Jemena Gas Networks (NSW) Ltd

2025-30 Access Arrangement Proposal

Attachment 7.4

Future of gas analysis

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Abbreviations

AA	Access Arrangement
ABS	Australian Bureau of Statistics
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AIC	Average Incremental Cost
BAU	Business As Usual
CAM	Cost Allocation Methodology
Capex	Capital Expenditure
FoG	Future of Gas
GJ	Gigajoule
JGN	Jemena Gas Networks (NSW) Ltd
NGR	National Gas Rules
NPV	Net Present Value
O&M	Operational and Maintenance
Opex	Operating Expenditure
PTRM	Post-Tax Revenue Model
PV	Present value
RAB	Regulatory Asset Base
RBA	Reserve Bank of Australia
TAB	Tax Asset Base
WACC	Weighted Average Cost of Capital
WTP	Willingness to Pay

Key Messages

- The Australian energy sector is undergoing rapid transformation driven by desire to decarbonise and this is influencing the gas sector with increasing speed and impact.
- For Australian gas distribution networks to mitigate stranding risk of assets, it is important to understand and adapt to the high degree of uncertainty over the future role of gas. This has prompted us to undertake the analysis set out in this attachment. We have also been guided by the Australian Energy Regulator's (**AER**'s) information paper, *Regulating gas pipelines under uncertainty*.[1]
- Incorporating input from our Expert Panel, Advisory Board and customers, other stakeholders, and forecasting experts, we developed and applied a modelling framework that:
  - Tested four Expert Panel's plausible alternative future scenarios over the period to 2050
  - Assessed the potential impact of different future (demand) scenarios on our network and our customers
  - Analysed the potential impacts from different stranding mitigation initiatives that we identified and filtered with our Advisory Board, including accelerated depreciation, on our customers and network.
- Our analysis found that:
  - Customer demand and throughput is projected to decline across all scenarios over time, but the pace and extent vary depending on the assumptions and external factors
  - Absent mitigation initiatives, end-customer gas prices increase across all scenarios, although these price impacts vary significantly
  - It is important to achieve a balance between what consumers pay now to mitigate future price increases and the risk of greater price increases in the future if mitigation is delayed
  - Accelerated depreciation, and other mitigation initiatives, can help to improve price stability and intergenerational equity (i.e., spreading costs fairly over current and future customers), and gas competitiveness with alternative energy sources, particularly electricity
  - Accelerated depreciation can also create a pathway to inclusion of more renewable gas in our network by making network costs more competitive in future
- This long-term directional analysis was an important input to our engagement and our 2025 Plan.

Overview

In navigating the uncertain future of gas demand while having approximately $3.8B invested in long life assets, it's imperative that we proactively start planning now on ways to keep prices stable over the longer period, mitigate asset stranding risks, support greener gases by offering competitive transportation prices and offer our customers more energy choices in the future.

The Expert Panel provided diverse perspectives on how the future may unfold and developed plausible future scenarios to demonstrate the potential paths. It is based on four scenarios that reflect different assumptions about consumer preferences, technology adoption, policy settings, and gas supply conditions.

To understand these scenarios comprehensively and the different risks they entail, we developed the Future of Gas (**FoG**) model. The crux of this long-term model is based on economic theory by Crew and Kleindorfer (1992)[1], which looks at appropriate levels of depreciation in situations where a current monopolist is likely to face competition in the future as the price of substitutes (electricity) fall. This scenario model has been used extensively for assisting our Expert Panel and Advisory Board discussions.

In this attachment, we present the results of our future of gas analysis, which explores the potential pathways and outcomes for our gas network over the next 25 years to 2050. The main purpose of the analysis was to compare the effectiveness of different asset stranding mitigation initiatives Jemena Gas Networks (NSW) Ltd (**JGN**) can undertake to improve long term customer outcomes under each scenario. These mitigation initiatives include changing asset management approaches, accelerating capital recovery, supporting renewable gases and increasing connection charges. The analysis incorporates input from consumers and experts, who helped us shape and test our scenarios and assumptions. The analysis was also a key input to our accelerated depreciation engagement with customers and our proposal, which is detailed in *JGN - Att 7.3 - Depreciation approach*.

The attachment is structured as follows:

- **Context, drivers, and purpose:** Section 1 explains the background and objectives of the future of gas work, and the key factors that influence the outlook for gas demand and supply in NSW.
- **Consumer and expert input:** Section 2 describes the steps we took to engage with consumers and experts throughout the development and review of the analysis, and how their feedback informed our approach and outputs. It also sets out the future scenarios developed by the Expert Panel and the potential mitigation initiatives that we consulted on.
- **Modelling framework:** Section 3 outlines the method, and broader modelling framework, that we used to model the future of gas scenarios using a standard building block calculation approach that—consistent with that commonly applied by the AER—estimates the revenue requirement and average network prices for each scenario.
- **Data and assumptions:** Section 4 details the data and assumptions we used to populate the model, including the demand forecasts, expenditure forecasts, and other inputs. We also identify key limitations with our future of gas analysis.

[1] Crew, M and Kleindorfer, P, *Economic Depreciation and the Regulated Firm under Competition and Technological Change, Journal of Regulatory Economics, 4(1), 1992*

- **Results and insights:** Section 5 presents the results and insights from the modelling, highlighting the key findings and implications for our network and our customers.

Supporting attachments

Table OV–1: List of supporting attachments

Attachment	Name	Author
2.2	Customer forum engagement report	BD Infrastructure
2.3	Expert Panel Report	KPMG
2.4	Advisory Board Report	KPMG
2.5	Appendix C to KPMG Advisory Board Report	JGN
4.1	Emissions reduction program	JGN
5.1	Capital expenditure	JGN
7.3	Depreciation approach	JGN
7.5	Long term demand forecast report	Blunomy

1. Context, drivers, and purpose

1.1 Context and drivers

Our gas network is a vital part of the energy system, providing essential services to millions of homes and businesses across NSW. Gas is used for heating, cooking, hot water, industrial processes, power generation, feedstock and transport. It is also a flexible and reliable source of energy that can complement the increasing penetration of variable renewable electricity.

However, our gas network—like others throughout the country—is also facing significant challenges and uncertainties in the context of the transition to a low-carbon economy. Key drivers of this transition are:

- **Policy and regulation:** The Australian government has committed to reduce greenhouse gas emissions by 43% below 2005 levels by 2030 under the Paris Agreement,[2] to help the country achieve net zero emissions by 2050. The NSW government has also committed to net zero by 2050 for our state,[3] and set targets and policies to support renewable energy and energy efficiency (among other actions). Collectively, these policies and regulations are expected to heavily influence the transportation of natural gas through our network given its carbon content.
- **Market and technology:** The gas market is undergoing rapid changes due to the emergence of new technologies and business models that enable the production, transportation, and consumption of renewable and low-emission gases, such as biomethane, hydrogen and synthetic methane. These gases have the potential to decarbonise the gas network and provide new sources of demand and value for gas network operators and customers. However, they also pose technical, economic, and regulatory challenges and uncertainties, such as the availability and cost of feedstocks, the compatibility and safety of network infrastructure (to transport hydrogen), the integration and coordination with the electricity system, and the allocation of risks and benefits among different stakeholders.
- **Customer and social:** The customer and social preferences and expectations are also evolving in response to the energy system transition. Customers are becoming more aware and engaged with their energy choices and consumption, and are demanding more control, flexibility, and transparency from energy providers. Customers are also increasingly concerned about the environmental and social impacts of their energy use, and are seeking more sustainable and affordable solutions. Unsurprisingly, customers are influenced by broader social and cultural factors that affect their trust and satisfaction with the energy system, such as the media, the community, the government and the industry.

