FORECASTING METHODOLOGY INFORMATION PAPER

NATIONAL GAS FORECASTING REPORT 2016

Published: **February 2017**

AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

IMPORTANT NOTICE

Purpose

AEMO has prepared this document to provide information about methodology, data and assumptions used to produce the 2016 *National Gas Forecasting Report*, as at the date of publication.

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Acknowledgement

AEMO acknowledges the support, co-operation and contribution of all participants in providing data and information used in this document.

Version control

Version	Release date	Changes
1	01/02/2017	

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CHAPTER 1. INTRODUCTION

The *National Gas Forecasting Report* (NGFR) provides regional gas consumption and maximum daily demand forecasts for Queensland, New South Wales, Victoria, Tasmania, and South Australia. The regional forecasts represent demand to be met from gas supplied through the natural gas transmission system in southern and eastern Australia, and are the sum of a number of component forecasts, each having a distinct forecasting methodology. These components (defined in Section 1.2) are:

- Liquefied natural gas (LNG).
- Gas-powered generation (GPG).
- Industrial.
- Residential and commercial.
- Network losses and other unaccounted for gas (UAFG).

For annual consumption, each of these component forecasts is modelled separately, and then summed at the regional level. Chapters 2–5 describe the methodologies used for each of the first four components. Network losses and other UAFG are covered in Appendix C.

Maximum demand forecasts provide an annual projection of maximum daily demand for each region. This requires the component forecasts to be coincident on the day of the system peak, so the maximum demand methodology uses an integrated modelling approach that forecasts the component models jointly to produce a forecast of maximum coincident daily demand (see Chapter 6).

1.1 Summary of NGFR scenarios

In 2016, AEMO updated its scenarios framework for forecasting and planning publications. Following this update, all AEMO's major reports[1] are exploring the most probable pathway for Australia, using three scenarios representing weak, neutral, and strong economic and consumer outlooks. Table 1 summarises the main assumptions of each scenario.[2]

Table 1 2016 NGFR scenarios

Driver	Weak scenario	Neutral scenario	Strong scenario
Population growth[A]	Australian Bureau of Statistics (ABS) projection C	ABS projection B	ABS projection A
Economic growth	Weak	Neutral	Strong
Consumer	Low confidence, less engaged	Average confidence and engagement	High confidence and more engaged
Gas and electricity network charges	Based on current (2016–17) AER tariff determinations (escalated as necessary). Beyond the determination period, these are kept constant at the level of the last year of the determination.		
Gas and electricity retail costs and margin	Assume current margins throughout		
Technology uptake	Hesitant consumer in a weak economy	Neutral consumer in a neutral economy	Confident consumer in a strong economy
Energy efficiency uptake	Low	Medium	High
Emissions policies	Assumed to achieve 26% to 28% reduction in 2005 National Electricity Market (NEM) emissions by 2030. Proxy carbon abatement cost starting at \$25/t CO_2e in 2020, rising to \$50/t CO_2e in 2030, affecting both electricity and gas retail prices.		

[A] Australian Bureau of Statistics, 2013, *Population Projections, Australia 2012 (base)*, cat. no. 3222.0.

[1] *National Electricity Forecasting Report, National Gas Forecasting Report, NEM Electricity Statement of Opportunities, Gas Statement of Opportunities* for eastern and south-eastern Australia, and *National Transmission Network Development Plan*.

[2] For more detail about scenarios see the 2016 NGFR, available at: http://www.aemo.com.au/Gas/National-planning-and-forecasting/National-Gas-Forecasting-Report.

Comparison to 2015 NGFR scenarios

While the Neutral scenario of this NGFR is generally comparable with the Medium scenario from the 2015 NGFR, the new Weak and Strong scenarios have alternative assumptions on consumer sentiment, so they are not directly comparable with the Low and High scenarios respectively in the 2015 NGFR.

The adjustment of consumer sentiment was to realign the economic outlook of the scenario with the willingness of consumers to invest in energy efficiency, rooftop PV, and other investments affecting their energy consumption. The 2016 scenarios assume higher willingness (and capability) to invest under high economic growth. This improves the internal consistency of the scenarios compared to the 2015 scenarios, which had less such investment during high economic growth and more such investment in low economic growth conditions.

Overall, the Strong and Weak scenarios still form an estimate of the range of likely outcomes and should be used as such.

1.2 Key definitions

Annual gas consumption refers to gas consumed over a calendar year, and can include residential and commercial consumption, industrial consumption, GPG consumption, or transmission and distribution losses. Gas used for LNG processing and exports is considered separately. Unless otherwise specified, annual consumption data includes transmission and distribution losses.

Distribution losses refers to gas leakage and metering uncertainties (generally referred to as UAFG) in the distribution network. This is calculated as a percentage of total residential and commercial consumption and industrial consumption connected to the distribution networks.

Effective degree days (EDD) is a measure that combines a range of weather factors that affect energy demand.

Gas-powered generation (GPG) refers to generation plant producing electricity by using gas as a fuel for turbines, boilers, or engines. In the NGFR forecasts, this only includes GPG that is connected to the National Electricity Market (NEM). AEMO engaged the consultancy Jacobs to provide the GPG forecasts based on their modelling of future electricity generation in the NEM.

Industrial, also known as Tariff D, refers to users that generally consume more than 10 terajoules (TJ) of gas per year. Industrial consumption includes gas usage by industrial and large commercial users, and some GPG that is not connected to the NEM, for example, GPG around Mt Isa.

Liquefied natural gas (LNG) refers to natural gas that has been converted to liquid form.

Maximum demand refers to the highest daily demand occurring during the year. This can include residential and commercial demand, industrial demand, GPG demand, or distribution losses. Gas used for LNG production is considered separately. Unless otherwise specified, maximum demand includes transmission and distribution losses.

Per customer connection refers to the average consumption per residential and commercial gas connection. Expressing consumption on this basis largely removes the impact of population growth, and allows commentary about underlying consumer behaviour patterns.

Probability of Exceedance (POE) refers to the likelihood that a maximum demand forecast will be met or exceeded, reflecting the sensitivity of forecasts to changes in weather patterns in any given year. The 2016 NGFR provides these forecasts:

- **1-in-2** maximum demand, also known as a 50% POE, means the projection is expected to be exceeded, on average, one out of every two years (or 50% of the time).
- **1-in-20** maximum demand, also known as a 5% POE, means the projection is expected to be exceeded, on average, one out of every 20 years (or 5% of the time).

Residential and commercial, also known as Tariff V, refers to residential and small-to-medium-sized commercial users consuming less than 10 TJ of gas per year. Unless otherwise specified, historical residential and commercial data is not weather-corrected.

Transmission losses refers to gas that is unaccounted for or consumed for operational purposes (such as compressor fuel) when transported through high-pressure transmission pipelines to lower-pressure distribution networks. Transmission losses are calculated as a percentage of total residential and commercial, industrial, and GPG consumption, and distribution losses.

Winter refers to June to August and **summer** refers to December to February.

1.3 Improvements to the 2016 NGFR methodology

This NGFR continues a major shift in AEMO's forecasting methods that began with the 2015 NGFR. In 2015, AEMO changed its forecasting methods to use detailed "bottom-up" models that embrace a mix of economic and technical methods to better capture the continuing transformation of the energy supply and demand system. By looking at each emerging dynamic separately, the shift in forecast methodology allows AEMO to both improve the accuracy of the forecast and better explain the reason for forecast changes.

Compared to 2015, further enhancements have been made to produce this NGFR:

- Impacts on temperature-dependent gas consumption (heating) from longer term climate change have been built into the models, based on advice from the Bureau of Meteorology. See Appendix B for details.
- Retail market gas metering data has replaced the need for large industry data requests, providing an automated and timely data-stream for distribution data (this included data up to August 2016). This means forecasts are based on more current data than the data requests previously provided.
- The forecasting models now integrate supply and demand, gas and electricity, and international and domestic models. This energy system integration enables the identification of dynamic price and competition feedbacks, and provides results that are more indicative of a convergent equilibrium. Notably, it means the gas forecasts used the latest electricity projections (input to GPG fuel usage), which include the following updates and inclusions since the publication of the June 2016 *National Electricity Forecasting Report*:
  - Electric Vehicle projections.
  - Inclusion of the proposed Victorian Renewable Energy Target (VRET).
  - Inclusion of the results of AEMO's 2016 survey and interviews with the largest industrial gas users.
  - Inclusion of updated projections for electricity use by the Queensland LNG export industry.
  - Inclusion of the announced Hazelwood Power Station retirement.
  - Updated gas/GPG fuel costs based on the upstream supply demand balance that is an outcome of these NGFR forecasts.

CHAPTER 2. LIQUEFIED NATURAL GAS (LNG) – ANNUAL GAS CONSUMPTION

In preparing the 2016 *National Electricity Forecasting Report* (NEFR), AEMO engaged Lewis Grey Advisory (LGA) to estimate projections of gas and electricity consumption used in the production and export of LNG. LGA updated these estimates for the 2016 NGFR, after the 2016 NEFR was published.

LGA's estimates enabled a number of key assumptions to be refined, based on recent market data. AEMO and LGA also met with all LNG producers to collect and validate information to assist the forecasting process.

As a result, LNG consumption forecasts have changed since the publication of the 2015 NGFR and the 2016 NEFR.

2.1 Differences since 2016 NEFR

A full explanation of the forecasting methodology used in the 2016 NEFR is in the June 2016 LGA report.[3] Key differences in methodology for the 2016 NGFR are:

- New project planning information has been received from LNG project operators:
  - Australia Pacific LNG (APLNG) second train was deferred from Q2 2016 to Q4 2016.
  - Gladstone LNG (GLNG) is experiencing a slower ramp-up to full production.
- Strong forecast scenario – gas exports are 5% higher than the 2016 NEFR Strong scenario, reflecting production at 110% of nameplate capacity instead of 105% of nameplate capacity, due to assumed optimisation of the operation at the LNG plants (in industry terms, called "debottlenecking").
- Weak forecast scenario – the decline in the Weak scenario from 2028 starts earlier than in the 2016 NEFR projections, due to non-replacement of coal seam gas (CSG) production capacity that is consequential to projections of low oil/LNG prices.

2.2 Methodology

The LNG forecasts were developed by undertaking modelling, using a range of public data and the outcomes of technical engagement with the LNG producers.

A full explanation of the forecasting methodology can be found in the November 2016 LGA report for the 2016 NGFR.[4]

[3] Lewis Grey Advisory, *Projections of Gas and Electricity Used in LNG*, 22 April 2016. Available at: http://aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEFR/2016/Projections-of-Gas-and-Electricity-Used-in-LNG.pdf.
[4] Lewis Grey Advisory, Updated Projections of Gas and Electricity Used in LNG; 18 November 2016. Available at: https://www.aemo.com.au/-/media/Files/Gas/National_Planning_and_Forecasting/NGFR/2016/Projections-of-Gas-and-Electricity-Used-in-LNG-Public-Report-November-2016.pdf.

CHAPTER 3. GAS-POWERED GENERATION (GPG) – ANNUAL GAS CONSUMPTION AND MAXIMUM DEMAND

This chapter describes the methodology and key assumptions AEMO used to forecast GPG annual gas consumption in supplying electricity to the NEM.[5] The methodology and assumptions in this chapter were also used to forecast GPG maximum demand. For the 2016 NGFR, AEMO engaged consultancy firm Jacobs to produce the GPG forecasts. The following description of the methodology was provided by Jacobs detailing how the GPG forecasts were performed.

3.1 Methodology

Jacobs' approach to projecting gas consumption for GPG in the NEM for the period from 2017 to 2037 was to use a PLEXOS model of the NEM under three modelling scenarios.

PLEXOS is a stochastic mathematical model, developed by Energy Exemplar, which can be used to project electricity generation by power station, pricing, and associated costs for the NEM. AEMO use a PLEXOS model and Jacobs have designed their PLEXOS model to follow the same techniques used by AEMO in operating the NEM. In addition the model incorporates Monte Carlo forced outage modelling. This model uses mixed integer linear programming to determine an optimal long-term generation capacity expansion plan.

The modelling was conducted in two phases.

Phase 1

The first phase was to determine the capacity expansion plan, which included fulfilling the Large-scale Renewable Energy Target (LRET) and more recent VRET targets with new renewable generation capacity. Some of these measures for Australia to meet the 2030 emissions reduction target may touch the pricing mechanisms of the market, so a "proxy abatement cost" was assumed in the modelling. Including a pricing impact encouraged the entry of additional renewable generation and some economic retirement of some existing coal-fired power stations within the modelling horizon.

Phase 2

The second modelling phase was to run the detailed simulations in PLEXOS one year at a time, to more accurately model system dispatch and pricing.

The first part of this process was to run the model in 2030 to ensure the emissions target was met. In the event of a shortfall, one coal-fired generating unit was retired[6] and the model rerun. The generating unit to be retired was chosen from a "retirement merit order" that had already been developed for 2016 NEFR modelling.

Once the 2030 target was met, the spacing of these regulatory coal-fired retirements was smoothed out, taking into account the existing retirement sequence. This was done to avoid rapid changes in the generation mix, which could result in large discontinuities in market prices and in annual GPG levels.

Following this, each year in the modelling horizon was run separately and the projected GPG level was determined.

For the annual simulations:

[5] This includes the vast majority of GPG in the eastern and south-eastern gas markets. Any GPG outside this, such as in Mount Isa, is captured as Industrial (tariff D) demand.

[6] The retirement mechanism was assumed to be a government imposed regulatory measure that was supplementary to the carbon price, and designed to ensure the 2030 emission reduction target would be achieved

- Prior to optimising dispatch in any given year, PLEXOS schedules planned maintenance and randomly pre-computes a user-specified number of forced outage scenarios for Monte Carlo simulation. Dispatch is then optimised on an hourly basis for each forced outage sequence, given the load characteristics, plant capacities and availabilities, fuel restrictions and take-or-pay contracts, variable operating costs including fuel costs, interconnector constraints, and any other operating restrictions that were specified.
- Expected hourly electricity prices for all the NEM regions, and hourly dispatch for all NEM power stations, were produced as output and were calculated by modelling strategic behaviour, based on PLEXOS' Cournot equilibrium gaming model. The Nash-Cournot model was benchmarked to historical market outcomes to ensure the bidding strategies employed produced price and dispatch outcomes commensurate with historical outcomes.
- The impact of financial contracts on the bidding strategy of market participants was incorporated implicitly by specifying a proportion of a portfolio's output that is typically contracted, and hence restricting strategic bidding to the uncontracted proportion. Choosing the contract levels for each portfolio was part of the benchmarking exercise carried out.

For the maximum demand forecasts:

- Jacobs provided AEMO with 20 different hourly GPG Monte Carlo simulations for each scenario for a peak winter month. After reviewing the simulations, AEMO based the maximum demand forecast off the median trace for each region in the NEM.

3.2 Scenario descriptions

The three market scenarios explored for this study were the Neutral, Strong, and Weak scenarios, modified to reflect recent developments in the market. The scenario labels refer to the state of the economy, and broadly speaking respectively reflect average, low, and high levels of consumer confidence. See Appendix E: Scenarios Summary for the assumptions used for the GPG study.

Key high level assumptions

Key assumptions used in the electricity market modelling included:

- The demand projections used were based on the historical 2010–11 hourly load profile for the NEM regions grown to match the projected median (50% POE) summer and winter maximum demand from the 2016 NEFR.
- Wind power in the NEM was based on the chronological hourly profile of wind generation for each generator from the 2010–11 financial year, and was therefore accurately correlated to the demand profile.
- Capacity was installed to meet the target reserve margin for the NEM in each region. Some of this peaking capacity may represent demand side response rather than physical generation assets.
- Infrequently used peaking resources were bid near Market Price Cap (MPC) or removed from the simulation to represent strategic bidding of these resources when demand is moderate or low.
- Generators were assumed to behave rationally, with uneconomic capacity withdrawn from the market and bidding strategies limited by the cost of new entry. This was a conservative assumption, as there have been periods when prices have exceeded new entry costs when averaged over 12 months.
- Implementation of the LRET and Small-scale Renewable Energy Scheme (SRES) schemes. The LRET target is for 33,000 gigawatt hours (GWh) of renewable generation by 2020.
- Any demand side action for emissions abatement (energy efficiency) or otherwise economic responses (such as to increasing electricity prices) throughout the NEM was assumed to be included in the NEM demand forecast.

CHAPTER 4. INDUSTRIAL – ANNUAL GAS CONSUMPTION

This chapter outlines the methodology used to develop annual gas consumption forecasts for industrial customers. Industrial consumption, also known as Tariff D consumption, is defined as consumption by network customers who are billed on a demand basis.[7] These customers typically consume more than 10 TJ per year.

AEMO defined two categories of industrial customer for analysis purposes:

- Large industrial loads (LIL): consume more than 500 TJ annually at an individual site. Typically includes aluminium and steel producers, glass plants, paper and chemical producers, oil refineries and GPG not included in GPG forecasts.[8]
- Small-to-medium industrial loads (SMIL): consume more than 10 TJ but less than 500 TJ annually at an individual site. Typically includes food manufacturing, casinos, shopping centres, hospitals, stadiums, and universities.

Industrial gas consumption has historically tended to be dominated by very large users, often representative of heavy manufacturing. Over the last ten to fifteen years, industrial consumption has experienced large declines in most states, and declines in heavy gas-intensive manufacturing can dominate the historic data that is used to forecast future consumption. Growing sectors for gas consumption, such as services and food and beverage manufacturing, represent only 17% of total annual industrial consumption across all regions.

