Gas Demand Forecasting Methodology Information Paper

April 2020

For the 2020 Gas Statement of Opportunities for eastern and south-eastern Australia

Important notice

PURPOSE

AEMO has prepared this document to provide information about the methodology and assumptions used to produce gas demand forecasts for the 2020 Gas Statement of Opportunities under the National Gas Law and Part 15D of the National Gas Rules.

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VERSION CONTROL

Version	Release date	Changes
1	21/04/2020	Initial release

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1. Introduction

The Gas Statement of Opportunities (GSOO) incorporates regional gas consumption and maximum daily demand forecasts for the eastern and south-eastern Australian gas market of Queensland, New South Wales, Victoria, Tasmania, and South Australia.

These 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. The components (defined in the Glossary) 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 through 5 describe the methodologies used for each of the first four components. Network losses and other UAFG are covered in Appendix A3.

Maximum demand forecasts provide an annual projection of maximum daily demand for each region. 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).

The GSOO provides three scenarios – Central, Step Change, and Slow Change – that consider different drivers of demand. These scenarios are in alignment with those used in AEMO's 2020 Draft Integrated System Plan (ISP)[1]. Specific detail on scenarios used in the 2020 GSOO is available in the GSOO report, available on AEMO's website[2].

[1] AEMO, 2020 Draft ISP, available at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp

[2] AEMO, GSOO, March 2020, available at https://www.aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities.

2. Liquefied Natural Gas (LNG) consumption

There are three LNG projects located on Curtis Island in Queensland – APLNG, GLNG and QCLNG. The annual consumption forecasts for this demand sector includes all gas that the three LNG projects plan to export from Curtis Island to meet international LNG demand, plus all the gas consumed in producing, transporting and compressing these export quantities. Pipeline transportation losses directly related to transporting gas from production centres to Curtis Island are also included in these forecasts.

LNG consumption forecasts are developed using a combination of LNG consortia survey responses and stakeholder feedback.

In the preparation of the 2020 GSOO, AEMO started with the long-term trajectory prepared for the 2019 GSOO, as a starting point to estimate projections of gas and electricity consumption used in the production and export of LNG for the 20-year outlook. AEMO then engaged directly with the east coast LNG Consortia to obtain their best estimates of the LNG forecasts consistent with the AEMO scenarios, across the forecast horizon but particularly over the short term[3]. AEMO then applied internal analysis and an understanding of global LNG dynamics to shape the long-term trajectory of the LNG export forecasts.

Prior to finalising AEMO's LNG consumption forecasts, AEMO engaged with stakeholders including AEMO's Forecasting Reference Group[4] in December 2020 to provide feedback on these forecasts.

[3] Short-term here refers to 3-5 years.

[4] AEMO Forecasting Reference Group, detailed at: https://aemo.com.au/en/consultations/industry-forums-and-working-groups/list-of-industry-forums-and-working-groups/forecasting-reference-group-frg.

3. Gas-Powered Generation (GPG) consumption

This chapter describes the methodology and key assumptions AEMO used to forecast annual gas consumption as the fuel required for GPG to supply electricity to the National Electricity Market (NEM)[5].

To forecast the GPG consumption, AEMO performed electricity modelling of the NEM for the 2020 Draft ISP's Central, Step Change and Slow Change scenarios. The scenarios are consistent with the GSOO.

To forecast GPG AEMO conducted market modelling in two stages. Further detail on the market modelling methodology is available on AEMO's website[6].

Phase 1 – long-term modelling

The first long-term (LT) phase determines the co-optimised generation and transmission expansion plan for the NEM using AEMO's Detailed Long Term (DLT) model. The modelling incorporates various policy, technical, financial and commercial drivers to develop the least cost NEM development path. This includes state and national renewable energy targets, technology cost reductions, and electricity demand and consumption forecasts over the forecast period. The approach considers the variability of renewable energy resources and the transmission developments required to access potential renewable energy zones (REZs). It also considers the need to replace ageing thermal generation, and the role that energy storage technologies and flexible thermal generation technologies may have, such as GPG, given increased penetration of variable renewable energy sources at utility scale and from distributed energy resources (DER).

Phase 2 – time-sequential modelling

The second phase models the NEM with increased granularity using hourly, time sequential modelling incorporating the generation and transmission mix determined by the LT phase. This short-term (ST) phase is essential to validate generation and transmission plans from the LT phase and assess detailed dispatch of electricity generators across the horizon.

This short-term time-sequential modelling phase was separated into two different methodologies, depending on the time period.

- The first four calendar years were forecast using a bidding behaviour model.
- The forecast from year five to year 20 used a Nash-Cournot bid optimisation model.

The bidding behaviour model forecasts the gas required for GPG by developing NEM spot market bids for each individual generator unit, based on historical analysis of actual bidding data and benchmarked to historical generation levels. Depending on observed behaviour, the modelled bids might change on a 30

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[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] AEMO, Market Modelling Methodology Paper, available at http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies.

minute or monthly level, or due to certain conditions (for example, a generator outage may be balanced within a portfolio by increasing their generation output across other generating units within the portfolio at a lower price).

This bidding behaviour captures current market dynamics such as contract and retail positions of portfolios which are generally not captured as well using other market behaviour modelling methods. In the short term these dynamics are assumed to stay relatively unchanged.

In the longer term, it is not realistic to assume that current behavioural patterns will continue to hold. Instead, the competitive behaviour of generation portfolios is captured through application of a Nash-Cournot bid optimisation model for the largest NEM portfolios. This bidding model provides a realistic approximation of generator dispatch and unit commitment decisions by optimising the model solution to ensure each portfolio maximises profit, without necessarily locking the behaviour of generators into their existing patterns.

For both methodologies:

- Prior to optimising dispatch in any given year, the model schedules planned maintenance and randomly assigns unplanned generator outages to be simulated using a Monte Carlo simulation engine. Dispatch is then optimised on a 30-minute 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 30-minute electricity prices for each NEM region, and 30-minute dispatch for all NEM power stations, are calculated.
- The model produces the amounts of gas used in each 30-minute period on a power generating unit-by-unit basis, which AEMO then aggregates into daily traces by power station to be fed into the GSOO gas model.

4. Tariff D (industrial) 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 consumers 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, this includes aluminium and steel producers, glass plants, paper and chemical producers, oil refineries and GPG that are not included in GPG forecasts[8].
- Small-to-Medium Industrial Loads (SIL): consume more than 10 TJ but less than 500 TJ annually at an individual site. These sites include food manufacturing, casinos, shopping centres, hospitals, sporting arenas, and universities.

AEMO's industrial sector modelling uses an integrated, bottom-up sector modelling approach to industrial forecasts to capture the structural change effect in the Australian economy, which was first introduced in the 2015 NGFR.

4.1 Data sources

The industrial sector modelling relies on a combination of sources for input data, shown in Table 1. For more details and source references please see Appendix A4.