1.2 Our future of gas project

In light of these drivers, we initiated the future of gas project to proactively explore and plan for the possible pathways and outcomes of the gas network transition, and to identify and evaluate the best mitigation initiatives for our network and our customers.

The purpose of the future of gas analysis was to:

- develop and test a range of plausible future scenarios that reflect the different drivers and uncertainties of the gas network transition
- quantify and compare the impacts of our mitigation initiatives under different future scenarios on our customers and investors
- communicate and seek feedback from customers and other stakeholders of our mitigation initiatives, and
- inform JGN's strategic decision-making and prepare for the upcoming access arrangement review for 2025–30.

We developed the modelling framework in collaboration with our customers and experts to achieve that purpose, with further elaboration provided in the subsequent sections.

2 See: https://www.dfat.gov.au/international-relations/themes/climate-change/international-cooperation-on-climate-change.

3 See: https://www.climatechange.environment.nsw.gov.au/about-adaptnsw/nsw-government-action-climate-change.

2. Consumer and expert input

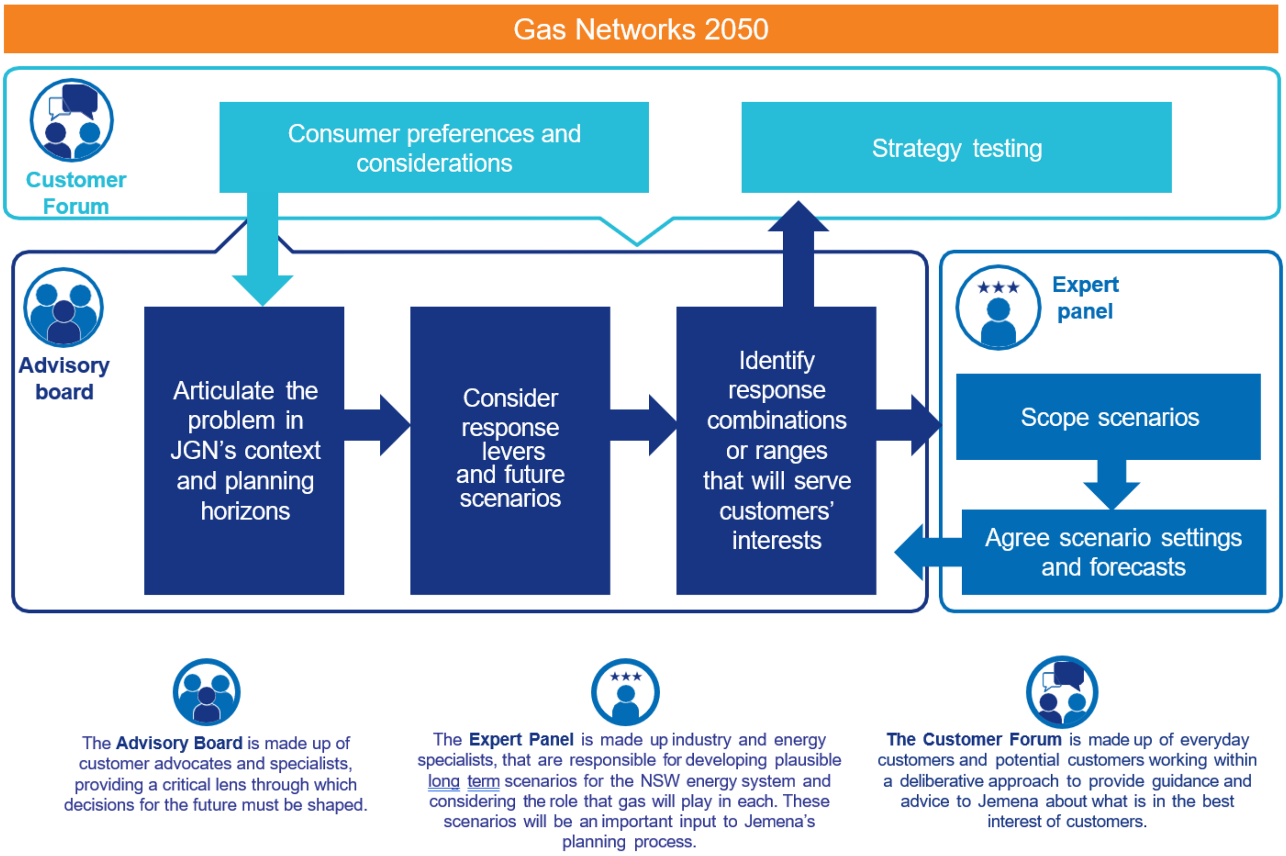
Consumer, stakeholder, and expert input was central to our future of gas analysis. This section describes the steps taken to incorporate that input into the design, development, and review of the modelling underpinning that analysis.

2.1 Overview

We established an Advisory Board and Expert Panel to guide and oversee development of our future of gas analysis which will seek to inform the range of future outcomes and impacts of different mitigation initiatives:

- **Advisory Board**: the Advisory Board consists of representatives from various stakeholder groups, such as customers, retailers, regulators, government agencies, industry associations, academia, and environmental organisations. The Advisory Board's role is to provide guidance, feedback, and perspectives on the overall approach, methodology, and outcomes of the future of gas analysis. The Advisory Board met nine times throughout the project to review and discuss the key deliverables and findings, in addition to two opt-in sessions.

- **Expert Panel**: the Expert Panel consists of subject matter experts from various fields and sectors related to the future of gas, such as technology, economics, policy, environment, and customer behaviour. The Expert Panel's role was to co-create and validate the scenarios and mitigation initiatives for the future of gas, based on their insights and expertise. The Expert Panel also contributed to the demand forecasting by providing inputs on the key drivers and assumptions for each scenario, and voting on their views about the probability of these plausible scenarios.



Inputs and feedback from the Expert Panel, Advisory Board and independent forecasters were embedded into each stage of our modelling. It involved three main stages:

- **Scenario planning:** the Expert Panel participated in four sessions to develop four plausible scenarios for the future of gas in NSW, based on 2 key drivers–decarbonisation policy direction and renewable gas penetration. The Expert Panel also provided their views on the relative likelihood of each scenario. The scenario narratives, drivers, and likelihoods were documented, and once agreed by the Expert Panel, were shared with the Advisory Board for review and discussion. We discuss the scenarios further in section 2.2 and mitigation initiatives in section 2.3.
- **Quantifying externally driven assumptions:** We engaged Blunomy, an independent expert in energy systems and impact measurement, to translate the Expert Panel scenario narratives and drivers into customer demand forecasts for our network. Blunomy used customer profile data, population and economic forecasts including relevant AEMO forecasts, and electricity and gas price forecasts, and electrification cost forecasts to quantify the demand for different customer segments and sub-segments under each scenario. Blunomy also developed projections on renewable gas blending and wholesale gas prices to provide a comprehensive picture of the customer impacts. Their methodology and findings were presented to and deliberated upon by the Advisory Board, whose feedback played a pivotal role in refining the final demand forecasts. We discuss these demand forecasts further in section 2.4.
- **Quantifying JGN related assumptions and outputs:** We forecasted expenditure to 2050 based on the key drivers of each future scenario developed by the Expert Panel. We adopted the AER's standard building block approach to forecast the revenue we are allowed to recover from customers. We consolidated all the external and internal inputs into the FoG model that allows us to calculate the network prices and compare end-customer gas prices with the equivalent cost of electrification. The expenditure and revenue forecasting approach and outputs were presented in and discussed with the Advisory Board across multiple sessions. Our modelling framework is discussed further in section 3.