In the 2015 NGFR, AEMO introduced an integrated, bottom-up sector modelling approach to industrial forecasts to capture the structural change effect in the Australian economy. The 2016 NGFR continues to use a bottom-up sector modelling approach with the following refinements:

- Changed forecast drivers for manufacturing sector econometric forecasts to improve the accuracy of the underlying trend (see 0 and 0).
- Considered the impact of climate change on the heating load of the 'Other' business sector (primarily comprising of large commercial services). Heating load was also calculated as a post-model adjustment to econometric forecasts.
- Improved the split between Manufacturing sector to Other business sector, using better quality AEMO meter data and surveys received from Distribution and Transmission Network Service Providers that have become available since the 2015 NGFR (see Section 4.2.2 for further details).
- Refined the approach for producing base year forecasts.

The details of these changes will be covered in the following sections.

4.1 Data sources

Meter gas consumption data

AEMO receives aggregated historical industrial consumption data from distribution and transmission business owners for all regions except Victoria. In Victoria, this data is obtained from AEMO's Market Management System (MMS) used in market settlements.

AEMO aggregates the historical and forecast data to region level for confidentiality purposes.

[7] Customers are charged based on their Maximum Hourly Quantity (MHQ), measured in gigajoules (GJ) per hour.
[8] This includes GPG which is not connected to the NEM, and large co-generation.

Public data sources

The Energy Statistics Data (ESD)[9] published by the Office of the Chief Economist. The ESD provided a means to segment total business consumption into the main categories of manufacturing and other business sectors.

Please see Table 37 in Appendix D for a list of detailed references.

Consultant data sources

- Wholesale gas price forecasts were modelled by consultancy CORE Energy.[10]
- Retail gas price forecasts were modelled by AEMO, with CORE Energy forecasts used as a key input.
- Industrial Production forecasts, used as a key driver of manufacturing sector forecasts, are available in the Deloitte Access Economics Business Outlook forecasts. These forecasts were used by AEMO in the Neutral scenario. Weak and Strong scenarios were created by AEMO using the Neutral scenario as a benchmark.
- Gross Value Added (GVA) forecasts for services and manufacturing sector were provided by consultancy KPMG.

4.2 Methodology

The Industrial gas consumption forecasts were developed in three main phases (summarised in the following diagram):

Phase 1: Short-term model forecasts (2016).

Phase 2: Long-term model forecasts (2016 to 2036)

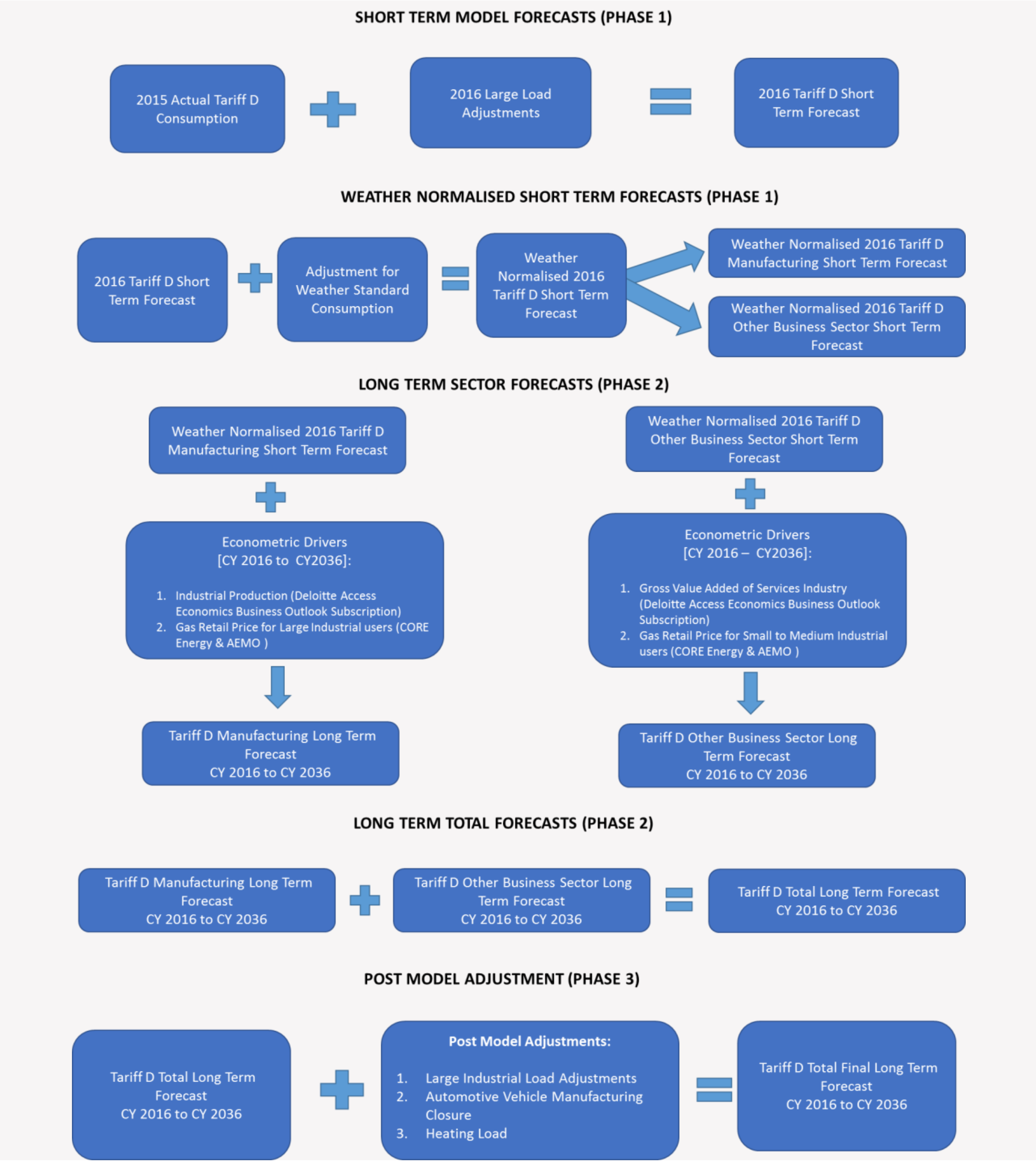
Phase 3: Post-model adjustments, made for expected variations not captured organically by the econometric models.

The detailed methodology of each phase is discussed in Sections 4.2.1 to 4.2.3.

[9] http://www.industry.gov.au/Office-of-the-Chief-Economist/Publications/Pages/Australian-energy-statistics.aspx. Viewed: 16 January 2017

[10] Core Energy Group. *NGFR Gas Price Review Final Report*, October 2016. Available at: http://www.aemo.com.au/Gas/National-planning-and-forecasting/National-Gas-Forecasting-Report.

Figure 1 Methodology process flow for industrial gas consumption forecasts for New South Wales, South Australia, and Victoria



4.2.1 Phase 1: short-term model forecasts

A base year forecast was developed to provide a starting point for the long-term forecasts. This starting point was the forecast consumption in 2016 in the absence of change to macroeconomic drivers and assumed a weather standard year.[11]

As consumption data for 2016 had to be estimated, the following approach was taken.

[11] Forecasts assume standard weather years, as defined in Appendix B.

Steps:

1. The industrial load for 2015 was obtained from the meter gas data for all regions, with the exception of New South Wales which uses 2014 data.
2. The temperature dependent consumption that was due to specific weather in 2015 that would not have occurred in 2016 was accounted for (weather normalised).
3. Adjusting for any large industrial load closures that occurred in 2016 to which the data would be present in the 2015 data set.

Weather normalisation methodology

To weather normalise the 2015 actual consumption, a short-term model was developed to determine the relationship between Heating Degree Days (HDD) or EDD[12] and Tariff D gas consumption. This was used to calculate the adjustment amount (in petajoules) for weather normalising the 2015 actual consumption.

The short-term model specification was as follows:

$$TD\_Cons_t = \beta_0 + \beta_1 HDD/EDD_t + \beta_2 DoW_t$$

Table 2 Short-term model variable description

Variable names	ID	Units	Description
Tariff D consumption	TD_Cons	PJ	This is daily Tariff D consumption.
Heating Degree Days or Effective Degree Days	HDD or EDD	°C	HDD or EDD values were used to account for deviation in weather from normal weather standards. South Australia, Queensland, and New South Wales use HDD, while Victoria uses EDD.
Day of Week Dummy	DoW	{0,1}	A dummy for the days of the week to capture weekly seasonality. Weekends and public holidays take a value of 0 and other days of the week take a value of 1.

For the short-term model:

- The model was developed using 2015 daily data for the winter[13] period in all states except for New South Wales. New South Wales used 2014 data due to limitations in data availability.
- The Day of Week (DoW) variable was used to improve model specification.
- The interpretation of the HDD/EDD parameter (β_1) was petajoules of consumption per HDD or EDD.

The adjustment amount for the weather calculations was as follows:

$$\beta_1.(Actual\ HDD/EDD\ _{2015} - Weather\ Standard\ HDD/EDD_{2015}) = Weather\ Adjustment$$

4.2.2 Phase 2: long-term model forecasts

AEMO's 2016 industrial consumption model incorporate structural economic changes to more accurately reflect long-term influences on industrial business decisions and consequently on gas consumption.

Long-term models are used to reflect changes in macroeconomic drivers, which impact business decisions and operations, ultimately driving industrial gas consumption.

[12] See Appendix B for further details on HDD, EDD and weather standards.
[13] Winter is defined as the months of April to September of each calendar year.

Sector decomposition

Over the past couple of decades, the manufacturing sectors (excluding food and beverage manufacturing) have experienced a period of sustained decline with conservative growth anticipated in the long term. Meanwhile, other sectors of the economy such as commercial services are expected to exhibit long-term growth.

To mitigate the risk of a downward bias which would otherwise arise due to the dominating effect of the sectors in decline, AEMO modelled gas consumption for these sectors separately.

AEMO's model framework broke down the industrial users into two main categories[14]:

- Manufacturing – these are relatively energy-intensive, trade-exposed sectors with less upside growth opportunity (with the exception of food and beverage manufacturing).
- Other business – this is predominantly made of commercial services.[15] Other business is typically less energy-intensive than Manufacturing, and is driven by domestic market forces. Long run growth is expected for Other business sectors.

Splitting industrial (Tariff D) consumption data into Manufacturing and Other sectors

The Manufacturing to Other business sector split was applied to the 2016 base year forecast to give the starting point of the long-term forecast for each sector.

This year, AEMO has used its internally sourced meter data to calculate the Manufacturing vs. Other business sector split which was then applied to the base year (2016) to produce the starting point of the Manufacturing and Other sector forecasts.

The split is shown in the table below.

Table 3 Manufacturing to Other split for 2015

Region	Manufacturing (%)	Other business (%)
New South Wales	85.90	14.10
Queensland	98.20	1.80
South Australia	90.30	9.70
Tasmania	83.00	17.00
Victoria	83.00	17.00

Long-term model for New South Wales, South Australia, and Victoria

Separate long-term models were used for Manufacturing versus Other business sectors to reflect differences in business drivers. These are described in the following sub-sections.

Manufacturing sector model development

The manufacturing sector forecast was developed using the following econometric model:

$$log(Man\_Cons)_t = \beta_0 + \beta_1 \log(Ind\_Prod)_t + \beta_2 \log(Gas\_Price)_t + \delta_1 . GFC_t$$

[14] For further details on sectors see 0 in Appendix D.

[15] See Appendix D for complete list of ANZSIC categories that fall under 'Other Business'.

Table 4 New South Wales, South Australia, and Victoria – Manufacturing model variable description

Variable names	ID	Units	Description
Manufacturing Consumption	Man_Cons	PJ	Tariff D manufacturing consumption
Industrial Production	Ind_Prod	$'Mill	This is a measure of the output from the Manufacturing sector of the economy
Retail Gas Price	Gas_Price	$/GJ	Retail gas price for large industrial users is used.
GFC Dummy	GFC	{1,0}	Dummy variable to capture long-term effects of the economic shock from the Global Financial Crisis. This is a binary variable that takes on the value of 1 from 2009 to 2014 and 0 for other years.

In the long-term manufacturing model:

- The coefficients β_1 and β_2 were interpreted as the elasticity[16] of manufacturing consumption to changes in the respective macroeconomic variables, when all else is held constant.
- Global Financial Crisis (GFC) dummy variables were included to improve model specification as a clear trend can be seen in a different business environment since 2008.[17]
- This is an annual model, and model parameters were derived using historic data from 2000–14.[18]

Table 5 Manufacturing sector econometric model parameters

Region	Gas_Price	Ind_Prod	Man_GSP
New South Wales	-0.26	0.53	NA
Queensland	-0.46	NA	1.15
South Australia	-0.37	0.41	NA
Victoria	-0.35	0.86	NA

Other sector model development

The Other sector forecast was developed using the following econometric model:

$$log(Other\_Cons)_t = \beta_0 + \beta_1 \log(Services\_GVA)_t + \beta_2 \log(Gas\_Price)_t + \delta_1 . GFC_t$$

Table 6 New South Wales, Queensland, South Australia, and Victoria – Other model variable description

Variable names	ID	Units	Description
Other Business Sector Consumption	Other_Cons	PJ	Tariff D other business sector consumption
Services GVA	Services_GVA	$'Mill	This is the gross value added of the services sector
Retail Gas Price	Gas_Price	$/GJ	Retail gas price for small industrial users is used.
GFC Dummy	GFC	{1,0}	Dummy variable to capture long-term effects of the economic shock from the Global Financial Crisis. This is a binary variable that takes on the value of 1 from 2009 to 2014 and 0 for other years.

[16] Elasticity is defined as the percentage change in a variable in response to a 1% change in another variable. For example, if elasticity of manufacturing consumption to gas price is 2, this is interpreted as a 1% change in gas price results in a 2% change in manufacturing consumption.

[17] Model misspecification can arise when statistically significant variables are omitted from the model. This can result in the parameters, of the variables included in the model, being biased.

[18] The historic data has intentionally been restricted to the latest 14 years to reflect current businesses and business conditions and avoid biasing future estimates by historic conditions that are no longer prevalent.

In the long-term Other sector model:

- The coefficients β_1 and β_2 were interpreted as the elasticity of Other business sector consumption to changes in the respective macroeconomic variables, when all else is held constant.
- GFC dummy variables were included to improve model specification.
- This is an annual model, and model parameters were derived using historic data from 2000–14.[19]

Table 7 Manufacturing sector econometric model parameters

Region	Gas_Price	Services_GVA
New South Wales	-0.2	0.31
Queensland	-0.2	0.53
South Australia	-0.2	0.53
Victoria	-0.2	0.58

Long-term model for Queensland

Approximately 80% of Tariff D customers in Queensland are transmission customers or field direct customers[20]. Most of these customers were captured in AEMO's industrial survey and interview process. For this reason, Queensland was modelled slightly differently to other states. In Queensland, for those that were surveyed and interviewed AEMO used a survey-based actual forecast.[21]

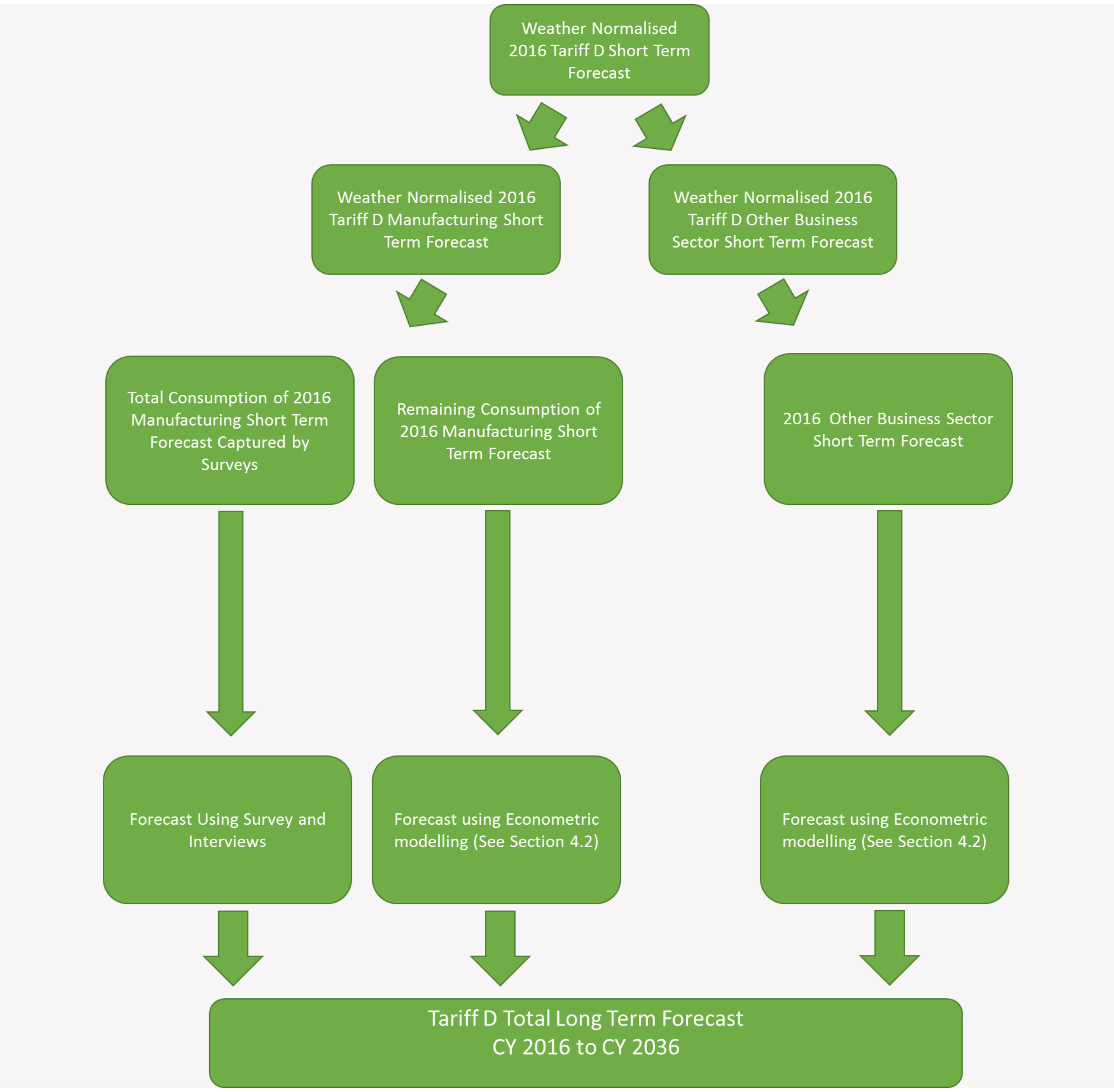
Figure 2 give a high level overview of the process.

