental Sustainability: understanding the attitudes and behaviour of Australian households, Australian Housing and Urban Research Institute, October 2010
http://www.ahuri.edu.au/publications/download/ahuri_20550_fr

Policies and programs contributing to appliance substitution and efficiency trends

Policy	Impact on Review Period Demand
Renewable Energy Target ▪ The Renewable Energy Target (RET) scheme is designed to ensure that a certain percentage of Australia's electricity comes from renewable sources by 2020. ▪ Since January 2011 the RET scheme has operated in two parts—the Small-scale Renewable Energy Scheme (SRES) and the Large-scale Renewable Energy Target (LRET). ▪ The SRES creates a financial incentive for households, small businesses and community groups to install eligible small-scale renewable energy systems such as solar water heaters, and solar photovoltaic (PV) systems.	▪ Core has assumed that the RET will continue to impact gas consumption to a similar extent that has existed over the historical period. ▪ At the time of writing, the future of the RET is not entirely certain. However, the existence of the target is not under threat. There is merely a deadlock of political opinion as to the size of the target. The significance of this is that the RET, no matter how big or small will be a driver of government policy. Policies for energy efficiency and greenhouse gas reduction will only strengthen or increase in number. ▪ Household appliances account for 41% of residential GHG emissions. This makes them an obvious target for future policy. This suggests current efficiency trends and appliance trends should pick up their pace and at the very least, hold their current rate of growth. The resulting fall in gas demand will continue at the very least. If the target is to be achieved, average gas usage will have to fall at faster rate over the Review Period.
NABERS, NATHERS and the Building Code of Australia ▪ National Australian Built Environment Rating System is a performance-based rating system for buildings and uses a star system to rate a building on the basis of its measured operational impacts on the environment. The NABERS system now extends to 6 stars and is a simple indication of how well a commercial building manages the environmental impact of the resources used, compared with similar buildings. ▪ In 2006, the Building Code of Australia ("BCA") set a new residential building energy efficiency standard of 5 stars, as rated by software tools accredited under the Nationwide House Energy Rating Scheme ("NatHERS"). To reach the 5-star energy efficiency standard, architects and builders could choose from a large variety of options, such as increasing insulation in ceilings, walls and floors; using double glazing; and redesigning house layout and orientation.	▪ Core knows of no reason to assume that future impact of the NaTHERS policy during the Review Period will vary materially from the impact observed during the 2011 to 2014 period. Therefore, Core assumes that energy efficiency gains from this program to continue over the Review Period.
Water Efficiency Labelling and Standards ("WELS") ▪ Increased penetration of energy efficient showerheads under the Water Efficiency Labelling and Standards Scheme, which reduces water usage by 40% compared to standard showerheads, has contributed to lower gas hot water usage.	▪ Core knows of no reason to assume that future impact of the WELS policy during the Review Period will vary materially from the impact observed during the 2011 to 2014 period. Therefore, Core assumes that energy efficiency gains from this program to continue over the Review Period.
Restriction on High Emission Water Heaters ▪ From 31 January 2010, domestic water heaters in houses and townhouses must comply with minimum greenhouse intensity and/or energy efficiency standards. Only certain solar, heat pump and gas storage and gas instantaneous water heaters can be installed in a hot water system. Electric resistance water heaters are no longer permitted; however, an electric-boosted heat pump or solar water heater can be installed if it meets the minimum standard.[45]	▪ Core analysis indicates that the reduction of use of Electrical Resistance systems will not have a material impact on demand per connection during the Review Period due to the low penetration rate of this appliance type. Therefore no adjustment has been made in arriving at a forecast of demand per connection. ▪ These requirements do not apply to: > Homes which had building approval for plans before 31 January 2010 > Water heaters installed in new apartments and units > Replacement water heaters in houses built before 31 January 2010 > Hot water systems being replaced under warranty, and > Hot-water systems containing solid fuel-burning equipment being installed in homes in non-urban land areas.