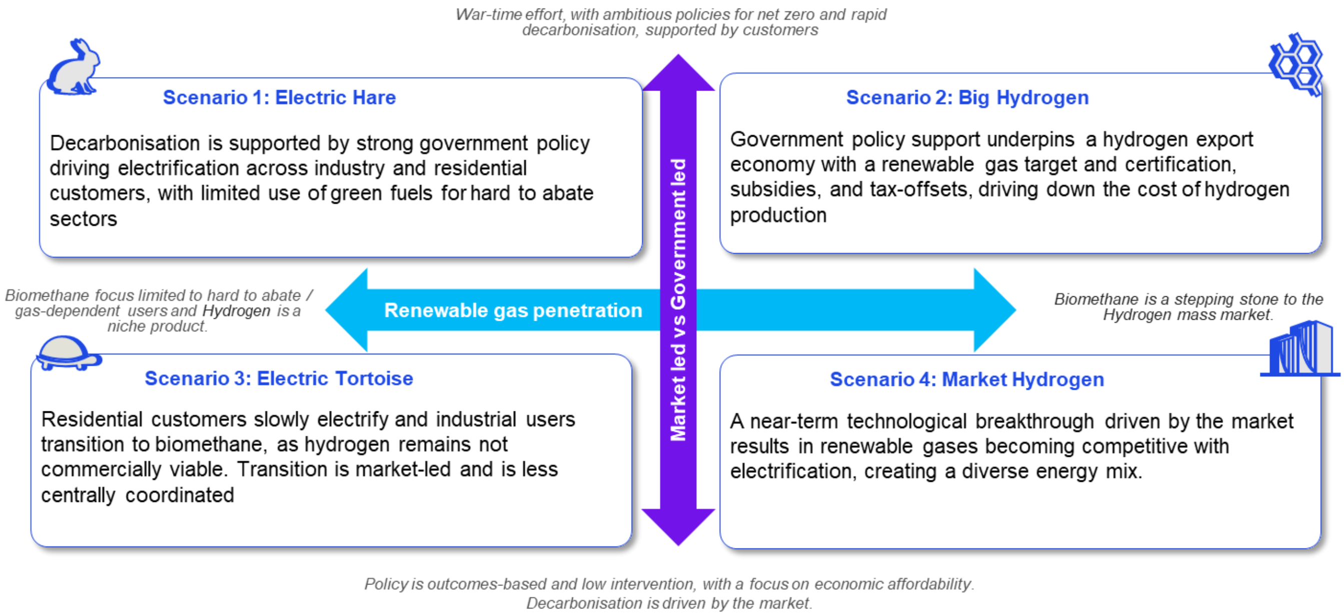
Through these stages, we sought to incorporate consumer and expert input to the design, development, and review of the modelling, as well as to ensure transparency and accountability for our modelling choices and assumptions. We also aimed to create a collaborative and interactive environment for the Advisory Board to engage with the modelling process and provide feedback and insights. We held 4 dedicated sessions with our Expert Panel, 11 sessions with our Advisory Board (including 3 opt-in sessions), and 8 sessions with our customer forums. We also engaged with AER staff on our future of gas analysis as part of the early signal pathway.

2.2 Future scenarios

The scenarios were defined using input from an Expert Panel, which consisted of representatives from government, academia, industry, and consumer groups. The panel was independently facilitated by KPMG. The scenarios designed were named ‘Electric Hare’, ‘Big Hydrogen’, ‘Electric Tortoise’, and ‘Market Hydrogen’.

The four scenarios against the two drivers are shown in Figure 2-1. The scenarios and their development are further described in *Gas Networks 2050: Future scenarios summary report* provided by KPMG and included as *JGN - KPMG - Att 2.3 - Expert Panel Report*.

Figure 2-1: Our future scenarios



2.3 Our mitigation initiatives

An important input to our future of gas analysis were the mitigation initiatives that could be undertaken in response to the future scenarios. These mitigation initiatives were identified and defined with inputs from the Advisory Board. The options were intended to improve customer outcomes in areas of delivering safe, reliable, affordable, and decarbonised services to our customers and stakeholders, regardless of the uncertainty and complexity of the future of gas.

By testing these mitigation initiatives within our modelling framework (described in section 3), we could quantify the impact on customers and JGN and the effectiveness of each initiative.

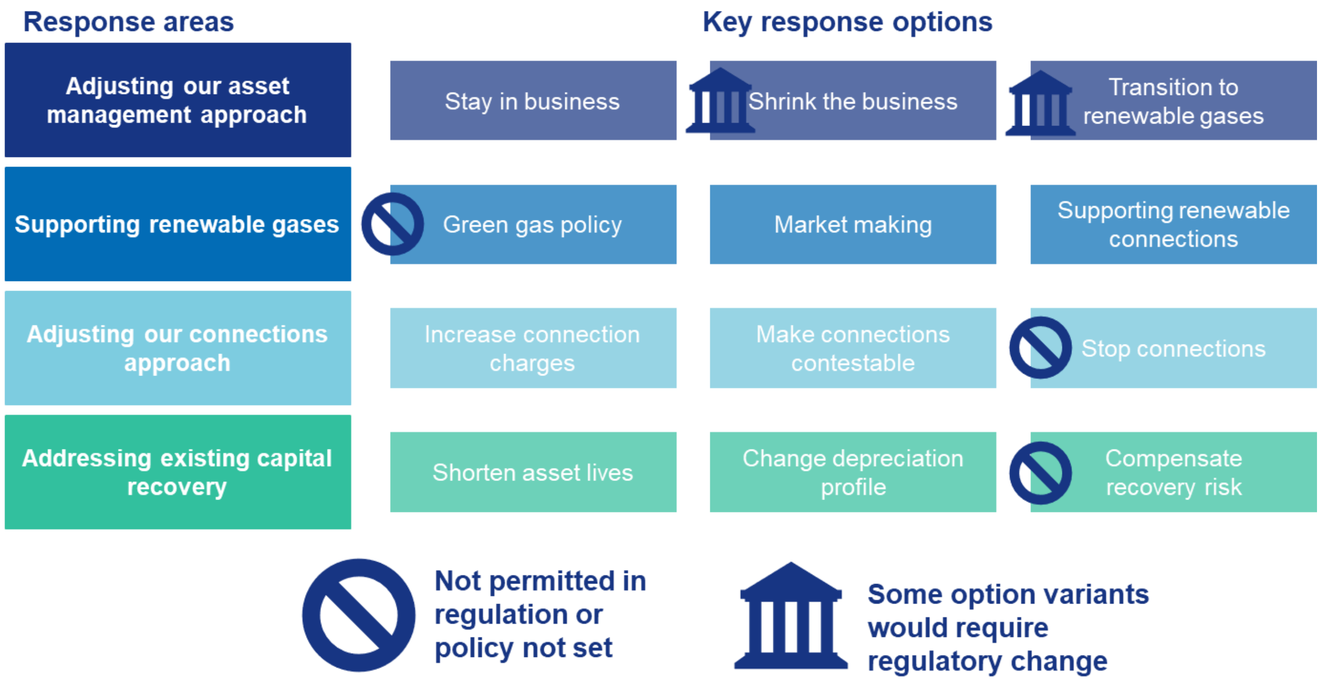
The mitigation initiatives were split across four areas:

1. **Adjusting the asset management approach**: replacing assets at a slower pace, undertaking more inspections and maintenance, decommissioning or shrinking parts of the network where appropriate and investing so our network can safely and reliably transport renewable gases (e.g., facilitating 10% hydrogen blending or preparing for 100% hydrogen conversion in some areas).