[19] The historic data has intentionally been restricted to the latest 14 years to reflect current businesses and business conditions and avoid biasing future estimates by historic conditions that are no longer prevalent.

[20] Field direct customers are customers that directly consume gas from gas fields.

[21] By contrast, for New South Wales, Victoria, and South Australia, the survey was used to make post-model adjustments for expected variations outside the econometrics.

Figure 2 Methodology process flow for industrial gas consumption forecasts for Queensland



Manufacturing sector forecasts

The surveyed industrial customers were all grouped in the Manufacturing sector, so the remaining Tariff D manufacturing consumption was forecast using econometrics.

The manufacturing sector forecast for Queensland was developed using the following econometric model:

$$log(Man\_Cons)_t = \beta_0 + \beta_1 \log(Man\_GVA)_t + \beta_2 \log(Gas\_Price)_t + \delta_1 . GFC_t$$

Table 8 Queensland Manufacturing model variable description

Variable names	ID	Units	Description
Manufacturing Consumption	Man_Cons	PJ	Tariff D manufacturing consumption
Manufacturing GSP	Man_GVA	$'Mill	Manufacturing Gross Value Added (GVA) is the revenue generated by the Manufacturing sector for the state of Queensland
Retail Gas Price	Gas_Price	$/GJ	Retail gas price for large industrial users is used.
Exchange Rate	USD	AUD/USD	Exchange Rate: Conversion rate of Australian dollars per US dollar
GFC Dummy	GFC	{1,0}	Dummy variable to capture long-term effects of the economic shock from the Global Financial Crisis. This is a binary variable that takes on the value of 1 from 2009 to 2014 and 0 for other years.

In the long-term manufacturing model:

- Unlike the other regions, Queensland's manufacturing model uses Manufacturing GVA as a key driver instead of Industrial Production. Both these variables are highly correlated. This is largely because Manufacturing GVA gave more robust model statistics.

This is an annual model, and model parameters were derived using historic data from 2000–14.

For model parameters please see section 4.2.2.

Other Sector Forecasts

The Other sector model follows the same methodology as the other regions. Please see section 4.2.2 for further details.

Long-term model for Tasmania

Tasmania's gas network started operation much later (2004) than the other states. SMIL (distribution customers') consumption growth since then has reflected the progressive connection of industrial energy users.

AEMO surveyed Tasmanian Gas Pipeline (TGP) to obtain actual consumption for 2015 for distribution-connected and transmission-connected Tariff D customers. Using this as a starting point, AEMO has modelled the long-term forecasts for the two classes of Tariff D customers using the following assumptions[22]:

- **Transmission-connected customers:** Forecast remains constant apart from any step changes.[23] Price impacts were assumed to have no direct impact apart from not allowing any growth.
- **Distribution-connected customers:** Forecast to grow in line with a logarithmic model, translated to match expected consumption in 2016. While recent data show some industrial customers have closed or reduced consumption, net gains are expected with growth from sectors such as food (vegetables and dairy) and hospitals. This year the impact of price increases in small industrials consumption has been incorporated into the modelling as a post-model adjustment, using elasticities of -0.1, -0.2, and -0.3 respectively for the Strong, Neutral, and Weak scenarios.

4.2.3 Aggregating to Tariff D Forecast (pre-adjustments)

Tariff D initial forecasts were obtained by adding together the Manufacturing sector forecast gas consumption and Other sector forecast gas consumption and in the case of Tasmania the total Tariff D

[22] Note that unlike other regions, AEMO did not do a bottom-up model by Manufacturing and Other sectors. Tasmania's Tariff D customers were modelled in aggregate, only distinguishing between Distribution and Transmission connect customers.
[23] On the basis of surveys and interviews.

forecast. These forecasts were then adjusted by post-model adjustments to get the final Tariff D final forecasts. The post model adjustments are outlined in the following section.

4.2.4 Phase 3: post-model adjustments

The reference models were used to capture long running trends in different industrial sectors. However, they did not capture significant deviations from trend, so post-model adjustments were made for near-certain anticipated changes. Three types of adjustments were considered:

- Automotive vehicle manufacturing closure adjustments (Victoria and South Australia only).
- LIL adjustments.
- Heating load forecasts.

The methodology for applying the post-model adjustments is detailed below.

Automotive vehicle manufacturing closure adjustments

With the announced closure of Toyota and Holden in 2017−18[24], the complete closure of the automotive vehicle manufacturing industry becomes a highly probable scenario. AEMO consulted Computable General Equilibrium (CGE) modelling analysis, used by the Productivity Commission[25], to estimate the impact of the automotive manufacturing industry closure on annual gas consumption. The process undertaken is outlined below.

Analysis of CGE Modelling Results

The CGE modelling results suggested the projected impact of automotive vehicle manufacturing closures would be predominantly felt in Victoria and South Australia. The modelling assumed the complete closure to occur in 2017−18.

Although the Productivity Commission has estimated that employment in the economy as a whole will return to pre-closure levels by 2025–26, given the conservative growth outlook for manufacturing, AEMO has assumed that this will occur in other sectors of the economy and not in manufacturing. Given that assumption, AEMO has used the CGE modelling results to estimate a permanent loss of consumption in manufacturing attributed to closures in the automotive vehicle manufacturing industry.

Estimating gas consumption impacts

To estimate the total gas consumption impact of automotive vehicle manufacturing industry closures, AEMO:

- Estimated gas consumption per employee, by estimating the gas input into the manufacturing process and spreading this across the number of employees.
- Aggregated this by the total job losses projected by the Productivity Commission.

To estimate the gas per employee measure, AEMO first estimated historic total gas use in the industry. The Input-Output tables published by the Australian Bureau of Statistics (ABS)[26] contain dollar value estimates of inputs used in the production process for the supply of an output good, on an industry basis.

AEMO used this dataset to:

24 ABC News, "Toyota to close: Thousands of jobs to go as carmaker closes Australian plants by 2017" (2014). Available: http://www.abc.net.au/news/2014-02-10/toyota-to-pull-out-of-australia-sources/5250114.

25 Productivity Commission, "Australia's Automotive Manufacturing Industry", 2014; Productivity Commission Enquiry Report. Available: http://www.pc.gov.au/inquiries/completed/automotive/report/automotive.pdf.

26 Australian Bureau of Statistics, Australian National Accounts: Input-Output Tables, 2012-13, "Table 2: Use Table- Input by Industry and Final Use Category and Supply by Product Group"". Available: http://www.abs.gov.au/AUSSTATS/abs@.nsf/DetailsPage/5209.0.55.0012012-13?OpenDocument. Viewed 22 December 2016.

1. Estimate the direct and indirect[27] gas consumption into the automotive vehicle manufacturing industry in dollars; then, using a composite price ($/gigajoule (GJ)) value, back-derive gas consumption in that year.
2. Using the CGE analysis results and the ABS data for total employment, scale gas consumption to derive the total gas consumed by employees, in the industry, in Victoria and South Australia, then apportion this consumption by region.

After deriving the gas consumption values using public data sources, AEMO validated the results through consultation with major automotive vehicle manufacturing industrial loads. After the validation process, AEMO used these calculations to adjust the final forecasts.

Adjusting annual gas consumption forecast

The final forecasts for industrial consumption in Victoria and South Australia were adjusted by a permanent decline due to the automotive vehicle manufacturing industry closure. AEMO's assumption on the cumulative impact for each region, for each scenario is explained in the following table.

Table 9 Automotive vehicle manufacturing closure impact by region, by scenario

Region	Neutral (PJ)	Strong (PJ)	Weak (PJ)
Victoria	-0.6	-	-1.2
South Australia	-0.48	-	-0.48

Large Industrial Load (LIL) adjustments

AEMO modelled all industrial gas consumption in aggregate using econometric analysis. In addition, AEMO interviewed and surveyed LILs to gather data for the forecasts. Where the survey forecasts significantly deviated from the model results, the survey data was prioritised for adjusting the industrial gas consumption forecast.

LIL data sources

AEMO used the following data sources when developing LIL consumption forecasts:

- LIL questionnaire responses.
- Detailed discussion with LILs.
- Publicly available information and announcements.
- Historical data from AEMO's MMS.
- Historical data from AEMO's service provider for the Gas Retail Market Systems (GRMS).

LIL survey methodology

While major changes to LIL operations are relatively infrequent, their occurrence does have a significant impact on regional forecasts. Major changes include starting-up, closing, expanding or reducing capacity or production, and fuel substitution.

AEMO surveyed and interviewed a range of LILs. This structured survey approach is well-suited to understanding how these customers are likely to respond to changing market dynamics (such as manufacturing competitiveness and gas prices), and analysing the effect of these responses on gas consumption.

[27] Gas consumed by other inputs used in the production process for automotive vehicle manufacturing.

LIL survey process

Step 1: Initial survey

AEMO distributed a survey to all identified LILs requesting historical and forecast gas consumption information. The survey requested annual gas consumption and site maximum demand forecasts for three scenarios:

- Neutral – reflecting the most likely forecast levels based on their current understanding and expectations about key drivers such as gas prices, commodity prices, economic growth, and the Australian dollar remaining at US$0.75.
- Strong – reflecting higher production and gas consumption under more favourable economic conditions than in the neutral scenario, such as higher GDP growth, and significantly increasing commodity prices over the next five years, tempered by the Australian dollar increasing to US$0.95.
- Weak – reflecting lower production and gas consumption from the network under less favourable economic conditions than in the neutral scenario, such as lower GDP growth and commodity prices that remain approximately at current levels, although ameliorated somewhat by a depreciation in the Australian dollar to US$0.65.

Step 2: Detailed interviews

Following the survey, AEMO contacted each customer directly to review and discuss the responses. This typically included discussions about:

- Key gas consumption drivers, such as exchange rates, commodity pricing, availability of feedstock, current and potential plant capacity, mine life, and cogeneration.
- Currently contracted gas prices and contract expiry dates.
- Gas prices the LILs forecast over the medium and long term (per scenario), and possible impacts on profitability and operations.
- Potential drivers of major change in gas consumption (e.g., expansion, closure, cogeneration, fuel substitution) including “break-even” gas pricing[28] and timing.
- Different assumptions between the Strong, Neutral, and Weak scenarios.

Heating load forecasts

This year, AEMO has calculated a heating load for the Other business sector industrial forecast as a post-model adjustment. AEMO assumes all heating load is in the Other business sector. Moreover, the 2016 NGFR introduced a climate change trend (see Section B.4 for more details). The methodology for post-model adjustment of the heating load forecast was as follows.

Step 1: Calculate the actual (weather normalised) heating load and non-heating load components for Other business sector consumption in 2015[29]

$$Heating\ Load_{2015} = (\beta_1 * Weather\ Standard\ HDD/\ EDD_{2015})$$

where:

- $Heating\ Load_{2015}$ = 2015 consumption (petajoules) that is driven by weather
- β_1 = petajoules of consumption per heating or effective degree days (this parameter comes from the calculations outlined in Section 0)

[28] This is the point of balance between profit and loss.
[29] AEMO assumes all heating load is in the Other business sector.

- Weather Standard HDD/ EDD = this is the weather standard heating degree day or effective degree day (Victoria only) for the calendar year 2015

$$Non\ Heating\ Load_{2015} = Weather\ Normalised\ Other\ Sector\ Consumption_{2015} - Heating\ Load_{2015}$$

where:

- $Non\ Heating\ Load_{2015}$ = 2015 consumption (petajoules) that is independent of weather
- Weather normalised actual consumption for 2015 was calculated as outlined in Section 0, then the manufacturing to other split (from Table 3) was applied to calculate weather normalised Other sector consumption for 2015.

Step 2A: Grow the heating load for calendar years 2016 to 2036 with underlying econometric trend and change in heating degree days with climate change

$$Heating\ Load_t = Heating\ Load_{t-1} * \frac{HDD/EDD_t}{HDD/EDD_{t-1}} * \frac{Other\_Sector\_Forecast_t}{Other\_Sector\_Forecast_{t-1}}$$

where:

- t = forecast year and t ∈ {2016,…, 2036}
- HDD/EDD = weather standard heating degree day or effective degree day (Victoria only)
- Other_Sector_Forecast = the econometric forecasts for Other business sector were developed as outlined in Section 4.2.2.

Step 2B: Grow the non-heating load for calendar years 2016 to 2036 with underlying econometric trend

$$Non\ Heating\ Load_t = Non\ Heating\ Load_{t-1} * \frac{Other\_Sector\_Forecast_t}{Other\_Sector\_Forecast_{t-1}}$$

where:

- t = forecast year and t ∈ {2016,…, 2036}
- Other_Sector_Forecast = the econometric forecasts for Other business sector were developed as outlined in Section 4.2.2.

Step 3: Re-aggregate heating and non-heating load for all years (2015 to 2036) to get final forecast with heating load adjustment

$$Heating\ Load_t + Non\ Heating\ Load_t = Other\_Final\_Sector\_Forecast_t$$

$$\Rightarrow\ Other\_Final\_Sector\ Forecasts_t + Manufacturing\ Forecasts_t = Industrial\ Final\ Forecast\ _t$$

4.2.5 Strong and Weak scenarios

Strong and Weak scenario sensitivities were developed in accordance with the characteristics of strong and weak economies:

- A strong economy is characterised by strong population growth, high consumer confidence, strong economic growth and also a strong Australian dollar.

- A weak economy is characterised by moderate population growth, low consumer confidence, weak economic growth and also a weak Australian dollar.

To quantify the inputs[30] for the scenarios, AEMO approximated 90% POE and 10% POE reference periods from recent history, and assumed the Australian economy would transition from its current point to the respective scenarios over the five-year period from 2015–16 to 2020–21.

[30] Inputs refer to the key economic drivers of the econometric models for Manufacturing and Other sector business models, such as Gross State Product, Gross Value Added, and Industrial Production.

CHAPTER 5. TARIFF V ANNUAL CONSUMPTION

Residential and small commercial and industrial consumption, also known as Tariff V consumption, is defined as consumption by network customers who are billed on a volume basis. These customers typically consume less than 10 TJ/year.

AEMO has used econometric models to develop forecasts for the established networks of Victoria, South Australia, New South Wales (including Australian Capital Territory) and Queensland. For Tasmania, which only started connecting residential and commercial customers in 2004, AEMO applied a network development model.

In the 2016 NGFR, AEMO has:

- Disaggregated models to a finer level of detail than in 2014 to further investigate energy efficiency, gas to electric fuel switching, and the impact of dwelling preferences and price response.
- Used a reference-model approach to overcome data limitations in some states, to produce a base-year forecast calibrated to local conditions. Reference models were then used to adjust the base forecast for key long-term trends such as energy efficiency, gas to electric fuel switching, and price response.
- Separately modelled heating and non-heating load, new versus older homes, and detached versus multi-unit homes, calibrated with actual meter data trends down to postcode level, and adjusting for the effects of the mid-2000s drought, as well as the 2008–09 global financial crisis.

5.1 Definitions

Tariff V customers are small gas customers consuming less than 10 TJ of gas per annum, or customers with a basic meter.

Victoria has the highest consumption and greatest number of gas customers of all the eastern and south-eastern states. Approximately 97% of Victorian Tariff V customers are residential.

Growth in both Tariff V residential and Tariff V commercial consumption can be attributed to similar key drivers including weather, gas price, energy efficiency measures, and growth in connections.

5.2 Forecast number of connections

The methodology used to estimate the future number of Tariff V customers has been left largely unchanged with respect to the analysis carried for the 2015 NGFR. Compared to the 2015 NGFR, the 2016 analysis has changed the assumptions on future conversions from existing all-electric households ('brownfield' conversions), effectively reducing the forecast number of new connections:

- In the 2015 NGFR, the number of brownfield conversions was assumed to be constant over the forecast period.
- In the 2016 NGFR, this number is assumed to decline linearly to zero within the first 10 years of the forecast horizon.

