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Report to ATCO Gas Australia Pty Ltd

Future of gas

Scenario development and modelling for the ATCO gas distribution system

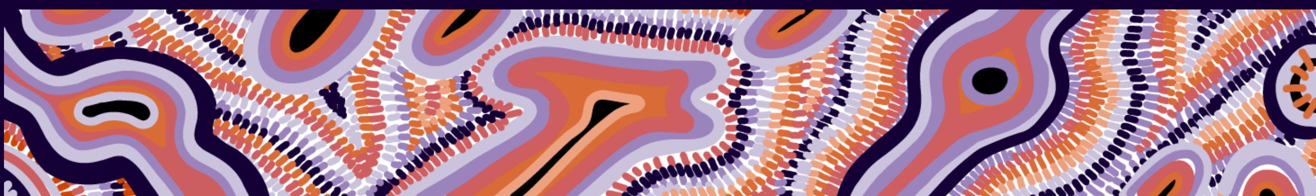
About ACIL Allen

ACIL Allen is a leading independent economics, policy and strategy advisory firm, dedicated to helping clients solve complex issues.

Our purpose is to help clients make informed decisions about complex economic and public policy issues.

Our vision is to be Australia's most trusted economics, policy and strategy advisory firm. We are committed and passionate about providing rigorous independent advice that contributes to a better world.

ACIL Allen acknowledges Aboriginal and Torres Strait Islander peoples as the Traditional Custodians of the land and its waters. We pay our respects to Elders, past and present, and to the youth, for the future. We extend this to all Aboriginal and Torres Strait Islander peoples reading this report.



Goomup, by Jarni McGuire

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Background

ATCO Gas Australia Pty Ltd (ATCO) engaged ACIL Allen PTY Ltd (ACIL Allen) to develop scenarios and undertake modelling for the ATCO Mid-West and South-West Gas Distribution System (from now on referred to as the gas distribution system). The scenarios and modelling aim to recommend the appropriate asset lives for ATCO to adopt for the AA6 period, especially concerning taking 'No regrets' actions from the stakeholders' perspectives.

The purpose of the modelling was to assess the impact of each scenario on the gas distribution system. When a scenario substantially reduces demand or increases capital expenditure to reconfigure or replace existing assets, the period over which existing assets are economically useful will likely be shorter. Shorter asset lives result in the depreciation of the relevant assets sooner.

Making recommendations concerning shortening asset lives assumes linear acceleration of depreciation. Acceleration of depreciation is justified where future consumption is likely to fall substantially or where policy requires, or technology development drives, faster replacement of assets than previously expected, and the resulting future tariffs rise to such an extent that consumers are unwilling to pay them (switch to substitutes such as electricity where feasible or close operations and stop consuming).

As the scenarios were developed, it became clear that future demand, policy requirements and technology development may not be gradual and may not support the linear acceleration of depreciation. In some scenarios, demand is projected to fall away relatively quickly. In the Hydrogen Future scenario, demand is relatively stable with some upward movement towards the end of the modelling as hydrogen becomes competitive. The Hydrogen Future scenario relies on the significant replacement of assets to cope with distributing hydrogen. Demand grows strongly over the modelling period in the Natural Gas Retained scenario.

Therefore, rather than recommending changes to asset lives, we have recommended changes to the depreciation schedule, incorporating accelerated depreciation. In most cases, the recommended depreciation schedule is not linear, implying that the asset consumption is also not uniform. However, asset life shortening is implicit in the accelerated depreciation schedule.

Scenarios

The future use of reticulated gas by households, businesses and industries is uncertain as Australia seeks to meet its 2030 and 2050 emissions reduction targets. The uncertainty primarily relates to unknowns such as the emergence and rate of development of zero-emission technologies and the Commonwealth and various state government policies that may be implemented to reduce emissions.

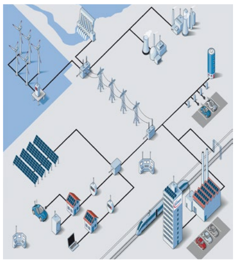
The scenarios aim to define plausible trajectories for the Western Australian gas sector for the potential market, policy, environmental, and industrial sensitivities. These scenarios generate model inputs concerning gas usage and cost, appliance switching, etc., beyond 2050

Four scenarios were developed in concert with ATCO and a group of ATCO's stakeholders, as shown in Figure ES 1 below.

Figure ES 1 Scenario summary

Hydrogen Future – Rapid learning rates relating to green hydrogen and renewable gas production enable these gases to displace natural gas domestically and internationally. The resulting green hydrogen industry mirrors the current natural gas and LNG industries with a broader high-volume export focus enabling the economic servicing of a smaller domestic market.

Electricity Dominates – Renewable electricity generation and storage experience a rapid reduction in cost through fast technological learning. Governments provide financial support to existing natural gas users to electrify their loads. As such, the relative cost of electricity against natural gas and renewable gases falls to such an extent that a broad-based electrification of industry and households occurs.



Energy Hybrid – Technical learning rates for renewable gases and electrification develop similarly, resulting in some customers electing to electrify and some remaining on the gas network. From an economic and environmental point of view, electricity and zero emissions gases become viable alternatives for natural gas. This results in a mixed response from residential/commercial and industrial consumers, with an even split electing to follow electrification or to stick with a gas-based energy supply chain.

Natural Gas Retained – global and local factors result in natural gas being retained in the ATCO network. Zero-emissions gases such as green hydrogen or renewable methane experience slow technological learning rates, which results in them generally remaining uneconomic at scale. As such, natural gas continues to be embraced as a 'transition fuel' used in large volumes globally to quickly and reliably reduce carbon emissions through coal-to-gas switching and to support/firm renewable generation. The carbon emissions intensity of natural gas and natural gas products such as LNG also reduce significantly through rapid technological learning relating to carbon capture and storage (CCS) and carbon capture utilisation and storage (CCUS) and improved access to adequate and affordable carbon offset options.

Source: ACIL Allen with ATCO and ATCO stakeholders

The scenarios were incorporated into the modelling by varying key uncertainties. The uncertainty settings for each scenario are shown in Table ES 1 below.

Table ES 1 Comparison of the four scenarios against each uncertainty

Uncertainty	Hydrogen Future	Electricity Dominates	Energy Hybrid	Natural Gas Retained
Global economic growth	Fast	Moderate	Moderate	Moderate
Domestic economic growth	Fast	Fast	Moderate	Moderate
Renewable gas / H_2 learning rate	Fast	Moderate	Moderate	Slow
Renewable electricity learning rate	Moderate	Fast	Moderate	Moderate
Global demand for renewable gas / H_2	Accelerated growth	Low growth	Moderate growth	Low growth
Electrification – households	Low demand	High demand	Moderate demand	Moderate demand
Electrification – industry	Low demand	Moderate demand	Moderate demand	Low demand
Carbon abatement policy (domestic)	Significant acceleration	Moderate acceleration	Current settings	Current settings
Carbon abatement policy (global)	Significant acceleration	Moderate acceleration	Current settings	Current settings
Fossil fuel technology development (i.e., CCS, CCUS, offsets)	Moderate	Slow	Moderate	Fast

Note: Darker shade = faster rate of change expected
Source: ACIL Allen

Methodology

The model produces a projection of gas demand and customer numbers to 2074 at the tariff class level. Customer numbers are split into new connections and disconnections, while average consumption per connection is also forecast to 2074.

Projections are split between residential (Tariff B3) and commercial customers (Tariffs B1 and B2) and industrial customers (Tariffs A1 and A2).

The modelling approach forecasts the impact of relative energy prices between gas and electricity on the projected demand for gas to 2074 while accounting for the effects of changes in relative appliance costs and running costs between gas and electricity on total gas volumes over time.

Modelling disconnections and connections

An S curve logistic function is used for residential customers (Tariff B3) and smaller commercial customers (Tariff B2). The relative NPV of switching from gas to electricity is calculated, and a logistic curve is used to estimate the market share of gas versus electricity over time. Separate logistic function calculations and projections are made for disconnections and new connections.

The usage per connection is projected separately and is driven by relative changes in the price of gas and electricity and long-term trends in per-customer usage. The tong term trends are based on the historical usage behaviour of each tariff class.

For commercial (B1) and industrial (A1 and A2) customers, usage per customer is a function of changes to gas and electricity prices and a long-term linear trend. Customer numbers for B1, A1 and A2 are projected to move proportionally with the projected number of residential customers.

Calculating accelerated depreciation

ACIL Allen's approach to calculating revised depreciation (accelerated) schedules was as follows:

— Develop the projected annual gas demands from 2025 to 2074 for the abovementioned scenarios.

— Extract the current asset base, the remaining asset lives, and the proposed new assets expenditure and lives and operating expenditures associated with each of the four scenarios.

— Calculate the revenue and depreciation schedules associated with the underlying demand and expenditures under the four separate scenarios via an integrated model that links ACIL Allens modelling to ATCOs PTRM.

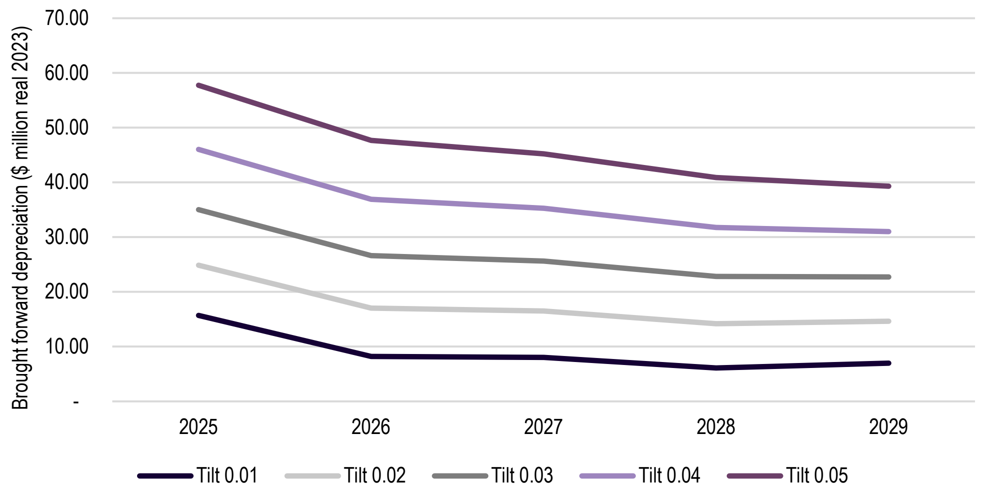
— Apply an appropriate tilt factor to the straight-line depreciation schedule to bring forward some depreciation into the up-coming regulatory period from 2025 to 2030.

— Apply a price cap to retail prices to limit prices to plausible levels.

Results

Figure ES 2 shows the brought-forward depreciation schedules by tilt-value for 2025-29. The higher the tilt-value, the greater the brought forward depreciation and the likelihood of asset stranding is lessened. The potential range of brought-forward depreciation for tilt-values of 0.01 to 0.05 averages between $9 million and $46 million from 2025 to 2029.

Figure ES 2 Brought-forward depreciation by tilt-value – 2025-29



Source: ACIL Allen

Conclusions and recommendations

The final choice of tilt-value determining the amount of brought forward depreciation is a trade-off between reducing the risk of asset stranding and near-term increases in consumer costs. ACIL Allen considers a tilt-value of 0.02 to provide a reasonable trade-off in reducing asset-stranding risk while resulting in modest cost increases for consumers.

The recommended brought-forward depreciation path is shown in Table ES 2.

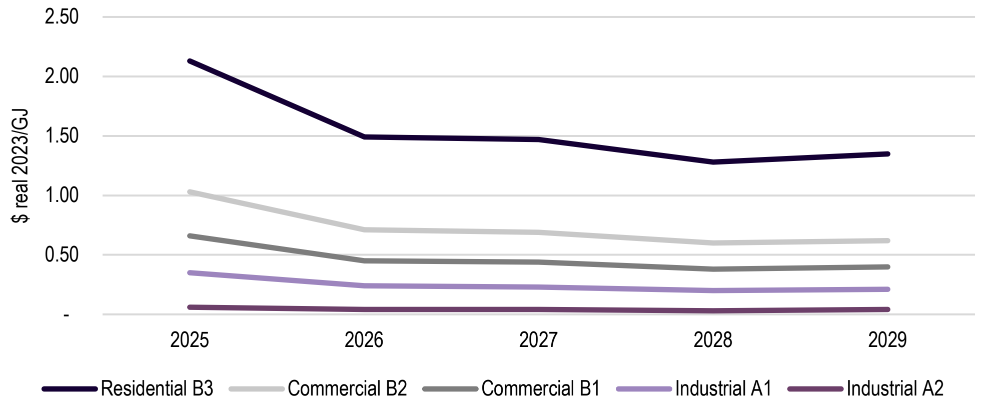
Table ES 2 Recommended brought forward depreciation: 2025 – 2029 ($ rmillion real 2023)

	2025	2026	2027	2028	2029
	2025	**2026**	**2027**	**2028**	**2029**
Brought forward depreciation	24.87	17.03	16.49	14.19	14.65

Source: FOGM

The tariff increase by customer class is shown in Figure ES 3. The residential B3 tariff increases by an average of $1.54 annually over the five years. The commercial B2 tariff increases by an average of $0.73 over the five years.

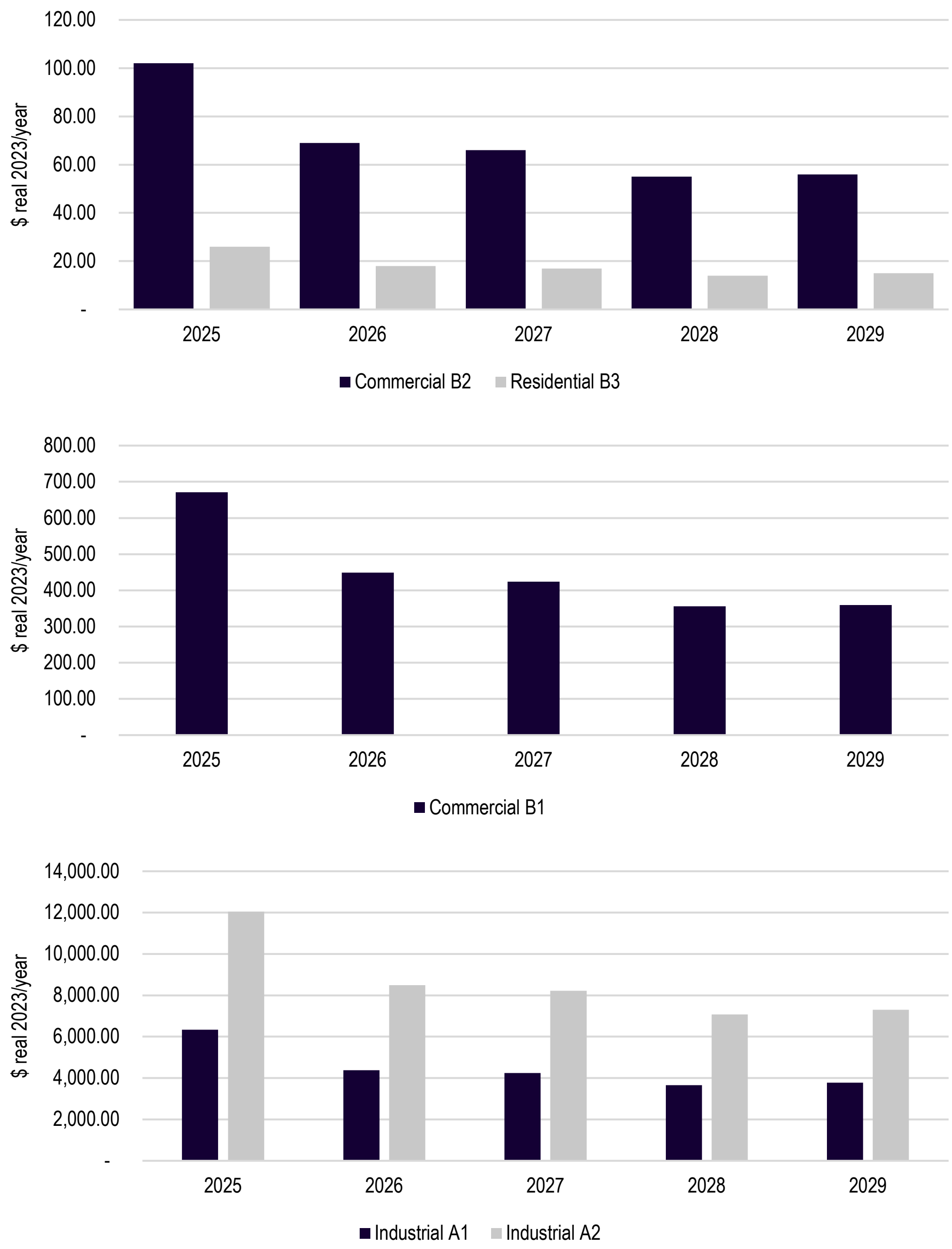
Figure ES 3 Recommended Path average tariff increases by customer class – 2025-29



Source: ACIL Allen

The average annual increase in the customer bill by customer class is shown in Figure ES 4 below.

Figure ES 4 Average annual increase in customer bill by customer class – 2025-29



Source: ACIL Allen

1 Introduction

ATCO Gas Australia Pty Ltd (ATCO) engaged ACIL Allen PTY Ltd (ACIL Allen) to develop scenarios and undertake modelling for the ATCO gas distribution system. The scenarios and modelling aim to recommend the appropriate asset lives for ATCO to adopt for the AA6 period, especially concerning taking 'No regrets' actions from the stakeholders' perspectives.

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As the scenarios were developed, it became clear that future demand, policy requirements and technology development may not be gradual and may not support the linear acceleration of depreciation. In some scenarios, demand is projected to fall away relatively quickly. In the Hydrogen Future scenario, demand is relatively stable with some upward movement towards the end of the modelling as hydrogen becomes competitive. The Hydrogen Future scenario relies on the significant replacement of assets to cope with distributing hydrogen. Demand grows strongly over the modelling period in the Natural Gas Retained scenario.