1. **Supporting renewable gases**: support establishing a market for green gas and focus on connecting to biomethane production facilities in the short term.
2. **Adjusting the connections approach**: increasing capital contributions from new customers, making connections contestable, and stopping connections in some areas.
3. **Adjusting the speed of capital recovery**: accelerating the depreciation of existing assets to align with the declining profile of customer base and reduce intergenerational inequity (e.g., by shortening asset lives or changing depreciation profiles), and compensating for recovery risk through rate of return to maintain investment incentives in our gas network.

The mitigation initiatives are summarised in Figure 2-2.

Figure 2-2: Potential mitigation initiatives



2.4 Demand forecasts

One of the key inputs for the future of gas modelling is the customer demand forecast, which reflects the expected changes in gas consumption and customer behaviour under each of the four plausible future scenarios. The initial demand forecasts were developed by Blunomy through a collaborative process involving the Expert Panel, the Advisory Board, and our internal team. The forecasts for the 2025–30 period were updated subsequently to align with those developed by CORE Energy for our Draft 2025 Plan.

The process involved the following steps:

- For each future scenario, the Expert Panel provided the narratives and key drivers that influence gas demand, such as policy direction, renewable gas penetration, energy efficiency, gas prices, electrification costs population growth and economic activity.
- Blunomy used the scenarios and the assumptions to develop detailed demand forecasts for each customer segment and network area, using a bottom-up approach that accounts for the diversity and characteristics of our customer base. Blunomy also applied a range of sensitivity and scenario analysis to test the robustness and uncertainty of the demand forecasts.
- The demand forecasts were then presented and discussed with the Advisory Board, who provided further feedback and validation. The demand forecasts were also peer-reviewed by our internal team, who confirmed the reasonableness of the methodology and the outputs.
- As a final step, the demand forecasts for the 2025–30 period were updated to align with those developed by CORE Energy for our Draft 2025 Plan.[4] The forecasts for the 2030–50 period remained at those developed by Blunomy.

Blunomy's demand forecasts and approach used to generate them is described in its report *Long-term demand forecasts*, included as *JGN - Blunomy - Att 7.5 - Long term demand forecast report*. The report explains how demand for gas was forecasted by customer segment, according to the narratives and indicators adopted for each future scenario. The customer segments were based on the key drivers of demand for different types of

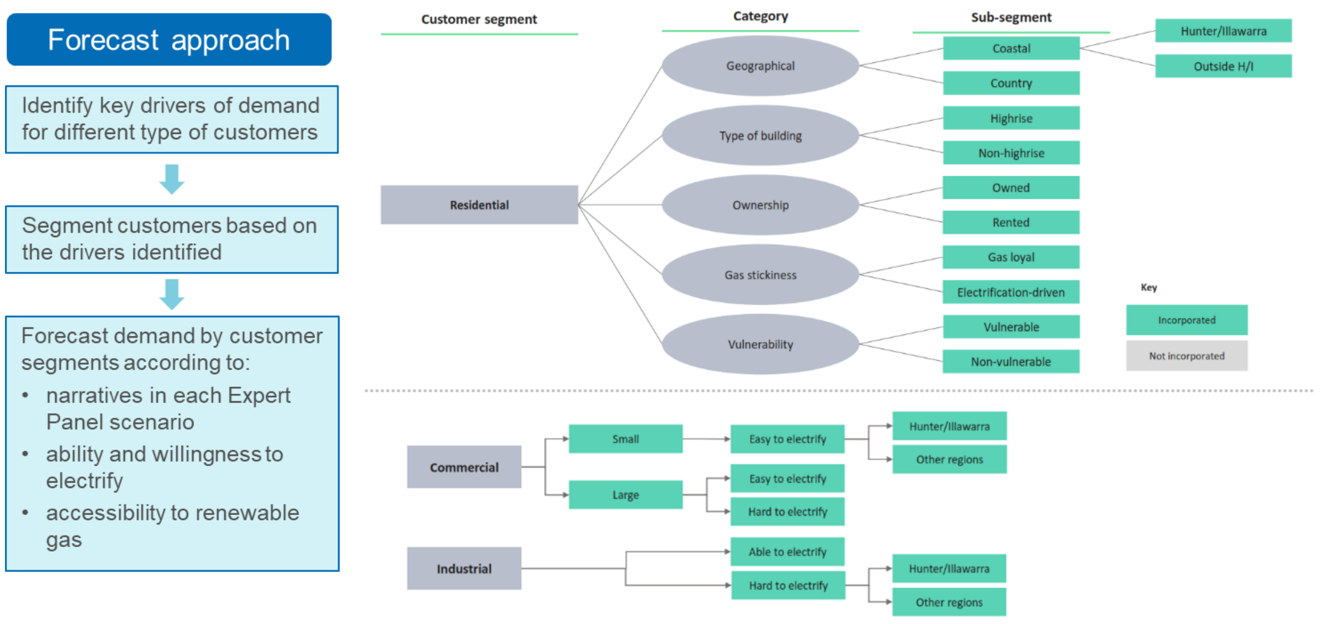
[4] This update was made to ensure alignment between our Draft 2025 Plan and our future of gas analysis.

customers, such as location, building type, appliance mix, energy efficiency, and income. The demand for gas by each customer segment was projected:

- based on their ability and willingness to electrify their energy needs, and their accessibility to renewable gas sources, such as biomethane and hydrogen
- as the product of the number of customers, the average consumption per customer, and the gas penetration rate

Blunomy's forecasting approach is summarised in Figure 2-3 which also shows the level of customer segmentation Blunomy examined when assessing how different customers may respond to the scenarios.

Figure 2-3: Demand forecasting approach



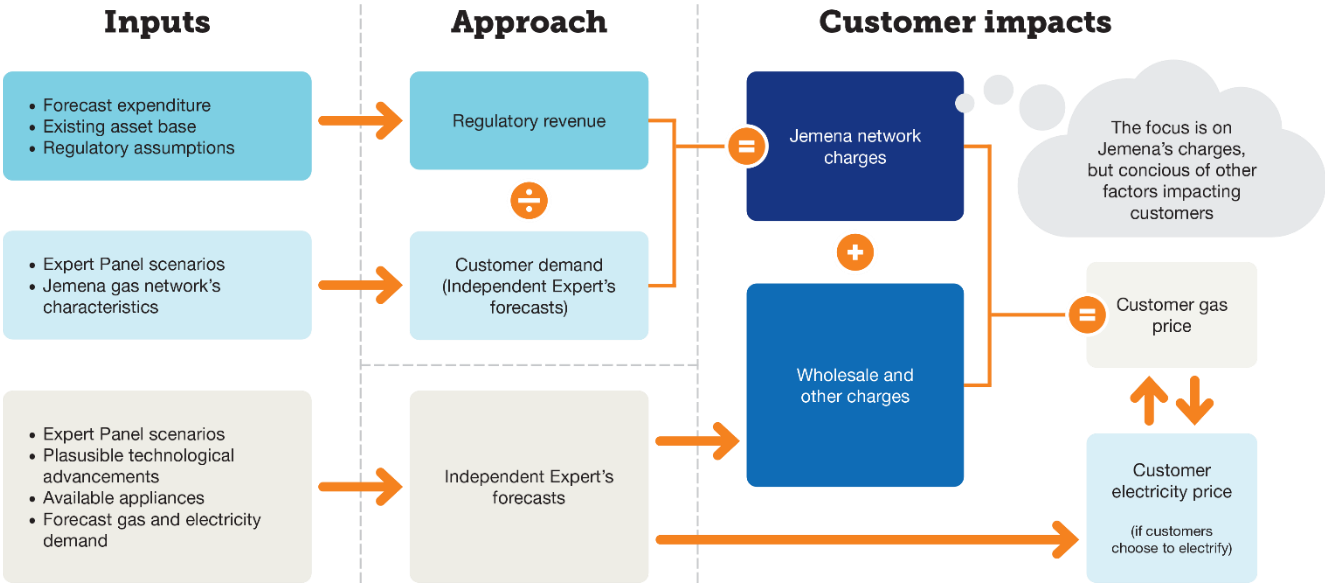
3. Modelling framework

3.1 Overview

The FoG model focuses on the next 25 years outlook from 2025 to 2050 and compares the effectiveness of different mitigation initiatives JGN can undertake under each scenario. The model compares the customer electricity and gas prices outlook over the 25 years period to evaluate the impact on customers and asset stranding risks for JGN.