This change causes the total number of connections at the end of the 20-year horizon to be 3% lower than it would be using the 2015 approach.

The input data regarding historical number of connections has been taken from the data sets collected by the system operators in four different jurisdictions (AEMO in Queensland and Victoria, and CGI in New South Wales and South Australia) and by the distribution business (TasGas) in Tasmania.

The Housing Industry Association (HIA) provided AEMO with an updated set of dwelling construction forecasts. The HIA data forecast the future number of dwelling completions differently from 2015, when the HIA data referred to dwelling starts and AEMO applied corrections to convert them to dwelling completions. The new HIA forecasts used in this 2016 NGFR improve the accuracy of results.

5.3 Forecasts annual consumption methodology – New South Wales, Queensland, South Australia, and Victoria

5.3.1 Overview of the methodology

The methodology described in this section relates to all east coast regions except Tasmania. It involved the following steps:

- Analyse Tariff V daily consumption and weather relationship for 2015–16 for each region. The regression results are used to estimate weather normalised residential and non-residential annual consumption, annual heating and base load for 2016.
- Analyse impact of gas price, appliance and home thermal efficiency, and appliance fuel switching on residential consumption using Victorian Tariff V residential meter data 2004–14. The Victorian consumer behaviour model applies to other east coast regions.
- Forecast Tariff V residential and non-residential annual consumption using results of the above analysis and other inputs described below.

5.3.2 Data sources

The input data can be grouped under two categories listed in the tables below.

Table 10 Input data for analysis of historical trend in Tariff V consumption

Data	Source	Purpose
Tariff V 2015–16 daily consumption by region and exclusive of UAFG	VIC and QLD: AEMO Settlements database. NSW and SA: Meter data agent (CGI data tables).	To estimate Tariff V temperature sensitivity used to estimate 2016 weather corrected estimated actual annual consumption.
Regional 2015/16 daily EDD (Vic) or HDD (other regions)[A]	BOM. [A]	Same as above.
Victorian residential meter data 2004–14[B]	AEMO meter database.	To estimate trend in Victorian residential base and heating load.
Victorian daily EDD 2004–14	Calculated using BOM data according to the formula described in Appendix B.	Same as the above.
Actual residential and non-residential annual consumption	Provided by gas distributors in 2016 NGFR stakeholder surveys.	Used to split Tariff V annual consumption by residential and non-residential.
Actual Tariff V residential and non-residential connections	Provided by gas distributors in 2016 NGFR stakeholder surveys.	Used to calculate average consumption per Tariff V residential and non-residential connection.
Historical residential prices	See details in Appendix A.	Used to estimate impact of gas prices on gas Tariff V residential and non-residential consumption.

A See Appendix B for more detail.
B Second tier residential customers only.

Table 11 Input data for forecasting Tariff V annual consumption

Data	Source	Purpose
Forecast residential prices[A]	See details in Appendix A.	Used to forecast gas price impact on residential and non-residential annual consumption forecasts.
Forecast Tariff V connections	See 5.2.	
Annual EDD/HDD standards	See Appendix B.	Used for forecasting Tariff V heating load.
Forecast non-residential annual consumption savings due to energy efficiency and fuel switching	Core Energy	Used to forecast impact of energy efficiency and fuel switching on Tariff V non-residential forecasts.
Impact of climate change on Tariff V annual heating load	See details in Appendix B.	Used to forecast impact of climate change on Tariff V annual heating load forecasts.

A Forecast residential prices are used for forecasting Tariff V residential and non-residential gas consumption because both forecast price series follow similar trends.

5.3.3 Forecast Tariff V annual consumption – Victoria

Step 1: Estimate Tariff V residential and non-residential annual consumption for 2016

The objective of this step was to estimate weather-corrected 2016 Tariff V residential and non-residential annual consumption for each region, to be used as the basis for forecasting regional Tariff V annual consumption over the 20-year horizon.

Analysis

Estimate weather normalised 2016 Tariff V annual consumption

Actual Tariff V consumption was available to the end of August 2016 at the time of preparing the 2016 NGFR consumption forecasts. The latest 12-month Tariff V consumption, between September 2015 and August 2016, was used as the best estimate of 2016 annual consumption.

The first step of the analysis was to correct the estimated 2016 annual consumption for standard weather conditions. This required estimating the appropriate temperature sensitivity to use by regression analysis of weekly Tariff V consumption against average weekly EDD.

The regression model took the following form:

$$Y_i = \alpha + \beta * EDD_i + \gamma * H + PH$$

where:

Y_i = average Tariff V daily consumption for week i

i = week number

α = average Tariff V base load

β = average Tariff V temperature sensitivity (TJ/EDD)

EDD_i = average daily EDD for week i

γ = estimate daily base load reduction over the 3 weeks Christmas – New Year business close down period

H = index to flag business close down period (= 3 for last week and first week of the year, 2 for week 2, 1 for week 3 of the New Year, 0 otherwise)

PH = 1 for public holiday, 0 otherwise

The weather normalised Tariff V estimated annual consumption for 2016 is therefore equal to

$$Y_{WN,2016} = Y_{2016} - \beta * (EDD_{2016} - 1340)$$

Note: 1340 EDD is the forecast weather standard. See Appendix B.

Estimate weather normalised 2016 Tariff V residential and non-residential annual consumption

Historical Tariff V residential and non-residential annual consumption was provided by distributors in NGFR stakeholder surveys and were used to estimate the share of residential and non-residential annual consumption of total Tariff V which were further split into heating and base load.

The following results were obtained for Victoria.

Table 12 Estimated Victorian residential and non-residential annual consumption 2016 (PJ)

	Residential	Non-residential	Total
Base load	41.7	7.4	49.1
Heating load	60.9	12.1	73.0
Total	102.6	19.5	122.1

Step 2: Analyse basic meter data

The objective of this step was to estimate Victorian residential annual base load (gas cooker, hot water) and heating load (room and central heaters) using Victorian Tariff V residential basic meter data available from AEMO's meter database.

Analysis

This analysis covers all Tier 2[31] Tariff V basic meter consumption available in AEMO's meter database including residential and non-residential customers.

For the purpose of this analysis, residential customers are Tariff V customers with annual base load and heating load below the pre-defined critical thresholds.[32] Only Tariff V customers with estimated annual consumption meeting these criteria were included for further analysis.

Most Victorian residential customers are billed every two months for their gas consumption. For most customers with gas heating, their gas bills are highest in winter. By contrast, for customers with electric heating their gas consumption is expected to be relatively stable throughout the year.

The following regression model was used to estimate individual residential customer's annual base load and heating load over the period 2005–14.

$$\boldsymbol{Y_{i,j,k} = \propto_{j,k} + \beta_{j,k} * EDD_{i,j}}$$

where:

$Y_{i,j,k}$ = average daily consumption for billing period i, year j and customer k

$\propto_{j,k}$ = average daily base load for year j and customer k

$\beta_{j,k}$ = average daily heating load/EDD for year j and customer k

= 0 for customers without gas heating

$EDD_{i,j}$ = average daily EDD for billing period i and year j

i = 1, 2…6 if 6 bills

j = 2004, 2005…2014

For customer k,

- Annual base load for year j = $\propto_{j,k} *$ number of days in year $(365\ or\ 366\ for\ a\ leap\ year)$ and
- Weather normalised annual heating load for year j = $\beta_{j,k} *\ 1{,}340\ EDD$ (Vic annual EDD standard).

[31] Customers not supplied by host retailers.

[32] Annual consumption threshold is 50 GJ pa for base load and 100 GJ for heating load.

Step 3: Analyse average gas appliance annual consumption in Victorian existing and new homes and by suburb types

Objective

To analyse historical trend in average residential annual heating and base load for existing and new homes by geographical locations (postcodes), and type of suburbs (inner, middle, outer, and regional).

New homes are defined as greenfield sites connected to the Declared Transmission System (DTS) since 2004, which are subject to the Victorian building codes for new residential homes.

Analysis

The results obtained in Step 2 above were screened to remove invalid base load and heating load (for example, negative values).

Summary statistics were derived from the distribution of annual heating and base load for Victorian existing and new homes.

The charts below display the trend in average annual base load and weather normalised heating for existing homes and new homes 2005–13 and by suburb type:

- Inner suburbs are postcodes within 10 km of Melbourne CBD.
- Middle suburbs are postcodes between 10 km and 20 km of Melbourne CBD.
- Outer suburbs are postcodes between 20 km and 50 km of Melbourne CBD.
- Regional suburbs are all other postcodes in Victoria.

Figure 3 Average annual consumption in existing residential homes

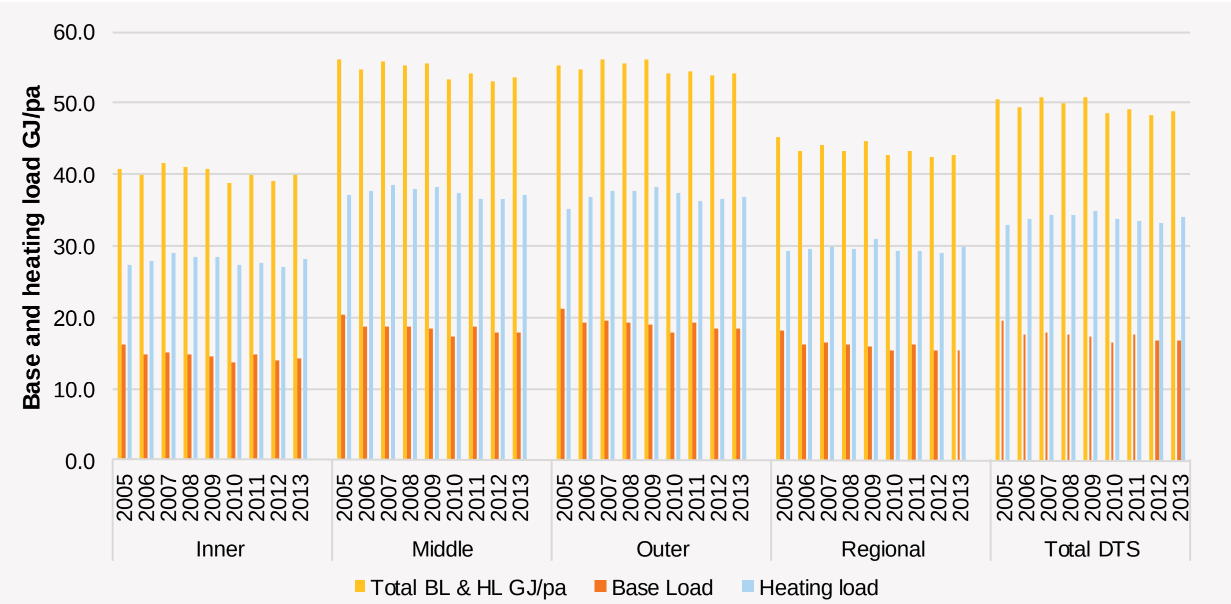
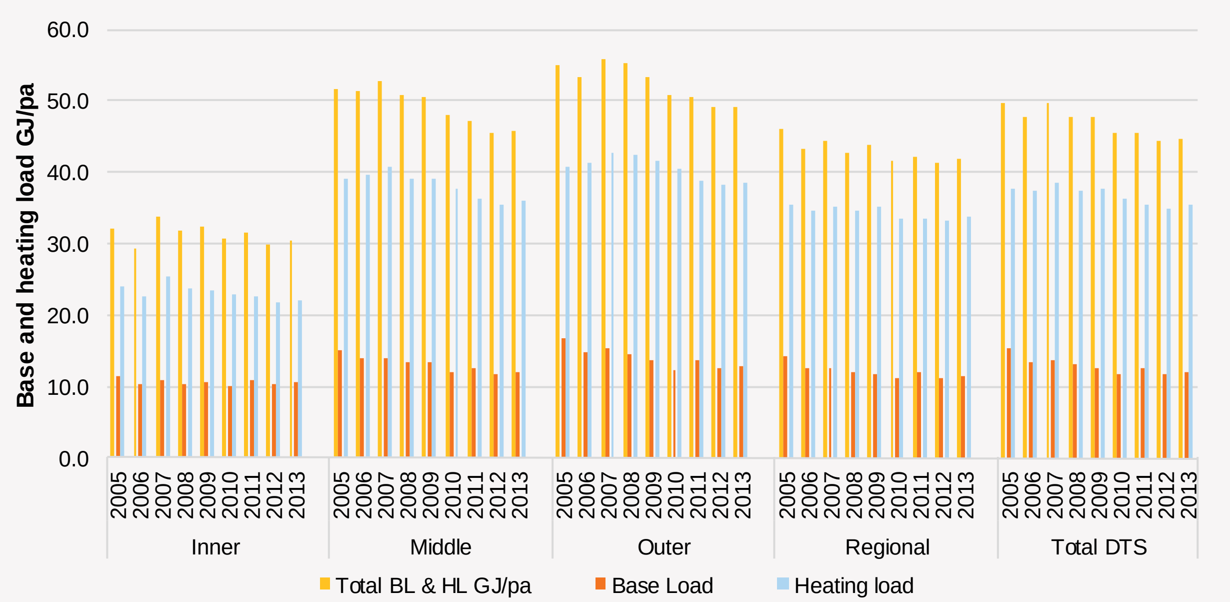


Figure 4 Average annual consumption in new residential homes



The results of the analysis are summarised below.

- Hot water consumption (base load) has been falling across all suburbs since 2005. It has fallen more rapidly in new homes than existing homes, driven by mandatory installation of solar hot water heaters in 5 and 6 star new homes. The decline was steeper between 2005 and 2008, driven by consumers' changing water usage behaviours in response to water consumption conservation measures (for example, water-efficient shower heads) at that time.
- Over the period 2005–13, hot water consumption in existing homes was 25% lower than in new homes.
- Heating consumption increased during 2005–08 (in new homes) and 2005- 2010 (in existing homes), driven by increased penetration of central heaters. Annual heating consumption fell since that time, due to improved home insulation (the Commonwealth Government pink batt scheme).
- Over the period 2005–13, heating consumption in new homes was about 9% higher compared to existing homes, despite mandatory 5 and 6 star building shells. This was due to increased building size in new homes and building design favouring full length glass windows, offsetting potential energy savings from improved home insulation.
- Comparing hot water and heating consumption by geographical locations, inner suburbs had the lowest annual hot water and heating consumption in both new and existing homes because of smaller house sizes in these suburbs. Over the period 2005–13, hot water and heating consumption in new homes in inner suburbs was 18% and 40% lower respectively, compared to the Victorian DTS average estimate.
- By contrast, existing and new homes in outer suburbs had the highest hot water and heating consumption of all suburbs (10% higher than the Victorian DTS average), due to the larger home sizes. These suburbs also showed the fastest rate of decline in appliance consumption.

Step 4: Analyse impact of gas price and appliance and building energy efficiency on Victorian residential existing and new home gas consumption

Objective

To analyse the impact of gas prices and gas appliance and building energy efficiency on existing and new homes annual base load and heating load obtained in Step 3.

Analysis

The analysis was conducted separately for existing and new homes gas appliance consumption.

To overcome the problem of insufficient historical data, the analysis used pooled appliance average annual consumption data to include inner, middle, outer, regional suburbs and total DTS.

Hot water annual consumption model

$$\boldsymbol{LN(BL_i) = \alpha + \beta * LN(P_{i-1}) + \gamma * LN(T_i) + \delta * I_i + \varepsilon * M_i + \epsilon * O_i + \theta * R_i}$$

where:

BL_i = average annual base load in year i

α= average annual base load for total DTS (not impacted by gas price and energy efficiency).

β= Price elasticity for base load

P_{i-1} = lagged price for year i

γ = base load energy efficiency elasticity.

T_i = time trend for year i (= 1, 2,…, 10, 1=2005 and 10 = 2014) was used to model the falling trend in historical base load driven by more energy efficiency appliances and changed hot water consumption behaviour

I_i = dummy variable for inner suburb for year i (= 1 if inner suburbs, = 0 otherwise).

M_i= dummy variable for middle suburbs for year i (= 1 if middle suburbs, = 0 otherwise).

O_i = dummy variable for outer suburbs for year i (= 1 if outer suburbs, = 0 otherwise).

R_i = dummy variable for regional suburbs for year i (= 1 if regional suburbs, = 0 otherwise).

δ = difference between inner suburb average annual base load and to DTS average annual base load

ε = difference between middle suburb average annual base load and DTS average annual base load

ϵ = difference between outer suburb average annual base load and DTS average annual base load

θ = difference between regional suburb average annual base load and DTS average annual base load

Table 13 Model parameters for average annual base load

		Intercept	Price	Time trend	Inner	Middle	Outer	Regional	R-Square
		α	β	γ	δ	ε	ϵ	θ	
Existing homes	Coefficient	0.200	-0.066	-0.034	-0.204	0.068	0.096	-0.109	97%
	Standard error	0.319	0.076	0.017	0.012	0.012	0.012	0.012	
New homes	Coefficient	0.631	-0.162	-0.085	-0.260	0.030	0.109	-0.095	92%
	Standard error	0.610	0.145	0.033	0.023	0.023	0.023	0.023	

Heater annual consumption model

$$\boldsymbol{LN(HL_i) = \alpha + * \beta * LN(P_{i-1}) + \gamma * LN(T_i) + \mu * LN(T_l) + \delta * I_i + \varepsilon * M_i + \epsilon * O_i + \theta * R_i}$$

where:

HL_i = average annual base load for year i

α = average annual heating load for total DTS (not impacted by gas price and energy efficiency).