[45] ACT Government, Environment and Planning Directorate, Hot water heater requirements, accessed 11 November 2014 < http://www.planning.act.gov.au/customer_information/community/hot_water_heater_requirements>

ACT Policy and Energy Efficiency Considerations

Policy	Impact on Review Period Demand
The ACT house Energy Rating Scheme ("ACTHERS") ▪ The ACT House Energy Rating Scheme (ACTHERS) was established in 1995 for rating new houses and units, and was expanded in 1999 to incorporate the mandatory disclosure of energy efficiency for the sale of residential properties. It uses software to assess the thermal performance of buildings.	▪ Core knows of no reason to assume that future impact of the ACTHERS policy during the Review Period will vary materially from the impact observed during the 2011 to 2014 period. Therefore, Core assumes that energy efficiency gains from this program to continue over the Review Period.
Home Energy Advice Team (HEAT) program ▪ The ACT HEAT Energy Audit program provided eligible ACT households with a $500 rebate to help save energy and money, and make their homes more comfortable. The rebate is no longer available, with the program integrated into EEIS, run by electricity retailers, on 21 April 2013. 7,000 houses were audited in 7 years.	▪ Core analysis indicates that the termination of the HEAT program will not have a material impact on demand per connection during the Review Period. Therefore, no adjustment has been made in arriving at a forecast of demand per connection.
Mr. Fluffy Buy Back Scheme ▪ On 4 December 2014, the ACT Legislative Assembly passed a bill to allow the ACT Government to proceed with the 'Mr Fluffy buyback scheme'. This scheme involves the buyback and demolition of around 1,021 houses contaminated with loose fill asbestos. Through publicly available information on the ACT Government's Asbestos Response Taskforce website,[46] it is expected the phased demolishment of the 1021 homes will occur over 3 years.	The recommendation by the Taskforce was reflected in Core's modelling of the Mr Fluffy buy back scheme, as follows: ▪ Assume 90% of houses affected are in our network (0.9 * 1021 = 918 disconnections and new connections) ▪ Assume disconnections are spread evenly over 3 years i.e. 306 per year starting 1 July 2016 ▪ Assume replacement homes built over 3 years i.e. 306 per year starting 1 July 2017 ▪ Assume this will have a pull forward effect on the existing connection forecast (to accommodate people as they move out)
Gas Service and Installation Rules Code and Gas Network Boundary Code Amendment ▪ The Gas Service and Installation Rules Code and ACT Utilities (Gas Network Boundary Code) Determination was revised in 2013 to prohibit the internal installation of gas meters in high rise developments by the gas distributor (other than gas hot water)	▪ The impact of this change is expected to be a fall in M/H density demand per connection due to the significantly higher cost to builders and property developers to offer gas heating and gas cooking connections in high rise developments ▪ ActewAGL Distribution provided analysis, which was reviewed by Core and found to be reasonable, that calculates the current demand per connection for medium density dwellings and high density dwellings, assuming high rise dwellings only have a gas hot water load. ▪ The demand per connection in 2015 is forecast to be 16.42GJ, 5.58GJ lower than the 22GJ recorded in the previous year (2014) to reflect this policy change.

[46] ACT Government, Asbestos Response Taskforce, Buyback, accessed 20 January 2015 < http://www.asbestostaskforce.act.gov.au/>

Annexure 8 | Demand Customer Consultation Questions

Context

As a network operator, we are required under the rules to provide a reasonable forecast of demand for the 2016-2021 access arrangement period to help us better plan for our network capacity requirements, including any potential network extensions or expansions. As you are a major customer on our network, we’re keen to engage with you as any changes to your forecast gas consumption may influence our future network planning decisions. We have engaged Core Energy Group to provide an independent forecast of gas demand.

Preliminary Questions

- Are you comfortable talking to us about the factors that may influence your gas demand over the 2016-2021 period?
- Are you comfortable discussing your recent gas load information with us?

Questions Relating to Future Demand

- What changes if any to you expect in the future regarding your gas consumption in terms of MDQ and ACQ?

Annexure 9 | Demand Customer | Economic Outlook

Demand customers were classified by ANZSIC 2006 divisional structure, with manufacturing further devised by manufactured product. The following table provides an estimate of the impact the economic outlook of each of the ANZSIC categories will have on ACQ and MDQ of demand market customers.