Table 1 Historical and forecast input data sources for industrial modelling

Data series	Source 1	Source 2	Source 3	Source 4
Historical consumption by region	AEMO database	CGI Logica	Transmission and distribution, industrial surveys	Gas Bulletin Board (GBB)
Historical consumption by sector	Dept of Energy and Environment			
Weather	Bureau of Meteorology (BoM)			
Climate change	CSIRO			
Economic data	Australian Bureau of Statistics (ABS)	Economic consultancy		
Wholesale gas prices	CORE Energy			
Retail gas prices	AEMO-calculated			

[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.

4.2 Methodology – All Eastern and South-Eastern States[9]

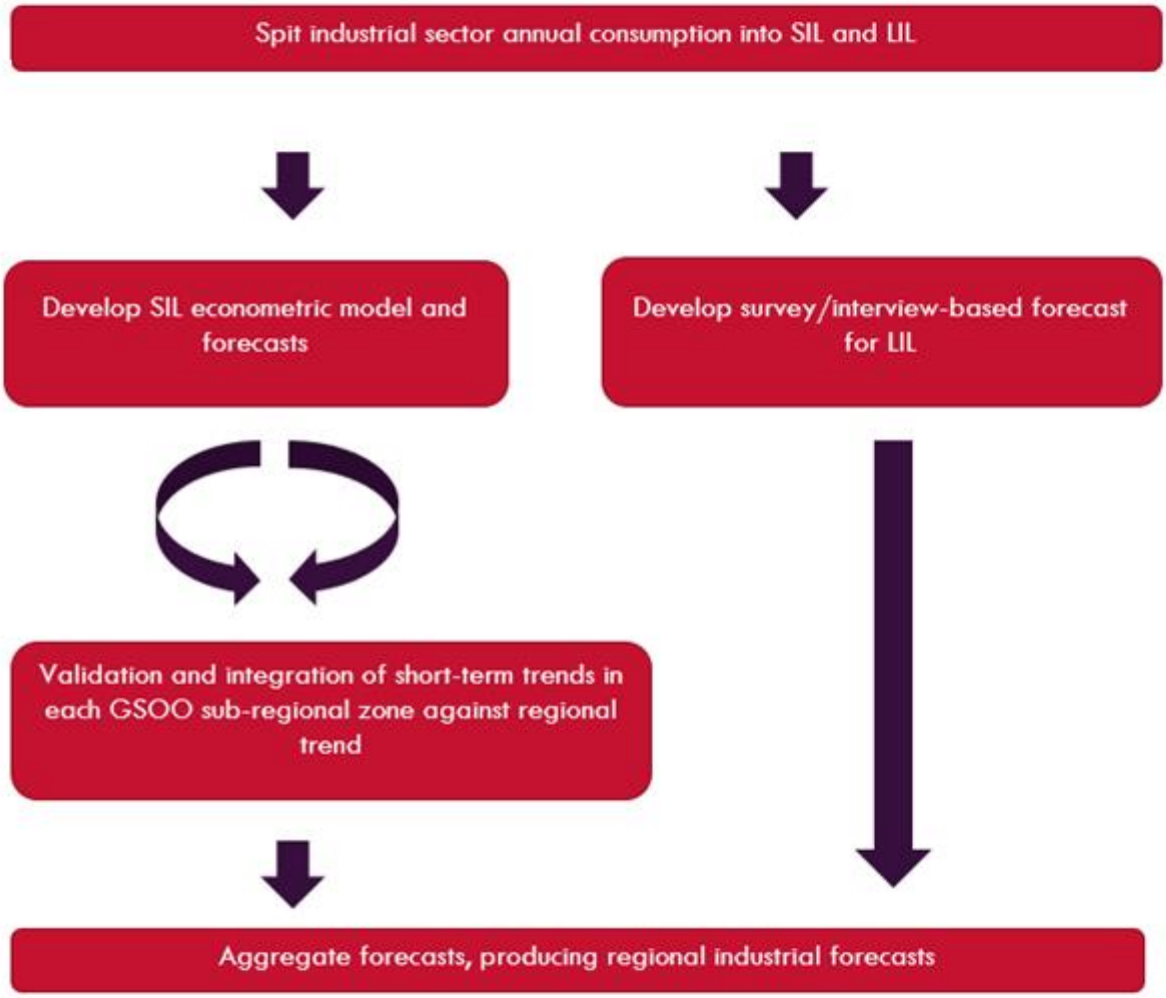
The energy intensive industrial sector is split between LILs and SILs as the underlying drivers for their energy consumption are quite different.

This uses a combination of survey and econometric modelling approaches to forecasting:

- SIL: Uses Econometric modelling.
- LIL: Survey and interview-based forecasts

The following flow-chart highlights the modelling process, from disaggregating the industrial consumption for each region, modelling the two components separately before combining again to produce the total forecast for each region.

Figure 1 Tariff D consumption forecasting method



4.2.1 Develop econometric model and forecast for SIL

The percentage in each region modelled in aggregate (SIL) is presented in Table 2. Overall this represents 30% of industrial consumption (by volume) with 70% either interviewed, surveyed or analysed separately. The

[9] The Western Australian Tariff D forecast, although component-based differs by its categories. Details can be found in the 2019 WA GSOO https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/wa_gsoo/2019/wa-gas-statement-of-opportunities---december-2019.pdf?la=en Accessed 14th April 2020

economic indicator correlated with historical consumption is also presented, reflecting the different dynamics in each region. The economic indicator was selected from a combination of analysing its relationship with historical consumption data and of its relevance to each region's economy and gas industry composition.

Table 2 Percentage split (based on 2019 consumption) of the industrial load modelled with economic indicators

Region	Economic Indicator	Proportion of industrial sector modelled using an econometric model
Victoria	Industrial Production	50%
New South Wales	Industrial Production (coefficient based on Vic analysis)	50%
Queensland	GSP	10%
South Australia	Industrial Production	25%
Tasmania	GSP	40%

AEMO engages a suitably qualified external Consultant to forecasts key economic parameters for each scenario. With these economic parameters a forecast is developed at the regional level using the co-efficient from the linear regression model for each macro-economic indicator.

Adjustments are made to the forecast consumption to capture the *negative* impact of expected price increases. An asymmetric response of consumers to price changes is used, with price impacts being estimated in the case of increases, but not for price reductions. The price elasticity was projected to be -0.05 in the Step Change Scenario, -0.10 in the Central scenario, and -0.15 in the Slow Change scenario.

A separate analysis was performed of the annual time-series data to examine the sub-regional trends at each GSOO zone (refer to Table 3). These sub-regional trends may not always align with the regional trend as the number, types and size of industry within each GSOO zone is not homogenous across a region. Statistical features such as the standard deviation and averages are then examined and included in a sub-regional trend-based model that captures the expected bandwidth in the 1-3 year period, assuming the values are normally distributed. The advantages of using time-series methods is that it captures intra-year volatility, short-term relationships, closer alignment with the latest year of consumption and an ability to model dispersion around the Central scenario.