β = price elasticity for heating load

P_{i-1} = lagged price for year i

γ = heating load energy efficiency elasticity for T_i

T_i = time trend for year i (= 1, 2,…, 6, 1=2005) used to model the falling trend in historical heating load since 2005

γ = heating load energy efficiency elasticity for T_l

T_l = time trend for year l (= 1, 2, 3, 1=2011) used to model the increase in average annual heating consumption in this period driven by increased penetration of gas central heaters.

I_i = dummy variable for inner suburb for year i (= 1 if inner suburbs, = 0 otherwise).

M_i= dummy variable for middle suburbs for year i (= 1 if middle suburbs, = 0 otherwise).

O_i = dummy variable for outer suburbs for year i (= 1 if outer suburbs, = 0 otherwise).

R_i = dummy variable for regional suburbs for year i (= 1 if regional suburbs, = 0 otherwise).

δ = difference between inner suburb average annual heating load and to DTS average annual base load

ε = difference between middle suburb average annual heating load and DTS average annual base load

ϵ = difference between outer suburb average annual heating load and DTS average annual base load

θ = difference between regional suburb average annual heating load and DTS average annual base load

Table 14 Model parameters for annual heating consumption

		Intercept	Price	Time trend	Time trend 2	Inner	Middle	Outer	Regional	R-Square
		α	β	γ	μ	δ	ε	ϵ	θ	
Existing homes	Coefficient	0.89	-0.20	-0.004	0.04	-0.35	0.15	0.13	-0.18	99%
	Standard error	0.49	0.11	0.02	0.01	0.01	0.01	0.01	0.01	
New homes	Coefficient	1.47	-0.33	-0.07	0.04	-1.24	0.04	0.11	-0.09	99%
	Standard error	1.37	0.31	0.05	0.03	0.03	0.03	0.03	0.03	

Step 5: Forecast impact of gas prices and energy efficiency on residential gas consumption

The price elasticities obtained in Step 4 were used to forecast impact of forecast increased gas prices on annual heating and base load over the forecasting horizon.

Impact of increased appliance and building energy efficiency was forecast by extrapolating the time trend derived in Step 4 above.

Cumulative impact was calculated relative to calendar year 2016.

Step 6: Forecast impact of appliance fuel switching in existing homes

Impact of fuel switching was estimated based on the following assumptions:

- Hot water consumption:
  - Existing home gas hot water appliances: the average lifespan of a gas hot water unit is 10–15 years. Current existing home gas hot water stock was assumed to change over within the next 10 years, and to be replaced with solar hot water units or heat pumps, reducing the forecast

difference between existing and new home average annual hot water consumption by 80% within the next 10 years.[33] A quadratic model was used to model the load reduction over the next 10 years of the forecasting horizon. In the absence of new energy policies from both the Commonwealth and State governments, the impact of fuel switching was forecast to plateau after the initial period.

- It was also assumed that 50% of the forecast reduced gas hot water consumption in existing homes is due to conversion of gas storage hot water units to instantaneous units. As such, an estimated load reduction was reallocated from fuel switching impact to energy efficiency impact.
- Fuel switching in new homes was not expected to be significant over the forecasting horizon

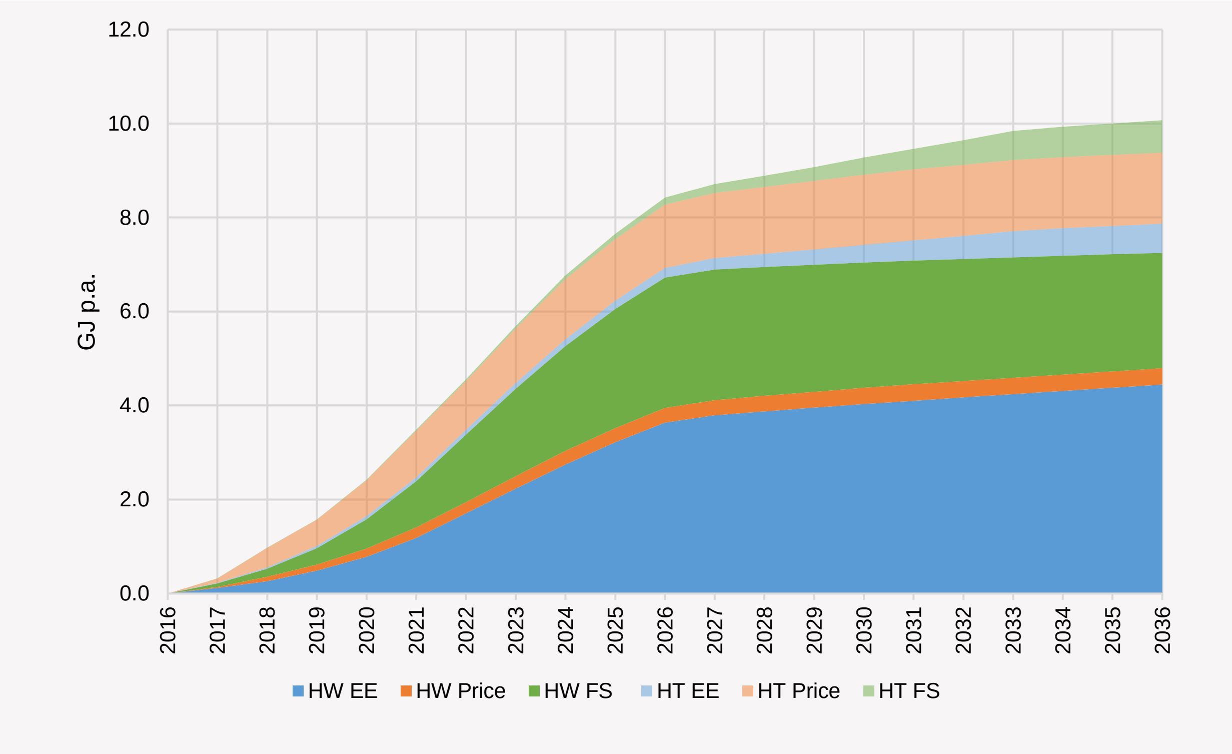
- Heating consumption:
  - Heating units in existing homes were assumed to change over within the next 20 years, and to be replaced with either smaller gas space heaters, or smaller gas space heater units combined with reverse-cycle air-conditioners (RCAC), or RCAC only.[34] This was modelled to reduce the forecast difference between existing and new home average annual gas heating consumption by 50% in the next 20 years.
  - Fuel switching for new home heating appliances is insignificant.

Summary of forecast load reductions

Figure 5 shows that existing home average annual consumption before climate change adjustments is forecast to reduce by 6.8% by 2021 and 19.5% by 2036, primarily driven by energy efficiency savings.

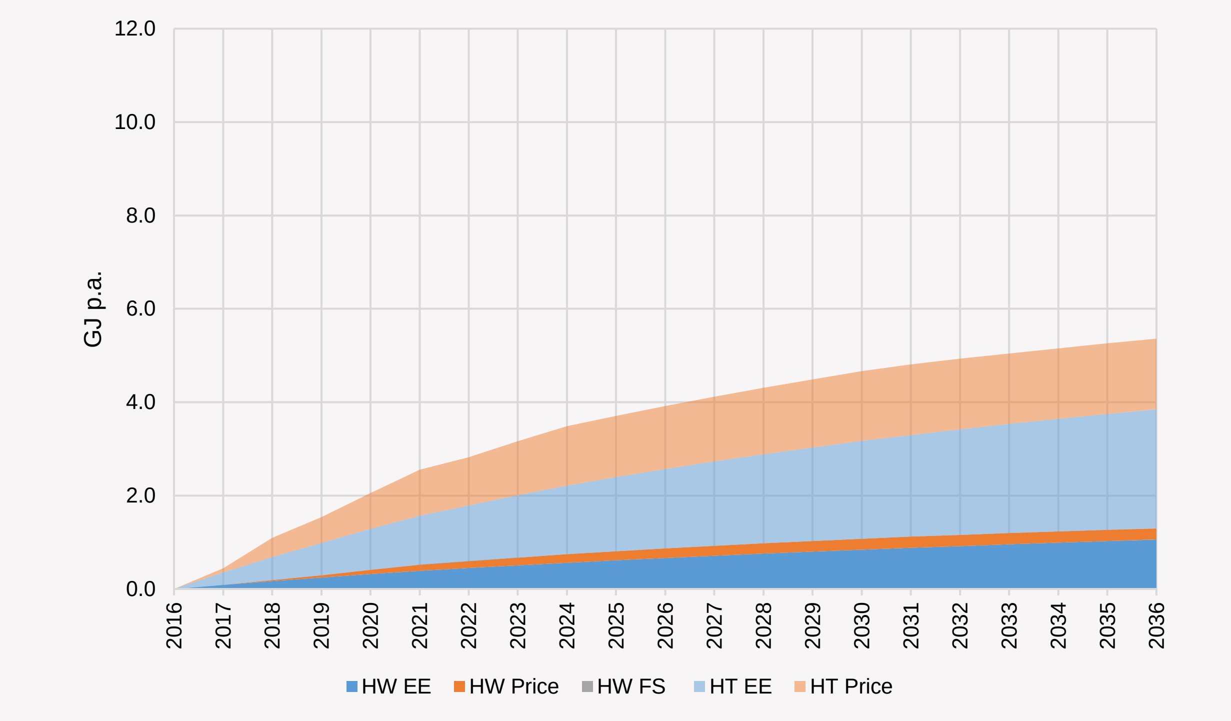
Figure 6 shows that new home average annual consumption before climate change adjustment is forecast to reduce by 5.1% by 2021 and 11.5% by 2036, driven by energy efficiency savings in heating consumption.

Figure 5 Forecast reduction in existing home average residential consumption



[33] The average life of a gas hot water unit is between eight and 12 years.
[34] The average life of a gas heating unit is between 18 and 22 years.

Figure 6 Forecast reduction in new home average residential consumption



Step 7: Forecast Victorian residential annual consumption

Residential annual consumption forecasts were compiled from the forecasts of the individual components listed in the table below, according to the following mathematical equation.

Table 15 Compilation of residential forecast components

The forecast residential annual consumption for each forecast year i (2017 – 2036) equals	$\boldsymbol{FC_i}$ =
Existing homes annual heating and base load in 2016	$Y_{WN,2016}$
Plus New homes/connections annual heating and base load for year i	$+(BL_{NH,2016} + HL_{NH,2016}) * C_{NH,2016}$
Minus the forecast total impact of gas price increases in all existing and new homes for year i	$--(P_{BL,EH,i} + P_{HL,EH,i}) * C_{EH,i}$ $-(P_{BL,NH,i} + P_{HL,NH,i}) * C_{NH,i}$
Minus the forecast cumulative impact of appliance and building energy efficiency for year i	$-(EE_{BL,EH,i} + EE_{HL,EH,i}) * C_{EH,i}$ $-(EE_{BL,NH,i} + EE_{HL,NH,i}) * C_{NH,i}$
Minus the forecast cumulative impact of gas to electric appliance switching in existing homes for year i	$-(FS_{BL,EH,i} + FS_{HL,EH,i}) * C_{EH,i}$
Minus the forecast cumulative impact of climate change on total heating consumption for year i	$-(P_{HL,EH,i} + EE_{HL,EH,i} + FS_{HL,EH,i}) * C_{EH,i} * CC_i$ $-(P_{HL,NH,i} + EE_{HL,NH,i}) * C_{NH,i} * CC_i$

Variables:

BL = base load, HL = heating load, P = forecast price impact, C = forecast connections

EE = forecast impact of energy efficiency, FS = forecast impact of appliance fuel switching

CC = impact of climate change

Subscripts:

EH = existing home, NH = new home, i = year i

Step 8: Forecast Tariff V non-residential annual consumption

Forecast Tariff V non-residential annual consumption follows a similar approach as outlined in Step 7 above. The forecast annual consumption for year i:

- Was derived from the 2016 weather normalised estimated actual Tariff V non-residential annual consumption.
- Plus forecast annual consumption growth due to new connections.
- Less forecast load reduction due to impact of gas prices, energy efficiency and fuel switching.
- And less impact of climate change on heating load.

The impact of gas prices was assumed to be similar to the combined total gas price impact on heating and base load in both existing and new homes. This is equivalent to a price elasticity of -0.13.

Forecast impact of energy efficiency and fuel switching was provided by Core Energy for Tariff D and V in each region for specific industry groups with likely potential for fuel switching (for example, health services, education, and public administration)

Step 9: Forecast total Tariff V annual consumption

Total Tariff V annual consumption is the sum of Tariff V residential and Tariff V non-residential annual consumption.

5.3.4 Forecast annual consumption methodology – New South Wales, Queensland, and South Australia

A similar approach to Victoria residential and non-residential forecasts was adopted. Steps 1 to 9 outlined in Section 5.3.3 for Victorian Tariff V annual consumption forecasts were adopted, with the following differences:

Step 1

The following table presents 2016 Tariff V weather normalised annual consumption.

Table 16 Estimated 2016 residential and non-residential annual consumption – New South Wales, Queensland, and South Australia (PJ)

	New South Wales			Queensland			South Australia		
	Res	Non-res	Total	Res	Non-res	Total	Res	Non-res	Total
Base load	19.3	9.9	29.2	2.1	3.7	5.8	4.4	1.8	6.2
Heating load	13.2	6.9	20.1	0.1	0.3	0.4	3.5	1.6	5.1
Total	32.5	16.8	49.3	2.2	4.0	6.2	7.9	3.4	11.3

Step 2

Meter data analysis was not performed because of insufficient meter data and resource constraints.

Step 3

This analysis was not performed. Average annual heating and base load per connection was estimated for 2015 using actual residential consumption and connections provided by distributors in the 2016 NGFR stakeholder survey. The results from the Victorian analysis were then applied to derive existing and new homes heating and base load by applying the ratios of existing and new homes consumption to the regional average residential consumption per connection.

Step 4

This step was not performed. However, the model parameters from the Victorian meter data analysis were used to forecast impact of gas price, energy efficiency savings, and appliance fuel switching described in Steps 5 and 6.

Steps 5 to 9

Unchanged.

5.4 Forecast annual consumption methodology – Tasmania

The Tasmanian gas network began operation in 2004, and subsequent residential and commercial consumption growth reflects the progressive connection of existing houses to the network.

The 2016 NGFR applied the following methodology to forecast Tariff V consumption:

- The methodology forecast total residential and commercial gas consumption separately based on historical data and then summed the two components to find total Tariff V gas consumption.
- The number of additional connections in Tasmania was estimated using the below formula. This year AEMO assumed that the number of additional connections each year would not drop below 150 residential customers or 15 commercial customers. For the Strong and Weak scenarios, AEMO assumed connection growth of 125% and 75% that under the Neutral scenario.

$$Addiotnal\_Connections_{Res} = 2168e^{-0.1265(year-2005)}$$

$$Addiotnal\_Connections_{Comm} = 108.4e^{-0.1070(year-2005)}$$

- AEMO assumed that average usage per residential and commercial customer will reduce under all scenarios in line with projected price increases, with elasticities of -0.2, -0.1 and -0.3 for the Natural, Strong and Weak scenarios respectively.
- For residential customers under the Neutral scenario, average usage per customer reduces to about 29 GJ/customer by 2030. For commercial customers under the Neutral scenario, average usage per customer reduces to about 427 GJ/commercial customer by 2030.
- Finally, AEMO multiplied the number of connections by the average consumption per connection for both residential and commercial customers and summed them together to find the total Tariff V forecast for each year.

CHAPTER 6. MAXIMUM DEMAND

This chapter outlines the methodology used to develop forecasts of maximum daily demand for each year in the 20-year forecast horizon.

AEMO used the same methodology as the 2015 NGFR, which was updated last year to better account for long-run weather trends, appliance-based influences on demand and to provide more detailed information on fuel switching, energy efficiency and price response. AEMO aligned the winter maximum demand models to the new annual consumption models.

Industry, government and stakeholders use daily maximum demand forecasts to assess the adequacy of infrastructure supply capacity, and to inform commercial and operational decisions that are dependent on the potential range of demand over time.

For most regions, maximum demand is determined by weather driving gas consumption for heating. GPG on an annual maximum demand day is otherwise unexceptional and is driven more by conditions in the electricity market than other drivers of gas consumption.

Forecasts of maximum daily demand for each region are estimated as the sum of the following:

- Residential, commercial and industrial maximum demand on day of system peak.
- GPG on day of system peak.
- LNG on day of system peak (in Queensland).

Phase 1: Tune daily models for the most recent winter heating season

AEMO developed short-term econometric forecasting models for Tariff V (residential and commercial) and Tariff D (industrial) gas consumption using daily data. The models:

- Captured current customer behaviour, including the current appliance mix of households and operational practices of industry; and
- Excluded the longer-term effects of price response, energy efficiency trends and fuel switching trends. These effects were added back in for the long-term forecast.

Since gas consumption is winter peaking, the short-term models were used to produce the maximum demand for the winter heating period.[35] AEMO used the most recent 18 months of data available to develop the model parameters and capture the most current heating trends and consumer behaviour.[36]

Tables 17 and 18 below show the formulation of the models. The process treated the heating and non-heating components of the respective Tariff V and D models separately. This recognises that, on a peak day, the heating component is larger as a proportion of total consumption than in the annual consumption forecast. This method also enabled separate heating and non-heating adjustments for fuel switching and energy efficiency, again, having different proportions on a peak day compared to an annual period.