That framework is illustrated in Figure 3-1, showing the inputs, calculation approaches, and impact on current and future customers that we considered.

Figure 3-1: Our future of gas modelling framework



Deriving JGN's network charges requires projecting our regulatory revenue requirements and demand forecasts. This involves:

- First, forecasting expenditure and revenue over the period from 2025–50 using the AER's standard building block approach
- Second, forecast demand for each future scenarios based on the Expert Panel inputs and JGN's network characteristics
- Third, divide that revenue by forecast demand to derive projected JGN network charges that make up part of a customer's gas bill.

JGN's network charges only make up around 30–35% of a residential customer's total bill. To assess the end-customer impacts, we bring in other components of our customers' gas price and the equivalent price if customers choose to switch to electricity from external forecaster Blunomy.

The next two sections describe the model (i.e., Excel workbook) used to apply the modelling framework above and the core calculations included within it. Model inputs are discussed in section 4.

3.2 JGN FoG model

3.2.1 Model structure

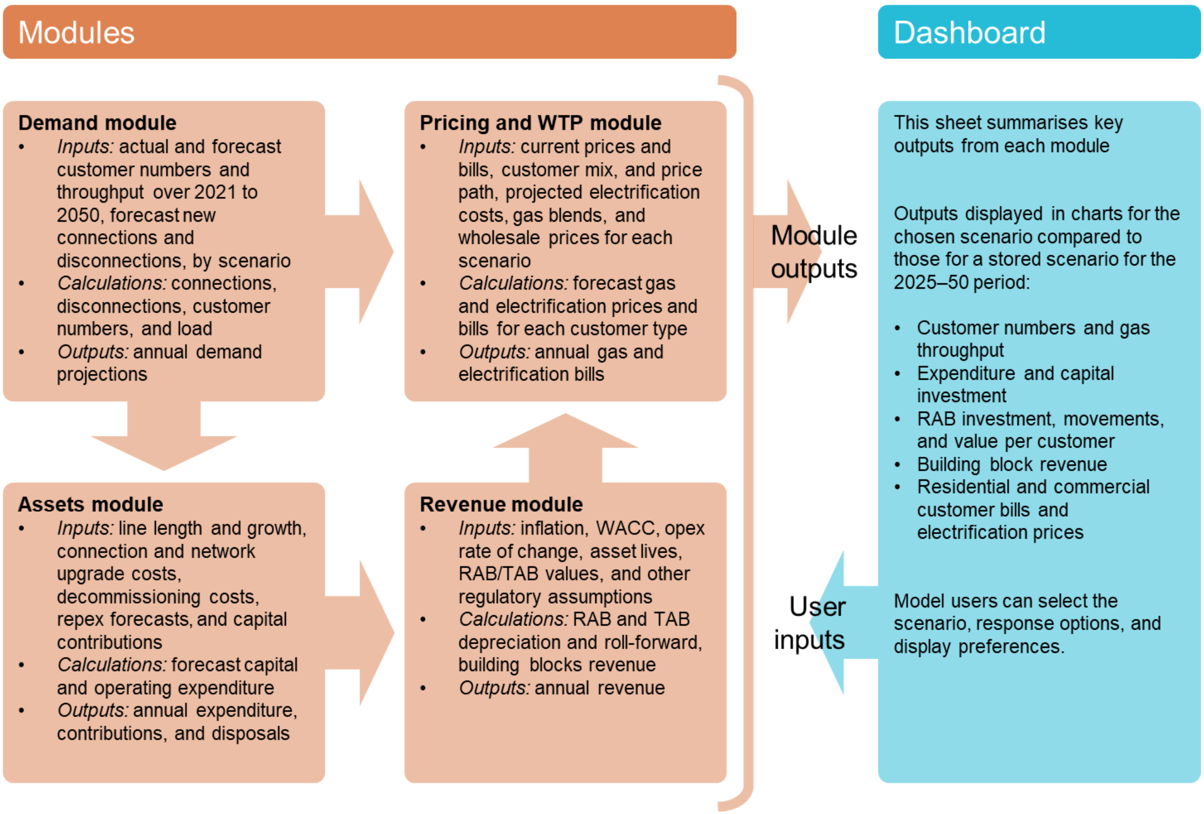
Consistent with the overall modelling framework, the FoG model was designed as a tool to help JGN, its customers and other stakeholders to understand the impact of different future scenarios and impact of different mitigation initiatives on customers and our gas network over time. The model was designed to be flexible and transparent, allowing model users to explore various combinations of scenarios and actions, and to see and compare the results in terms of customer demand, gas prices, revenue, and expenditure.

The mitigation initiatives we modelled include adjusting the asset management approach, transitioning to renewable gases, adjusting the connections approach, and accelerating the capital recovery.

As shown in Figure 3-2, the FoG model consists of four key modules (each made up of several input and calculation sheets):

- **Demand:** which inputs the demand forecasts provided by Blunomy for the four scenarios
- **Assets:** which projects the capital and operating expenditure for the chosen scenario and actions, with simplified assumptions to account for changes in customer base, network size, renewable gas blend, asset management approach along with other relevant network characteristics
- **Revenue:** which projects the building block revenue for the chosen scenario and actions using the AER's PTRM
- **Pricing and WTP:** which projects the price impacts for customers under the chosen scenario and actions, in terms of customer bills or $/GJ, and compares this to projected alternative energy costs (e.g., electricity).

Figure 3-2: Future of gas model structure



3.2.2 Regulatory revenue calculation

We developed our FoG model to use the AER's PTRM approach and extend the calculations out to cover the period from 2025 to 2050.

The AER's PTRM and therefore the FoG model uses the building block approach to calculate the allowed revenue

The building block approach consists of five components:

1. **Return on capital:** which compensates for the opportunity cost of investing in network assets, and is calculated for a given year as the product of the rate of return and the opening RAB for that year. The model includes three rate of return scenarios (high, mid, low) to account for varying market conditions.
2. **Return of capital (depreciation):** which allows recovery of the historical cost of network assets over their useful lives, and is calculated using the straight-line depreciation method. Our approach to modelling accelerated depreciation is set out in section 3.2.3.
3. **Operating expenditure (opex)**: which covers the ongoing costs of operating and maintaining the network.
4. **Tax allowance:** which reflects the expected corporate income tax, adjusted for tax credits and deductions.
5. **Incentive schemes:** which reward or penalise for achieving or failing to achieve certain expenditure targets. This revenue stream is only included for 2025-30 period to account for JGN's outperformance in the 2020-25 period.

The output from this calculation is building blocks revenue for each year over the 2025 to 2050 period in both real and nominal dollars. We then used this revenue to forecast network prices.

3.2.3 Accelerated depreciation

The FoG model allows depreciation to occur faster or slower than would apply using current regulatory assumptions, which can vary across scenarios.

The model allows for two sets of inputs:

- depreciation factors for each five year regulatory period from 2025-26 to 2049-50 that adjust up or down the amount of depreciation in each year for existing and new assets.[5]
- standard lives for each five year regulatory period from 2025-26 to 2049-50 that apply to new assets (i.e., capital expenditure incurred over the respective period).