Therefore, rather than recommending changes to asset lives, we have recommended changes to the depreciation schedule, incorporating accelerated depreciation. In most cases, the recommended depreciation schedule is not linear, implying that the asset consumption is also not uniform. However, asset life shortening is implicit in the accelerated depreciation schedule.

ACIL Allen developed a Future of Gas model (FOGM) jointly with ATCO to analyse the scenarios and develop recommendations for accelerating depreciation.

Throughout the report, references to gas refer to gas generically (natural gas, hydrogen and other renewable gases). Where specific types of gas are discussed, they are referred to specifically (e.g., natural gas, hydrogen, biogas, etc.).

The remainder of the report is structured as follows:

— Chapter 2 provides a profile of the Western Australian energy sector.
— Chapter 3 describes the four scenarios used in the analysis
— Chapter 4 sets out the modelling methodology and scenario input assumptions
— Chapter 5 provides the modelling results
— Chapter 6 sets out our conclusions and recommendations.

Western Australian Energy Sector Profile 2

The Western Australian energy sector is undergoing transformative change at most levels. Government action, policy, and gas project timing (supply and demand side) are key factors shaping the energy future in Western Australia. This section explores key themes of this energy future. It undertakes a high-level analysis of significant stakeholders and competitive dynamics in retail gas, explores technology developments within the sector, and assesses affordability, efficiency, and sustainability within the retail gas industry.

2.1 Government action and policy

Several key government actions and policies strongly influence the future of Western Australia's energy sector. The announcement of the closure of all government-owned coal generator units by the end of 2029 is a crucial example. This action has placed enormous pressure on the electricity market, raising capacity and reliability concerns. It has also resulted in AEMO's 2022 Gas Statement of Opportunities (GSOO) projecting a significant shortfall in gas supply by the early to mid-2030s.

The 2022 AEMO Electricity Statement of Opportunities (ESOO) and GSOO anticipate replacement generation from gas-powered generation (GPG) through new entrant plants and increases in the capacity factor of the incumbent plant. AEMO also forecasts a capacity shortfall following the closure of Synergy's coal fleet without timely investment in new capacity. This further underlines the importance of the gas supply to incumbent and new-entrant GPGs concerning the electricity system's reliability and security.

Figure 2.1 GPG Gas Demand Forecast

Source: AEMO 2022 GSOO

Additional GPG utilisation within the Western Australian Wholesale Electricity market (WEM) will drive domestic gas demand considerably. Domestic demand is expected to increase by approximately 200 TJ per day over the coal retirement schedule compared to relatively flat projections before the retirement announcement. AEMO's 2022 GSOO expects this demand to peak when the domestic gas supply is likely to decline following the commissioning of the Waitsia Stage 2 and Scarborough gas projects in 2027 and 2029, respectively. These projects have the most distant start date of projects currently expected to contribute to domestic supply in Western Australia. As such, AEMO forecasts significant supply shortfalls after the start of these projects, as supply falls in line with field depletion and GPG demand continues to grow.

The Commonwealth Government's Safeguard Mechanism' will impact large emitters' gas and energy consumption. The mechanism aims to "reduce emissions limits, called baselines, predictably and gradually on a trajectory consistent with achieving net zero by 2050". Measures must be taken annually by all 'large emitters' to reach net zero by 2050, irrespective of individual company commitments. This policy is expected to encourage companies to invest in energy efficiency improvements and switch from gas to electricity or renewable energy where appropriate and cost-effective. However, with Western Australia's potential access to cost-effective CCS/CCUS and competitive offset options, these methods may be economically and practically favourable to cutting emissions directly.

The Western Australian Government has several policies and initiatives supporting renewable hydrogen. 'Diversify WA' focuses explicitly on renewable hydrogen and downstream processing of natural gas (petrochemicals including ammonia) to leverage the competitive price of delivered gas in Western Australia. The 'LNG Jobs Taskforce' is also keenly interested in downstream natural gas manufacturing opportunities in Western Australia, with recently commissioned work from ACIL Allen exploring urea, ammonia, and methanol projects. The Western Australian Government is also encouraging international support, signing a Memorandum of Understanding (MOU) with the Japanese Bank for International Cooperation (JBIC) to "progress opportunities for decarbonisation and low emissions technologies". This MOU is expected to focus on hydrogen, ammonia, low-emissions technology, and decarbonisation.

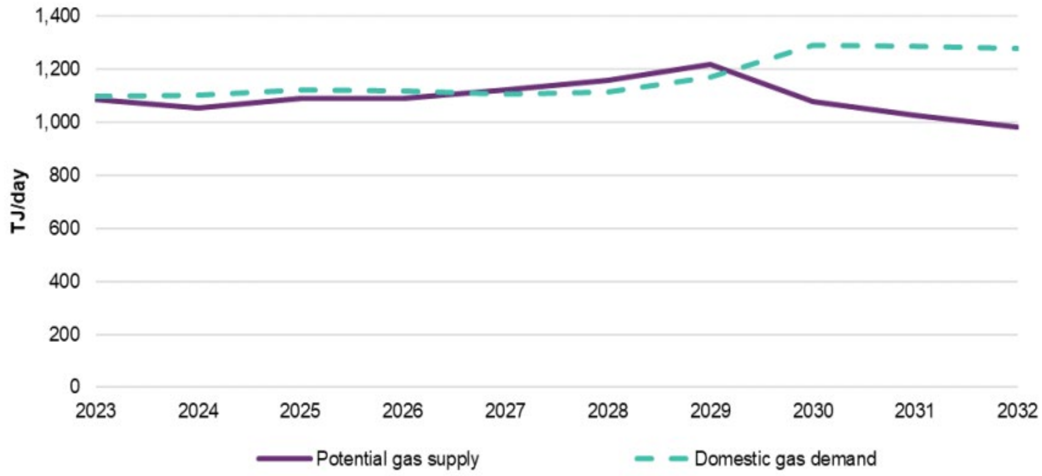
These government policies and the work surrounding them indicate a strong interest in developing future demand-side renewable and natural gas projects within Western Australia.

2.2 Gas Project Timing

The timing of supply and demand side projects within the Western Australian market is crucial to determining the balance within this market out to the mid-2030s.

Western Australian gas supply dynamics have generally been in surplus due to the gas reservation policy applicable to liquefaction plants operating within Western Australia. AEMO expects this surplus to give way to a tight supply, leading to potentially significant shortfalls once Synergy's coal plants are closed.

Figure 2.2 Base Scenario Gas Market Balance



Source: AEMO 2022 WA GSOO

During the period of tight supply (2023 to 2029), AEMO's 2022 GSOO expects the market to "*move into surplus with any delays to demand projects, or deficit if any supply projects do not progress according to current expectations*". These market dynamics place pressure on the timeline of the following major projects in the absence of new/additional domestic supply projects in the near to medium term.

Table 2.1 Assumed New Gas Supply

Project	Operator	Volume (TJ/day)	Available from
Scarborough	Woodside Energy	180	2027
Spartan	Santos	N/A (Backfill)	2023
Waitsia Stage 2	Mitsui E&P Australia	125	2029
Walyering	Strike Energy	30	2023
West Erregulla	Strike Energy	87	2025

Source: AEMO 2022 GSOO

A key feature missing from this 2022 GSOO is the industry response to the modelled shortfall. This response may be through new supply developments, such as within the Perth basin. These developments may offer significant quantities of natural gas to the domestic market, helping to manage the risk of the outlined shortfalls in supply.

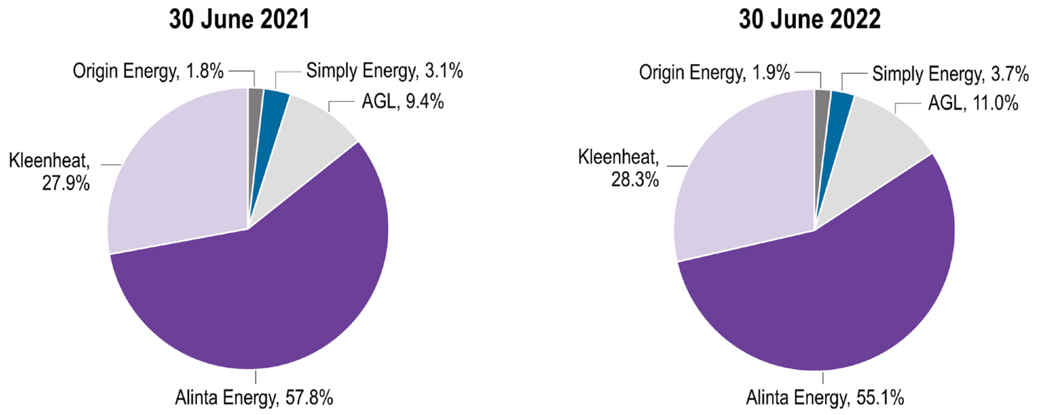
On the demand side, it is expected that continued strong demand for iron ore and base metals (Western Australia's largest export industry) will form the basis for continued growth in domestic gas demand. AEMO's 2022 GSOO analysis identifies an additional 43 TJ per day of demand from six committed resource projects to form the basis for short-term growth (out to 2026) and the coal closures to form the bulk of the medium-term growth in demand (out to 2030).

The potential market tightness, increased demand, and the increasing cost of production reflected in prospective supply projects are expected to increase wholesale gas prices in Western Australia. Gas prices are expected to escalate towards the mid-2030s, especially if additional projects, such as within the Perth basin, are not developed. This price escalation will encourage some users to develop and invest in energy efficiency. However, without specific policies promoting electrification, gas demand switching to electricity is less likely across this period because of the linkage between electricity and gas markets due to the large share of electricity produced from GPG.

2.3 Major Stakeholders and Competitive Dynamics

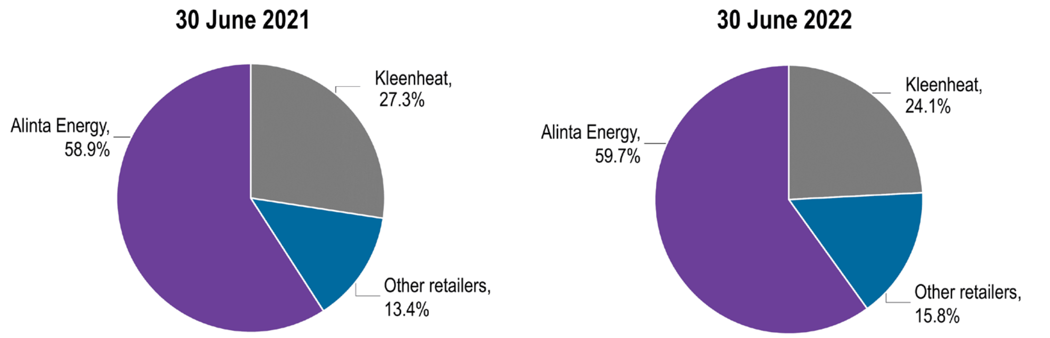
Retail gas has been fully contestable since 2004[1] and has transformed from one retailer (Alinta Energy) to nine authorised retailers at the end of 2022. These retailers compete for customers and face price competition leading to large conditional discounting. Despite this competition, the two longest-serving retailers (Alinta Energy and Kleenheat) comprise over 80 per cent of the total residential and business market share.

Figure 2.3 Residential gas market share – coastal supply area – 2021-2022



Source: Economic Regulation Authority

Figure 2.4 Business gas market share – coastal supply area – 2021-2022



Source: Economic Regulation Authority

Data from the Economic Regulation Authority (ERA) indicates that "*AGL, Origin Energy, Perth Energy and Simply Energy increased their combined share of residential customers from 14.2 per cent to 16.5 per cent. Kleenheat's market share increased by 0.4 percentage points following a 3.0 per cent increase in Kleenheat's customer base*" over the past year. This shift in market share underlines the competitive market dynamics and, ultimately, the mobility of gas customers.

The ERA's report also indicated growth in residential gas customers consistent with preceding years. Residential customers total 764,040, up from 752,359 in 2021. Business gas customers are also up from 2021, totalling 9,449; however, they still fall short of 2016/17 levels of 9,765.

[1] Synergy is prohibited from supplying gas to customers that consume less than 0.18 TJ of gas per annum under the Gas Moratorium.

Observed competition within the retail gas market is expected to continue to serve customers with competitively priced gas as minor players continue to vie for market share.

Anticipated increases in wholesale gas prices are expected to be passed on to consumers. However, this is not anticipated to result in a measurable switch from gas to electricity among this consumer group in the short term because of the linkage between electricity and gas markets (gas is used to produce most electricity within Western Australia). Reticulated gas is expected to remain competitively priced with electricity in the short term. The linkage is expected to be broken as GPG is displaced with electricity produced by renewable energy.

2.4 Technology Development

Green hydrogen blending represents a pathway to partial gas network decarbonisation requiring limited network augmentation and relatively low capital investment. Various projects around Australia have started trialling blended hydrogen within gas distribution systems, including ATCOs own hydrogen blending project located in Cockburn. The project delivers a blend of up to 10 per cent hydrogen to 2,700 customers within the project area.

A wider hydrogen industry may develop within Western Australia over the long term, supported by the sustained interest and tailored policy from the Western Australian government (WA Renewable Hydrogen Roadmap). Within the next 10 years, this is expected to be limited to smaller projects within gas distribution networks, with larger scale injections into transmission infrastructure possible in the longer term (the late 2030s to mid-2040s) to pick up GPG, mining and minerals customers.

The development of hydrogen technology and other renewable gases will boost the environmental sustainability of gas, which will be necessary for promoting continued gas use over the following decades.

Decarbonisation of electricity networks will mainly be driven by replacing fossil fuel generators with renewable energy systems. As decarbonisation moves forward, the role of GPG in providing firming services to electrical systems is expected to become more critical. GPG firming is especially important for Western Australia, where establishing long-duration pumped hydro will be challenging. The availability of hydrogen or other renewable gases or greenhouse gas emission offsets will be required to achieve net zero emissions in electricity in Western Australia.

Most of the gas used in GPG will be during peak periods and periods when renewables have lower availability (e.g., periods of low light and night coinciding with low wind availability). Therefore, the capacity to swing large volumes of gas for short periods will be necessary, while the overall volume of gas consumed will be a small fraction of the gas used in GPG today.

2.5 Affordability, Efficiency and Sustainability

The affordability of natural gas is expected to remain relatively competitive with alternative forms of energy within Western Australia for the foreseeable future. The main alternative to gas use for many users is electricity. As discussed above, the linkage between gas and electricity prices due to GPG being a significant electricity supplier is expected to maintain price relativity between electricity and gas in the short to medium term. The Commonwealth Government's Safeguard Mechanism (applying to natural gas but not electricity) will likely impact this price dynamic for some more significant users. However, this is not expected to affect retail/commercial customers over the short to medium term.

From a market perspective, the competitive dynamics observed between gas retailers are expected to maintain a workably competitive retail market. As all market participants are contestable and the market has several retailers, competition for new and existing customers is expected to continue, with efficiency gains passed on to customers.

From an environmental sustainability perspective, the development and blending of hydrogen and other renewable gases blending, and the use of gas for renewable energy 'firming' is expected to strengthen the environmental prospects of gas as a fuel. The early adoption of renewable gas options/blending will support gas on a trajectory towards net zero emissions and may result in the retention of more customers long-term. However, blending hydrogen in proportions above 10-20 per cent will likely require significant gas distribution capital expenditure. This expenditure would only be justified where long-term delivered gas prices remained competitive with other forms of energy.

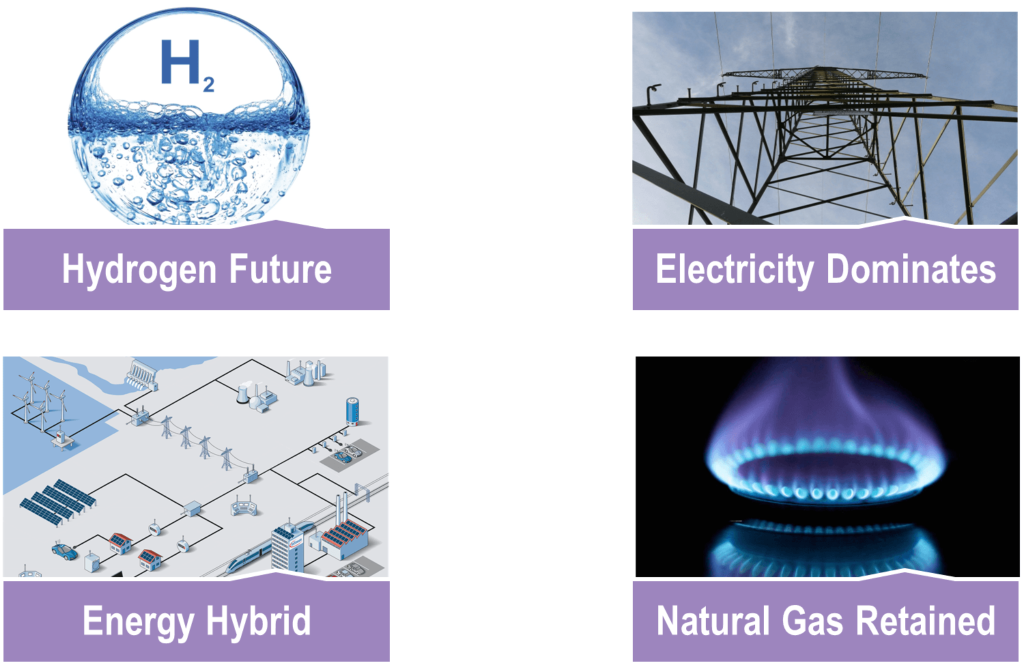
3 Scenarios

ATCO engaged ACIL Allen to undertake research and scenario development to define a set of plausible future scenarios for the Western Australian electricity and gas sectors. The specific focus is on reticulated gas in the ATCO distribution network. Reticulated gas could include natural gas, biomethane, hydrogen, or zero-emissions gases.

The future use of reticulated gas by households, businesses and industries is uncertain as Australia seeks to meet its 2030 and 2050 emissions reduction targets. The uncertainty primarily relates to unknowns such as the emergence and rate of development of zero-emission technologies and the Commonwealth and various state government policies that may be implemented to reduce emissions.