This year's methodology differs from last year's methodology in that this year, AEMO tuned the Tariff V base year models on total residential consumption rather than average consumption per connection point. Finding the average consumption per connection point was seen as an unnecessary given the forecast method applied in phase 3.

[35] AEMO defines the winter heating period as 1 May to 30 September in all states except for Victoria. In Victoria the heating period is defined as 1 April to 30 September. For 2016 NGFR, the most recent dataset available was for January 2015 to June 2016.

[36] Residential, commercial and industrial gas consumption values are exclusive of losses.

The gas consumption model

$$Consumption = f(HDD/EDD, Cosine, Friday\_Dummy, Saturday\_Dummy, Sunday\_Dummy, Holiday\_dummy, Christmas\_season, School\_Holidays, Hot\_Water, Trend\_Variable)$$ [37]

Table 17 State-specific residential and commercial model (Tariff V)

Region	Econometric model
New South Wales	$TV = \beta_0 + \beta_1 HDD + \beta_2 Cosine + \beta_3 Friday\_Dummy + \beta_4 Saturday\_Dummy + \beta_5 Sunday\_Dummy + \beta_6 Holiday\_Dummy + \beta_7 Christmas\_period + \beta_{10} Trend$
Queensland	$TV = \beta_0 + \beta_1 HDD + \beta_2 Cosine + \beta_3 Friday\_Dummy + \beta_4 Saturday\_Dummy + \beta_5 Sunday\_Dummy + \beta_6 Holiday\_Dummy + \beta_7 Christmas\_period + \beta_{10} Trend + Winter\_Dummy$
Victoria	$TV = \beta_0 + \beta_1 EDD + \beta_4 Saturday\_Dummy + \beta_5 Sunday\_Dummy + \beta_6 Holiday\_Dummy + \beta_8 School\_Holidays + \beta_9 Hot\_Water$
South Australia	$TV = \beta_0 + \beta_1 HDD + \beta_2 Cosine + \beta_3 Friday\_Dummy + \beta_4 Saturday\_Dummy + \beta_5 Sunday\_Dummy + \beta_6 Holiday\_Dummy + \beta_7 Christmas\_period + \beta_{10} Trend$
Tasmania	$TV = \beta_0 + \beta_1 HDD + \beta_7 Christmas\_period + \beta_{10} Trend$

Table 18 State-specific industrial model (Tariff D)

Region	Econometric model
New South Wales	$TD = \beta_0 + \beta_1 HDD + \beta_3 Friday\_Dummy + \beta_4 Saturday\_Dummy + \beta_5 Sunday\_Dummy + \beta_6 Holiday\_Dummy + \beta_7 Christmas\_period$
Queensland	$TD = \beta_0 + \beta_1 HDD + \beta_3 Friday\_Dummy + \beta_4 Saturday\_Dummy + \beta_5 Sunday\_Dummy + \beta_6 Holiday\_Dummy + \beta_{10} Trend + Winter\_Dummy$
Victoria	$TD = \beta_0 + \beta_1 EDD + \beta_3 Friday\_Dummy + \beta_4 Saturday\_Dummy + \beta_5 Sunday\_Dummy + \beta_6 Holiday\_Dummy + \beta_7 Christmas\_period + \beta_8 School\_Holidays + \beta_9 Hot\_Water + 2016\_Dummy$
South Australia	$TD = \beta_0 + \beta_1 HDD + \beta_3 Friday\_Dummy + \beta_4 Saturday\_Dummy + \beta_5 Sunday\_Dummy + \beta_6 Holiday\_Dummy + \beta_7 Christmas\_period + \beta_{10} Trend$
Tasmania	$TD = \beta_0 + \beta_1 HDD + \beta_3 Friday\_Dummy + \beta_4 Saturday\_Dummy + \beta_5 Sunday\_Dummy + \beta_6 Holiday\_Dummy + \beta_7 Christmas\_period + \beta_{10} Trend$

The tables below show the model parameters.

[37] The Christmas season variable covers the period from mid-December to early January recognising that a lot of businesses shut down over this period and a lot of people go on holidays.
The Cosine variable is the cosine of a trend series that is 1 on the first day of the sample period and N on the last day. The cosine variable takes a value between 0 and 2 where 2 is the peak of winter.

Table 19 Residential and commercial model (Tariff V)

Variables	NSW_Model	QLD_Model	SA_Model	VIC_Model	TAS_Model
Constant	86.14	14.57	19.37	285.30	0.30
Friday_Dummy	-4.02	-1.08			
Saturday_Dummy	-12.51	-3.14	-2.18	-12.05	
Sunday_Dummy	-11.37	-2.67	-1.87	-16.93	
Christmas_Period	-0.89	-0.21	-0.40		-0.06
Holiday_Dummy	-7.18	-3.04	-1.68	-13.05	
HDD/EDD	12.60	0.56	2.65	42.37	0.19
Cosine	26.63	2.58	8.66		
Trend	-0.01	0.001	-0.005		0.004
Winter_dummy		0.78			
School_Holidays				-16.73	
Hot_Water				1.13	

Table 20 Industrial model (Tariff D)

Variables	NSW_Model	QLD_Model	SA_Model	VIC_Model	TAS_Model
Constant	163.52	356.04	65.16	211.54	25.73
Friday_Dummy	-10.56		-2.93	-14.64	-1.48
Saturday_Dummy	-35.70	-12.23	-12.62	-49.07	-3.20
Sunday_Dummy	-34.35	-11.29	-12.58	-46.83	-3.17
Christmas_Period	-3.23		-0.58	-4.28	-0.82
Holiday_Dummy	-20.85	-11.38	-11.01	-36.68	-2.70
HDD/EDD	2.39		0.74	1.83	0.07
Trend		-0.11	0.01		0.00
Winter_dummy		7.36			
School_Holidays				-4.52	
Hot_Water				0.12	
2016_Dummy				-7.84	

Phase 2: Determine base-year residential, commercial, and industrial maximum demand

AEMO simulated weather data based on historical weather conditions to forecast maximum demand in the base year (2017) for both Tariff V and D. The forecast maximum demand in 2017 was then used as the base year for the subsequent forecasts.

AEMO used weather normalized EDD and HDD values by adjusting the data for climate change (see Appendix B. Weather Standards). In the simulation process, the EDD or HDD value for a given day was randomly drawn from the pool of climate change adjusted historical values. Approximately five million random days were drawn. The randomly drawn data was then passed into the short term Tariff V and Tariff D models, as described in Phase 1.

From each simulated heating season, the maximum daily demand for Tariff V and D was recorded. The 50% POE was calculated taking the median of the statistical distribution of the simulated maximum demands. In a similar fashion, the 5% POE was computed by identifying the 5% quantile of the simulated distribution.

Phase 3: Determine residential, commercial, and industrial maximum demand for the forecast horizon

AEMO used the base year maximum demand value from Phase 2 as the first point in the forecast horizon (2017), then applied the annual consumption forecasts growth rate to forecast the remaining years in the forecast horizon (2018 to 2036).

The growth rates of the heat and non-heat sensitive components were evaluated independently in the annual consumption forecast and applied to the base-year values of the maximum demand. This approach adjusts for the higher proportion of heating demand on a peak day, and therefore also enabled a more accurate forecast of energy efficiency and fuel-switching.

By evaluating the heat and non-heat sensitive component of MD against the components of annual consumption, AEMO assumed that MD grows at the same rate as annual consumption for the two components.

AEMO used the following formula to forecast both the residential and commercial (Tariff V) and the industrial (Tariff D) sectors separately.

(1) $Heating\ Load = (POE50\ or\ POE5\ of\ Tariff\ V\ or\ D\ Heating\ MD\ in\ 2016) * \frac{Annual\ Heating\ Load(forecast)}{Annual\ Heating\ Load\ 2016}$

(2) $NonHeating\ Load = (POE50\ or\ POE5\ of\ Tariff\ V\ or\ D\ NonHeating\ MD\ in\ 2016) * \frac{Annual\ NonHeating\ Load\ (forecast)}{Annual\ NonHeating\ Load\ 2016}$

The NGFR represents the sum of the heating and non-heating components for Tariff V and D forecast maximum demands.

Phase 4: Determine system peak forecast for all sectors

To obtain the system peak forecast for all sectors, AEMO aggregated the maximum demand for the residential, commercial and industrial sectors (obtained in Phase 3) with LNG maximum demand[38] and the median daily GPG value for winter. The reasoning for using an average GPG is because the system peak normally occurs on a cold winter day, and that is typically otherwise unexceptional for GPG (See Chapter 3.)

[38] This is assumed to be the LNG maximum demand estimate for July in Queensland.

APPENDIX A. GAS RETAIL PRICING

Price data was a key input in forecast models across multiple sectors.

The gas retail price projections used in the 2016 NGFR are bottom-up projections based on separate forecasts of the various components of retail prices. Separate prices have been prepared for four markets (residential, business, small industrial, and large industrial) in five regions (New South Wales, Queensland, South Australia, Tasmania, and Victoria). The prices are intended to represent those paid by the average or typical user in each market, located in a distribution zone in the capital city.

A.1 Price components

Gas retail prices typically include the wholesale market price, peak gas supply cost, transmission cost, distribution cost, retail cost of service, retail margin, and cost of carbon-equivalent emissions.

A.1.1 Wholesale market price (baseload gas supply)

Wholesale market price projections were prepared for AEMO by CORE Energy. The projections represent contract prices paid by retailers. The estimates were based on existing contracts up to 2016 or 2017 (depending on location), and from 2017 onwards assumed that contract prices are linked to oil prices.

Projections were provided for three scenarios: Reference case, High case, and Low case. In all scenarios, the wholesale price was assumed to escalate materially in 2017 and 2018 as existing contracts are replaced by oil-linked contracts. AEMO understands that these escalations have already been locked into some new contracts scheduled to start in 2017 and 2018.

AEMO's discussion with industrial customers suggests they are already facing higher wholesale prices, varying by region. For this reason, AEMO has applied a two-period premium (2019–22 and 2023–36) to the Neutral scenario, as shown in Table 21. The dual objective is to bring forward the transition to higher prices and to mark-up the wholesale costs provided by CORE Energy, on the basis of advice from large industrial interviews.

Table 21 Wholesale price premium (Neutral scenario)

Region	Period starting 2019	Period starting 2023
New South Wales	$1.00	$0.40
Queensland	$2.00	$1.25
South Australia	$1.30	$1.00
Tasmania	$0.60	$0.40
Victoria	$0.60	$0.40

Strong and Weak scenario premiums were constructed with respect to the Neutral scenario, for all regions, using the following criteria:

- Total dispersion of wholesale costs in the Strong scenario was $1.00/GJ *higher* than in the Neutral scenario in 2018–19, transitioning linearly to $1.50/GJ *higher* than the neutral scenario by 2023, and continuing for the remainder of the forecast period.
- Total dispersion of wholesale costs in the Weak scenario was $0.50/GJ *lower* than in the Neutral scenario in 2018–19, transitioning linearly to $1.00/GJ *lower* than the Neutral scenario by 2023, and continuing for the remainder of the forecast period.

A.1.2 Peak gas supply cost

Contract prices reflect gas supplied at load factors that are higher than most demand market load factors. The load factor gap is met by peak gas supply from underground storages, pipeline line-pack services (such as park and loan), and wellhead peak contracts.

The costs of peak gas were calculated using a cost of peaking capacity, set in $/GJ/day/year, and applying it to the peak supply required for each market per GJ of annual demand.

Peak supply required = 1/(365*market load factor) – 1/(365*wholesale contract load factor).

For the projections, it was assumed in real terms that the peak supply costs increase in line with the wholesale gas cost increases.

For some industrial markets, the market load factor was higher than the contract load factor, so no peak supply was required.

Note that peak supply charges are derived based on contractual agreement rather than regulated, therefore they may vary over time and across participants. Market participants have also noted that flexibility in wholesale contracts is diminishing, that is, load factors are increasing. Incorporating this would lead to a small increase in peak supply requirements.

A.1.3 Transmission cost

The majority of transmission pipelines charge for service on the basis of both capacity reserved and throughput. For retail pricing purposes it was assumed that each market is charged for capacity on a stand-alone basis, with capacity requirements per GJ of annual demand given by:

Transmission capacity required = 1/(365*market load factor)

Pipeline charges were based on 2016−17 tariffs for the following pipelines:

- New South Wales – Moomba Sydney Pipeline and Eastern Gas Pipeline.39
- Victoria – Victorian Transmission System.
- South Australia – Moomba Adelaide Pipeline.
- Queensland – Roma Brisbane Pipeline.
- Tasmania –Tasmanian Gas Pipeline.

It is noted that tariffs for competing pipelines serving some markets are similar to those selected.

For the projections it was assumed that all charges are constant in real terms, and, as other parameters are also constant, the projected transmission costs are constant in real terms. It is noted that Victorian and Queensland pipeline tariffs are regulated but New South Wales and South Australia are not.

A.1.4 Distribution cost

Distribution costs are determined by distribution tariffs, which are regulated by the Australian Energy Regulator (AER). Costs were based on 2016–17 tariffs (or the average of 2016 and 2017 calendar year tariffs) and escalated according to the most recent AER decision. From the end of the current tariff period, tariffs were assumed to be constant in real terms, though it is noted that last year the AER made a revenue determination resulting in significant tariff declines in New South Wales (Jemena Gas Networks). More recently, AER made a similar determination resulting in significant tariff declines in South Australia (Australian Gas Networks).

The tariffs used are listed below. It was assumed that large industrial consumers take supply directly from transmission pipelines and do not pay distribution charges.

[39] Due to the expansion of the Eastern Gas Pipeline, for the forward projections AEMO has used a weighted average tariff between the Moomba Sydney Pipeline and Eastern Gas Pipeline beyond 2017. Jemena media release, *"Jemena's Eastern Gas Pipeline delivers more gas to NSW and ACT*", 29 February 2016. Available at: http://jemena.com.au/about/newsroom/media-release/2016/eastern-gas-pipeline-delivers-more-gas-to-nsw-and.

Table 22 Network tariffs used

Region	Residential	Business	Small industrial
New South Wales	Jemena Volume Individual – Coastal	Jemena Volume Individual – Coastal	Jemena Demand Tariff DC−3
Queensland[40]	Australian Gas Networks Tariff R Brisbane	Australian Gas Networks Tariff C Brisbane	Australian Gas Networks Tariff D Brisbane
South Australia	Australian Gas Networks Tariff R Adelaide	Australian Gas Networks Tariff C Adelaide	Australian Gas Networks Tariff D Adelaide
Victoria	Multinet Tariff V Residential	Multinet Tariff V Business	Multinet Tariff L Non-residential

A.1.5 Retail cost of service

Retail cost of service was assumed to be a fixed annual cost per customer in each customer category. The cost per GJ was the fixed cost divided by the customer annual consumption, which varies from state to state.

A.1.6 Retail margin

Retail margins are set in a competitive market environment and have escalated significantly since retail price regulation was discontinued.

In the absence of a market model that can estimate future competitive market outcomes, current margins have been estimated by calibrating components to current retail prices, from which future margins can be projected using a number of alternative methods: at a constant real rate per GJ, or as a constant % of controllable costs (all other costs except regulated distribution costs).

A.2 New South Wales, Queensland, South Australia, and Victoria – price calibration

A.2.1 Industrial

For industrial users there are no standing offer retail tariffs, so there were no initial values to calibrate to.

AEMO's discussions with industrial users suggested that the wholesale components of their prices are considerably higher than the $4.20–$4.25/GJ in current contracts, and that they are already paying for some or most of the escalation projected in 2017 and 2018. Further, margins for industrial users are relatively small because many have direct access to the wholesale market.

The 2015–16 prices therefore assume that 67% of the projected wholesale price change from 2015 to 2018 has already been passed on and that margins are fixed at 5% of controllable costs. To match the wholesale price assumption, the projections assume that the price change is 83%, passed on in 2016–17 and fully passed on in 2017–18.

[40] Queensland distribution networks have moved to light handed regulation since 1 July 2016 (https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/envestra-qld-gas-network-access-arrangement-2011-16). AEMO kept distribution costs in Queensland constant in real terms over the forecast period.

Table 23 Small industrial price estimates 2016–17 ($/GJ)

Price component	New South Wales	Queensland	South Australia	Victoria
Wholesale	$6.75	$7.57	$6.99	$6.42
Peak	$0.15	$0.15	$0.14	$0.15
Transmission	$1.55	$0.95	$0.84	$0.37
Distribution	$0.21	$4.78	$1.77	$0.12
Retail cost	$0.01	$0.02	$0.02	$0.02
Retail margin	$0.42	$0.43	$0.40	$0.35
Carbon	$0.00	$0.00	$0.00	$0.00
Total	$9.09	$13.92	$10.16	$7.42

Table 24 Large industrial price estimates 2016–17 ($/GJ)

Price component	New South Wales	Queensland	South Australia	Victoria
Wholesale	$6.75	$7.57	$6.99	$6.42
Peak	$0.07	$0.00	$0.00	$0.04
Transmission	$1.40	$0.75	$0.70	$0.37
Distribution	$0.00	$0.00	$0.00	$0.00
Retail cost	$0.02	$0.03	$0.03	$0.02
Retail margin	$0.41	$0.42	$0.39	$0.34
Carbon	$0.00	$0.00	$0.00	$0.00
Total	$8.65	$8,77	$8.11	$7.19

A.2.2 Residential and commercial

As far as possible, the initial (2016–17) retail prices were tied back to actual prices paid. For residential and commercial prices, this meant:

- Calculating the retail price under a current standing offer retail tariff.
- Applying a typical market discount to the standing offer price.
- Adjusting the retail margin so the sum of the 2016–17 price components matched the discounted price (in a deregulated retail market the margin is effectively determined by the discount).