Table 3 GSOO Zone breakdown used for sub-regional analysis

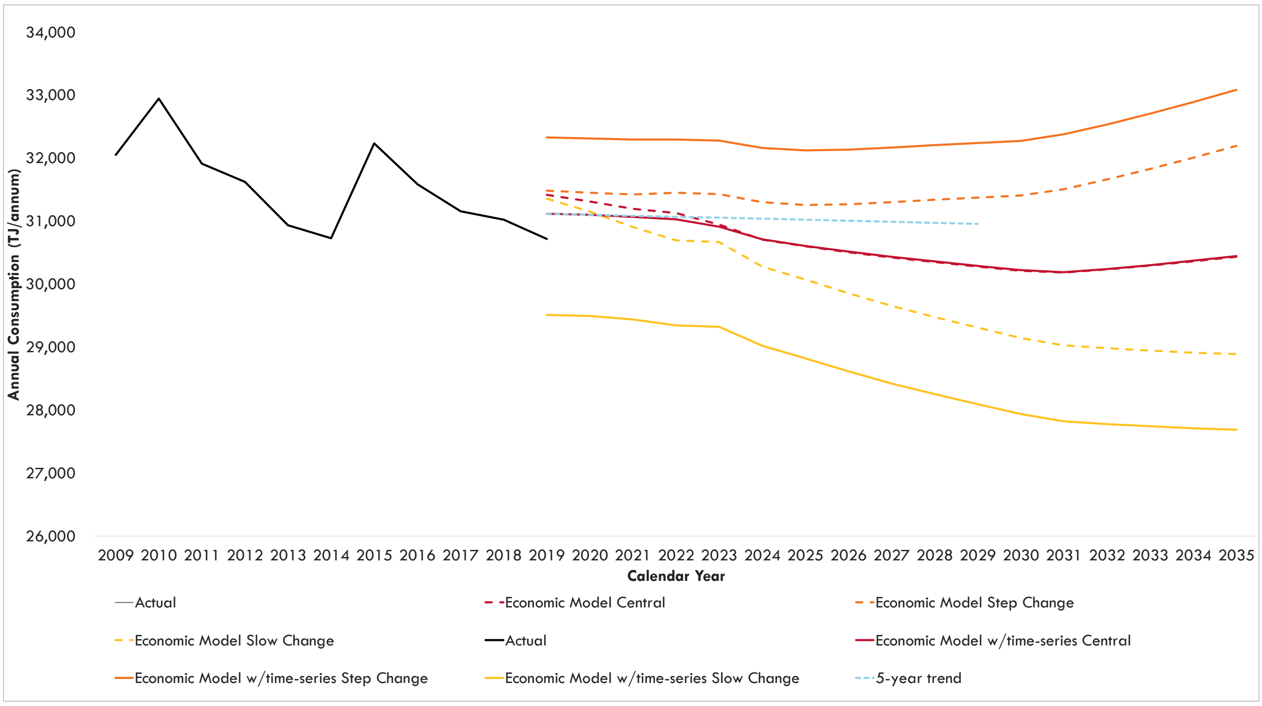
Region	GSOO Zone	Description[10]
NSW	ACT	Nodal point on the Australian Capital Territory
NSW	EGP	Nodal point on the Eastern Gas pipeline
NSW	MSP	Nodal point on the Moomba to Sydney pipeline
NSW	SYD	Nodal point on the Sydney region
QLD	QGP	Nodal point on the Queensland Gas pipeline
QLD	RBP	Nodal point on the Roma to Brisbane pipeline
SA	ADL	Nodal point on Adelaide
SA	MAP	Nodal point on the Moomba to Adelaide pipeline
SA	SEA	Nodal point on the South East Australia gas pipeline

[10] Nodal points from where gas leaves the transmission network. Refer to Figure 3 in the Gas Supply Adequacy Methodology for the nodal network topology, located here https://aemo.com.au/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo.

Region	GSOO Zone	Description[10]
TAS	TGP	Tasmanian Gas Pipeline (all of Tasmania)
VIC	BROOKLYN	Nodal point on Brooklyn
VIC	MELBOURNE	Nodal point on Melbourne
VIC	PAKENHAM	Nodal point on Pakenham
VIC	PORT CAMPBELL	Nodal point on Port Campbell
VIC	WOLLERT	Nodal point on Wollert

The trend and the regional economic model are then combined to produce a regional consumption forecast. The process for combining the two methods is a weighted average. The first year of the forecast applies a weighting of 100% to the trend-based forecast, dropping to 80% in year two, 60% in year three through to 0% by year 6. Figure 2 below highlights the process taken in Victoria.

Figure 2 The SIL econometric model for Victoria contrasted with the trend model, demonstrating the resulting ensemble model forecast



4.2.2 Develop survey-based forecast

AEMO conducted a survey and interview process with medium to large industrial users[11] to derive the LIL regional forecasts. The survey process followed five key steps as shown:

[11] Generally defined as industrial facilities that consumed more than 500 TJ per annum at least once over the previous four years, however in some cases facilities with lower consumption were also surveyed, such as where one organisation owned several facilities in the same state that in aggregate consumed more than 500 TJ per annum.

Identify Large Industrial users

Large industrial loads are identified through several means:

1. Distribution and Transmission Surveys: request information on loads consuming more than 10 TJ annually; request information on new large loads.
2. AEMO database: in Victoria and Queensland markets AEMO has all the registered distribution network connected industrials. In Victoria AEMO also has all the transmission connected industrials.
3. Media research.

Collect recent actual consumption data and analyse

Recent actual consumption data is analysed for each large industrial load site for two key reasons:

1. To understand latest trends at the site level
2. To prioritise the large industrial loads for interviews (detailed in the next section)

Request survey responses and conduct interviews

Step 1: Initial survey

AEMO sends out surveys to all identified LILs requesting historical and forecast gas consumption information by site. The surveys request annual gas consumption and maximum demand forecasts for three scenarios. The core economic drivers for each of the three scenarios are provided to survey recipients to ensure forecasts are internally consistent to other components. For a more detailed overview of the components behind AEMO's planning and forecasting scenarios, see AEMO's website[12].

Step 2: Detailed interviews

Following the survey, AEMO interviews large industrial loads to discuss their responses. This typically includes discussions about:

- Key gas consumption drivers, such as exchange rates, commodity pricing, availability of feedstock, current and potential plant capacity, mine life, maintenance shutdowns, and cogeneration.
- Currently contracted gas prices and contract expiry dates.
- Gas prices, the LILs forecast of their gas consumption 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[13] and timing.
- Different assumptions between the scenarios.

Interviews of large industrial loads are prioritised based on the following criteria, based on analysis of actual consumption:

- Volume of load (highest to lowest): Movement in the largest volume consumers can have bigger market ramifications (e.g. impact market price).
- Year on year percentage variation: Assesses volatility in load, those with highest volatility are harder to forecast.

[12] AEMO, Planning and Forecasting inputs, assumptions and methodologies, available at http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies

[13] This is the point of balance between profit and loss.