These depreciation factors and lives can vary across scenarios. Our analysis in section 5.4.1 is undertaken by only changing the depreciation factors for existing assets, with no adjustments for asset lives for new assets.

Accelerated depreciation is a key mitigation initiative for JGN. Crew and Kleindorfer 1992 paper on 'Economic Depreciation and the Regulated Firm under Competition and Technological Change' highlights the importance of capital recovery when technological change and competitive entry are occurring in the utility space. Crew and Kleindorfer note –

It is shown that, under conditions of competition and technological progress, front loading of capital recovery is essential if the regulated firm is to remain viable. In addition, if the introduction of accelerated capital recovery is delayed by regulators, they may effectively vitiate any opportunity of the firm to recover its invested capital. The breathing space, or period of time, that regulators can delay introducing the application of efficient capital recovery without ultimately compromising the firm's ability to recover its invested capital is called the "Windows of Opportunity" (WOO). This same window of opportunity requires that the level of depreciation initially be set optimally. There are limited opportunities in the future, under technological change and competition, to rectify

[5] A depreciation factor of 1.0x means that depreciation is not accelerated (i.e., it matches the profile that is calculated using the standard regulatory assumptions). A factor greater than 1.0x means that there is some acceleration, as depreciation is greater than would otherwise be the case. A factor smaller than 1.0x means that there is some deceleration.

mistakes made now. Thus, in the case of price-cap regulation, if depreciation is set solely based upon status quo, the initial price cap may be set at too low a level to allow full capital recovery.

It is therefore extremely important for the AER to consider the appropriate level of accelerated capital recovery so JGN can continue to provide an efficient and low cost service and choice to our customers in the long term. Lower network charges in the long term will also become critical in the development of renewable gas sources to meet the net zero target in future.

3.2.4 Distribution network charges

The FoG model calculates distribution network bills and implied network charges, in $/GJ terms, by dividing forecast regulated revenue (described) above by projected demand (in GJ) for the chosen scenario and initiatives. We used the model to calculate the distribution network charges for each scenario and customer segment (i.e., residential, commercial and industrial), considering the different gas blends, wholesale gas prices, and electrification costs.

3.2.5 End-customer gas price

The FoG model estimated end-customer gas prices, in $/GJ terms, for each customer segment each year as the sum of:

- the distribution network charges described above
- gas transmission charges for using Jemena's Eastern Gas Pipeline and APA's Moomba to Sydney Pipeline, adjusted for forecast inflation
- wholesale gas price represents the cost of purchasing gas from the market or from a producer—as noted in section 4, we used the weighted average forecast wholesale gas prices forecast by Blunomy for natural gas, biomethane and hydrogen, depending on the blending assumed for the relevant scenario
- an assumed retail margin, that represents the additional charges from a retailer, using data published by the AER's comparison website, *EnergyMadeEasy.gov.au*.[6]

The resulting end-customer gas price reflects the average price that a customer is projected to pay for gas, excluding taxes and environmental charges, assuming that they continue to use our network.

3.2.6 End-customer electrification costs

The FoG model compares the end-customer gas price with the alternative scenarios of electrifying gas appliances, such as hot water systems, space heaters, and cooktops. The FoG model estimated the end customer electrification costs for each customer segment each year as the sum of:

- annualised upfront capital costs of new appliances (e.g., hot water systems, space heaters, and cooktops)[7]
- ongoing electricity costs, including wholesale, retail, and network components[8].

The end-customer electrification costs are converted into a $/GJ charge based on the energy consumption of electricity and gas appliances and gas-to-electric efficiency rates. The electricity price forecasts were developed in line with the scenario narratives and reflect the costs that customers would incur if they were to switch their energy use from gas to electricity. Comparing these costs to those projected if customers continue using gas allowed us to assess how much customers may be willing to pay for gas and the extent of value at risk due to stranding under the different future scenarios and mitigation initiatives.

[6] We used average retail margins of 57% and 34% for residential and commercial customers respectively, which we translated into $/GJ amounts based on current customer bills.

[7] The upfront capital costs of new appliances are calculated as the difference between electricity and gas appliances. It represents the additional costs a customer pays for switching to electricity appliances as oppose to paying for new gas appliances.

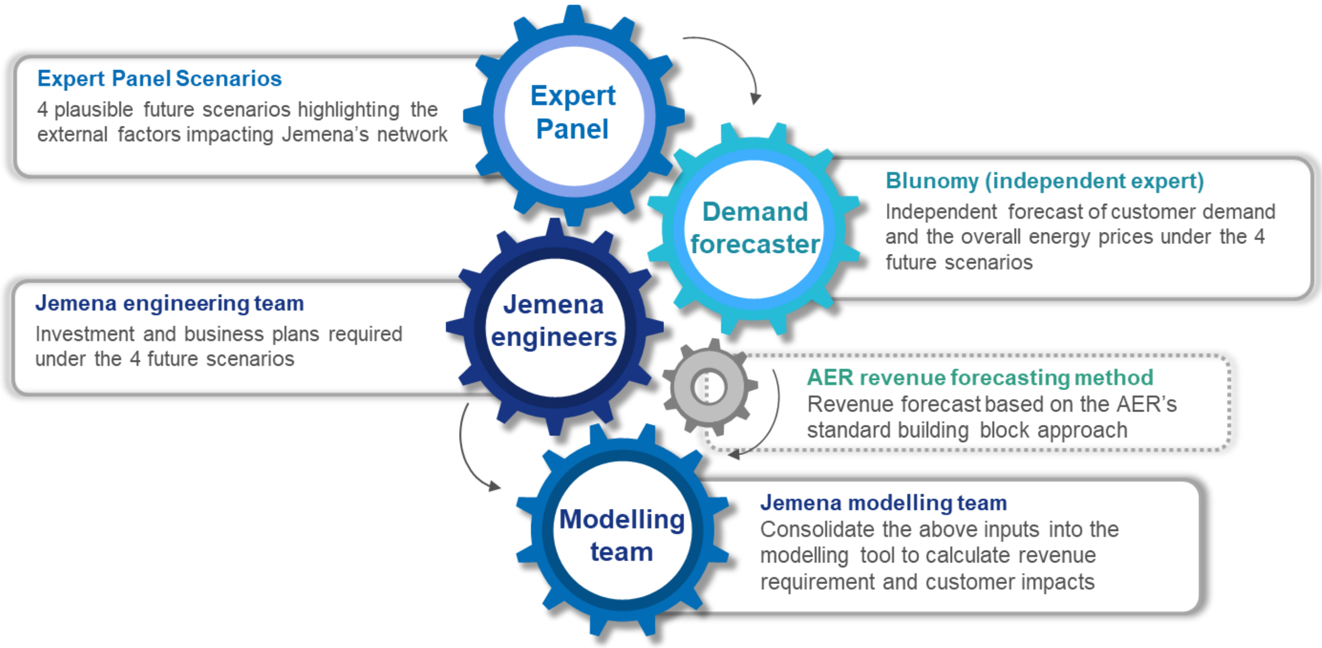
[8] Only the incremental variable component of the electricity bill was included in this analysis, as customers would pay for the electricity fixed charges regardless of the choice of electrifying gas appliances.

4. Data and assumptions

4.1 Overview

We relied on a wide range of data and assumptions to undertake our future of gas analysis, which—as illustrated in Figure 4-1—we sourced from the Expert Panel, independent experts, and internal engineering and modelling teams. We also relied on publicly available data sources, such as that published by the AER, AEMO and Reserve Bank of Australia (**RBA**).