This ensured projected changes in the sectors linked back consistently to current and historical prices.

The retail standing tariffs used for calibration are listed below. They were chosen to be consistent with the network tariffs.

Table 25 Retail standing tariffs used

Region	Residential	Business
New South Wales	AGL Residential	AGL Business Standard
Queensland	Origin Residential AGN Brisbane	Origin QLD Small Business AGN Brisbane
South Australia	Origin Residential Adelaide	Origin SA Small Business
Victoria	Origin Multinet Main 1	Origin Multinet Main 1 Small Business Tariff 13/21

Typically, customers do not pay a standing tariff, but obtain a discount under a competitive offer. AEMO takes an assumed discount rate based on Origin Energy's reported discounts.[41] These assumptions are considered sound, as they result in similar estimates of retail margins as expected. It is also noted that retail margins in the discounted prices are typically 20% to 35% of controllable costs, compared to 6-8% margins allowed in regulated retail prices. Similar margins apply in current electricity prices.

Table 26 Tariff discounts assumed

Region	Residential (%)	Business (%)
New South Wales	10	10
Queensland	5	12.5
South Australia	12.5	12.5
Victoria	15	15

Table 27 Residential retail price calibration 2016−17 ($/GJ)

Price component	New South Wales	Queensland	South Australia	Victoria
Wholesale	$6.48	$7.50	$6.80	$6.08
Peak	$0.97	$0.62	$0.77	$1.24
Transmission	$3.20	$1.49	$1.42	$0.48
Distribution	$16.36	$42.70	$21.15	$6.71
Retail cost	$5.28	$12.11	$5.00	$2.05
Retail margin	$1.75	$5.39	$2.28	$2.31
Carbon	$0.00	$0.00	$0.00	$0.00
Total	$34.05	$69.81	$37.43	$18.88
Standing Tariff	$37.83	$73.48	$42.78	$22.21

Table 28 Business retail price calibration 2016−17 ($/GJ)

Price component	New South Wales	Queensland	South Australia	Victoria
Wholesale	$6.48	$7.50	$6.80	$6.08
Peak	$0.55	$0.41	$0.47	$0.55
Transmission	$2.36	$1.25	$1.15	$0.42
Distribution	$9.43	$20.05	$11.50	$2.55
Retail cost	$0.54	$0.56	$0.36	$0.35
Retail margin	$3.03	$2.51	$2.63	$2.77
Carbon	$0.00	$0.00	$0.00	$0.00
Total	$22.39	$32.28	$22.91	$12.72
Standing Tariff	$24.97	$36.89	$26.18	$14.96

A.2.3 Effect of price calibration

It is important to note that the calibrations have significant impacts on the price projections:

- For residential and commercial, the full change in wholesale prices between 2015 and 2018 has still to flow through to retail prices.
- For industrial, this is already 67% accomplished, so the future impact is diminished.

[41] Origin Energy. "Improving Returns in Energy Markets", 10 June 2015. Available at: https://www.originenergy.com.au/content/dam/origin/about/investors-media/docs/improving-returns-in-energy-markets-presentation-2015.PDF. Viewed: 1 January 2017.

A.3 Tasmania's retail price forecast

Limited information is available on pricing for Tasmania[42], therefore a bottom-up forecast by component was only possible for residential and business sectors. Small to medium and large industrial retail prices used Victorian retail prices as a reference.

The assumptions for calculating retail price for each are shown in the following sub-sections. For further details on the methodology behind calculating each of the retail price components, see Section A.1).

Residential retail price forecast

AEMO calculated residential retail price forecasts on the basis of published residential gas rates by TasGas for the 2017 calendar year.

For the forecast period 2018 – 2036, AEMO made a year-on-year adjustment for expected changes in wholesale prices, peak supply costs, and transmission costs. All other components were assumed to be constant in real terms over the forecast period.

The assumptions for the components are shown in the following table.

Table 29 Assumptions for calculating residential retail price forecasts by component

Component	Source/assumptions
Wholesale	Wholesale prices were provided by consultancy CORE Energy.
Peak	Victoria's peak supply cost forecasts were used.
Transmission	Transmission costs were calculated using CORE Energy transmission cost forecasts and applying a load factor for residential customers.
Distribution	Kept constant in real terms over the forecast period.
Retail cost	Kept constant in real terms over the forecast period.
Retail margin	Kept constant in real terms over the forecast period.
Carbon	Carbon assumptions were the same across all states. See Table 6 for more details.

Business retail price forecast

Similar to the residential retail price forecasts, AEMO calculated business price forecasts on the basis of published small business gas rates by TasGas for the 2017 calendar year.

For the forecast period 2018–36, AEMO made a year-on-year adjustment for expected changes in wholesale prices, peak supply costs, and transmission costs. All other components were assumed to be constant in real terms over the forecast period.

The assumptions for the components are same as the residential retail price forecasts. Please see Table 29 for further details.

[42] Tasmanian Transmission and Distribution are not currently regulated by the Australian Energy Regulator (AER) and therefore are not required to publish their prices.

Small to Medium Industrial Load (SMIL) retail price forecast

SMIL retail price forecasts were calculated by applying a premium to LIL retail price forecasts.

The premium was calculated by taking an average of difference between SMIL and LIL forecasts in other states. i.e.

$$Premium_{TAS} = Average\{(SMIL_{NSW} - LIL_{NSW}), (SMIL_{QLD} - LIL_{QLD}), (SMIL_{SA} - LIL_{SA}), (SMIL_{VIC} - LIL_{VIC})\}$$

Large Industrial Load (LIL) retail price forecast

For Tasmanian LIL retail forecasts, AEMO took Victorian LIL retail price forecasts, and subtracted the Victorian transmission cost forecasts and added Tasmanian transmission cost forecasts to reflect the higher transmission costs of getting the gas to Tasmanian demand centres. Transmission cost forecasts for Tasmania were calculated using CORE Energy’s transmission cost forecasts, and applying a LIL load factor.

APPENDIX B. WEATHER STANDARDS

B.1 Heating Degree Days (HDD)

To help determine heating demand levels, the 2016 NGFR used an HDD parameter as an indicator of outside temperature levels below what is considered a comfortable temperature. If the average daily temperature falls below comfort levels, heating is required, with many heaters set to switch on if the temperature falls below this mark.

HDDs are determined by the difference between the average daily temperature and the base comfort level temperature (denoted as T_{base}). The HDD formula was used in forecasting Tariff D and V annual consumption and daily maximum demand for New South Wales, Queensland, South Australia, and Tasmania.

To obtain the best correlation with gas consumption, high resolution (three-hourly) temperature averages (denoted as T_{312}) were taken for multiple weather stations in each region, then the averages were weighted according to population centres with high winter gas consumption (denoted as T_{avg312}). Finally T_{base} was determined by examining historical gas consumption patterns with temperature in each region to find the optimal cut-off point for each region.

T_{312} was first calculated from using eight three-hourly temperature readings for each Bureau of Meteorology weather station between 3.00 am of the current calendar day and 12.00 am of the following calendar day, as denoted by the following formula:

$$T_{312} = (T3AM + T6AM + T9AM + T12PM + T3PM + T6PM + T9PM + T12AM)/8$$

A weighted average taken across the relevant weather stations in the region to obtain a regional average daily temperature (T_{reg312}). The station weightings and T_{base} are shown in Table 31. The approach to determine the weightings and base temperature were determined for the 2015 NGFR and reviewed again with slight changes to account for the requirement of half-hourly data for the 2016 NGFR.

Table 30 Station names and ID along with weightings and base temperature used for the 2016 NGFR, excluding VIC

Region	Station name	Station ID	Weight	T_{base} (°C)
New South Wales	Sydney (Observatory Hill)	66062	0.74	19.57
New South Wales	Bankstown Airport	66137	0.16	19.57
New South Wales	Wagga Wagga	72150	0.10	19.57
Queensland	Archerfield	40211	0.34	19.30
Queensland	Rockhampton	39083	0.33	19.30
Queensland	Townsville	32040	0.33	19.30
South Australia	Edinburgh RAAF	23083	0.94	17.94
South Australia	Adelaide (Kent Town)	23090	0.06	17.94
Tasmania	Hobart (Ellerslie Road)	94029	1.00	17.72

Finally the Degree Day (DD_{312}) was calculated for each region, applying the standard HDD formula to the weighted T_{avg312} for each region:

$$HDD = DD_{312} = max(T_{reg312} - T_{base}, 0)$$

B.2 Effective Degree Days (EDD)

In Victoria, an EDD is an index previously developed to quantify the impact of a range of meteorological variables on gas consumption and maximum demand. This is due to Victoria showing a high sensitivity to seasonality, wind speed, and the hours of sunshine with its heating load.

There are several EDD formulations, and AEMO uses the EDD312 (2012) for modelling Victorian medium- to long-term gas demand.[43] The 2016 NGFR applied this EDD standard with an adjustment for the Melbourne Olympic Park weather station that commenced operation in 2015.

Similar to the approach to calculate HDDs in this NGFR, the EDD312 also uses DD_{312} for determining the average degree day load.

The EDD312 formula is a function of temperature, wind chill, seasonality and solar insolation:

$$EDD_{312} = \max(DD_{312} + Windchill - Insolation + Seasonality, 0)$$

The following sections outline how each of the components were calculated.

Temperature (T_{312}) and Degree Days (DD_{312})

Similar to the calculation of DD_{312} as used for the HDD calculation for the other regions in the 2016 NGFR, the average of the eight three-hourly Melbourne temperature readings from 3.00 am to 12.00 am the following day inclusive was taken. The Melbourne Regional Office weather station data was used until its closure on 6 January 2015, with the new Melbourne Olympic Park weather station data used afterwards. To align the Melbourne Olympic Park weather station with historic data, an adjustment factor has been applied such that:

$$T_{312}(OlympicPark) = 1.028 * (T3AM + T6AM + T9AM + T12PM + T3PM + T6PM + T9PM + T12AM)/8$$

Table 31 Weather stations used for the temperature component of the Victorian EDD

Region	Station name	Station ID	Weight	T_{base} (°C)
Victoria	Melbourne Regional Office (until 5 Jan 2015)	86071	1.00	18.00
Victoria	Melbourne Olympic Park (from 6 Jan 2015)	86338	1.00	18.00

Wind chill

To calculate the wind chill function, first an average daily wind speed was calculated, again using the average of the eight three-hourly Melbourne wind observations (measured in knots) from 3.00 am to 12.00 am the following day, inclusive. The average wind speed was defined as:

$$W_{312} = (W3AM + W6AM + W9AM + W12PM + W3PM + W6PM + W9PM + W12AM)/8$$

This was calculated at the weather station level, and a weighted average of the stations in the region was taken to get regional wind speed. The weather station temperature data was sourced from the Bureau of Meteorology, and the stations used and weighting applied are given below.

Table 32 Weather stations used for the wind speed component of the Victorian EDD

Region	Station name	Station ID	Weight
Victoria	Laverton RAAF	87031	0.50
Victoria	Moorabbin Airport	86077	0.50

The wind chill formula is a product of both the average temperature and the average wind speed, with a constant (0.037) applied to account for the perceived effect of wind on temperature. A localisation

[43] EDD312 (2012) is available at: https://www.aemo.com.au/Datasource/Archives/Archive1719.

factor (0.604) was also applied, to account for the shift from the Melbourne wind station (closed in 1999) to the average of Laverton and Moorabbin wind stations, to align them with the Melbourne wind station reading.

$$Windchill = 0.037 \times DD_{312} \times 0.604 \times W_{312}$$

Solar insolation

Solar insolation is the power received on Earth per unit area on a horizontal surface, and depends on the height of the Sun above the horizon. Insolation factor provides a small negative adjustment to the EDD when included, as a higher insolation indicates more sunlight in a day, a factor that can decrease the likelihood of space heating along with a higher output from solar hot water systems (reducing gas from gas hot water systems).

An average daily solar insolation was estimated by the amount of sunlight hours as measured by the Bureau of Meteorology at Melbourne Airport using the following calibration:

$$Insolation = 0.144 \times Sunshine\ Hours$$

Table 33 Weather station used for the solar insolation component of the Victorian EDD

Region	Station name	Station ID	Weight
Victoria	Melbourne Airport	86282	1.00

Seasonal factor (COSINE function)

This factor modelled seasonality in consumer response to different weather. Data show that Victorian consumers have different energy habits in winter than outside of winter despite days with the same temperature (or DD_{312}). This may indicate that residential consumers more readily turn on heaters, adjust heaters higher, or leave heaters on longer in winter than in shoulder seasons for the same weather or change in weather conditions. For example, central heaters are often programmed once cold weather sets in, resulting in more regular use.

This change in behaviour is captured by the Cosine term in the EDD formula, which implies that for the same weather conditions, heating demand is higher in the winter periods than the shoulder seasons or in summer and is defined as:

$$Seasonality = 2 \times cos(2\pi \times (day.of.year - 190)/365)$$

B.3 Determining HDD and EDD standards

As for the 2015 NGFR, the same methodology of using weather data from 2000 to 2015 was used to derive a median weather year. The following table shows the weather standard for each state.

Table 34 Annual Degree Days used in the 2016 NGFR

		NSW HDD	QLD HDD	SA HDD	TAS HDD	VIC EDD
Median	1 in 2	1,070	210	1,070	1,860	1,340
Upper 5%	1 in 20	1,220	300	1,170	2,070	1,470
Lower 5%	19 in 20	940	130	930	1,750	1,200

B.4 Climate change impact

In the 2015 NGFR, AEMO used the derived median weather standard for future EDD/HDD projections.

For the 2016 NGFR, AEMO investigated the impact that recent changes in climate have had on HDDs (and therefore also EDDs), and examined the further forecast increases in temperature for use in developing weather standards for the 20-year forecast horizon.

Approach

To consider how best to incorporate the climate change impact on forecast energy demand, AEMO sought both advice and data from the Bureau of Meteorology and the CSIRO, then analysed historical and forecast temperature changes for the different weather regions across Australia.

In this process, AEMO obtained the median forecast increase in annual average temperatures for more than 40 different climate models. This median was used as a “consensus” forecast. The climate models simulate future states of the Earth’s climate using Representative Concentration Pathways (RCPs) that span a range of global warming scenarios.

There are several future RCP trajectories available. AEMO chose the RCP4.5 as it has an emissions scenario consistent with current policy assumptions, noting that the difference between emissions scenarios tend to be small in the first 20 years regardless, as most of the forecast temperature increase is already locked in. This RCP4.5 scenario results in an estimated increase in average temperatures by approximately 0.5 °C over the next 20 years across all regions in Australia compared to current (2016) temperatures.

Validation against historical weather

To include the effect of a climate change signal on the heating demand of energy consumers, an adjustment to be made on the HDD forecasts was proposed. Analysis of historical temperature records show that climate change effect since 1980 has been at least a 0.5 °C increase in average temperatures across Australia.[44] This increase is large enough to have potentially affected the number of HDDs, as the variable itself derived from average temperatures. AEMO sought to first observe and quantify changes in the HDD variable over time to provide historical validation, before applying a climate change trend to the HDD forecast.

To validate the methodology AEMO first examined the historical HDDs to identify the historical warming trend over the last 20 years for weather stations in different regions of Australia.

In addition, investigation was required to quantify the impact of the so-called Urban Heat Island Effect (UHI). Some of the recent warming in capital cities can be attributed to the increase in urbanisation in capital cities with higher overnight temperatures as buildings and other concrete structures can absorb and retain heat much more when compared to surrounding rural environments.

To quantify this effect, AEMO compared temperature measurements in rural and city-based weather stations in the same climate region. For example, a comparison of the average winter temperatures from 1995 until 2015 for the city-based station (Melbourne Regional Office) and in a regional area (Melbourne Airport) showed an increase in the average daily winter temperatures of 0.42 °C and 0.24 °C respectively. This finding, of the city station showing twice the warming of the rural station, is consistent with other work that has estimated that approximately half the warming in Melbourne city can be attributed to the UHI.[45]

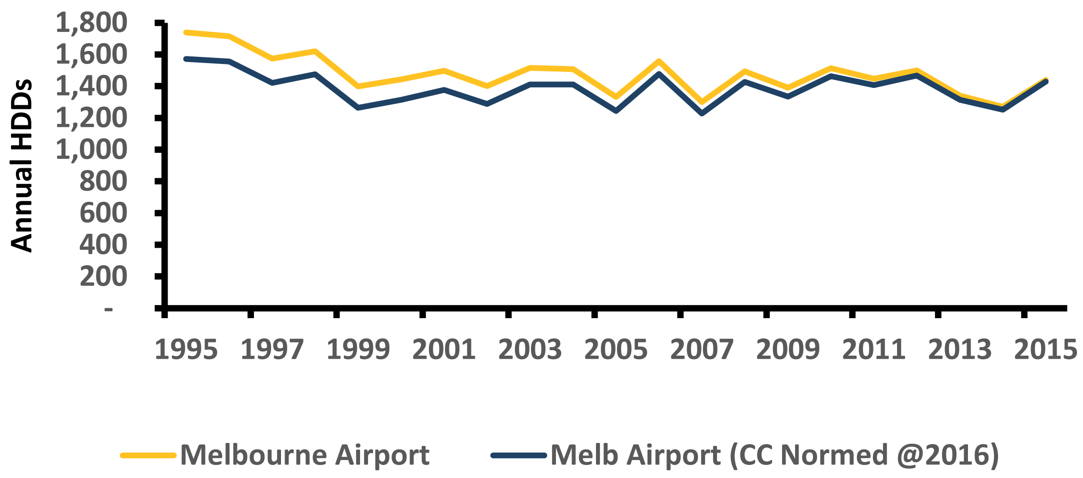
Investigation of the other main weather stations (see Table 30) used for calculating HDDs in the 2016 NGFR identified only small effects of UHI, likely due to these stations being situated in less urban or open aired environments.