The scenarios aim to define plausible trajectories for the Western Australian gas sector for the potential market, policy, environmental, and industrial sensitivities. These scenarios generate model inputs concerning gas usage and cost, appliance switching, etc., beyond 2050.

Figure 3.1 Scenarios



Source: ACIL Allen

3.1 Hydrogen Future

Under the Hydrogen Future scenario, rapid learning rates relating to green hydrogen and renewable gas production enable these gases to displace natural gas domestically and internationally. The resulting green hydrogen industry mirrors the current natural gas and LNG industries with a broader high-volume export focus enabling the economic servicing of a smaller domestic market.

Internationally, green hydrogen and, in some cases, biomethane are used as a replacement fuel for natural gas, leveraging existing infrastructure and supply chains where possible. This creates a significant export opportunity for Australia, which comes at the expense of traditional exports such as LNG. Therefore, upstream natural gas developments and natural gas supply to the Western Australian domestic market are expected to be disrupted, as the world and gas suppliers move to produce and consume green hydrogen.

The Commonwealth and states under this scenario view green hydrogen as a cost-effective pathway to the decarbonisation of industry, gas power generation, and residential/commercial gas loads while maintaining Australia's role as a significant energy exporter. Government support for hydrogen infrastructure and other mechanisms designed to catalyse the green hydrogen and zero emissions gases industry are assumed under this scenario. Government programs include support for replacing appliances so they can operate on 100 per cent hydrogen.

Technologies that support reductions in carbon emissions from electricity and other stationary energy have moderate technological learning rates. These learning rates limit existing reticulated gas customers switching to electricity to lower emissions in the medium term.

Low-cost green hydrogen and renewable gas posed under this scenario will also significantly improve economic conditions within Western Australia, Australia and internationally, driving higher economic growth rates because of lower consumer energy bills and enhanced industrial operating margins. The growth of the hydrogen export industry also adds to economic growth. This improved economic outlook results in sustained growth in gas usage within all consumer groups, especially in the industrial sector. As a result, gas infrastructure continues to be utilised at existing levels, with expansion opportunities and green field projects likely in the medium to long term.

ATCO gas distribution system implications

From ATCO's gas distribution system perspective, this scenario will result in continued strong domestic demand gas, leading to modest growth in the volume of gas sold and the number of customers connected. Competitive pricing of the renewable gases under this scenario, including their lower carbon footprint, reduces the drive to electrify loads. However, the existing gas distribution network will likely need to be upgraded to carry a concentration greater than 10 per cent blended hydrogen and methane and placed on a pathway towards 100 per cent hydrogen carriage. The conversion of consumer facilities to run on higher concentrations of hydrogen will have a cost impact where facilities must be replaced before end-of-life. Under this scenario, it is assumed that government support is forthcoming to assist in this modification and that technical learning will bring this cost down over time.

Table 3.1 Hydrogen Future uncertainty setting matrix

Uncertainty	Substantial change	⟵	⟶	Insubstantial change
Global economic growth	**Fast**	Moderate	Slow	
Domestic economic growth	**Fast**	Moderate	Slow	
Renewable gas / H_2 learning rate	**Fast**	Moderate	Slow	
Renewable electricity learning rate	Fast	**Moderate**	Slow	
Global demand for renewable gas / H_2	**Accelerated growth**	Moderate growth	Low growth	No growth
Electrification – households	High demand	Moderate demand	**Low demand**	
Electrification – industry	High demand	Moderate demand	**Low demand**	
Carbon abatement policy (domestic)	**Significant acceleration**	Moderate acceleration	Step up	Current settings
Carbon abatement policy (global)	**Significant acceleration**	Moderate acceleration	Step up	Current settings
Fossil fuel technology development (i.e., CCS, CCUS, offsets)	Fast	**Moderate**	Slow	

Source: ACIL Allen

3.2 Electricity Dominates

Electricity Dominates

Under the Electricity Dominates scenario, renewable electricity generation and storage experience a rapid reduction in cost through fast technological learning. As such, the relative cost of electricity against natural gas and renewable gases falls to such an extent that a broad-based electrification of industry and households occurs.

The Commonwealth and the states provide financial support to existing natural gas users to electrify their loads, seeing this as a critical factor in meeting climate goals and bringing down the cost of living for the Australian population. Government support could include grants, subsidies and prohibitions on the sale or installation of new gas or other fossil space or water heating appliances. This would drive greenfield and brownfield appliance electrification, and government policy would be specifically tailored to ensure electricity price reductions.

The pace of renewable generation and storage cost reduction is assumed to start slow and ramp up by the mid-2030s, driven by faster learning rates as international adoption of renewable energy grows. As such, the most significant effect on gas distribution businesses will begin to be felt after the mid-2030s, with reduced but still economic gas volumes assumed to be sold beyond 2050. The gas sold within the network is taken to remain primarily natural gas, with hydrogen blending limited to 10 per cent.

As a result of the scenario's low electricity prices, the cost to produce green hydrogen and renewable gas will also fall, making these gases more affordable. However, the scale of electricity price reductions means more households and businesses will electrify their energy use. As such, there is limited scope for renewable gases within commercial/residential and many industrial customers. However, hydrogen and renewable gases play a role in hard-to-abate industries and exports in the longer term. Thanks to rapid reductions in electricity storage costs, gas power generation using hydrogen is also unlikely under this scenario due mainly to the significant energy round trip losses experienced during this process. Investments and technical learning in technologies such as CCS/CCUS are also assumed to be slow under this scenario.

Lower electricity prices and lower conversion costs faced by electrification under this scenario also significantly improve economic conditions within Western Australia and Australia. The economic conditions internationally are also expected to benefit under this scenario, with moderate growth rates projected based on lower energy input costs for all consumer groups.

ATCO gas distribution system implications

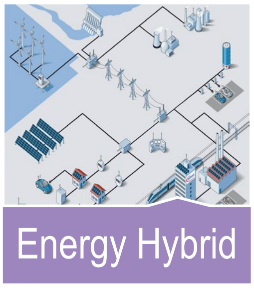
From the ATCO gas distribution system perspective, this scenario will see a substantial and sustained reduction in the volume of gas sold and the number of customers connected to the network. The strength of government policy will drive the pace of the decrease in volume and customers, and the rate of cost reduction experienced because of lower renewable electricity generation and storage costs. This scenario assumes that initially, the primary driving force is the reduction in energy costs and carbon emissions offered by a renewable-focused Western Australian grid, with government subsidies held off and used primarily to accelerate climate goal achievement.

Table 3.2 Electricity Dominates uncertainty setting matrix

Uncertainty	Substantial change	↔		Insubstantial change
Global economic growth	Fast	**Moderate**	Slow	
Domestic economic growth	**Fast**	Moderate	Slow	
Renewable gas / H_2 learning rate	Fast	**Moderate**	Slow	
Renewable electricity learning rate	**Fast**	Moderate	Slow	
Global demand for renewable gas / H_2	Accelerated growth	Moderate growth	**Low growth**	No growth
Electrification – households	**High demand**	Moderate demand	Low demand	
Electrification – industry	High demand	**Moderate demand**	Low demand	
Carbon abatement policy (domestic)	Significant acceleration	**Moderate acceleration**	Step up	Current settings
Carbon abatement policy (global)	Significant acceleration	**Moderate acceleration**	Step up	Current settings
Fossil fuel technology development (i.e., CCS, CCUS, offsets)	Fast	Moderate	**Slow**	

Source: ACIL Allen

3.3 Energy Hybrid



Under the Energy Hybrid scenario, technical learning rates for renewable gases and electrification develop similarly, resulting in some customers electing to electrify and some remaining on the gas network. From an economic and environmental point of view, electricity and zero emissions gases become viable alternatives for natural gas. This results in a mixed response from residential/commercial and industrial consumers, with an even split electing to follow electrification or to stick with a gas-based energy supply chain.

From a government policy perspective, this scenario represents a 'market forces' approach, with government policy and support not favouring a particular technology or pathway to achieve government emission reduction targets.

Under the scenario settings, moderate electricity and renewable/zero emissions gases cost reductions engender moderate economic growth. This is because energy bill savings and improved industrial operating margins are more modest under this scenario than in the Electricity Dominates case. Hard-to-electrify industrial loads operate economically on natural gas and, later, hydrogen or other forms of renewable gas.

Technologies that support reductions in carbon emissions from electricity and other stationary energy have moderate technological learning rates. These learning rates limit existing reticulated gas customers switching to electricity to lower emissions in the medium term.

ATCO gas distribution system implications

From the ATCO gas distribution system perspective, this offers a mixed future. Due to the low prices and clear carbon benefits of electrification, some gas consumers electrify their loads. Concurrently, as the product sold via the gas network is decarbonised through the introduction of green hydrogen and renewable/zero-emissions gas, many customers do not electrify. This results in ATCO retaining much of its existing customer base and limits reductions in gas demand under this scenario.

Table 3.3 Energy Hybrid uncertainty setting matrix

Uncertainty	Substantial change	⟵	⟶	Insubstantial change
Global economic growth	Fast	**Moderate**	Slow	
Domestic economic growth	Fast	**Moderate**	Slow	
Renewable gas / H_2 learning rate	Fast	**Moderate**	Slow	
Renewable electricity learning rate	Fast	**Moderate**	Slow	
Global demand for renewable gas / H_2	Accelerated growth	**Moderate growth**	Low growth	No growth
Electrification – households	High demand	**Moderate demand**	Low demand	
Electrification – industry	High demand	**Moderate demand**	Low demand	
Carbon abatement policy (domestic)	Significant acceleration	Moderate acceleration	Step up	**Current settings**
Carbon abatement policy (global)	Significant acceleration	Moderate acceleration	Step up	**Current settings**
Fossil fuel technology development (i.e., CCS, CCUS, offsets)	Fast	**Moderate**	Slow	

Source: ACIL Allen

3.4 Natural Gas Retained

Natural Gas Retained

Under the Natural Gas Retained scenario, global and local factors result in natural gas being retained in the ATCO network, broadly in line with medium-term expectations as of the previous Access Arrangement process. Zero-emissions gases such as green hydrogen or renewable methane experience slow technological learning rates, which results in them generally remaining uneconomic at scale. This results in low local and international uptake of zero emissions gases. As such, natural gas continues to be embraced as a 'transition fuel' used in large volumes globally to quickly and reliably reduce carbon emissions through coal-to-gas switching and to support/firm renewable generation. The carbon emissions intensity of natural gas and natural gas products such as LNG also reduce significantly through rapid technological learning relating to carbon capture and storage CCS/CCUS and improved access to adequate and affordable carbon offset options.

The capture, transportation and storage of carbon dioxide are critical to this scenario. In this scenario, it is expected that CCS/CCUS will become widely used by carbon-intensive industrial customers who can easily capture their emissions. In addition, CCS/CCUS will become a significant industry internationally with the expected emergence of a regionally based price for carbon to reflect the cost of the industry's operation. This international cooperation on CCS/CCUS will enable natural gas emissions to be captured and stored when used in industrial applications and electricity generation. In the longer term, technologies that utilise the captured carbon emerge. This will enable the continued use of natural gas while avoiding emitting greenhouse gases.

The impact of CCS/CCUS on the gas distribution business is indirect insofar as it would not be expected that ATCO would play a role in this industry. However, the successful development of CCS/CCUS technology would allow for the continued development of Western Australia's natural gas reserves, which is critical to maintaining the domestic gas supply through the Domestic Gas Reservation Policy. Success in CCS/CCUS would also underpin the continued use of gas for gas-fired power generation in Western Australia. However, this gas is supplied outside the ATCO gas distribution network.

Hard-to-capture gas loads, such as residential and commercial consumption, have their emissions managed via a certified carbon offset crediting scheme at an economically viable price. Such schemes are fit for purpose and economical at the scale these loads represent.

Economic growth domestically and internationally is assumed to be moderate under this scenario. The wide adoption of CCS/CCUS and the availability of cost-effective offsets enables many gas users to continue mainly using unmodified appliances and industrial processes, avoiding costly upgrades for electrification or hydrogen compatibility. However, the cost to operate CCS/CCUS and provide offsets, coupled with the likely higher cost of gas production as more marginal reserves are exploited, increases energy bills and reduces industrial operating margins compared with other scenarios.

In this scenario, the gradual electrification of household appliances would be expected to occur, generally in line with appliance replacement cycles, as opposed to an acceleration in demand for switching. Industrial users would be expected to continue using carbon-neutralised natural gas or undertake CCS/CCUS where scale permits.

It is reasonable to characterise this scenario as contingent on developing CCS/CCUS technology and effective offset markets. Without them, the continued use of natural gas in all contexts is unlikely to be consistent with global or domestic government policy.

ATCO gas distribution system implications

From the ATCO gas distribution system perspective, this scenario results in little to no operational changes to the network. Low amounts of blended zero emissions gases such as H2 are expected, but these will not exceed the 10 per cent threshold within which the network can operate without significant capital expenditure. Natural gas prices in Western Australia are expected to increase by a small margin, resulting in gas volumes remaining primarily unchanged over the forecast horizon. Growth is expected in industrial and power generation applications proportional to economic growth rates. The assumed clean carbon credentials and stable natural gas prices limit the volume of gas demand switching to electricity and the development of renewable/zero emissions gases.

Table 3.4 Natural Gas Retained uncertainty setting matrix

Uncertainty	Substantial change	⟵	⟶	Insubstantial change
Global economic growth	Fast	**Moderate**	Slow	
Domestic economic growth	Fast	**Moderate**	Slow	
Renewable gas / H_2 learning rate	Fast	Moderate	**Slow**	
Renewable electricity learning rate	Fast	**Moderate**	Slow	
Global demand for renewable gas / H_2	Accelerated growth	Moderate growth	**Low growth**	No growth
Electrification – households	High demand	**Moderate demand**	Low demand	
Electrification – industry	High demand	Moderate demand	**Low demand**	
Carbon abatement policy (domestic)	Significant acceleration	Moderate acceleration	Step up	**Current settings**
Carbon abatement policy (global)	Significant acceleration	Moderate acceleration	Step up	**Current settings**
Fossil fuel technology development (i.e., CCS, CCUS, offsets)	**Fast**	Moderate	Slow	

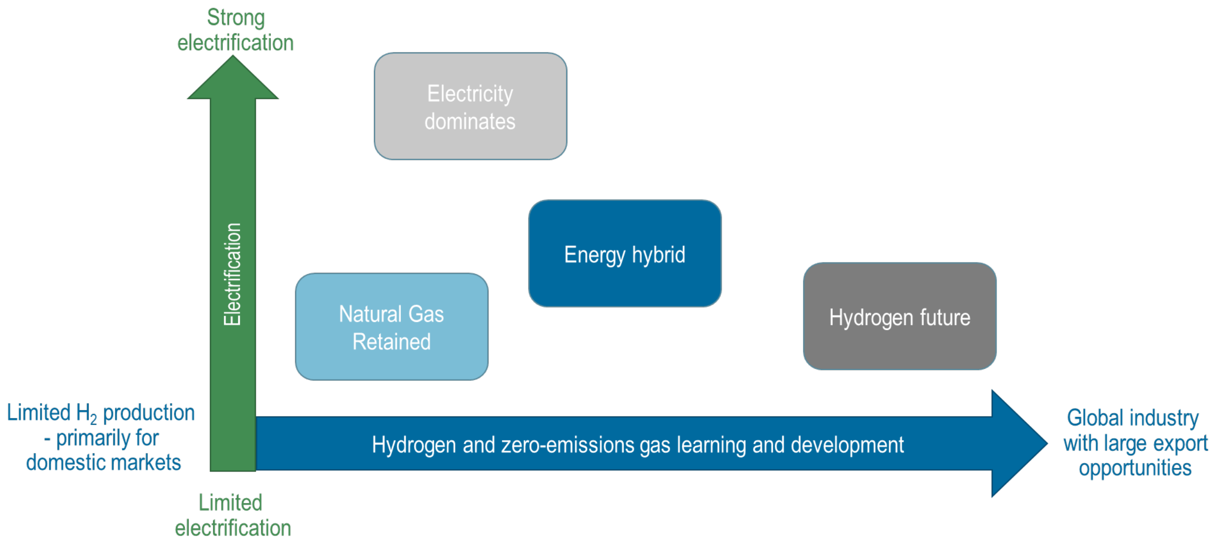
Source: ACIL Allen

3.5 Scenario comparison

This section briefly compares the scenarios regarding the two key factors, electrification and zero emissions gas development.

Hydrogen Future and Electricity Dominates represent the bookends in either electrification of natural gas heating demand or replacing natural gas with zero emissions gas. The Energy Hybrid scenario is a mid-range scenario. The Natural Gas Retained scenario is most like the status quo. However, it is contingent on the economic development of CCS/CCUS and the long-term availability of carbon credits to offset emissions produced by distribution system gas consumers.

Figure 3.2 Scenarios compared



Source: ACIL Allen

Table 3.5 Comparison of the four scenarios against each uncertainty

Uncertainty	Hydrogen Future	Electricity Dominates	Energy Hybrid	Natural Gas Retained
Global economic growth	Fast	Moderate	Moderate	Moderate
Domestic economic growth	Fast	Fast	Moderate	Moderate
Renewable gas / H_2 learning rate	Fast	Moderate	Moderate	Slow
Renewable electricity learning rate	Moderate	Fast	Moderate	Moderate
Global demand for renewable gas / H_2	Accelerated growth	Low growth	Moderate growth	Low growth
Electrification – households	Low demand	High demand	Moderate demand	Moderate demand
Electrification – industry	Low demand	Moderate demand	Moderate demand	Low demand
Carbon abatement policy (domestic)	Significant acceleration	Moderate acceleration	Current settings	Current settings
Carbon abatement policy (global)	Significant acceleration	Moderate acceleration	Current settings	Current settings
Fossil fuel technology development (i.e., CCS, CCUS, offsets)	Moderate	Slow	Moderate	Fast

Note: Darker shade = faster rate of change expected

Source: ACIL Allen

Modelling Methodology and Scenario Input Assumptions

4

This section describes the methodology adopted to model the demand for gas in the ATCO network up to 2074 and the method used to calculate brought-forward depreciation. The section also explores the key assumptions and inputs used in the model calculations. The key assumptions cover carbon, hydrogen, gas, and electricity prices and appliance costs, as well as costs of switching. In some scenarios, government rebates are determined by each scenario's characteristics.