- Year on year absolute variation (PJ): Even if loads are volatile, if they are relatively small, it might be captured in the uncertainty around our forecasts and not impact overall trend whereas the largest loads will have a more material impact.
- Forecast vs actuals for historical survey responses (where available): This measure is used to assess accuracy of forecasts. For instance, if there was high volatility in actual consumption, was it anticipated it in last year's survey forecasts? If not, then it requires further investigation.

This process is also used as a benchmark for validating the survey responses.

Finalise forecasts

The site-based survey forecasts for each scenario is finalised based on interview discussion[14]. All the survey forecasts are aggregated to regional level for each region. Climate change adjustment factors with temperature changes in consumption are not included in the Tariff D forecast due to the low weather sensitivity of industrial usage of gas when examined in regression analysis.

4.2.3 Aggregate all sector forecasts to get total industrial (Tariff D) forecasts

The resultant industrial forecast combines the separately derived SIL and LIL forecasts, as the following infographic details:

[14] This may include override of initial survey results on the basis of AEMO's discussion with the industrial user.

5. Tariff V (residential and commercial) consumption

This chapter outlines the methodology used in preparing residential and small commercial consumption, also known as Tariff V consumption, is defined as consumption by network customers who are billed on a volume basis. These consumers typically use less than 10 TJ/year.

AEMO's Tariff V consumption modelling uses econometric models to develop forecasts for the networks of Victoria, South Australia, New South Wales (including Australian Capital Territory), Queensland and Tasmania. AEMO's methodology now disaggregates the Australian Capital Territory region from the New South Wales region as a separate model. This allowed AEMO to develop richer insights into the key trend drivers for this region and identify structural and behavioural changes.

5.1 Definitions

Tariff V customers are gas consumers of relatively small gas volumes, using 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, fuel switch measures, and growth in connections.

5.2 Forecast number of connections

Tariff V gas connection forecasts are made up of two components, residential and non-residential gas connection forecasts.

Residential gas connections are determined by:

- Forecasting the total number of households for each State.
  - To forecast the number of households for each State, AEMO used the historical trend of electricity connections (NMIs) and the Australian Bureau of Statistics (ABS) housing census data and forecasts.
- Forecasting the number of gas connections (MIRNs):
  - Inspecting the long-term (5+ year) trends in the MIRN usually shows a stable year-on-year growth but as the ratio of households to those with gas could differ, any relationship between the growth rates of NMI and MIRNs is examined to ensure the model captures any change over time.
  - A trend is used for the first 5 years of growth (with the standard deviation of previous year-on-year growth used to moderate the low and high connections forecast) then a blend is done into the NMI growth rates (household growth). The process for combining the two methods is a weighted average.

The first year of the forecast 100% of the trend is used, dropping to 80% in year two, 60% in year three through to 0% by year 6.

- Splitting the MIRN forecast into residential and business connections:
  - The split between residential and non-residential connections is made from survey data collected from all distribution businesses in the forecast regions.
  - The relative growth rate for the residential and non-residential connections is determined by examining the average percentage year-on-year growth rate from the distribution survey from the two customer classes.
  - The total MIRN forecast is then split by residential and non-residential using the relative historical growth rates to split the two classes from the total, for each scenario. An upper band of an additional 20% year-on-year growth in commercial connections was used for the Step Change and a lower band of -20% was used for Slow Change providing dispersion in the forecast as the standard deviation shows annual variation of approximately that magnitude.

5.3 Forecast annual consumption methodology

5.3.1 Overview of the methodology

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

- The average Tariff V residential and non-residential consumption which are made up of base load and heating load were estimated. This was based on projected annual effective degree days (EDD) for Victoria and heating degree days (HDD) for New South Wales, Queensland, South Australia and Tasmania under 'standard' weather conditions.
- The forecast then considered the impact of modelled consumption drivers including connection growth, energy efficiency savings, climate change impact, behavioural response to retail prices and gas-to-electricity switching.

Data sources for the Tariff V forecast are listed in Appendix A4.

5.3.2 Methodology detail

Step 1: Weather normalisation of Tariff V residential and non-residential consumption

The objective of this step is to estimate weather-corrected average annual consumption for Tariff V for each region. This was to be used as the base for forecasting regional Tariff V annual consumption over the 20-year horizon.

This step required an estimation of the sensitivity of Tariff V consumption to cool weather. Average weekly Tariff V consumption was regressed against average weekly EDD, for Victoria and average weekly HDD, for other regions, over a two-year window (training data) leading up to the reference year.

The models are expressed as follows:

$$Y_i = \alpha + \beta_{XDD} * XDD_i + \beta_H * H$$

where:

Y_i = average Tariff V daily consumption for week i

i = week number

α = average Tariff V daily base load

β_{XDD} = average Tariff V temperature sensitivity (TJ/XDD)

XDD_i = average daily EDD for week i for Victoria, or average daily HDD for week i for New South Wales, South Australia, Queensland, and Tasmania.

β_H = 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)

The weather normalised Tariff V estimated average annual consumption for year j is therefore equal to

$$Y_{WN,j} = Y_j - \beta_{XDD} * (XDD_j - XDD_{WS})$$

Note: XDD_{WS} is the forecast weather standard EDD or HDD. See Appendix A2.

As outlined in Appendix A4, historical Tariff V residential and non-residential annual consumption was provided by distribution data providers, AEMO's internal database and distributors in stakeholder surveys. This data is used to estimate the share of residential and non-residential annual consumption of total Tariff V. These shares were further split into heating and base load using the coefficients determined in the above regression.

Step 2: Apply forecast trends and adjustments

The weather-corrected Tariff V residential and commercial average consumption estimated in Step 1 were used as the base forecast consumption and is affected over the forecast horizon by the driving factors as detailed below.

For each year in the forecast, the total forecasted gas consumption follows the following calculation:

- Weather normalised consumption for the region in the reference year as calculated in step one.
- Plus the *positive* impact of new gas connections from the reference year.
- Plus the *negative* impact of climate change.
  - AEMO adjusted the consumption forecast to account for the impact of increasing temperatures with the strategic assistance from Bureau of Meteorology and CSIRO (see Appendix A2.3 for further information). Climate change is anticipated to increase average temperatures, which will reduce heating load from gas heaters and hot water systems.
- Plus the *negative* impact of energy efficiency savings.
  - In 2019, *Strategy.Policy.Research*[15] developed energy efficiency forecasts for the residential and commercial sectors in each region, taking into account the impact of the national construction codes, the NSW Energy Savings Scheme, and the Victorian Energy Upgrades (VEU) Program. AEMO further modified the gas savings for Victorian Energy Upgrade (VEU) Program for the final forecasts.
- Plus the *negative* net impact of fuel switching.
  - Residential sector:
    - AEMO developed models to quantify the fuel switching impacts from changes in water and space heating technologies during the forecasting period. AEMO used data from the Residential Energy Baseline Study[16] (RBS) to develop base appliance stock models. The stock models were updated with data from the Commonwealth Department of Environment and Energy, to represent estimated changes in stock from current and planned policy measures. Measures include the National Construction Code 2022 for water heating, the Victorian Solar Homes Program for solar electric water heating, the ACT Gas Heater Rebate, and the planned E3 Zones Space Heating Label Program. Stock changes varied by scenario. AEMO also estimated the potential impact of the ACT

[15] Strategy.Policy.Research, *Energy Efficiency Forecasts: 2019 – 2041: Final Report*. Available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/StrategyPolicyResearch_2019_Energy_Efficiency_Forecasts_Final_Report.pdf. Accessed: 7th January 2020.