Figure 4-1: Where we sourced our inputs



This section describes the key data and assumptions that we used which includes inputs affected by the choice of future scenario and common inputs that apply across all scenarios.

4.2 Common inputs

We used a set of common inputs that apply across all scenarios as set out in Table 4-1 below.

Table 4-1: Common inputs

Input	Description	Source
Demand related inputs		
Customer numbers and gas throughput 2020–30	Historical and forecast customer numbers and gas throughput by customer segment for 2020-21 to 2029-30	JGN, CORE Energy
Asset related inputs		
Line length 2020–30	Historical and forecast line length by pressure type (i.e., low, medium, and high) for 2020-21 to 2023-30	JGN

Input	Description	Source
Expenditure related inputs		
Capital expenditure 2020–30	2020-21 to 2022-23: Historical capital expenditure (including gross capex, capital contributions and disposals) by asset class are sourced from annual RINs 2023-24 to 2029-30: Forecast capex is projected in line with our proposal in the 2025 Draft Plan	JGN
Cost of connection to gas generation facilities	Estimated unit costs of connecting to biomethane and hydrogen generation facilities split by asset type	JGN
Network upgrade costs	Estimated costs of upgrading our network to safely transport different blends of hydrogen split by pipeline pressure	JGN
Specified renewable gas projects	Forecast renewable gas project costs over 2025-26 to 2029-30 in line with our 2025 Draft Plan	JGN
Costs per new connection	Weighted average unit costs per new connection by asset class	JGN
Base operating expenditure	Forecast base operating expenditure by category from 2023-24 in line with our 2025 Draft Plan	JGN
Regulatory assumptions		
RAB and TAB	The following RAB and TAB assumptions for JGN: • Closing 2020 RAB and TAB values by asset class • Standard regulatory and tax asset lives • Existing assets' regulatory and tax depreciation profiles	AER's 2020-25 determination for JGN
Current period expenditure and revenue allowances	Allowed revenue, capital and operating expenditure for 2020-21 to 2024-25, by asset class and category as appropriate	AER's 2020-25 determination for JGN
Opex rate of change inputs	Price growth, output growth and productivity growth assumptions for 2025-26 to 2049-50	AER's most recent determination for JGN / JGN's 2025 Plan
Inflation	Historical and forecast inflation from 2020-21 to 2049-50	ABS[9] / RBA
Allowed rate of return assumptions	Rate of return assumptions for the current and future regulatory periods The assumptions include 3 risk-free rate scenarios (high, mid, low) to capture customer impacts under varying market conditions.	AER / RBA / Bloomberg
Revenue and pricing related inputs		
Current prices	Prices for 2023-24 for volume tariffs allowed by the AER	AER
Expected pricing assumptions for 2024-25	Expected X factor and automatic adjustment factor for the 2024-25 pricing year	AER / JGN
Composition of typical end-customer gas bills	The composition of gas bills for residential and commercial customers, made up of retail, network, wholesale and transmission components. The retail portion of the bill is estimated based on retail bills for EnergyAustralia, Origin and AGL customers in JGN's network area.	EnergyMadeEasy / JGN / AEMO / APA / EGP

[9] Australian Bureau of Statistics

Input	Description	Source
	The transmission charges are estimated as the average of APA's Moomba to Sydney Pipeline and Jemena's Eastern Gas Pipeline transmission standing charges.	
Demand allocation into tariff categories	The proportion of customers by tariff categories and the gas throughput by tariff components are based on historical averages	JGN

4.3 Scenario specific inputs

Apart from common inputs, we also have scenario based inputs that vary depending on the future scenario that is selected. These are outlined in Table 4-2 below.

Table 4-2: Scenario specific inputs

Input	Description	Source
Demand related inputs		
Customer numbers (including connections and disconnections) 2030–50	Forecast by customer segment[10] for each year from 2030-31 to 2049-50. Blunomy identified the key drivers of demand for different type of customers segments and forecasted demand for each customer segment based on Expert Panel scenarios, the similarity with AEMO's GSOO demand forecasts, customers' ability and willingness to electrify and the their accessibility to renewable gas.	Blunomy
Average consumption 2030–50	Forecast average consumption per connection by customer segment for each year from 2024-25 to 2049-50, consistent with the approach for forecasting customer numbers.	Blunomy
Gas throughput and blend	Forecast by gas type (i.e., natural gas, biomethane, hydrogen) for each year from 2024-25 to 2049-50. The forecast of biomethane is based on Australia's Bioenergy Roadmap developed for the Australian Renewable Energy Agency (**ARENA**). (https://theblunomy.com/publications/australia-s-bioenergy-roadmap). The forecast of hydrogen is based on the Australian Hydrogen Market Study report and the drivers outlined by the Expert Panel. The forecast of natural gas are based on the AEMO's GSOO demand forecasts as well as the drivers outlined by the Expert Panel and the relative prices between gas and electricity.	Blunomy
Asset and expenditure related inputs		
Connection capex 2030–50	Forecast capex for connecting new customers was derived based on the forecast connections by customer type (residential, commercial, or industrial) from Blunomy, multiplied by the corresponding unit cost per connection	JGN based on Blunomy demand forecasts
Stay-in-business capex 2030–50	Stay-in-business capex includes replacements, facilities, IT systems and other essential activities to ensure the safe and reliable operation of our network. Stay-in-business capex is projected to change with decreasing/increasing demand and scale of our network (i.e. pipeline length).	JGN based on Blunomy demand forecasts

[10] Customers are segmented by type of customers (residential, commercial or industrial), geographical areas (urban or rural), type of building (high rise or non-high rise), ownership (owned or rented), gas stickiness (gas loyal or electrification-driven), and vulnerability.

Input	Description	Source
Renewable gas capex 2030–50	Forecast capex to enable the transportation of renewable gas blends driven by cost assumptions on transporting specific gas blends safely through the network.	JGN based on Expert Panel and Blunomy forecast gas blends
Opex 2030–50	Forecast opex is derived following a base-step-trend approach. It is driven by movements in customer numbers, pipeline length, decommissioning requirements and frequency to inspect pipelines based on renewable gas blends.	JGN based on Blunomy demand forecasts and gas blends
Pipeline decommissioning	Pipeline decommissioning assumptions are derived based on the forecast demand and pipeline length. The decommissioning activities include burning, purging, concreting, and grouting of pipeline mains to ensure that the pipeline is safe to remain underground. Costs relating to remediation costs, meter removal and other decommissioning activities were not included.	JGN based on Blunomy demand forecasts
Pipeline length	Forecast pipeline length by pressure level based on movements in forecast customer numbers by customer segments.	JGN based on Blunomy demand forecasts
Pricing related inputs		
Demand market revenue proportion	The projected revenue proportions we recover from volume and demand markets remaining on our network.	JGN based on Blunomy /CORE demand forecasts
End-customer electrification costs	The price of electrification is estimated using the total cost of ownership of electric appliances. It considers the electricity consumption and the efficiency rates of household appliances, the variable component of retail electricity prices, AEMO electricity price forecasts, residential Distributed Energy Resources (**DER**) uptake and the resulting cost of electricity, and the upfront investment in purchasing the electric appliances versus gas.	Blunomy
Wholesale gas price	Forecast prices by gas type (i.e., natural gas, biomethane, hydrogen) for each year from 2024-25 to 2049-50. The forecast of biomethane is based on Australia's Bioenergy Roadmap developed for the Australian Renewable Energy Agency (**ARENA**). (https://theblunomy.com/publications/australia-s-bioenergy-roadmap). The forecast of hydrogen is based on the Australian Hydrogen Market Study report and the drivers outlined by the Expert Panel. The forecast of natural gas are based on the AEMO's GSOO demand forecasts as well as the drivers outlined by the Expert Panel and the relative prices between gas and electricity. The weighted average wholesale gas prices are calculated as the component gas prices weighted by the gas blend.	Blunomy