4.1 Methodology

This section provides an overview of the modelling methodology adopted to simulate gas demand across ATCO's five tariff classes and calculate the brought-forward depreciation schedule for each scenario.

The model produces a projection of gas demand and customer numbers to 2074 at the tariff class level. Customer numbers are split into new connections and disconnections, while average consumption per connection is also forecast to 2074.

Projections are split between residential (Tariff B3) and commercial customers (Tariffs B1 and B2) and industrial customers (Tariffs A1 and A2).

The modelling approach forecasts the impact of relative energy prices between gas and electricity on the projected demand for gas to 2074 while accounting for the effects of changes in relative appliance costs and running costs between gas and electricity on total gas volumes over time.

An S curve logistic function is used for residential customers (Tariff B3) and smaller commercial customers (Tariff B2). The relative NPV of switching from gas to electricity is calculated, and a logistic curve is used to estimate the market share of gas versus electricity over time. Separate logistic function calculations and projections are made for disconnections and new connections.

The usage per connection is projected separately and is driven by relative changes in the price of gas and electricity and long-term trends in per-customer usage. The tong term trends are based on the historical usage behaviour of each tariff class.

For commercial (B1) and industrial (A1 and A2) customers, usage per customer is a function of changes to gas and electricity prices and a long-term linear trend. Customer numbers for B1, A1 and A2 are projected to move proportionally with the projected number of residential customers. The heterogeneous nature of these tariff classes makes creating separate customer connection and disconnection models very difficult. For this reason, we have adopted the simplistic approach described. It is important to note that while these customer classes account for a large share of ATCO gas volumes, they are responsible for only a tiny percentage of the network’s revenues.

Brought-forward depreciation is determined once the gas demand and customer projections are developed. This is done by imposing a tilt function on the base method of straight-line depreciation such that some depreciation is brought forward from the future. The amount of accelerated depreciation brought forward is a function of the size of the tilt imposed on the tilt function. The tilt function and its application are explained further in section 4.1.3 below.

As part of this study, the four separate scenarios discussed in the previous section are simulated:

— Hydrogen Future
— Electricity Dominates
— Energy Hybrid
— Natural Gas Retained

4.1.1 Logistic model of disconnecting or connecting

For the commercial (B2) and residential (B3) tariff classes, the model considers two groups of customers:

— Existing customers may choose to disconnect and switch to electricity
— New customers may choose to connect to the gas network.

The probability of disconnections is a function of the NPV of switching. As the NPV of switching to electricity from gas becomes progressively less negative or positive, the proportion of customers making the switch increases. The NPV is a function of relative appliance costs and usage charges driven by the relative costs associated with gas and electricity prices. The introduction of appliance rebates to facilitate the switching from gas to electric appliances also plays a role in the NPV calculations in the Electricity Dominates and Energy Hybrid scenarios.

The other main driver of the NPV calculation is the discount rate. Three separate discount rates are used to capture the extent to which potential connecting or disconnecting customers are more or less forward-looking. Higher-income households are more forward-looking and have lower discount rates than lower-income households with higher discount rates and are less forward-looking. Data from the 2021 ABS Census of Population and Housing was used to categorise customers within the ATCO network into Low-, Medium- and High-income categories. Separate NPV series were then calculated with a single income-weighted average NPV produced and used as an input into the separate connection and dis-connection S curve logistic functions.

The key inputs into the NPV calculation for switching decisions are:

— Relative capital costs of the appliances
— Relative running costs
— Gas dis-connection charges
— Electricity upgrade connection costs
— Rebates for electric appliances.

Customers are assumed to consider switching when their appliances are 15 years old.[2] Although we don't know the distribution of appliance ages within the ATCO network, we assume that appliance ages follow a uniform distribution as of 2024, so there is an even spread of appliances between ages 1 and 15. The distribution of appliance ages then changes as new customers connect to the network, existing customers stay connected with new appliances, and existing customers disconnect from the network. The default setting for the decision point is every 15 years.

2 Appliances are assumed to have an average life of 15 years.

The logistic function is used to determine the probability of switching. This function resembles an S curve characterised by a slow build-up, a ramp-up phase, and a mature phase where the take-up has reached a saturation point.

The logistic model converts underlying drivers of choice to switch to electric appliances into a probability or market share of switching. The model values each attribute that drives the decision and applies an elasticity or weight to each factor. In our case, we are using a single factor, the NPV of switching, which incorporates the set of underlying drivers, such as relative prices and appliance costs, into a single measure.

The function takes any value from zero to infinity as inputs and converts them to output between zero and 1.

The function takes the form of an S curve:

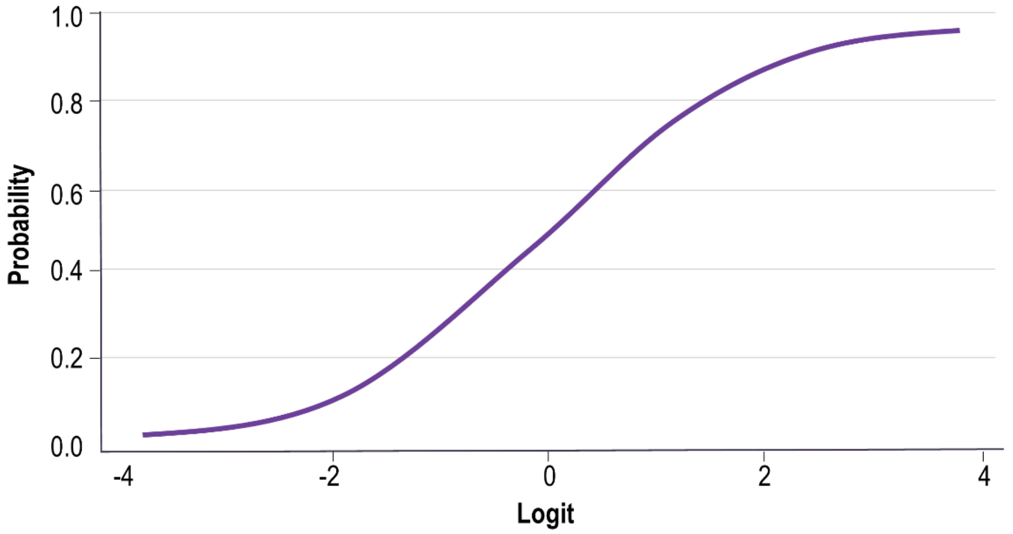
$\pi(x) = 1/(1 + \exp(-y))$ where:

$y = \beta_0 + \beta_1 NPV$

y is a linear utility function of the drivers denoted by the NPV.

The theoretical S curve is shown in Figure 4.1 below.

Figure 4.1 The logit S curve

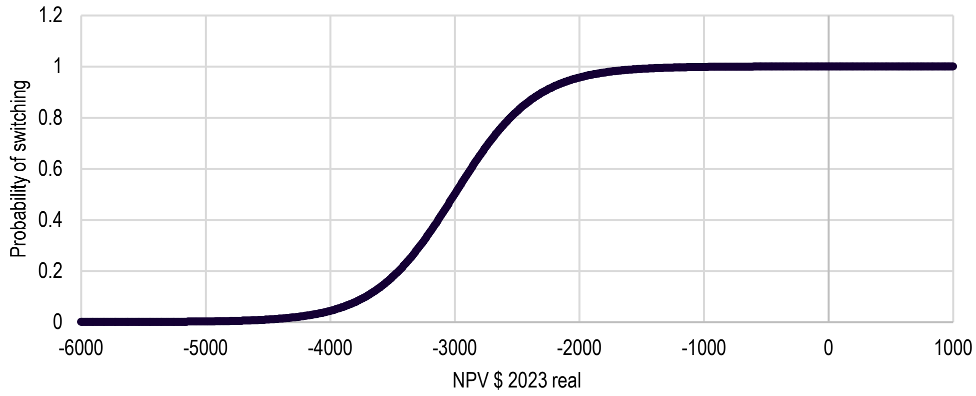


For potential new customers, the NPV calculation for the connection decision is similar to that of the disconnection NPV, which includes the relative capital and running costs for electricity and gas. However, it excludes gas disconnection or electricity upgrade charges, as they only relate to the switching decision.[3]

Figure 4.2 shows the S curve that calculates the probability (or market share) of residential customers disconnecting from the network. As the NPV of switching becomes less negative, the probability of switching from gas to electric appliances increases.

3 No gas to disconnect and electricity connection charges will occur regardless of whether the customer chooses gas or electricity for gas and heating.

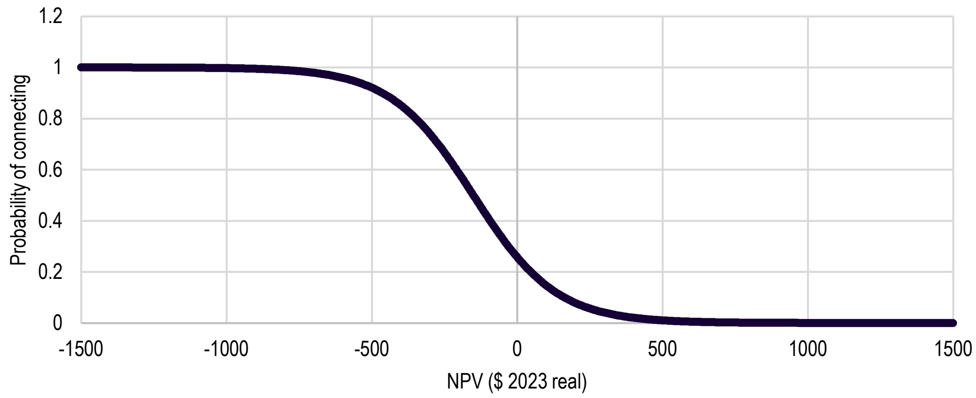
Figure 4.2 S curve for residential gas disconnection decision



Source: ACIL Allen

The S curve relating to the connection of new residential customers to the has network is shown in Figure 4.3 below. It takes the shape of an inverted S curve. The probability of a new customer connecting to the gas network declines as the NPV of choosing electric appliances relative to gas appliances becomes less negative over time.

Figure 4.3 S curve for residential gas new connection decision



Source: ACIL Allen

4.1.2 Econometric models of volume per customer

While the logistic function can model the number of connections and disconnections to the ATCO network for residential (B3) and commercial (B2) customers, the average volume per customer consumed by B3 and B2 customers is modelled via separate econometric models. For B3 customers, the average volume consumed is a function of the retail gas price, the retail electricity price and a declining linear trend based on historical movements. For commercial B2 customers, average consumption is a function of gas and electricity prices and a linear declining trend.

Similar specifications were used for commercial (B1) and industrial (A1 and A2) customers. These were also a function of gas and electricity prices and a linear trend. Changes in electricity and gas prices translated through to usage changes via an assumed set of price elasticities of demand.

Correcting for weather-related variation in usage was unnecessary because Core Energy had already weather-normalised the base-level historical data using their method. ACIL Allen took the weather-normalised data as a starting point, so making any additional adjustments or corrections for the weather was unnecessary. This approach differs from that adopted previously, where ACIL Allen applied its weather correction methodology to ATCO's historical data, resulting in inconsistencies between Core's and ACIL Allen's respective weather correction methodologies.

4.1.3 Calculating accelerated depreciation

ACIL Allen's approach to calculating revised depreciation (accelerated) schedules was as follows:

- Develop the projected annual gas demands from 2025 to 2074 for the four separate scenarios
- Extract the current asset base, the remaining asset lives, and the proposed new assets expenditure and lives and operating expenditures associated with each of the four scenarios.
- Calculate the revenue and depreciation schedules associated with the underlying demand and expenditures under the four separate scenarios via an integrated model that links ACIL Allens modelling to ATCOs PTRM.
- Apply an appropriate tilt factor to the straight-line depreciation schedule to bring forward some depreciation into the up-coming regulatory period from 2025 to 2030.
- Apply a price cap to retail prices to limit prices to plausible levels.

The methodology is explained in more detail below.

Revenue and depreciation

The starting point for the assessment was the current asset base and the proposed new asset expenditure under each of the four scenarios. ACIL Allen linked its model to ATCOs PTRM to access the revenue and depreciation schedules, including:

- Asset values and asset lives
- New asset investment profile and lives
- Assumed inflation, cost of equity, cost of debt and WACC

This information replicates the PTRM results under the four separate scenarios. The PTRM part of the integrated model takes the volume and customer number projections from ACIL Allen's simulations of the four scenarios. Then it generates a set of distribution tariffs, which are fed back into the volumes and customer numbers calculation through a 1-year lag in the retail price.

Brought forward regulatory depreciation

In this report, accelerated depreciation in a year refers to the total quantum of depreciation calculated with the FOGM set to accelerated depreciation. Brought-forward depreciation refers to the difference between accelerated and standard straight-line depreciation calculated under the straight-line setting.

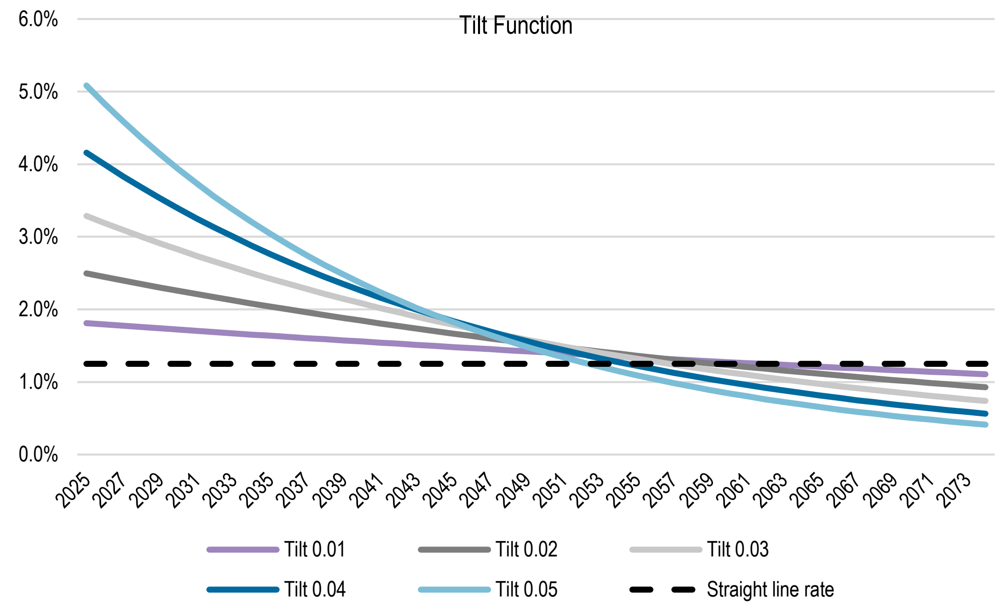
ATCO Australia implemented a facility for calculating accelerated depreciation within the PTRM component of the FOGM. ATCO Australia informed ACIL Allen that the implementation replicates the approach used by the Victorian gas distributors in their submissions to the Australian Energy Regulator for their current access arrangements (2023-28).

Accelerated depreciation is calculated by applying a so-called tilt function to each component of the asset base (existing and new capex) in each year. The tilt function is a geometric progression with the tilt-value as the constant ratio. As the tilt-value is much less than 1, the function decays from the initial tilt-value and approaches zero over time. The tilt function is adjusted by a factor of $1/(1-(1-r)^a)$ where r is the geometric progression constant ratio, and a is the original asset life for each component of the asset base.

If the residual asset value in any year falls below the calculated accelerated value, the depreciation for that year is set to the residual asset value, at which point the asset is fully depreciated. This ensures that accumulated depreciation cannot exceed the total asset value.

Examples of the tilt function for tilt-values of 0.01 to 0.05 are shown in Figure 4.4 below.

Figure 4.4 Tilt function for values 0.01 to 0.05 for 80-year asset lives



Source: ATCO Gas Australia Pty Ltd

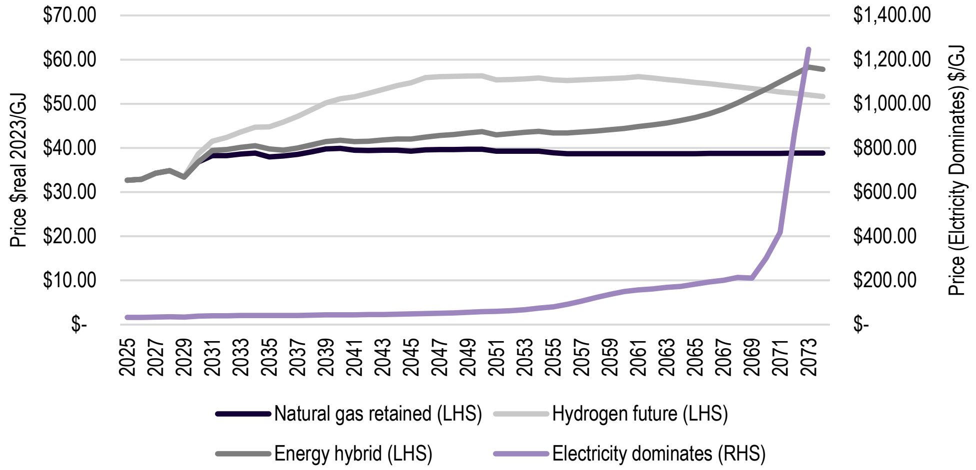
The tilt function approach reduces asset stranding risk by 'tilting' the rate of depreciation to be used in the earlier years upwards (higher than the straight line rate). The FOGM is a fifty-year model (2025-2074). However, many of the existing ATCO assets have asset lives of longer than 50 years, and some of the projected new assets have lives that go beyond the modelled end date. Therefore, the accelerated depreciation function does not entirely remove asset stranding risk as depreciation in the later years is tilted below the straight line rate, and residual asset values exist in all scenarios. However, the asset-stranding risk is reduced by bringing forward depreciation.

Application of a price cap

The model allows a retail price cap to be applied as a multiple of the 2029 retail gas price. In scenarios where customer numbers and demand decline significantly, gas distribution tariffs and retail prices rise to unreasonable levels. Applying a gas retail price cap overcomes this; the gas retail price cap constrains the gas distribution tariffs.