Table A 9.1 Change in ACQ and MDQ by Industry Sectors | %

	Change in ACQ and MDQ (%)							
Industry Sectors	2014	2015	2016	2017	2018	2019	2020	2021
Manufacturing | Chemicals	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Manufacturing | Construction	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Manufacturing | Food	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Manufacturing | Health	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Manufacturing | Metals	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Manufacturing | Minerals	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Manufacturing | Other	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Manufacturing | Packaging	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Manufacturing | Pharmaceuticals	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Manufacturing | Printing	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Manufacturing | Refining	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Manufacturing | Textiles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Accommodation and food services	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%
Administrative and support services	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Agriculture, forestry and fishing	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Arts and recreation services	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Construction	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Education and training	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Electricity, Gas, Water and Waste Services	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Financial and Insurance Services	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Health care and social assistance	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Information media and telecommunications	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Mining	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Other services	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Ownership of dwellings	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Professional, scientific and technical services	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Public administration and safety	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Rental, hiring and real estate services	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Retail trade	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Transport, postal and warehousing	7.2%	7.2%	7.2%	7.2%	7.2%	7.2%	7.2%	7.2%
Wholesale trade	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

These percentage changes in ACQ and MDQ were applied to each demand market user based on their ANSZIC classification. The year on year change in demand due to the economic outlook was subsequently determined. Historical demand for each industry segment was regressed on historical gross value add using four different models. The four models are as follows:

1. $Demand = \beta_0 + \beta_1 \, GVA$

2. $log\ Demand = \beta_0 + \beta_1\ log\ GVA$

3. $log\ Demand = \beta_0 + \beta_1\ log\ GVA_{t-1}$

4. $log\ Demand = \beta_0 + \beta_1\ log\ GVA_t + \beta_2\ log\ GVA_{t-1}$

The table below summarises the regression output by industry sector and the associated significance levels.

Table A 9.2 Regression Output Significance Level

Industry Sector	Significance Level			
	Model 1	Model 2	Model 3	Model 4
Manufacturing | Chemicals				
Manufacturing | Construction				
Manufacturing | Food				
Manufacturing | Health				
Manufacturing | Metals				
Manufacturing | Minerals		-0.587 *		
Manufacturing | Other				
Manufacturing | Packaging				
Manufacturing | Pharmaceuticals				
Manufacturing | Printing				
Manufacturing | Refining				
Manufacturing | Textiles				
Manufacturing				
Accommodation and food services				β_1 -2.20 ** β_2 2.45 **
Administrative and support services				
Agriculture, forestry and fishing				
Arts and recreation services	-0.00616 **	-3.27 **		
Construction				
Education and training	0.000600 **	1.34 **	1.53 **	
Electricity, Gas, Water and Waste Services				
Financial and Insurance Services				
Health care and social assistance				
Information media and telecommunications				
Mining				
Other services				
Ownership of dwellings				
Professional, scientific and technical services				β_1 0.816 ** β_2 -0.687 *
Public administration and safety				
Rental, hiring and real estate services				*
Retail trade				
Transport, postal and warehousing	0.00506 **	3.87 **	3.62 **	β_1 3.51 *
Wholesale trade				

*Represents significance at the 10% level and ** represents significance at the 5% level

The percentage change in ACQ and MDQ based on the regression coefficients in the above table, and growth in GVA was applied to the following demand sectors (exclusive of customers who provided feedback on future gas demand through consultation with JGN):

1. Accommodation and food services (Model 4)
2. Education and training (Model 3)
3. Professional, scientific and technical services (Model 4)

Detail on the regression model and associated coefficients applied to each sector are provided in the Assumptions tab of the Gas Demand Forecast model. Note that even though the coefficient for the Transport, Postal, and Warehousing sector was found to be significant, the relationship of 1% growth in GVA resulting in 3.87% (model 2), or 3.62% (model 3) growth in gas demand is unrealistic. This relationship was not applied to forecast demand in the Transport, Postal and Warehousing sector. GVA growth has a significant relationship with Manufacturing | Minerals and Rental, hiring and real estate services gas demand. The coefficients of the regressions were negative implying an inverse relationship between GVA growth and gas demand. This is an unexpected result, and as such it was assumed that economic outlook would have no impact on gas demand for these sectors.

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