[16] Energy Rating, *Residential Baseline Study* http://www.energyrating.gov.au/document/report-residential-baseline-study-australia-2000-2030 Accessed 7th January 2020. (Data provided separately to AEMO)

Government's Climate Change Strategy, which is legislated to achieve net zero emissions from gas use by 2045[17].

  - Commercial sector: The impact was captured in the energy efficiency component as some commercial schemes include the potential for fuel switching.

- Plus the *negative* impact of behavioural response to price.

  - Response to price change that was not captured by energy efficiency and gas-to-electricity switch was modelled through consumer behavioural response. An asymmetric response of consumers to price changes is used, with price impacts being estimated in the case of increases, but not for price reductions. A price rise was estimated to have minimal impact on base load, as it is assumed that baseload usage is largely from the daily operation of appliances such as cooktop or a hot water heating system. If consumers change their cooktop or hot water heating system, this impact is captured in the modelling of energy efficiency and fuel switch impacts. Therefore, the price elasticity for base load was set to 0. For heating load, price elasticity was projected to be -0.1 in the Neutral scenario, -0.2 in the Slow Change scenario, and -0.05 in the Fast Change scenario, reflecting a lower estimation of gas price elasticity for an economic good with limited substitutability.

[17] ACT Government, *ACT Climate Change Strategy 2019-2025*. Available at https://www.environment.act.gov.au/__data/assets/pdf_file/0003/1414641/ACT-Climate-Change-Strategy-2019-2025.pdf/_recache

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.

The 2020 GSOO utilized Monte Carlo simulation techniques similar to those employed by the electricity demand forecasts. The Monte Carlo simulation simulated demand to produce a full demand distribution related to weather, other demand drivers and stochastic volatility. The demand forecasts were then driven by population growth, fuel switching, energy efficiency, and price response for Tariff V and Tariff D.

Gas maximum demand modelling can be broken into three steps:

- Capture the relationship between demand and the underlying demand drivers.
- Simulate demand based on the relationship between demand and the demand drivers.
- Forecast demand using long term demand drivers.

Forecasts of daily maximum demand are used by government and industry to assess the adequacy of infrastructure supply capacity. They also inform commercial and operational decisions that are dependent on the potential consumption range of demand over time. Variations in domestic gas consumption are mostly driven by heating demand and GPG. For all states except Queensland, this means maximum daily demand occurs during the winter heating season.

In Queensland, due to the low penetration of gas for residential use and the warm climate, maximum demand may occur in either summer or winter driven by GPG, large industrial load consumption and LNG exports.

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.

Step 1: capture the relation between demand and demand drivers

Step 1 developed short-term econometric forecast models for Tariff V (residential and commercial) and Tariff D (industrial) gas consumption using daily data. These models describe the relationship between demand and explanatory variables including calendar effects such as public holidays, day of the week and month in the year and weather effects.

The models represent a snapshot of consumer behaviour as at the base forecast year, de-trended to remove the impact of population growth, price response, fuel switching and other growth drivers. The demand models were trained on the most recent three years of daily data. The Tariff V and Tariff D models are outlined below:

Equation 1[18]

$$Tariff\ V\ Consumption = f(HDD/EDD, Weekend\_Dummy, Public\_Holiday\_Dummy, Trend\ Variable)$$

Equation 2

$$Tariff\ D\ Consumption = f(HDD/EDD, Weekend\_Dummy, Public\_Holiday\_Dummy, Trend\ Variable\ , summer\_shutdown)$$

[18] See Appendix A2 for the description of EDD and HDD

Step 1 also found the most appropriate model to capture the relationship between demand and the demand drivers for Tariff V and Tariff D. This step specified an array of models for Tariff V and Tariff D using the variables available, and explored a range of model specifications. Step 1 then used an algorithm to cull any models that had:

- Variance Inflation Factor[19] greater than 4.
- Nonsensical coefficient signs – all the coefficients must have reasonable signs. Heating degree variables should be positively correlated with demand, and weekend and public holidays should be negatively correlated with demand (unless in the case of a tourist economy).
- Insignificant coefficients.

The algorithm then ranked and selected the best model, based on the model's:

- Goodness-of-fit – R-Squared, Akaike Information Criterion, and Bayesian information criterion.
- Out-of-sample goodness-of-fit – for each model based on 10-fold cross validation[20] to calculate the out-of-sample forecast accuracy.
- Histogram of the residuals, quantile-quantile (Q-Q) plot, and residual plots.

Step 2: Simulate demand to normalize weather and other explanatory variables

Once the most appropriate model was selected, step 2 then used the linear demand models from stage 1 to simulate and normalise demand for weather effects and other explanatory variables. The simulation process randomly draws from a pool of historical weather values from 1 January 2001 to the most recent weather data available, by bootstrapping historical fortnights. The bootstrapping method sampled actual historical weather blocks, preserving the natural relationship between time-of-year and temperature.

Equations 1 and 2 can be represented in their general form as equation 3. Equation 4 represents the generalised model used for predicting prediction intervals of demand.

Equation 3 $$TJ_t = f(x_t) + \varepsilon_t$$

Equation 4 $$\widehat{TJ}_t = f(x_t) + \sigma_\varepsilon z_t$$

Where:

- $f(x_t)$ is the relationship between demand and the demand drivers (such as weather and calendar effects) at time t
- ε_t represents the random, normally distributed[21] residual at time t ($\sim N(0, {\sigma_\varepsilon}^2)$)
- z_t follows a standard normal distribution ($\sim N(0,1)$)

Equation 4 was used to calculate daily demand for the synthetic weather year, consisting of 365 days randomly selected from history (using the $f(x_t)$ component). The prediction interval of the model was simulated (using the distribution of ε_t in Equation 4).

The simulation process created 3500 synthetic weather years with random prediction intervals for each day of each weather year following a $N(0, \sigma_\varepsilon^2)$ distribution.

From each iteration demand for Tariff V and Tariff D was calculated individually for each day in the year. The daily regional demand was calculated as Tariff V + Tariff D. The maximum daily regional demand was found for each iteration as the single day with the highest demand in both summer and winter (3500 maxima for summer and winter). The 50% POE was calculated taking the median of the statistical distribution of the

[19] The variance inflation factor is a measure of multicollinearity between the explanatory variables in the model.

[20] A 10-fold cross validation was performed by breaking the data set randomly into 10 smaller sample sets (folds). The model was trained on 9 of the folds and validated against the remaining fold. The model was trained and validated 10 times until each fold was used in the training sample and the validation sample. The forecast accuracy for each fold was calculated and compared between models.