Figure 4.5 below shows the annual calculated B3 retail tariffs for each scenario (tariffs are set to recover simulated approved revenue in each year fully). The Electricity Dominates tariff rises to $1,246/GJ in 2073 on meagre customer numbers and demand. It is scaled to the right-hand side to allow the remaining tariff details to be observed. The Hydrogen Future B3 tariff rises to $56.32/GJ in 2050 before moderating as customer numbers grow with hydrogen becoming competitive with electricity. The Energy Hybrid tariff increases to $59.35/GJ in 2074 as customers are simulated to switch in large numbers to electricity. The Natural Gas Retained tariff remains flat at around $38/GJ.

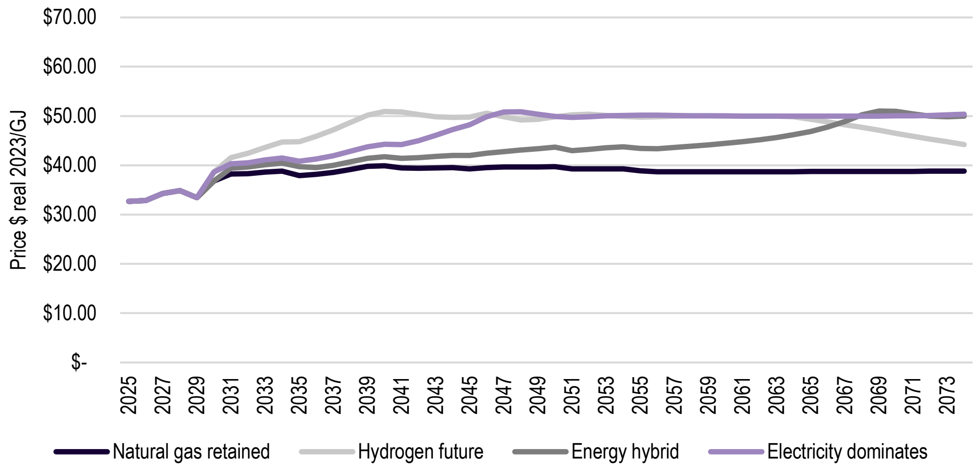
Figure 4.5 Uncapped B3 tariff retail prices – straight line depreciation



Source: FOGM

The above tariff rises become implausible when considering customer willingness to pay. Therefore, ACIL Allen has proposed a price cap of 1.5 times the 2029 gas retail tariff for residential customers as a realistic upper limit that gas retailers could charge B3 tariff customers. Where straight-line depreciation is applied, the price cap is $50.12. This rises slightly to $52.40 where accelerated depreciation is applied with a tilt-value of 0.02.[4] The effect of the price cap is shown in Figure 4.6, with Hydrogen Future, Energy Hybrid and Electricity Dominates, all being affected at various points in time by the price cap. The price cap reduces ATCO's ability to recover required revenues, especially when customer numbers and demand decline catastrophically. In some scenarios, the price cap slightly slows the rate of customer switching. This is especially noticeable in the Hydrogen Future scenario, where the price cap binds from around 2040.

Figure 4.6 Capped B3 tariff retail prices – straight line depreciation



Note: B3 retail gas tariffs capped at 1.5 times the 2029 tariff (price capped at $50.12/GJ)
Source: FOGM

The results shown in Chapter 5 include a price cap of 1.5 times the projected 2029 retail gas tariff.

4 The bringing forward of depreciation results in an increase in the 2029 gas retail tariff to accommodate the higher depreciation charge. The effect of the small differences in the price cap is not material in the analysis.

4.2 Model input assumptions

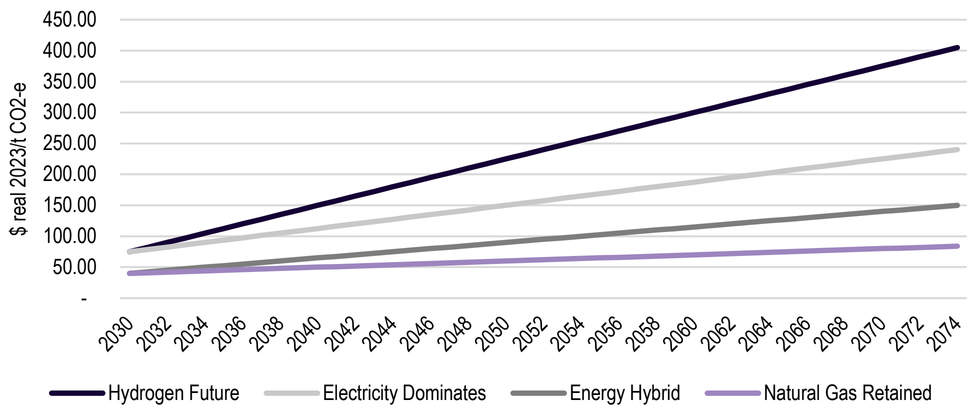
This section describes the main input assumptions used in the modelling process. All dollars are real 2023 dollars unless otherwise stated.

4.2.1 Carbon price

The carbon price assumptions are contained in Figure 4.7. Carbon prices in all scenarios are assumed to escalate at different liner rates. Under the Hydrogen Future and Electricity Dominates scenarios, the carbon price starts at AUD 75 per tonne CO_2-e in 2030. Under the Energy Hybrid and Natural Gas Retained scenarios, the carbon price starts at AUD 40 per tonne of CO_2-e in 2030. Under the Hydrogen Future scenario, the carbon price escalates to AUD 150 per tonne CO_2-e by 2040, reaching AUD 405 per tonne CO_2-e in 2074. This carbon price is the highest assumed price for the four scenarios and thus provides the highest uplift to gas prices. This high price assumption represents the 'significant acceleration in carbon abatement policy' domestically and internationally, which is also assumed under this scenario.

The next most aggressive scenario in terms of the carbon price is the Electricity Dominates scenario, where the price of carbon reaches AUD 113 per tonne CO_2-e by 2040 and AUD 240 per tonne CO_2-e by 2074. This is followed by the Energy Hybrid scenario, which reaches 65 AUD per tonne CO_2-e by 2040 and AUD 150 per tonne CO_2-e by 2074. The Natural Gas scenario shows the smallest increase in the carbon price at AUD 50 per tonne CO_2-e in 2040 and AUD 84 per tonne CO_2-e by 2074.

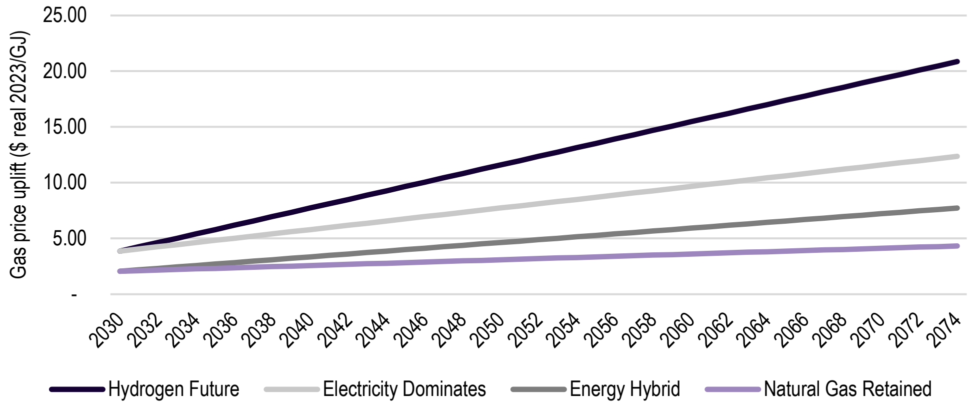
Figure 4.7 Projected carbon price



Source: ACIL Allen

The impact of the projected carbon prices on the projected uplift in gas prices is shown in Figure 4.8 below. Under the Hydrogen Future scenario, the gas price increases by $7.73 per GJ by 2040. This increase is followed by $5.80 per GJ for Electricity Dominates, $3.35 per GJ for Energy Hybrid and $2.58 per GJ for Natural Gas Retained.

Figure 4.8 Projected gas price uplift

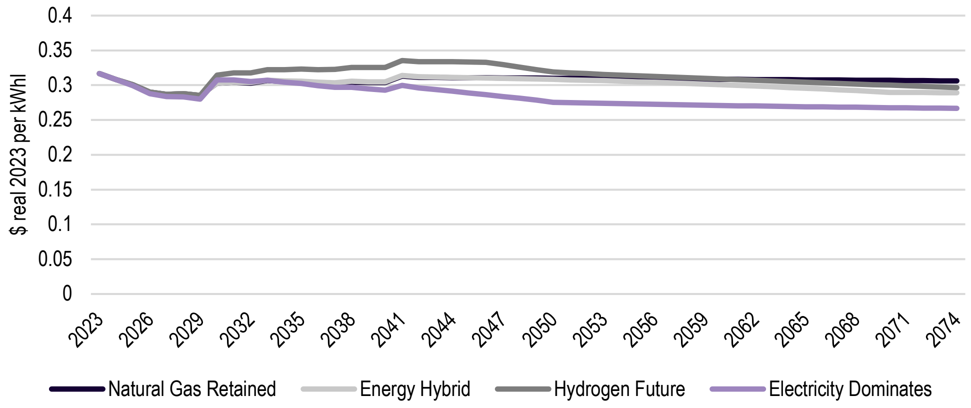


Source: ACIL Allen

4.2.2 Electricity prices

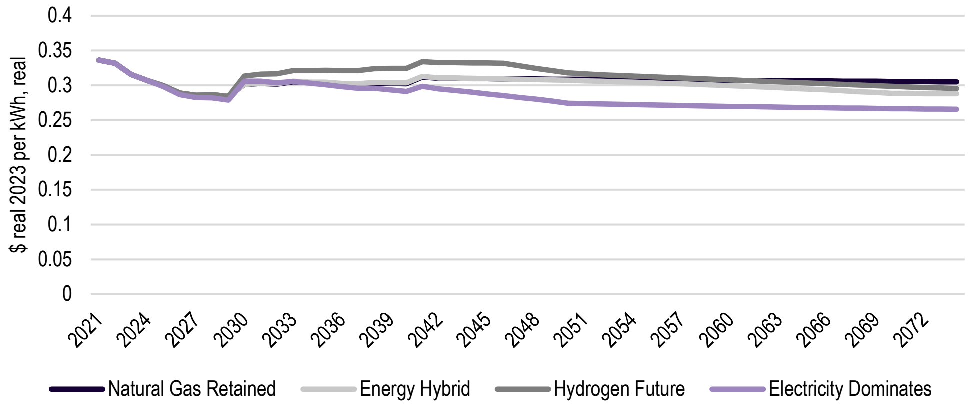
Projected retail electricity prices are shown in Figure 4.9 and Figure 4.10 below. The path of electricity prices differs across the four scenarios. Under the Hydrogen Future scenario, electricity prices rise consistently from 2029 onwards before peaking at $0. 34 per kWh in 2041. Prices then decline steadily after 2041. Under the Electricity Dominates scenario, electricity prices peak at $0.30 per kWh in 2041 before declining to $0.276 per kWh by 2050. They continue to decline steadily for the remainder of the projection period. The projected price paths for Energy Hybrid and Natural Gas Retained are similar up to 2045, after which Energy Hybrid commences a more rapid decline in electricity prices relative to the Natural Gas Retained scenario.

Figure 4.9 Projected electricity prices, residential



Source: ACIL Allen

Figure 4.10 Projected electricity prices, commercial



Source: ACIL Allen

4.2.3 Gas prices

The gas price is a likely driver of gas consumption. The responsiveness of consumption to changes in price is known as the price elasticity of demand. The degree of responsiveness is thought to differ considerably across customer classes. Residential customers are generally less responsive to price changes than non-residential customers because energy costs comprise a more significant proportion of the total expenditures for non-residential customers. Therefore, price increases might lead to adaptive behaviour designed to reduce consumption/demand and costs.

For example, higher gas prices would be expected to reduce gas consumption by incentivising customers to become more energy efficient or switching appliances away from gas to electricity.

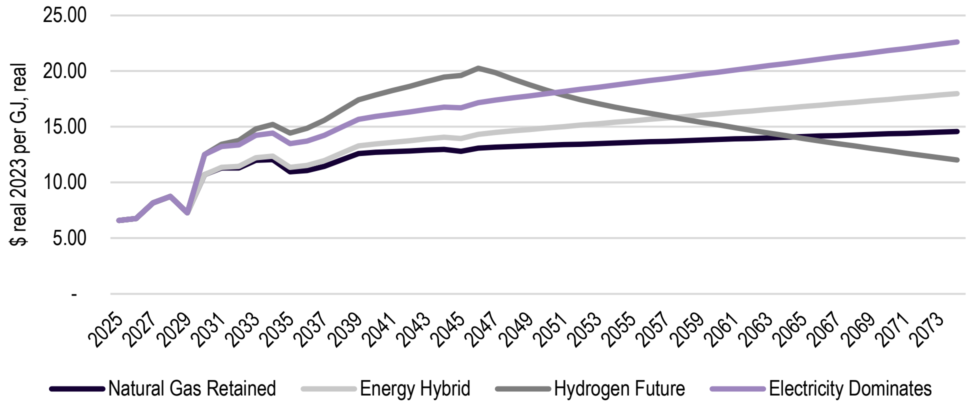
ACIL Allen forecasts gas prices using a bottom-up approach. Gas prices are broken into five components:

1. Wholesale market prices using ACIL Allen's proprietary GasMark model
2. Transmission costs
3. Distribution costs
4. Environmental policy
5. Retail margins

Our projections of wholesale gas prices are shown in Figure 4.11 below.

The wholesale price of gas follows a similar upward trajectory for all four scenarios, reaching $12.52 per GJ by 2030. After 2030, wholesale gas prices diverge across the four scenarios. Under the Energy Hybrid and Natural Gas Retained scenarios, the price peaks at $15.03 per GJ and $14.25 per GJ, respectively. Under the Hydrogen Future scenario, the wholesale price of gas peaks at $20.21 per GJ in 2046. Under this scenario, wholesale gas prices take a different path, declining consistently after 2046. Gas prices under this scenario are assumed to escalate initially due to the uplift in carbon prices and then moderate through the shift to competitively priced green hydrogen.

Figure 4.11 Wholesale price of gas



Source: ACIL Allen

Retail gas prices are input to the FOGM as a building block made up of:

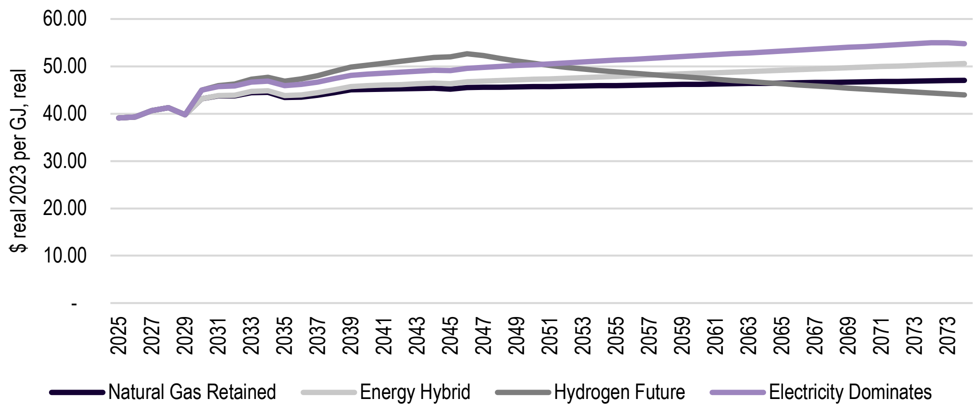
- wholesale gas prices
- fixed and variable gas distribution prices
- gas transmission prices
- retail margin.

Gas prices vary across the scenarios with:

- changes in wholesale gas prices (incorporating carbon penalty price and hydrogen price assumptions
- changes in gas distribution prices derived by the FOGM under different scenarios and rates of depreciation.

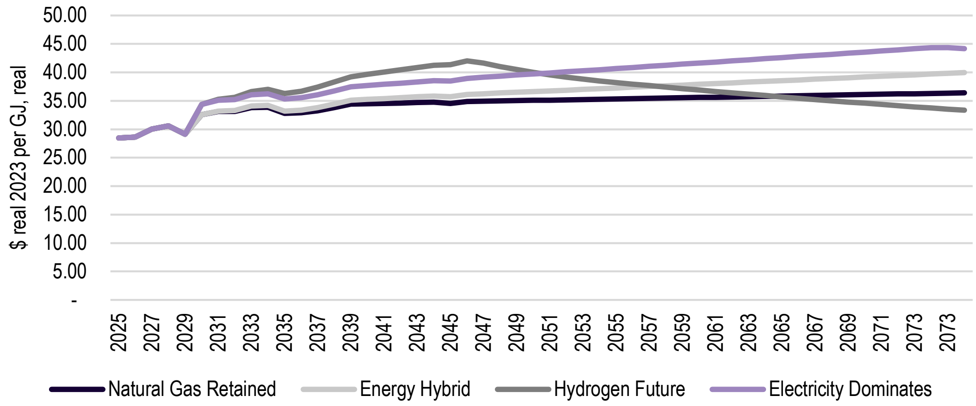
Projected retail gas prices for the four scenarios used as inputs are presented for illustrative purposes in $/GJ in Figure 4.12 and Figure 4.13. Fixed costs are converted to variable costs using an average consumption rate for residential and commercial customers. The prices presented assume constant real distribution tariffs over time. The figures closely resemble the wholesale price figure shown above, as the main driver of the differences across the 4 scenarios in the retail gas prices is the wholesale gas price.