Using historical temperature anomaly data from the Bureau of Meteorology, AEMO adjusted the daily average temperature data against the average temperature anomaly to re-baseline the last 20 years of HDDs (approximately compounding + 0.025°C per annum). Figure 7 below shows how the application of the climate change trend in Melbourne Airport’s temperature data (on an annual basis) can account for a large part in the observed reduction of HDDs over the last 20 years.

[44] http://www.bom.gov.au/climate/change/index.shtml#tabs=Tracker&tracker=timeseries.
[45] Suppiah. R and Whetton, P.H., “Projected changes in temperature and heating degree-days for Melbourne and Victoria, 2008-2012”, March 2007. Available at: http://www.ccma.vic.gov.au/soilhealth/climate_change_literature_review/documents/organisations/csiro/MelbourneEDD2008_2012.pdf

This adjustment was applied to all the weather stations as described in Table 31. The ability to quantify the historical component of climate change in HDD changes over time provided a strong validation to apply a climate change signal to the HDD forecast.

Figure 7 Comparison of HDD historical models for Melbourne Airport with and without a climate change adjustment

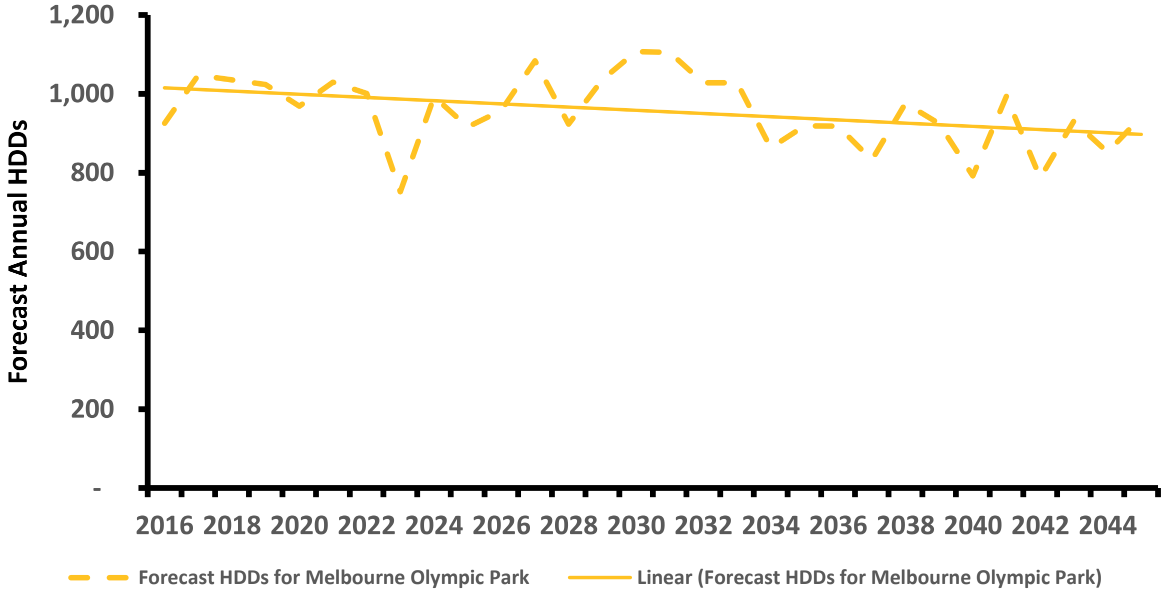


Inclusion in forecast data

Using the median trace of the 40 RCP4.5 models predicts a 0.5 °C increase in average temperatures from 2016–37 across Australia. AEMO used this data to extract the average daily temperature forecasts from 2016–36 for each weather station used for the 2016 NGFR, and calculate the annual HDDs.

Climate models also simulate natural year-to-year natural weather volatility. Applying the climate change trend to the HDD will also contain this year-to-year volatility. As the 2016 NGFR uses a single reference weather year across the 20 year forecast horizon, this variability was removed but the average annual reduction in HDDs was preserved by extracting the linear trend (refer to Figure 8 for an example on Melbourne's Olympic Park forecast HDDs). This linear trend was then applied against the reference HDD (or HDD component of the EDD) forecast. The annual reductions for HDDs calculated for each state were 7.7 in New South Wales, -1.7 in Queensland, and - 5.6 in South Australia, and the annual reduction in EDDs for Victoria was - 6.8.

Figure 8 Figure B.2 A climate change adjusted HDD showing annual weather variability with a linear trend overlayed for Melbourne Olympic Park



To model gas maximum demand, high resolution historical half hourly temperature data was used to observe distributions of weather scenarios. As it is optimal to have large sample sizes for distribution analysis but also consider weather that is reflective of current climatic conditions, the temperature data was restricted to more recent historical weather data (1995–15). This data was re-baselined to 2016, by applying an adjustment using the Bureau of Meteorology's historical temperature anomaly data from climate change impacts since 1995. This followed a similar method to what was performed to baseline the HDDs, but at a finer (half-hourly) granularity, preserving historical volatility from an individual historical weather year but a data set more reflective of the climate in 2016.

A limitation of this approach is that it takes an average effect of the climate change impact only on HDDs. Temperature events such as heatwaves, which potentially show an increase in intensity faster than the average change in temperatures, have been examined.[46] As such, AEMO will be working towards utilising higher resolution temperature forecast data, and will undertake further collaboration with climate scientists, to quantify changes in maximum demand from where maximum/minimum daily temperature variations show greater volatility compared to the daily average.

[46] Perkins, S. E., and L. V. Alexander. "On the measurement of heat waves." Journal of Climate 26.13 (2013): 4500-4517. http://journals.ametsoc.org/doi/abs/10.1175/JCLI-D-12-00383.1 Viewed: 24 January 2017.

APPENDIX C. DISTRIBUTION AND TRANSMISSION LOSSES

Gas is transported through high-pressure transmission pipelines to lower-pressure distribution networks before it is used.[47] During this process, some gas is unaccounted for and some is used for operational purposes. This gas is collectively referred to as “total losses” in this document.

In the distribution networks, losses are typically a result of gas leaks and metering uncertainties. These losses are also known as UAFG.

Transmission pipeline losses are mainly gas used by compressors and heaters in support of normal pipeline operation. UAFG also occurs along high-pressure pipelines, but in smaller quantities.

In Victoria, operational gas used to fuel compressor stations is forecast separately. Operational gas has been increasing rapidly in recent years due to growing exports from Victoria to New South Wales (via the Interconnect) and South Australia.

C.1 Annual consumption

AEMO obtained historical losses from the sources listed in Table 36.

Historical data was normalised before being used in the forecasts. In particular, transmission losses are expressed as a percentage of total gas consumption by residential and commercial users, industrial users, GPG, and distribution losses. Distribution losses are expressed as a percentage of total gas consumed by residential, commercial, and distribution-connected industrial users.

AEMO forecast transmission and distribution separately due to different underlying drivers, but aggregated them in the final forecasts. Transmission losses are primarily driven by operational losses, while distribution losses are driven by Unaccounted for Gas (UAFG).

Regional transmission losses are forecast to range from 0.7% to 1.2% of total consumption, while distribution losses vary between 1.1% and 5.3%. These variations arise from differences in the number, size, type of users, age of assets, network upgrades, and total gas demand.

C.2 Maximum demand

Losses during times of maximum demand were forecast in a similar way to annual consumption losses. It was assumed the normalised losses (transmission or distribution) during times of maximum demand are similar to those on an average day.

[47] Many commercial and Industrial gas consumers also take gas directly from high-pressure pipelines.

APPENDIX D. DATA AND RECONCILIATION

Table 35 Historical data sources

Demand component	Data source for all regions except for Victoria	Data source for Victoria
Residential and commercial	Distribution businesses	AEMO's internal database
Industrial	1. Distribution businesses (for all Tariff D customers, aggregated on a network basis) 2. Direct surveys (for specific large industrial customers)	AEMO's internal database
Transmission losses	Transmission businesses	AEMO's internal database
Distribution losses	Distribution businesses	1. Distribution businesses 2. AEMO's internal database
GPG	1. Transmission businesses where permission has been granted 2. AEMO's internal database	AEMO's internal database

Table 36 ANZSIC code mapping for industrial sector disaggregation

ANZSIC division ID	ANZSIC division name	AEMO sector category
A	Agriculture, Forestry and Fishing	Other
B	Mining	Other
C	Manufacturing	Manufacturing
D	Electricity, Gas, Water and Waste Services	Other
E	Construction	Other
F	Wholesale Trade	Other
G	Retail Trade	Other
H	Accommodation and Food Services	Other
I	Transport, Postal and Warehousing	Other
J	Information Media and Telecommunications	Other
K	Financial and Insurance Services	Other
L	Rental, Hiring and Real Estate Services	Other
M	Professional, Scientific and Technical Services	Other
N	Administrative and Support Services	Other
O	Public Administration and Safety	Other
P	Education and Training	Other
Q	Health Care and Social Assistance	Other
R	Arts and Recreation Services	Other
S	Other Services	Other

Table 37 Business sector datasets – Detailed description

Indicator	Description	Units	Source
Gas consumption data – Source 1	Historic actual data comes from AEMO's metering databases and from a third party data service provider, CGI. This is available at a daily frequency. However, historic data is only available going back to 2003 for VIC and 2009 for all other states. This data is not disaggregated by industry. It is used to develop the 2016 base year forecast.	PJ	AEMO internal
Gas consumption data – Source 1	Office of the Chief Economist publishes historic annual consumption data by ANZSIC category. AEMO uses this longer time period dataset, which is broken down by industry sector, as the dependent variable in developing Business sector econometric models.	PJ	*Table F. Australian energy consumption, by state, by industry, by fuel, energy units.* https://industry.gov.au/Office-of-the-Chief-Economist/Publications/Pages/Australian-energy-statistics.aspx#:
GVA Services	Gross Value Added of the Services sector. The historic data is used in the development of the Other sector econometric forecasts. GVA services forecasts are a key driver of Other sector consumption forecasts	$'Mill	KPMG history and forecasts, provided by region
Gas Price	History is calculated using Australian Bureau of Statistics Consumer Price Index for Gas and Household Fuels, by Industry. Retail price forecasts are built by AEMO using wholesale prices produced by CORE energy and public information (including retail tariffs) for estimating the other components that make up the retail price.	$/GJ	CORE Energy forecasts for wholesale price projections and AEMO
Industrial Production	This is a measure of the output from the Manufacturing sector of the economy. For the NGFR, this is a key driver of the manufacturing econometric model for New South Wales, South Australia and Victoria.	$'Mill	Deloitte Access Economics Business Outlook subscription supporting data is used for the Neutral scenario. Scenario variations are created internally by AEMO.
Manufacturing Gross Value Added	This is the revenue generated by the manufacturing sector. For the NGFR Manufacturing GVA is only used for the Queensland manufacturing econometric model.	$'Mill	History and forecasts provided by KPMG

APPENDIX E. SCENARIOS SUMMARY

These Strong, Neutral, and Weak scenario assumptions were modelled in the 2016 NGFR and are now being used in all AEMO major reports.

Table 38 Detailed summary of modelling assumptions

Assumptions	Type	Weak	Neutral (most probable)	Strong
Economy	Variable	Weak	Neutral	Strong
Consumer	Variable	Low confidence, less engaged.	Average confidence and engagement.	High confidence, more engaged.
Population	Variable	Low (ABS)	Medium (ABS)	High (ABS)
Electricity network charge over 5 years	Fixed	Current AER determinations, fixed after 5 years.		
Gas network charge over 5 years	Fixed	Current AER determinations, fixed after 5 years.		
Electricity network charges – long run	Fixed	Constant real.		
Gas network charges – long run	Fixed	Constant real.		
Retail costs and margins	Fixed	Assume current margins throughout.		
Tariff structure	Fixed	Same as current.		
LREC/SRES	Fixed	Assume current to 2020, with LGCs/SSTC deemable to 2030.		
Weather	Fixed	Neutral weather assumption for consumption forecasts, probabilistic weather settings for peak demand.		
Rainfall – Hydro generation	Fixed	Median value for water availability (last 15 years).		
LNG growth	Fixed	Australian LNG export growth per oil price projections.		
Oil prices / gas prices	Variable	UD30/bbl (BR) with pricing affecting the industry as existing contracts expire.	UD60/bbl (BR) with pricing affecting the industry as existing contracts expire.	UD90/bbl (BR) with pricing affecting the industry as existing contracts expire.
Electricity wholesale prices	Variable	As per the supply-side impact of this scenario. Assumes some abatement cost affecting end-user prices.		
Electricity demand	Variable	Based on end-point consumption (behind the meter), translated back to the grid.		
Other policy and regulatory settings affecting electricity prices	Fixed	Status quo.		
Technology uptake	Variable	Hesitant consumer, weak economy.	Neutral consumer, neutral economy.	Confident consumer, strong economy.
Energy efficiency	Variable	Policy measures deliver lower uptake of EE.	Policy measures deliver medium uptake of EE.	Policy measures deliver high uptake of EE.
Technology cost and uptake curve	Variable	Technology cost and uptake curve assumptions for weak economy, low consumer confidence/engagement.	Median technology cost and uptake curve assumptions.	Technology cost and uptake curve assumptions for strong economy, high consumer confidence/ engagement.
Climate policy up to 2030	Fixed	Assume Australia's Paris commitment is achieved.		
Climate policy post 2030	Fixed	2030 status quo maintained to 2040, but including announced coal plant closures post 2030.		

Assumptions	Type	Weak	Neutral (most probable)	Strong
Climate policy impacts (energy prices)	Fixed	Scenario assumes most abatement cost hits the pricing mechanism of the industry. Proxy emissions abatement price of $25/tonne in 2020 rising to $50/tonne by 2030. Emissions Intensive Trade Exposed Industry pays only 20% of this cost in 2020, rising to 100% in 2030.	Scenario assumes most abatement cost hits the pricing mechanism of the industry. Proxy emissions abatement price of $25/tonne in 2020 rising to $50/tonne by 2030. Emissions Intensive Trade Exposed Industry pays only 20% of this cost in 2020, rising to 100% in 2030.	Scenario assumes most abatement cost hits the pricing mechanism of the industry. Proxy emissions abatement price of $25/tonne in 2020 rising to $50/tonne by 2030. Emissions Intensive Trade Exposed Industry pays only 20% of this cost in 2020, rising to 100% in 2030.
Climate policy impacts (plant shut downs and generation replacement)	Fixed	Fossil fuel plant shut-down list informs scenario, assumes 2030 targets are achieved. Announced shutdowns beyond 2030 assumed in scenario. Technology replacement options do not include coal and are least cost.		
Climate policy impacts (other)	Fixed	Energy efficiency initiatives consistent with National Energy Productivity Plan.		

MEASURES AND ABBREVIATIONS

Units of measure

Abbreviation	Unit of measure
DD	Degree days
EDD	Effective degree days
GJ	Gigajoules
GWh	Gigawatt hours
HDD	Heating degree days
TJ	Terajoules

Abbreviations

Abbreviation	Expanded name
ABS	Australian Bureau of Statistics
AER	Australian Energy Regulator
APLNG	Australia Pacific LNG
CGE	Computable General Equilibrium
CSG	Coal seam gas
DB	Distribution business
DoW	Day of Week
DSM	Demand side management
DTS	Declared Transmission System
ESD	Energy Statistics Data
GFC	Global Financial Crisis
GLNG	Gladstone Liquefied Natural Gas
GPG	Gas-powered generation
GRMS	Gas Retail Market Systems
GVA	Gross Value Added
HIA	Housing Industry Association
LGA	Lewis Grey Associates
LIL	Large industrial loads
LNG	Liquefied natural gas
LRET	Large-scale Renewable Energy Target
MHQ	Maximum Hourly Quantity
MMS	Market Management System
MPC	Market Price Cap
NEFR	National Electricity Forecasting Report
NEM	National Electricity Market
NGFR	National Gas Forecasting Report
NTNDP	National Transmission Network Development Plan
POE	Probability of exceedance
PPI	Producer Price Index

Abbreviation	Expanded name
QCLNG	Queensland Curtis LNG
RCAC	Reverse-cycle Air-conditioners
RCP	Representative Concentration Pathways
SMIL	Small-to-medium industrial loads
SRES	Small-scale Renewable Energy Scheme
TGP	Tasmanian Gas Pipeline
UAFG	Unaccounted for gas
UHI	Urban Heat Island Effect
VRET	Victorian Renewable Energy Target