[21] A fundamental assumption of Ordinary Least Squares (OLS) is that the error term follows a normal distribution. This assumption is tested using graphical analysis and the Jarque–Bera test.

simulated maxima for each season. In a similar fashion, the 5% POE was computed by identifying the 5% percentile of the simulated distribution.

Step 3: Forecast demand using long term demand drivers

The demand values produced by the previous process reflect the relationship between demand and conditions as at the base year. The forecast process then grew the demand values by economic, demographic and technical conditions.

The long-term growth drivers affecting annual consumption were applied to maximum demand within the simulation process, for each of the key drivers discussed in Chapters 4 and 5. The annual growth drivers were applied to demand as indexed growth from the base year. The annual growth indices were found by considering the forecast year-on-year growth. The year-on-year growth in Tariff V and Tariff D was applied to each daily demand value to grow demand for each day in the relevant forecast year.

LNG peak day forecast was produced by an external consultant and can be found on AEMO's website[22].

GPG peak day demand was simulated using electricity market modelling and identified for each generator. From each simulation the top 10 demand days for the gas market was found for each year and season. The median GPG fuel offtake for the top 10 regional demand days was calculated. The median GPG fuel offtake represents coincident GPG peak at time of regional demand peak.

[22] The 2017 LGA report is available at https://www.aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities.

A1. Gas retail pricing

Price data is a key input in forecast models across multiple sectors. AEMO calculates the retail price forecasts sourcing a combination of consultant forecasts and publicly available information.

Separate prices have been prepared for three market segments:

1. Residential prices
2. Small Business prices
3. Small Industrial prices

A1.1 Retail pricing methodology

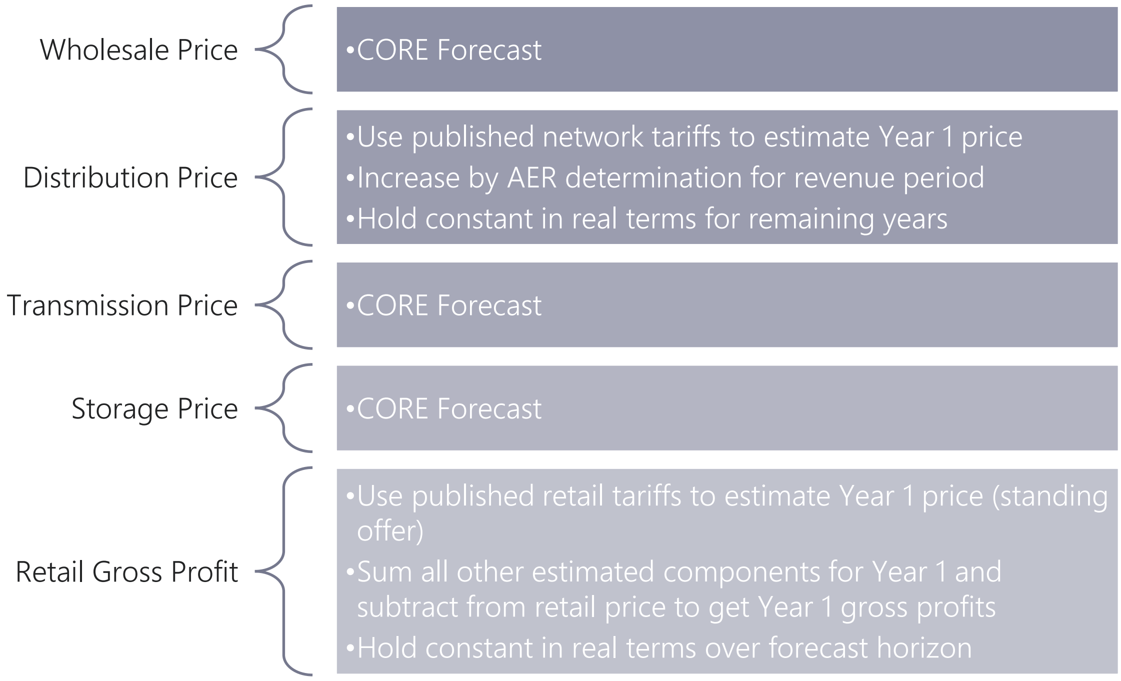
The gas retail price projections are formed from bottom-up projections based on separate forecasts of the various components of retail prices.

The key components are:

- Wholesale Prices
- Network Prices
- Storage Costs
- Retail Costs
- Retail Margin

Figure 3 gives a general outline of how the retail prices are produced. Retail Gross Profit captures both retail costs and retail margins. For details on data sources please see Appendix A4.

Figure 3 Building blocks of retail gas prices



A2. Weather standards

A2.1 Heating Degree Days (HDD)

To help determine heating demand levels, an HDD parameter is used 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 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 calculated 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}). T_{base} was determined by examining historical gas consumption patterns with temperature in each region to find the optimal base comfort level temperature for each region.

T_{312} was calculated 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 7. Finally, the Degree Day (DD312) was calculated for each region, applying the standard HDD formula to the weighted T_avg312 for each region:

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

Table 4 Station name and ID along with weighting and base temperature used for the 2020 GSOO, excluding Victoria

Region	Station name	Station ID	Tariff V Weight	T_{base} (°C)
New South Wales	Sydney (Observatory Hill)	66062	0.00	19.57
New South Wales	Bankstown Airport	66137	1.00	19.57
New South Wales	Wagga Wagga	72150	0.00	19.57
Queensland	Archerfield	40211	1.00	19.30
Queensland	Rockhampton	39083	0.00	19.30
Queensland	Townsville	32040	0.00	19.30
South Australia	Edinburgh RAAF	23083	1.00	17.94
South Australia	Adelaide (Kent Town)	23090	0.00	17.94
Tasmania	Hobart (Ellerslie Road)	94029	1.00	17.72

A2.2 Effective Degree Days (EDD)

In Victoria, an EDD is used 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, AEMO applies the EDD312 (2012) for modelling Victorian medium- to long-term gas demand[23]. In this GSOO the EDD312 (2012) standard was applied with an adjustment for the Melbourne Olympic Park weather station that commenced operation in 2015. The EDD312 standard is a function of temperature, wind chill, seasonality and solar insolation with the formulation given as:

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

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, 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 Melbourne Olympic Park weather station data used afterwards. To align the Melbourne Olympic Park weather station with historic data, an adjustment factor was applied such that:

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

Table 5 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 produce a regional wind speed. The wind speed data was sourced from the Bureau of Meteorology, and the stations used and weighting applied are given below.

Table 6 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 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.

[23] EDD312 refers to the specific start time and end time of the daily inputs that are used to calculate the EDD. This start time is 3am and end time is 12am the next day.

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

Solar insolation

Solar insolation is the solar radiation 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 7 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 shows 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 seasonal specific 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:

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

Determining HDD and EDD standards

A median of HDD/EDD weather data from 2000 to the current year was used to derive a standard weather year.