Figure 4.12 Retail price of gas, residential



Source: ACIL Allen

Figure 4.13 Retail price of gas, commercial

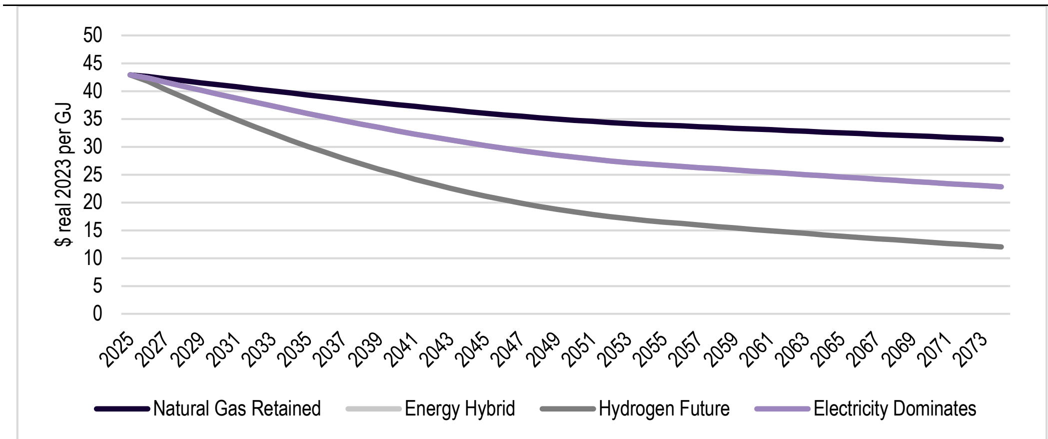


Source: ACIL Allen

4.2.4 Hydrogen Prices

The cost of green hydrogen is assumed to start at $43 per GJ in 2025 and gradually decrease over time as per AEMO projections (see Figure 4.14). Under the Hydrogen Future scenario, hydrogen prices are assumed to decline to $18 per GJ by 2050. Under the Energy Hybrid and Electricity Dominates scenarios, the price of hydrogen is projected to be $28 per GJ by 2050, while under the Natural Gas retained scenario, it is projected to be $35 per GJ. Wholesale and reticulated gas is taken to switch to 100 per cent green hydrogen by 2033.

Figure 4.14 Projected hydrogen prices



Source: AEMO

4.2.5 Appliance energy consumption

The assumed average energy consumption for each appliance type is shown in Table 4.1 below.

Table 4.1 Average assumed annual appliance energy consumption

	Average Consumption
Cooking	
Electric cooktop (induction) kWh	133.60
Gas stove (GJ)	1.01
Hot water	
Heat pump hot water (kWh)	1,285
Gas instant hot water (GJ)	13.6
Room heating	
RCAC split system (kWh)	361.25
Gas wall furnace (GJ)	3.83
Ducted heating	
Ducted RCAC (kWh)	952.00
Ducted gas heating (GJ)	10.08

Source: ATCO Gas and the Grattan Institute

The gas cooking, hot water and room heating usage numbers were obtained from internal ATCO Gas analysis. The gas ducted heating number was estimated as the difference between Grattan Institute's estimate of gas usage for a 3 appliance household (24.7 GJ) in Perth and ATCOs estimate of gas hot water and cooking usage (see "Flame Out: The Future of Natural Gas", November 2020 by Tony Wood and Guy Dundas).

The equivalent electric appliance usage was derived after accounting for heat loss and efficiency gains from switching to electric appliances.

4.2.6 Appliance capital costs

Appliance capital costs were obtained from Appendix D of the Grattan Institute publication "Flame Out: The Future of Natural Gas", November 2020 by Tony Wood and Guy Dundas. They have been adjusted for the rate of inflation.

Table 4.2 Appliance capital costs ($real 2023)

	Appliance cost
Cooking	
Electric cooktop (induction)	3255
Gas stove	2357
Hot water	
Heat pump hot water	3479
Gas instant hot water	1571
Room heating	
RCAC split system	2469
Gas wall furnace	1961
Ducted heating	
Ducted RCAC	12064
Ducted gas heating	5097

Source: Grattan Institute (adjusted for inflation)

4.2.7 Appliance maintenance costs

Maintenance cost data was obtained from the report "Are we still cooking with gas" produced by the ATA for the Consumer Advocacy Panel in November 2014. The numbers have been adjusted for the rate of inflation.

Table 4.3 Appliance annual maintenance costs (real $2023)

	Annual maintenance cost
Cooking	
Electric cooktop (induction)	0
Gas stove	3
Hot water	
Heat pump hot water	62
Gas instant hot water	46
Room heating	
RCAC split system	42
Gas wall furnace	37
Ducted heating	
Ducted RCAC	41
Ducted gas heating	97

Source: ATA, Are we still cooking with gas, November 2014

4.2.8 Appliance usage efficiency

Appliance usage efficiency is assumed to remain unchanged over the course of the forecast period.

4.2.9 Customer discount rates

The customer discount rates reflect how forward-looking or myopic customers are when evaluating the decision to switch from gas to electric appliances. High-income and commercial customers are assumed to look further into the future when making decisions. Rates were chosen based on judgement. There is some (not much) international evidence which suggests that consumers tend to have high discount rates when making appliance choices.

Table 4.4 Assumed customer discount rates by income class

Customer discount rates	Percent
High income	5%
Medium income	10%
Low income	15%
Commercial customers	3%

Source: ACIL Allen

4.2.10 High, medium and low-income class assumptions

LGAs with medium total household income (as measured by the ABS in the 2021 Census) of more than $2,000 were classified as high income. LGAs with a median household income of $1,700 or less were classified as low income. Those between $1,700 and $2,000 weekly were classified as medium income.

Table 4.5 Share of high, medium and low-income households in the gas distribution network

Income level	Percentage of households
Low income	17.1%
Medium income	62.1%
High income	20.8%

Source: ACIL Allen analysis of ABS 2021 Census data

4.2.11 Non-appliance cost-related rates of connection and disconnection

The non-appliance cost rate of connection and disconnection are calculated based on the historical rates of connection and disconnection to the gas distribution network before any significant changes to the attractiveness of switching take place in the model. They capture the fact that customers connect and disconnect irrespective of their relative attractiveness.

Table 4.6 Non-appliance cost rate of connection and disconnection

	Residential	Commercial
Non-Appliance Cost-Related Growth	1.57%	1.90%
Non-Appliance Cost-Related Disconnections	0.38%	0.40%

Source: ACIL Allen based on ATCO data

4.2.12 Price elasticities of demand for usage per customer

As real gas prices increase, the usage per customer declines. For example, a 1% increase in the real retail price of gas results in a 0.25% decline in the average usage per customer. Commercial and industrial customers are assumed to be more price-elastic than residential customers. Demand is considered to be price inelastic, which is a realistic assumption. This is supported by a significant body of academic empirical evidence and our experience in estimating price elasticities for electric, gas and water utilities in Australia.

Table 4.7 Price elasticity of demand by tariff

Elasticities	Residential B3	Commercial B2	Commercial B1	Industrial A1	Industrial A2
Gas price	-0.250	-0.300	-0.300	-0.370	-0.400
Electricity price	0.100	0.100	0.100	0.100	0.100

Source: ACIL Allen

4.2.13 Trend in usage per customer over time

Analysis of ATCOs per usage data shows a downward trend in usage per customer over time for most tariff classes. These trends were estimated and projected into the forecast period.

Table 4.8 Annual trend change in usage per customer by tariff class

Change per annum (GJ)	Residential B3	Commercial B2	Commercial B1	Industrial A1	Industrial A2
Trend change in usage per customer (GJ)	-0.100	-1.000	-13.220	1529.183	-88.803

Source: ACIL Allen analysis of ATCO data

Residential usage per customer is assumed to decline by 0.1 GJ per annum in the forecast period, while commercial B2 is assumed to decline by 1 GJ per annum. Commercial B1 declines by 13.2 GJ per annum. Industrial A1 increases by 1529 GJ per annum.

These trend rates are assumed to decay by 5% per year over the forecast period for all scenarios except under Electricity Dominates, where no decay rate is applied. This assumption limits the decline (or increase in the case of A1) of gas usage per customer to reasonable levels over the very long projection period.

4.2.14 Decision rule for switching decision

A customer is assumed to face a switching decision when their appliances are 15 years old. As at 2024, we assume that the distribution of appliance ages in the ATCO network follows a uniform distribution between zero and 15 years of age. This distribution then changes over time as new customers connect, existing customers reconnect, and existing customers disconnect.

4.2.15 Gas disconnection and Electricity upgrade costs

The cost of disconnecting from gas is assumed to be $898. The cost of upgrading an electricity connection to switch away from gas appliances is assumed to be $3367. These figures are derived from the Grattan Institute estimates made in 2020 and adjusted for movements in the CPI (see Appendix D of “Flame Out: The Future of Natural Gas”, November 2020 by Tony Wood and Guy Dundas.

4.2.16 Appliance rebates across scenarios

Appliance rebates are assumed to commence from 2041 onwards for the Energy Hybrid and Electricity Dominates scenarios. No rebates are paid under the Natural Gas Retained and Hydrogen Future scenarios.

Table 4.9 Appliance rebates per appliance $ per appliance (real $2023)

	Cooktops	Hot water	Room heating
Natural Gas Retained	0	0	0
Energy Hybrid	40.63	43.75	31.25
Hydrogen Future	0	0	0
Electricity Dominates	162.5	175	125

Source: ACIL Allen

4.2.17 Ban on new connections

Under the Electricity Dominates scenario, it is assumed that new connections are banned from 2040 onwards.

5 Modelling results

This chapter sets out the results by applying the methodology through the FOGM, as described in the previous section.

Specifically, under the four scenarios we present:

— Gas volumes and customer numbers
— Closing Regulatory Asset Base (RAB)
— Capital expenditure over the modelled period
— Depreciation (including brought-forward depreciation)
— The average impact of the proposed brought forward depreciation on average tariffs and annual customer bills by customer class.

5.1 Modelling parameters

The following sections describe the choice of modelling parameters used in the analysis. These parameters are set on the "Dashboard" worksheet in the FOGM.

5.1.1 Tilt-value

The accelerated depreciation function in the FOGM is driven by the tilt function (discussed in section 4.1.3 above). ACIL Allen recommends that ATCO use a tilt-value of 0.02 for reasons set out in section 5.3 below. Various simulated results for straight-line depreciation and accelerated depreciation are compared below. The recommended accelerated depreciation results are based on the 0.02 tilt-value.

5.1.2 Price cap

The price cap in the assessment was set to 1.5 times. The price cap applies to the 2029 B3 retail tariff in each scenario/sensitivity.

5.1.3 Operating expenditure reduction factor

The Opex reduction factor was set to number per 1000 connections provided by ATCO. ATCO will provide this number to the ERA separately. ATCO incorporated this functionality into the FOGM, reducing operating costs if the customer base falls compared with the Base Case.

5.1.4 Capital expenditure cost reduction trigger

The Capital Expenditure, "Cost reduction trigger", was set to minus 40,000 customers. ATCO incorporated this functionality into the FOGM, and it reduces capital costs if the customer base falls more than the trigger compared with the Base Case.

5.1.5 Deduct OPEX and CAPEX reduction?

The checkbox was ticked. ATCO incorporated this functionality into the FOGM. It activates the Opex reduction factor, and the Capex Cost reduction trigger when ticked.

5.1.6 Accelerated depreciation start year and end year

The accelerated depreciation start year and end year were set to 2025 and 2074 for the tilt depreciation function for both the Existing RAB and Capex.

5.2 Volume and Customer Numbers

5.2.1 Straight line depreciation

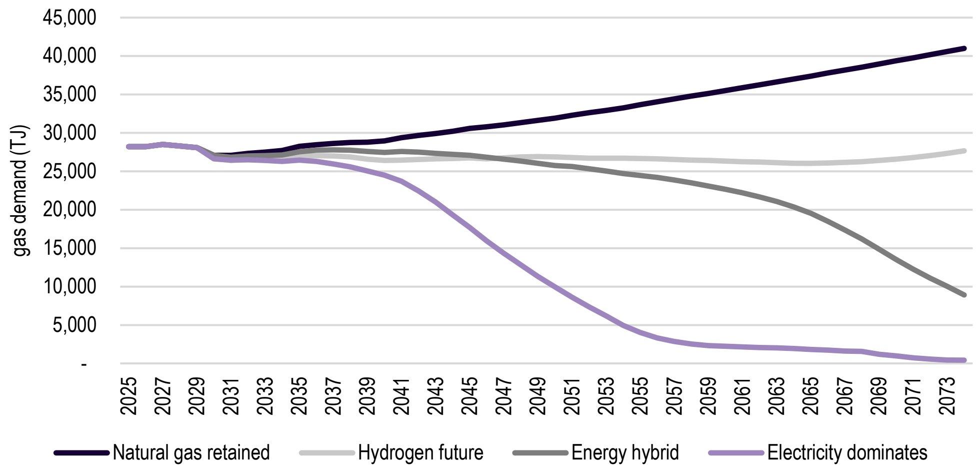
The gas volume paths under the four scenarios over the forecast period are shown in Figure 5.1, where straight-line depreciation is applied.

Gas demand in the Electricity Dominates and Energy Hybrid scenarios is simulated to decline to levels where asset stranding risk is very high and significant, respectively. Gas demand in the Electricity Dominates scenario reaches negligible levels by around 2070. In the Energy Hybrid scenario, gas demand commences declining terminally from around 2060.

In the Hydrogen Future scenario, gas demand remains stable until around 2066 and grows slightly afterwards.

In the Natural Gas Retained scenario, gas demand is simulated to rise over the modelling period after a gradual decline to 2032. By the end of the modelling period, gas demand is around 45 per cent higher in the Natural Gas Retained Scenario than projected demand in 2025.

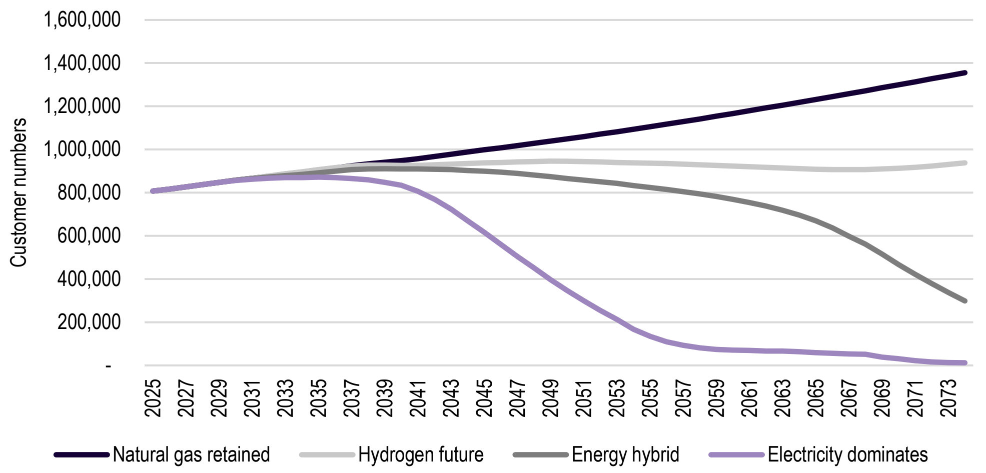
Figure 5.1 Projected gas demand, Terajoules – straight line depreciation



Source: ACIL Allen

A similar pattern to Figure 5.1 can be seen in the projected customer numbers for all four scenarios (see Figure 5.2). Under the Natural Gas Retained scenario, total customers are projected to reach 1.36 million in 2074, a growth rate of 1.04 per cent annually. For Hydrogen Future, customer numbers are projected to increase to around 938 thousand by 2074. In the case of Energy Hybrid and Electricity Dominates, customer numbers are simulated to fall to around 299 thousand and 12 thousand, respectively, by 2074. In the Energy Hybrid scenario, the viability of the network is at risk in 2074. In the Electricity Dominates scenario, the network would no longer be viable in 2074, given the low customer numbers and demand.

Figure 5.2 Projected customer numbers – straight line depreciation



Source: ACIL Allen

5.2.2 Accelerated depreciation

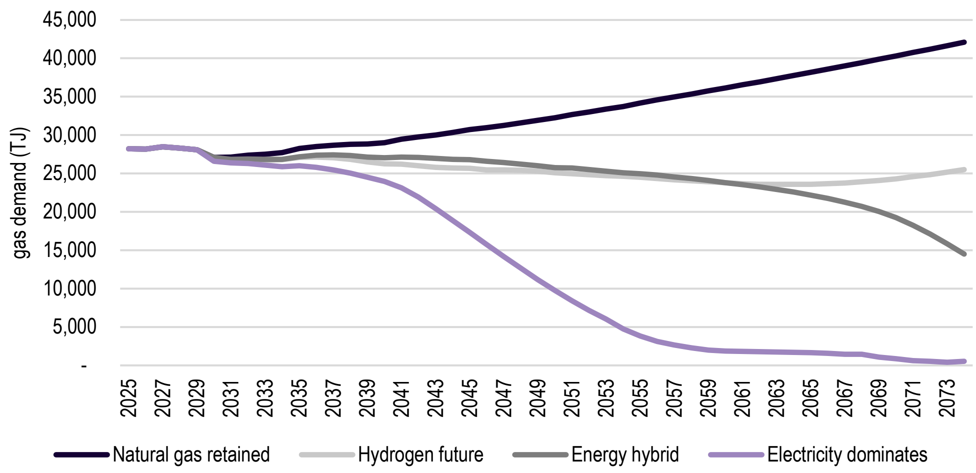
The gas volume paths under the four scenarios over the forecast period are shown in Figure 5.3, where accelerated depreciation with a tilt of 0.02 is applied.

Gas demand declines in the Electricity Dominates and Energy Hybrid scenarios. The rate of decline using accelerated depreciation is slower for the Energy Hybrid Scenario than straight-line depreciation. The point at which gas demand commences to decline terminally is delayed by around five years to 2065. There is no significant difference in the rate of decline for the Electricity Dominates scenario. Gas demand in the Electricity Dominates scenario reaches negligible levels by around 2070.

In the Hydrogen Future scenario, gas demand remains stable mainly with a slight uptick from around 2065(as hydrogen becomes competitive with electricity), but slightly lower than where straight-line depreciation is applied.

In the Natural Gas retained scenario, gas demand grows linearly from around 2032 to around 49 per cent higher than demand in 2025. This is slightly higher than when applying straight-line depreciation.

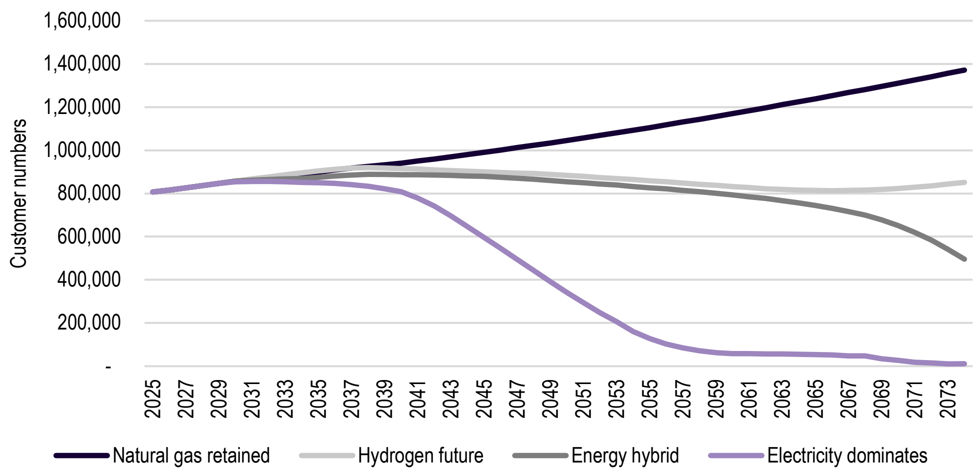
Figure 5.3 Projected gas demand, Terajoules – accelerated depreciation



Source: ACIL Allen

A similar pattern to Figure 5.3 can be seen in the projected customer numbers for all four scenarios (see Figure 5.4). Under the Natural Gas Retained scenario, the total number of customers is projected to reach 1.37 million in 2074, a growth rate of 1.08 per cent annually. For Hydrogen Future, customer numbers are projected to end the modelling period at around 851 thousand. In the case of Energy Hybrid and Electricity Dominates, customer numbers are simulated to fall to around 496 thousand and 15 thousand, respectively, by 2074. As noted in section 5.2.1 above, in the case of Electricity Dominates, the network would no longer be viable in 2074 with such low customer numbers and demand.

Figure 5.4 Projected customer numbers – accelerated depreciation



Source: ACIL Allen

5.3 Stranded asset risk

The approach to assessing and recommending acceleration of depreciation is set out below. For each scenario:

— ATCO developed Capex programs that are consistent with the different scenario characteristics.

- An additional Capex reduction factor is applied where the annual customer base reduction exceeds a user-entered amount (-40,000 is used in the analysis – recommended by ATCO).
- Straight-line depreciation was calculated based on remaining asset lives for existing and new assets (The tilt function is turned off).
- Accelerated depreciation (tilt function turned on) was calculated for tilt-values between 0.01 and 0.05.
- The resulting straight line and accelerated depreciation residual RABs in 2074 are compared to determine the effect of the selected tilt-value.
- ACIL Allen recommended a tilt-value and amount of brought forward depreciation to be applied by considering the near-term impact on consumers and ATCO's residual asset stranding risk.

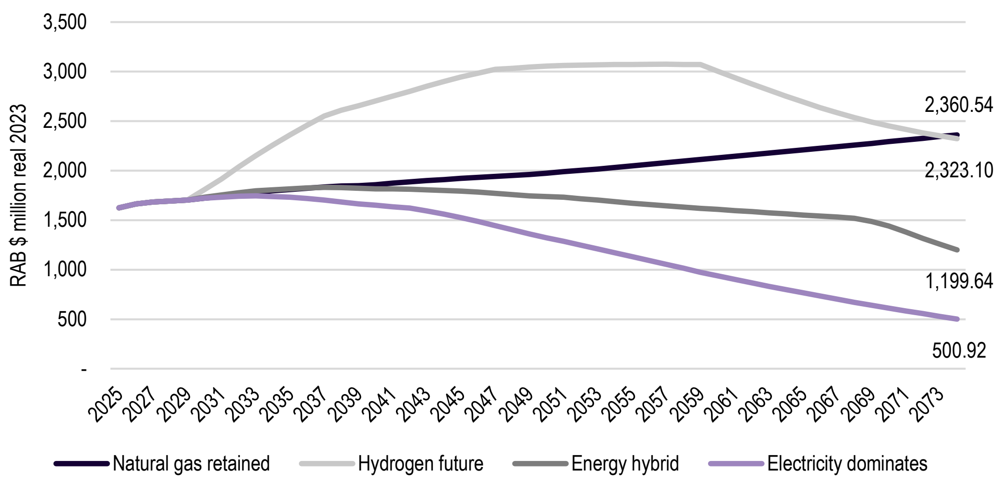
5.3.1 Straight line depreciation

Figure 5.5 below shows each scenario's simulated RAB (closing) trajectories under straight-line depreciation. The Natural Gas Retained scenario grows consistently to 2074. This is consistent with a growing customer base and the business remaining viable over the long term. The Hydrogen Future scenario shows a rise in RAB to 2047, stabilisation of the RAB until 2059, and then a gradual fall in the RAB to 2074, which is a little below that for the Natural Gas Retained scenario. The Hydrogen Future trajectory is consistent with higher capital investment from 2030 to 2059 as the ATCO gas distribution network is converted to operate on hydrogen.

The RAB trajectory in the Energy Hybrid scenario declines slowly from 2038 to 2068. The decline accelerates, with a residual RAB of $1.2 billion in 2074 on a rapidly declining customer base.

The RAB trajectory in the Electricity Dominates scenario declines from 2033 and accelerates from 2043. The residual RAB in 2074 is $515 million on a negligible customer base.

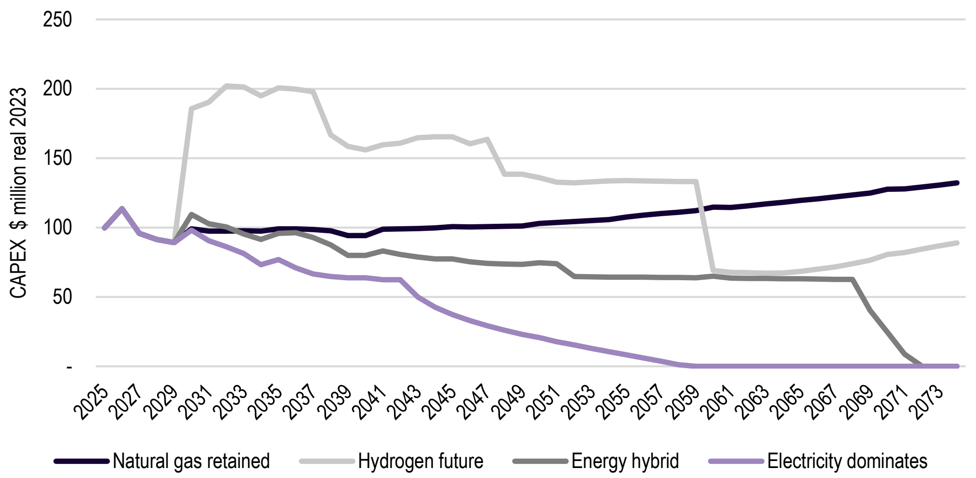
Figure 5.5 RAB trajectories for each scenario – straight-line depreciation



Source: FOGM

The Capex profiles are adjusted for the different circumstances of each scenario, as shown in Figure 5.6 below. The Natural Gas retained scenario has a linear profile reflecting the ongoing sustainable nature of the business under that scenario. The Hydrogen Future scenario has a large increase between 2030 and 2059, consistent with conversion to transporting hydrogen. The Energy Hybrid scenario gradually declines as customers gradually disconnect and then falls to zero from 2072 as the gas distribution business falls into terminal decline. The Electricity Dominates scenario has a faster decline associated with a higher rate of customer disconnections, with Capex falling to zero from 2063.

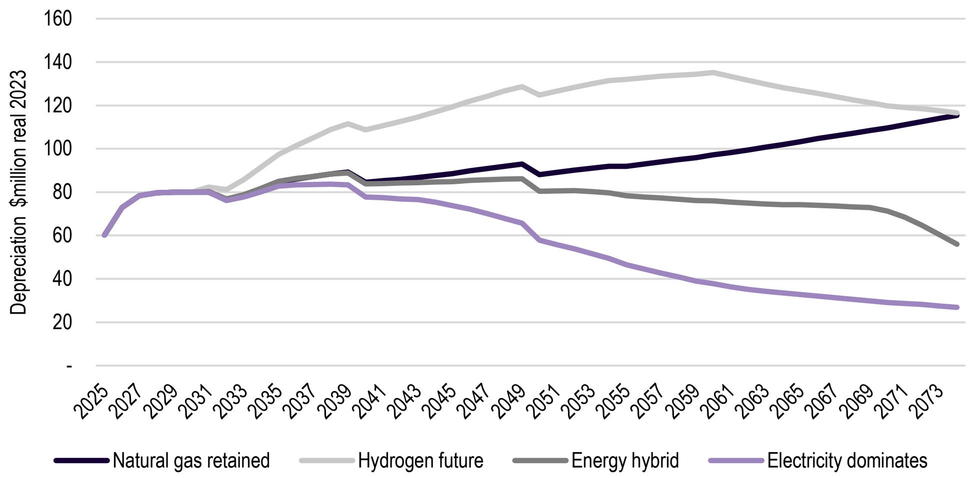
Figure 5.6 Capex profile for each scenario – straight-line depreciation



Source: FOGM

The depreciation schedule for each scenario is shown in Figure 5.7 below. The profile of each schedule is linked to the growth or decline in the customer base, and in the case of Hydrogen Future, the large increase in Capex between 2030 and 2059. Depreciation between 2025 and 2029 is the same for all scenarios, as there is no simulated demand or projected Capex difference over that period.

Figure 5.7 Depreciation profile for each scenario – straight line depreciation



Source: FOGM

5.3.2 Risk assessment

Asset stranding risk is affected by several factors:

— The starting RAB value at the point in time that the risk is considered.

— The rate at which the asset base is depreciated.

— The amount of capital to be invested and the profile of the investment

— Upper limits on the amount of revenue that can be collected because of existing customers disconnecting and switching to electricity and potential customers choosing electricity over gas.

ATCO is faced with the dilemma of needing to maintain and invest in the gas distribution network to ensure a reliable gas supply to existing and potential future customers while facing the risk that existing customers may disconnect and future customers may choose not to connect.

Asset stranding is likely if a scenario occurs in which customers decline faster than ATCO can recover its invested capital (via depreciation charges). Conceptually, customers will choose to disconnect or not connect when the life cycle costs of using electricity over gas are lower. Practically, customer preferences vary, with early adopters willing to choose electricity when it is not necessarily cheaper and lethargic late adopters willing to continue using it, even when remaining on it is more expensive. There is a range of factors in the decisions of individual customers, which may include:

— Underlying preferences for the use of gas over electricity or vice versa.

— The availability of information and the ability to undertake a cost assessment of options.

— Split incentives for renters (landlord pays the capital but not the operating costs).

— The capacity to access capital to switch to electricity.

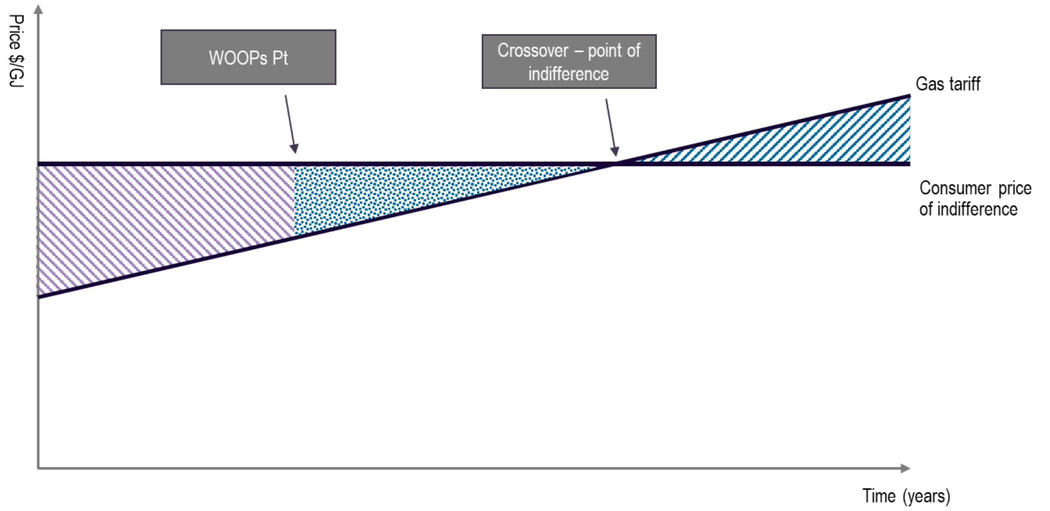
Therefore, the FOGM uses S-curves to reflect variations in consumer behaviour when the decision to switch or connect is required.

In scenarios where customers disconnect or choose not to connect, the remaining smaller customer base faces higher charges as operating costs and the fixed costs associated with the return to capital (cost of capital) and return of capital (depreciation) are spread over a smaller customer base and smaller volume of gas. Operating costs and future Capex would be expected to fall in such scenarios, but the existing sunk capital costs (the existing RAB) cannot be undone. At some point, revenues that can be recovered will be insufficient to cover all fixed and variable costs. This is referred to as the point of indifference in Figure 5.8 below. Fixed costs not recovered beyond the point of indifference are stranded.

Window of Opportunity Past

The solution to avoiding stranding of the fixed costs is to bring forward the costs (depreciation) ahead of the point of indifference, where there is some headroom between underlying costs and the point of indifference. The last point at which costs must be brought forward to avoid stranding of costs is the Window of Opportunity Past point, or WOOPs point.

Figure 5.8 Window of Opportunity Past point



Source:

Where the future is known with 100% certainty, bringing forward depreciation costs could be left to the last point (the WOOPs point). However, the future is uncertain, and where asset stranding risk is plausible, acting earlier has two advantages:

1. It reduces the risk of asset stranding where the timing of the WOOPs point is uncertain.
2. The brought forward depreciation costs can be spread over a more extensive period and avoid a more significant step up in costs (and gas tariffs) when the WOOPs point is reached.

Simulated scenarios

The Electricity Dominates and Energy Hybrid scenarios simulate a terminal decline in customer bases and high asset stranding risk. The Hydrogen Future and Natural Gas Retained scenarios simulate maintenance or solid customer base growth and little asset-stranding risk over the next fifty years.

Table 5.1 below shows the residual closing RAB value in 2074 for each scenario under a straight line and accelerated depreciation using tilt-values of 0.01 to 0.05. None of the assessed depreciation options removes the risk for the two scenarios with high asset stranding risk. However, the asset stranding risk reduces as the tilt-value increases (bringing forward more depreciation).

The residual RAB under straight-line depreciation represents the stranded asset risk under the traditional approach to depreciating assets. Under this depreciation approach, stranded asset risk is $515.5 million for the Electricity Dominates scenario and $1,200 million for the Energy Hybrid scenario (although a small portion of the residual RAB in the Energy Hybrid scenario may be depreciated after 2074 before the customer base disappears).

Applying accelerated depreciation with a low tilt-value of 0.01 reduces the stranded asset risk by $122 million and $106 million for the Energy Hybrid and Electricity Dominates scenarios, respectively. If a tilt-value of 0.05 is used, stranded asset risk is reduced by $365 million and $374 million, respectively.

Table 5.1 Residual RAB values ($ million real 2023) in 2074 for straight line and accelerated depreciation (tilt-values of 0.01 to 0.05)

Depreciation	Natural gas retained	Hydrogen future	Energy hybrid	Electricity dominates
Straight line	2,360.54	2,323.10	1,199.64	500.92
Accelerated – tilt-value of 0.01	2,191.08	2,027.64	1,079.60	396.50
Accelerated – tilt-value of 0.02	2,018.34	1,790.55	1,067.56	310.90
Accelerated – tilt-value of 0.03	1,837.86	1,589.66	1,040.43	238.02
Accelerated – tilt-value of 0.04	1,661.24	1,415.61	934.30	178.99
Accelerated – tilt-value of 0.05	1,481.76	1,481.76	846.91	132.93

Source: FOGM

The final choice of tilt-value and, therefore, the amount of brought forward depreciation is a matter of judgment, trading off reduction in stranded asset risk and the risk of missing the WOOPs point, with some modest short-term increases in consumer costs. Therefore, an element of judgement needs to be applied when settling on the final approach. However, two of the four scenarios demonstrate significant asset stranding risk.

ACIL Allen considers the case has been made to allow some acceleration of depreciation to mitigate the asset stranding risk. There is no right amount to be allowed. Faster acceleration can be allowed during AA7 and beyond if it is too little. Similarly, if it is too much, the rate of acceleration can be reduced in future regulatory cycles. In this sense, allowing some acceleration of depreciation in the current period can be considered an option to avoid stranded asset risk in the future, which can be adjusted as further information becomes available.

Recommended accelerated depreciation

ACIL Allen considers using a tilt-value of 0.02 as a reasonable trade-off in reducing asset stranding risk while resulting in relatively modest cost increases for consumers (discussed in section 5.4 below). The proposed increase in depreciation is shown in Table 5.2 below. It is noted that ATCO retains significant asset stranding risk under two scenarios after the recommended accelerated depreciation is applied.

Table 5.2 Recommended brought forward depreciation: 2025 – 2029 ($ million real 2023)

	2025	2026	2027	2028	2029
	2025	**2026**	**2027**	**2028**	**2029**
Brought forward depreciation	24.87	17.03	16.49	14.19	14.65

Source: FOGM

5.4 Impact on consumers

The proposed bringing forward of depreciation will result in an increase in cost to gas consumers. The cost increases (average by customer class) are set out below.

Table 5.3 shows the brought-forward depreciation costs allocated to each customer class from 2025 to 2029. The percentage allocation by customer class was determined by ATCO and is included in the FOGM. More than 80 per cent of costs are allocated to residential customers (B3).