A2.3 Climate change impact

In order to apply weather standards for the 20-year forecast horizon AEMO has estimated the impact that recent changes in climate have had on HDDs (and therefore also EDDs) and adjusted the forecast to account for expected increases in temperatures as result of further climate change.

Approach

To consider how 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 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[24]. This increase is significant enough to have potentially affected the number of HDDs, as the variable is 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.

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[25].

Figure 6 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. Investigation of the other main weather stations (see Table 7) used for calculating HDDs identified only small effects of UHI, likely due to these stations being situated in less urban or open aired environments.

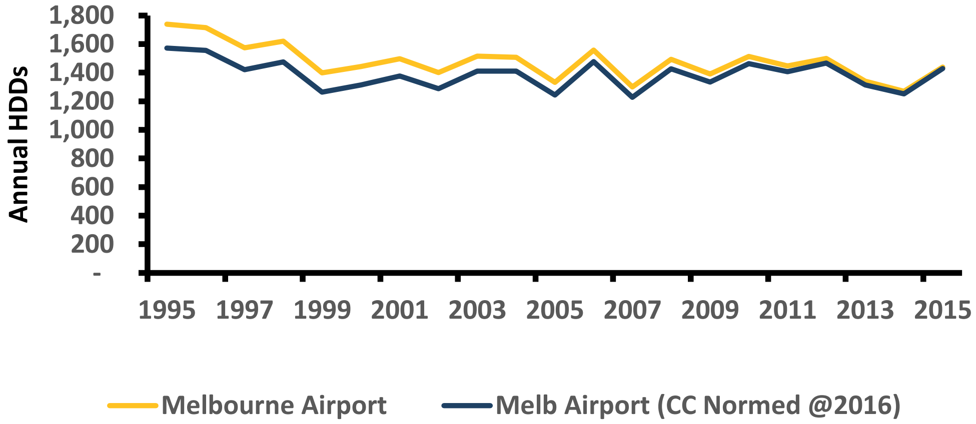
Using historical temperature anomaly data from the Bureau of Meteorology, AEMO adjusted the daily average temperature data against the climate change average temperature anomaly to re-baseline the last 20 years of HDDs (approximately compounding + 0.025°C per annum).

This adjustment was applied to all the weather stations as described in Table 7. 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.

[24] See http://www.bom.gov.au/climate/change/index.shtml#tabs=Tracker&tracker=timeseries.

[25] 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.

Figure 4 Comparison of HDD historical models for Melbourne Airport with and without a climate change adjustment

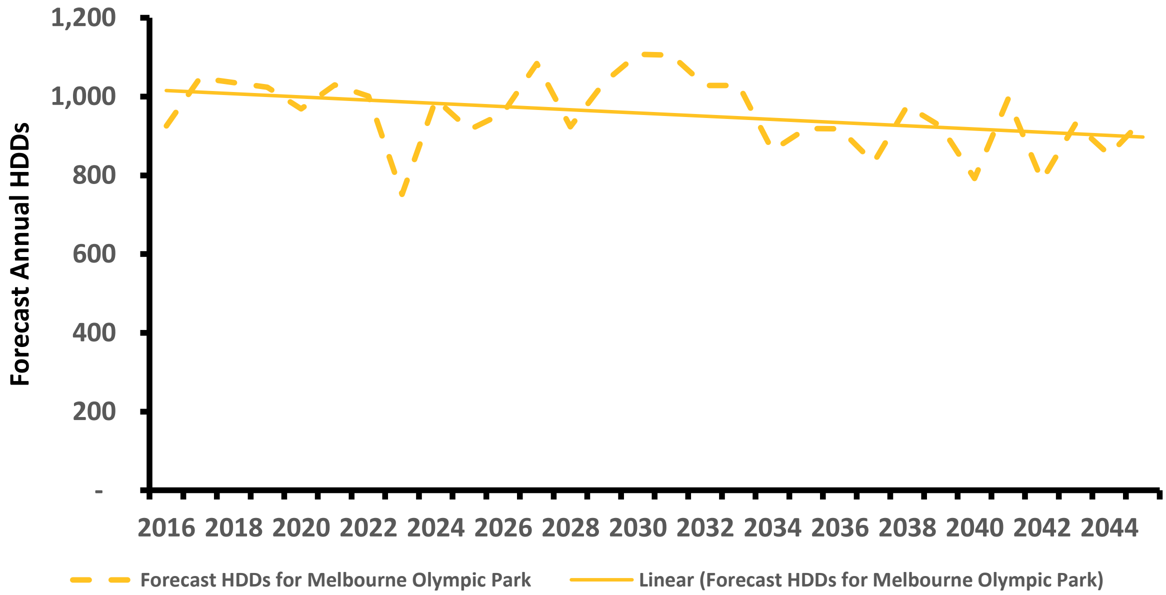


Inclusion in forecast data

The median trace of the 40 RCP4.5 models predicts a 0.5 °C increase in average temperatures from 2018–38 across Australia. AEMO used this data to adjust the forecast weather standard used in each region over the forecast period, 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 contains this year-to-year volatility. As the GSOO 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 5 A climate change adjusted HDD showing annual weather variability with a linear trend 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 (1995–2015). This data was re-baselined to the reference year, 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 the reference year.

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. 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.

A3. Distribution and transmission losses

Gas is transported from high-pressure transmission pipelines to lower-pressure distribution networks before it is used. During this process, some gas is unaccounted for and some is used for operational purposes. This quantity of gas is collectively referred to as "total losses".

In the distribution networks, losses typically result from gas pipe leakages, metering recording errors, gate station losses and other uncertainties. These gas losses are commonly known as UAFG.

Transmission pipeline losses mostly relate to gas used by pipeline compressors and heaters in normal gas pipeline operations. While UAFG also occurs along high-pressure pipelines, due to the volumes of gas transported by transmission pipelines losses are addressed more rapidly than distribution losses and therefore tend to be lower.

Due to AEMO's management of the Victorian gas Declared Transmission System, operational gas used to fuel compressor stations in Victoria is forecast separately. Operational gas has been increasing rapidly in recent years due to increasing inter-state exports from Victoria to New South Wales (via the Interconnect) and South Australia.

A3.1 Annual consumption

AEMO obtained historical losses from the sources listed in Table 9.

Historical data was normalised before being used to estimate forecasts. Transmission losses are expressed as a percentage of total gas consumption by residential and commercial consumers, industrial consumers, GPG, and distribution losses. Distribution losses are expressed as a percentage of total gas consumed by residential, commercial and industrial consumers within the distribution-connected areas.

AEMO forecasts transmission and distribution losses separately as they are driven by different underlying factors, these are then aggregated to form the final forecasts.

Transmission losses are primarily driven by operational losses, while distribution losses are driven by UAFG. Regional transmission losses are forecast to range from 0.6% to 1.6% of total consumption, while distribution losses vary between 0.1% and 6.3% for each State. These variations arise from differences in the number, size, type of users, and age of assets, network upgrades, and total gas demand for each state.