Table 5.3 Allocation of brought forward depreciation costs ($ million real 2023) to customer classes: 2025 – 2029

Customer class	% Allocation by class	2025	2026	2027	2028	2029
Total	100%	24.87	17.03	16.49	14.19	14.65
Industrial A1	3.39%	0.84	0.58	0.56	0.48	0.50
Industrial A2	2.65%	0.66	0.45	0.44	0.38	0.39
Commercial B1	5.72%	1.42	0.97	0.94	0.81	0.84
Commercial B2	5.37%	1.34	0.91	0.89	0.76	0.79
Residential B3	82.87%	20.61	14.11	13.67	11.76	12.14

Source: FOGM, ATCO and ACIL Allen analysis

Table 5.4 shows the customers in each customer class from 2025 to 2029.

Table 5.4 Customer numbers by customer class: 2025 – 2029

Customer class	**2025**	**2026**	**2027**	**2028**	**2029**
Industrial A1	70	68	68	68	68
Industrial A2	104	103	103	103	103
Commercial B1	2,120	2,170	2,222	2,275	2,330
Commercial B2	13,104	13,299	13,496	13,766	14,040
Residential B3	791,959	800,769	810,484	820,622	831,004

Source: FOGM

Table 5.5 shows the annual increase in cost to customers by customer class because of the recommended depreciation brought forward from 2025 to 2029. The increase is calculated by dividing the allocated cost to each customer class in each year in Table 5.3 by the number of customers in each class in Table 5.4.

Table 5.5 Annual increase in the cost of brought forward depreciation per customer by customer class: 2025 – 2029 ($ real 2023)

Customer class	**2025**	**2026**	**2027**	**2028**	**2029**
Industrial A1	12,048	8,490	8,223	7,073	7,305
Industrial A2	6,342	4,384	4,246	3,652	3,772
Commercial B1	671	449	424	356	359
Commercial B2	102	69	66	55	56
Residential B3	26	18	17	14	15

Source: FOGM and ACIL Allen analysis

Table 5.6 shows the volume of gas delivered over the distribution network by customer class from 2025 to 2029.

Table 5.6 Volume of gas delivered to customers by customer class: 2025 – 2029 (TJ)

Customer class	2025	2026	2027	2028	2029
Industrial A1	13,178	13,379	13,877	13,855	13,821
Industrial A2	1,900	1,886	1,882	1,877	1,873
Commercial B1	2,154	2,143	2,132	2,122	2,111
Commercial B2	1,301	1,292	1,282	1,276	1,274
Residential B3	9,694	9,490	9,314	9,160	9,021

Source: FOGM

Table 5.7 shows the increase in cost per GJ of gas delivered by customer class from 2025 to 2029. The increase is calculated by dividing the allocated cost to each customer class in each year in Table 5.3 by the volume of gas consumed by each customer class in Table 5.6**.**

Table 5.7 Increase in cost ($ real 2023 per GJ) of brought forward depreciation by customer class: 2025 – 2029

Customer class	2025	2026	2027	2028	2029
Industrial A1	0.06	0.04	0.04	0.03	0.04
Industrial A2	0.35	0.24	0.23	0.20	0.21
Commercial B1	0.66	0.45	0.44	0.38	0.40
Commercial B2	1.03	0.71	0.69	0.60	0.62
Residential B3	2.13	1.49	1.47	1.28	1.35

Source: FOGM and ACIL Allen analysis

Overall, the impacts on consumers from the proposed brought-forward depreciation are modest. For B3 residential customers, the average price increase over the five years is 4.6%.

Conclusions and recommendations 6

6.1 Scenarios

6.1.1 Scenario summary

Four scenarios were developed in concert with ATCO and a group of ATCO's stakeholders:

— **Hydrogen Future** – Rapid learning rates relating to green hydrogen and renewable gas production enable these gases to displace natural gas domestically and internationally. The resulting green hydrogen industry mirrors the current natural gas and LNG industries with a broader high-volume export focus, enabling the economic servicing of a smaller domestic market.

— **Electricity Dominates** – Renewable electricity generation and storage experience a rapid reduction in cost through fast technological learning. As such, the relative cost of electricity against natural gas and renewable gases falls to such an extent that a broad-based electrification of industry and households occurs.

— **Energy Hybrid** – Technical learning rates for renewable gases and electrification develop similarly, resulting in some customers electing to electrify and some remaining on the gas network. From an economic and environmental point of view, electricity and zero emissions gases become viable alternatives for natural gas. This results in a mixed response from residential/commercial and industrial consumers, with an even split electing to follow electrification or to stick with a gas-based energy supply chain.

— **Natural Gas Retained** – global and local factors result in natural gas being retained in the ATCO network. Zero-emissions gases such as green hydrogen or renewable methane experience slow technological learning rates, which results in them generally remaining uneconomic at scale. As such, natural gas continues to be embraced as a 'transition fuel' used in large volumes globally to quickly and reliably reduce carbon emissions through coal-to-gas switching and to support/firm renewable generation. The carbon emissions intensity of natural gas and natural gas products such as LNG also reduce significantly through rapid technological learning relating to CCS/CCUS and improved access to adequate and affordable carbon offset options.

6.1.2 Scenario effects

The Energy Hybrid and Gas Retained scenarios project minimal disruption to gas markets in Western Australia. The Hydrogen Future and Electricity Dominates scenarios project considerable disruption, with the first requiring a significant investment in gas distribution infrastructure associated with the transition to hydrogen and the second resulting in a rapid decline in usage of gas as customers disconnect from the distribution system (switching to electricity) from around 2030.

The Energy Hybrid and Gas Retained scenarios show a slight decline in gas demand (compared with 2025) through to 2032 and then return to slight growth after that. Customer numbers growth does not decline in either scenario. The reduction in gas demand is the ongoing reduction in demand by each customer (energy efficiency). Demand growth after 2032 is driven by new customers offsetting energy efficiency improvements per customer.

The Hydrogen Future scenario also shows a slight decline in demand to 2035, after which demand is projected to rise quickly as customer numbers grow. This demand growth is driven by the falling price of gas (hydrogen), resulting in gas consumption becoming very competitive with the alternative of switching to electricity.

The Electricity Dominates scenario shows a slight decline in overall demand by 2030. From 2030, customer numbers are projected to decline by around 1 per cent per annum initially, rising to about 6 per cent by 2060 and nearly 14 per cent by 2074. The average annual rate of decline in customer numbers is around 6 per cent per annum from 2030 to 2074.

6.1.3 Scenario weighting

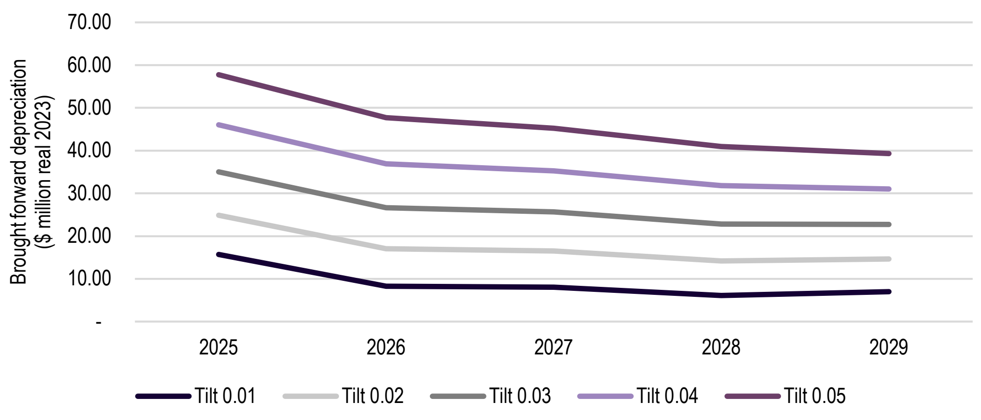
Each scenario is a distinct future driven by specific technology and policy developments. They represent plausible futures but do not represent the complete set. Also, each scenario does not have an equal probability of occurring. Therefore, as the relative probability of each scenario is unknown, and the scenarios are not a complete set of the future, deriving conclusions by some form of a weighted average of results or settling on the central case is not feasible. Therefore, we have not used either of these approaches in our conclusions or in developing our recommendations.

6.1.4 Brought forward depreciation options

ACIL Allen has considered the value of creating options for the future and has recommended a brought-forward depreciation path for 2025 to 2029. The standard regulatory cycle is five years in length, which allows flexibility in decisions relating to tariff pricing. Decisions made in the upcoming regulatory cycle (2025-2029) concerning accelerating depreciation can be adjusted in future regulatory cycles based on better information that becomes available in the intervening period. Not acting now may make it impossible to avoid asset stranding in the future.

Figure 6.1 shows the brought-forward depreciation schedules by tilt-value for 2025-29. The higher the tilt-value, the greater the brought forward depreciation and the likelihood of asset stranding is lessened.

Figure 6.1 Brought-forward depreciation by tilt-value – 2025-29



Source: ACIL Allen

6.2 Recommended actions

As shown in Figure 6.1 above, the potential range of brought-forward depreciation for tilt-values of 0.01 to 0.05 averages between $9 million and $46 million from 2025 to 2029. As discussed in section 5.3.2 above, the final choice of tilt-value determining the amount of brought forward depreciation is a trade-off between reducing the risk of asset stranding and near-term increases in costs for consumers. ACIL Allen considers a tilt-value of 0.02 to provide a reasonable trade-off in reducing asset-stranding risk while resulting in modest cost increases for consumers.

The recommended brought-forward depreciation path is shown in Table 6.1.

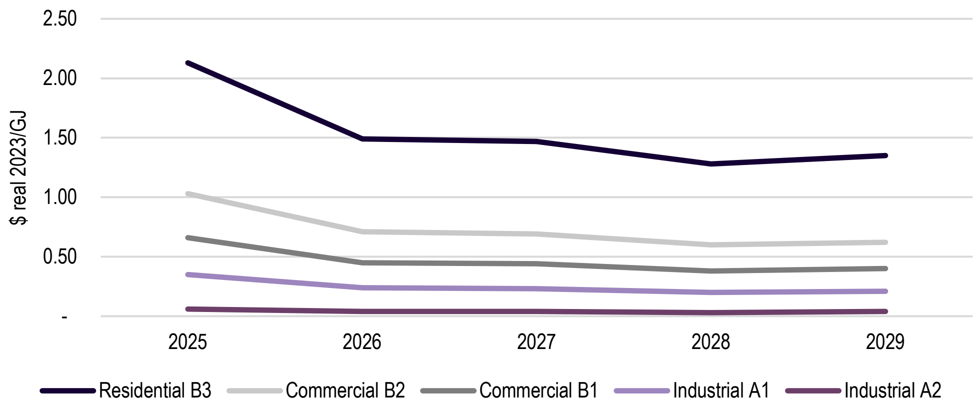
Table 6.1 Recommended brought forward depreciation: 2025 – 2029 ($ million real 2023)

	2025	2026	2027	2028	2029
	2025	**2026**	**2027**	**2028**	**2029**
Brought forward depreciation	24.87	17.03	16.49	14.19	14.65

Source: FOGM

The tariff increase by customer class is shown in Figure 6.2. The tariff increases were calculated using the allocation of revenues to each tariff class (developed by ATCO) divided by the annual gas demand for that class. The residential B3 tariff increases by an average of $1.54 annually over the five years. The commercial B2 tariff increases by an average of $0.73 over the five years.

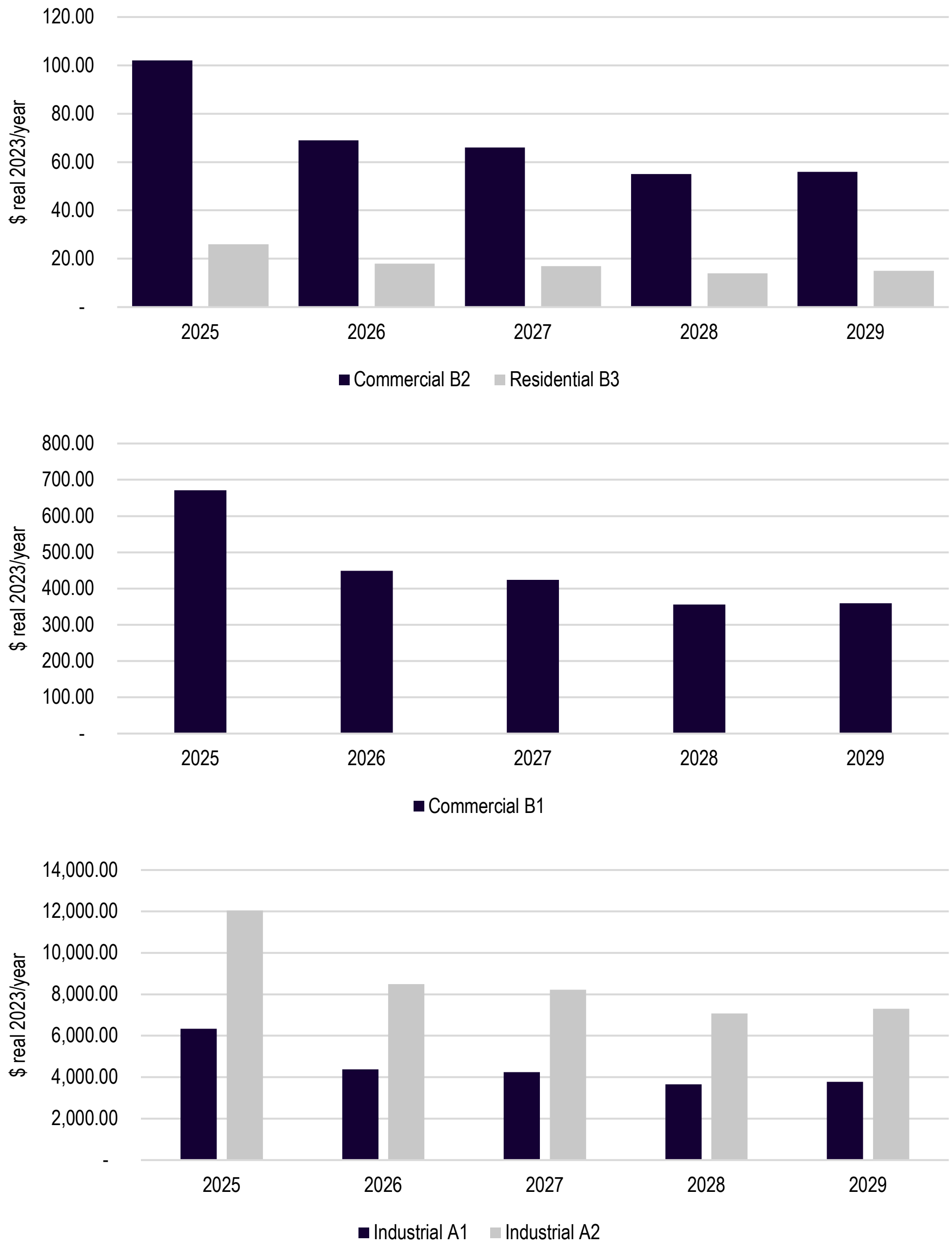
Figure 6.2 Recommended Path average tariff increases by customer class – 2025-29



Source: ACIL Allen

The average annual increase in the customer bill by customer class is shown in Figure 6.3 below. This increase is calculated by multiplying the average tariff increase for each customer class by the average annual consumption for each customer class. The average annual increase in customer bills for residential B3 customers is around $18 per annum over 2025-29. For commercial B2 customers, the average yearly increase in customer bills is around $70 per annum.

Figure 6.3 Average annual increase in customer bill by customer class – 2025-29



Source: ACIL Allen

Glossary of terms A

Abbreviation	Definition
AA6	Access Arrangement for the period commencing 2025
Accelerated depreciation	Acceleration of straight-line depreciation by applying a tilt function
ACIL Allen	ACIL Allen Consulting
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ARENA	Australian Renewable Energy Agency
ATCO	ATCO Gas Australia Pty Ltd
AUD	Australian dollar
Brought-forward depreciation	The difference between accelerated depreciation and straight-line depreciation
Carbon price	Price for 1 tonne of CO_2-e
CCS	Carbon capture and storage
CCUS	Carbon capture, utilisation and storage
CO_2-e	Carbon dioxide equivalent – a measure of greenhouse gas emissions
CPI	Consumer Price Index
Electrification	The act of switching from appliances powered by natural gas to electricity-powered appliances
ERA	Economic Regulation Authority
ESOO	Electricity Statement of Opportunities
GJ	Gigajoule – one thousand million joules
GPG	Gas for power generation
GSOO	Gas Statement of Opportunities
GSP	Gross State Product
GWh	Gigawatt hours – one thousand Megawatt hours
H_2	Hydrogen gas – made up of diatomic molecules
kWh	kilowatt-hours – one thousand watt-hours
LGA	Local Government Area
LNG	Liquefied Natural Gas
MOU	Memorandum of Understanding

Abbreviation	Definition
Mt	million tonnes
MW	Megawatt – one million Watts
MWh	megawatt-hour – one million watt-hours
Net zero	Reduction in greenhouse gas emissions to zero where offsets are included as emission reductions
NPV	Net present value
PJ	Petajoule – one million gigajoules
PV	Photovoltaic
RAB	Regulated Asset Base
Safeguard Mechanism	Commonwealth emissions reduction scheme requiring major (non-electricity) greenhouse gas emitters to phase emissions down over time
S curve	The shape of a logistic function
SWIS	South West Interconnected System
USD	United States dollar
WACC	Weighted Average Cost Of Capital
WEM	Wholesale Electricity Market
WOOPS	Window of Opportunity PaSt

Melbourne
Suite 4, Level 19; North Tower
80 Collins Street
Melbourne VIC 3000 Australia
+61 3 8650 6000

Sydney
Suite 603, Level 6
309 Kent Street
Sydney NSW 2000 Australia
+61 2 8272 5100

Brisbane
Level 15, 127 Creek Street
Brisbane QLD 4000 Australia
+61 7 3009 8700

Canberra
Level 6, 54 Marcus Clarke Street
Canberra ACT 2601 Australia
+61 2 6103 8200

Perth
Level 12, 28 The Esplanade
Perth WA 6000 Australia
+61 8 9449 9600

Adelaide
167 Flinders Street
Adelaide SA 5000 Australia
+61 8 8122 4965

ACIL Allen Pty Ltd
ABN 68 102 652 148

acilallen.com.au