A3.2 Maximum demand

Losses during times of maximum demand were forecast by finding the highest demand days by season by tariff type. From the highest demand days, the average percentage of losses relative to demand on those days was calculated. These normalised losses (transmission and distribution) during times of maximum demand in history were then applied to maximum demand days in the forecast horizon.

A4. Data sources

Table 8 Historical data sources

Demand component	Data source for all regions except for Victoria	Data source for Victoria
Residential and commercial	1. CGI Logica - SA and NSW 2. AEMO internal database - QLD 3. Distribution business survey - TAS	AEMO's internal database
Industrial	1. Distribution businesses (for all Tariff D customers, aggregated on a network basis) 2. Transmission businesses (for all Tariff D customers, aggregated on a network basis) 3. 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	AEMO's internal database	AEMO's internal database

Table 9 Historical and forecast input data sources for industrial sector

Data series	Data sources	Reference	Notes
Historical consumption data by region	AEMO Database	http://forecasting.aemo.com.au/	This is metered data. Actual consumption is derived from aggregate of these sources are available on AEMO's forecasting data portal
Historical consumption data by region	CGI Logica	http://forecasting.aemo.com.au/	
Historical consumption data by region	Transmission & Distribution, Industrial Surveys	http://forecasting.aemo.com.au/	
Historical consumption data by region	Gas Bulletin Board (GBB)	https://www.aemo.com.au/Gas/Gas-Bulletin -Board	LNG export information is available on the GBB.
Historical consumption data by industry sector	Dept. of Energy and Environment	https://www.energy.gov.au/government-priorities/energy-data/australian-energy-statistics	Energy related data is applied in estimating long-term consumption for the Manufacturing and Other Business sectors.
Weather data	BOM	http://www.bom.gov.au/	Effective Degree Days (EDD) and Heating Degree Days (HDD) are estimated from BOM weather data.
Climate change data	CSIRO	https://www.climatechangeinaustralia.gov.au/en/climate-projections/about/	Climate Change in Australia is a CSIRO website. AEMO references this for climate change projections.
Economic data	ABS	http://www.abs.gov.au/ausstats/abs@.nsf/Latestproducts/0C2B177A0259E8FFCA257B9500133E10?opendocument	Historic values for Services sector GVA and Industrial Production are available on the ABS website
Economic data	Economic Consultancy	http://forecasting.aemo.com.au/	Economic consultants provide forecasts for Services sector GVA and Industrial Production. The index for these forecasts

Data series	Data sources	Reference	Notes
			are available on AEMO's forecasting data portal
Wholesale gas price	AEMO estimates + CORE Energy	http://forecasting.aemo.com.au/	Wholesale gas prices are inputs into the estimation of retail gas prices. The index of prices is available on AEMO's forecasting data portal.

Table 10 Data sources for input to retail gas price model

Data series	Data sources	Reference	Notes
Wholesale price forecasts	CORE Energy	http://forecasting.aemo.com.au/	CORE provides wholesale price forecasts to AEMO. Index of wholesale prices are available on AEMO's forecasting data portal.
Revenue determinations	AER Network Determinations	https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements	AEMO calculates the real change from the AER determinations over the revenue reset period and applies this to the base year network price to project prices for the long term.
Retail published prices	NSW: AGL prices SA, VIC & QLD: Origin Energy TAS: TasGas	AGL: https://www.agl.com.au/get-connected/electricity-gas-plans Origin Energy: https://www.originenergy.com.au/for-home/electricity-and-gas.html TasGas: https://www.tasgas.com.au/	For each region, a reference retailer is used to estimate current year retail prices. The estimates are based on the retailer with the largest share of retail customers for each region that are outlined in AER's "State of the market Report."
Distribution published prices	NSW: Jemena SA& QLD: AGN VIC: Multinet TAS: None publicly available.	Jemena: http://jemena.com.au/about/document-centre/electricity/tariffs-and-charges AGN: https://www.australiangasnetworks.com.au/our-business/regulatory-information/tariffs-and-plans Multinet: https://www.multinetgas.com.au/tariff-pricing/	For each region, tariffs from a reference distribution network provider are used to estimate the first-year distribution price forecast.
Storage price forecasts	CORE Energy	http://forecasting.aemo.com.au/	CORE provides wholesale price forecasts to AEMO. Index of wholesale prices are available on AEMO's forecasting data portal.
Transmission price forecasts	CORE Energy	http://forecasting.aemo.com.au/	CORE provides wholesale price forecasts to AEMO. Index of wholesale prices are available on AEMO's forecasting data portal.

Table 11 Input data for analysis of historical trend in Tariff V consumption

Data	Source	Purpose
Tariff V daily consumption by region and exclusive of UAFG	VIC and QLD: AEMO Settlements database. NSW and SA: Meter data agent (CGI data tables). TAS: Provided by gas distribution business in stakeholder survey.	To estimate Tariff V temperature sensitivity. This is used to estimate weather corrected annual consumption.
Regional daily EDD (Vic) or HDD (other regions)	BOM. Further detail provided in Appendix A2	Same as above.

Data	Source	Purpose
Actual residential and non-residential annual consumption	Provided by gas distributors in stakeholder surveys.	Applied to split Tariff V annual consumption into residential and non-residential sectors.
Actual Tariff V residential and non-residential connections	VIC and QLD: AEMO Settlements database. NSW and SA: Meter data agent (CGI data tables). TAS: Provided by gas distribution business in stakeholder survey.	Applied to estimate average consumption per Tariff V residential and non-residential connection.
Historical residential prices	See details in Appendix A1.	Applied to estimate impact of gas prices on gas Tariff V residential and non-residential consumption.

Table 12 Input data for forecasting Tariff V annual consumption

Data	Source	Purpose
Forecast residential prices	See details in Appendix A1.	Applied to forecast gas price impact on residential and non-residential annual consumption forecasts.
Forecast Tariff V connections	See section 5.2.	
Annual EDD/HDD standards	See Appendix A2.	Applied to forecast Tariff V heating load.
Forecast residential annual consumption savings due to fuel switching	Provided by the Commonwealth Department of Industry, Science, Energy and Resources (formerly the Department of Environment and Energy)	Applied to forecast the impact of fuel switching on Tariff V residential forecasts
Forecast annual consumption savings due to energy efficiency	Strategy.Policy.Research	Applied to forecast the impact of energy efficiency on Tariff V residential and non-residential forecasts.
Impact of climate change on Tariff V annual heating load	See details in Appendix A2.	Applied to forecast the impact of climate change on Tariff V heating load forecasts.

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

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

Abbreviation	Expanded name
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
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

Glossary

Term	Definition
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)	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.
Nash-Cournot	Nash-Cournot algorithms are used to simulate competitive behaviour in electricity markets. In a Nash-Cournot gaming environment, participants adjust the quantity of supply they allow to the market and find an equilibrium against a demand function. The demand function represents how responsive to price the load is i.e. how much consumers will adjust their demand as price increases. These dynamics enable the model to simulate, to a reasonable extent, market competition which in turn provides more accurate forecasts for gas consumption by GPG
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 GSOO 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).

Term	Definition
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.
Summer	December to February.
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	June to August