4.4 Limitations of the model

Our FoG model offers valuable insights to the directional long-term impacts of our decisions today. It is a simplified tool to help engage with different stakeholders. However, the focus on keeping the analysis simple for customers to understand and engage on, meant that we had to limit some functionalities in the model. These are discussed below -

1. **Demand responsiveness** — we have used demand forecasts for each scenario that align with the narrative for that scenario. However, the demand once set in each scenario does not respond to changes in other inputs such as projected prices. If we introduced demand responsiveness this would have resulted in an iterative or dynamic modelling which may have required us to develop the tool on another platform instead of Excel or required backend programming which may be difficult to review for stakeholders and not provide full transparency on working of the model and assumptions.
2. **Simplified expenditure**—to capture changes in expenditure responding to changes in future demand, simplistic (often linear) assumptions were made to connection and stay-in-business capital expenditure, decommissioning costs, renewable gas connections and network upgrade costs. In reality, these interactions could be more complex.
3. **Willingness to pay**—the FoG model only includes WTP for residential and commercial customers, but not industrial customers. The WTP for industrial customers is heavily dependent on the nature of business and the technology available on a case-by-case basis. It was not feasible to estimate an overall WTP for industrial customers as part of our future of gas analysis.
4. **Simplified pricing**—the analysis uses simplified pricing assumptions and calculations to assess the potential impact on bills for three broad customer segments: residential, commercial and industrial customers. This means that the actual customer impacts are likely to be more nuanced than what the analysis suggests.

4.5 Engagement on the model

We conducted a series of sessions with the Advisory Board and other stakeholders, where we tested the modelling objectives, framework, outputs and the functionality of the FoG model, and allowed the participants to explore the scenarios and the response actions using the tool. These sessions helped us to test the sensitivity and reasonableness of the model outputs, and to collect feedback and suggestions on the model parameters and inputs.

We also consulted internal and external stakeholders throughout the analysis, and incorporated their inputs and feedback into our analysis. This includes internal stakeholders such as our engineering, network planning, renewable gas, and commercial teams as well as external stakeholders such as the Expert Panel, Advisory Board, Customer Forum and the AER through the early signal pathway engagement.

These engagement processes helped us review and validate the workings of the model. This ensured that the model was simple but credible, and that it reflected the views and expectations of the Advisory Board, the Expert Panel, and other stakeholders.

We provide more details on our engagement in *JGN - BD Infrastructure - Att 2.2 - Customer forum engagement report, JGN - KPMG - Att 2.3 - Expert Panel Report, JGN - KPMG - Att 2.4 - Advisory Board Report* and *JGN - Att 7.3 - Depreciation approach*.

5. Results and insights

This section sets out the results from our FoG analysis. We start by exploring the gas demand forecasts generated by Blunomy for the four future scenarios developed by the Expert Panel and step through how our mitigation initiatives change the outcomes for customers.

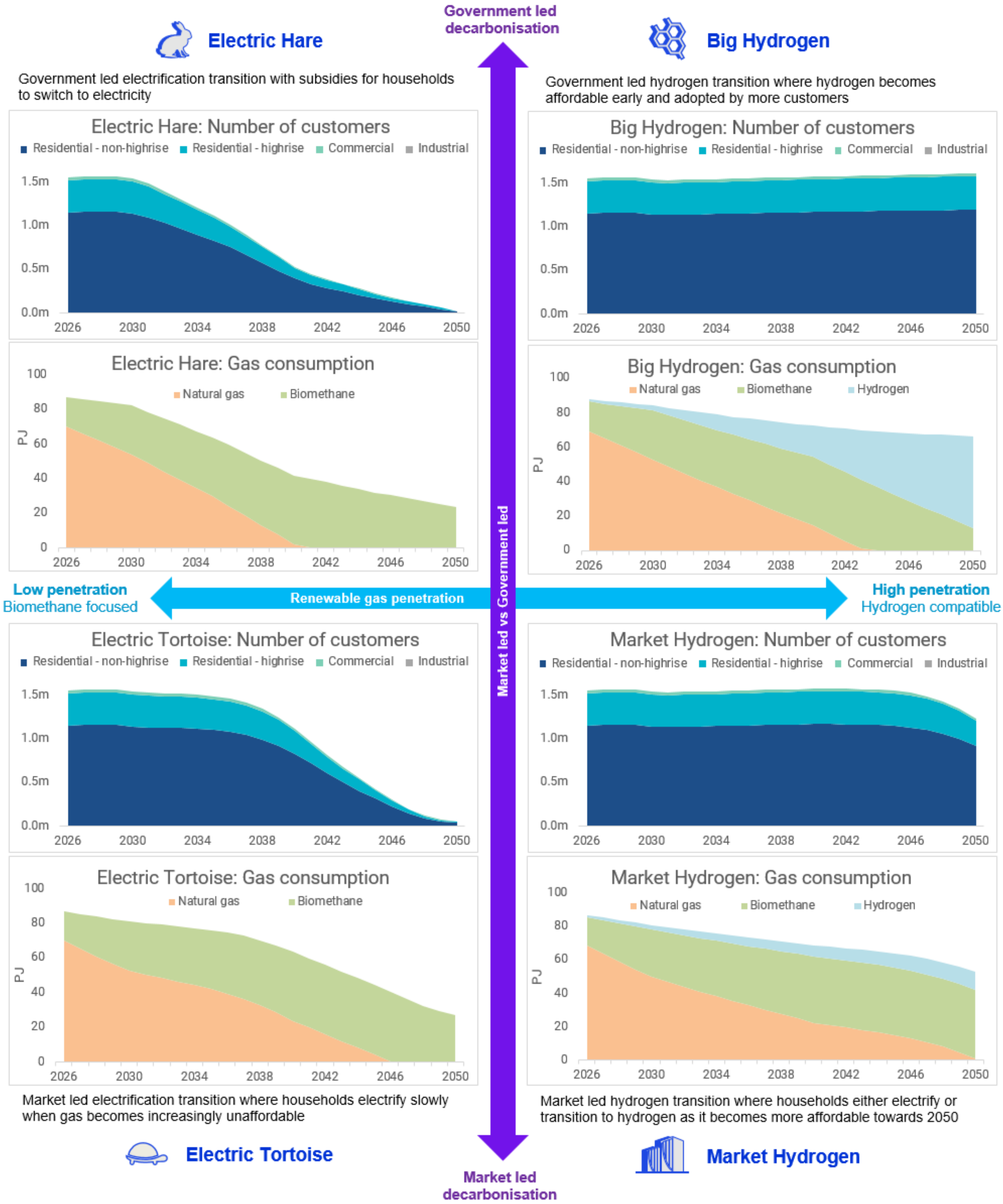
Key takeaways are:

- Customer demand and throughput are projected to decline across all scenarios over time, but the pace and extent vary depending on the assumptions and external factors
- Absent mitigation initiatives, end-customer gas prices increase across all scenarios, but are lowest in the Big Hydrogen scenario and highest in the Electric Hare scenario
- Accelerated depreciation, and other mitigation initiatives, can help to improve both price stability and intergenerational equity (i.e., spreading costs fairly over current and future customers), as well as prolonging the life of our network and improving the competitiveness of renewable gases.

5.1 Long term demand outlook

The demand projections[11] depicted in Figure 5-1 highlight varying paths of future gas consumption for the four scenarios, aligning to the drivers outlined by the Expert Panel, being the potential uptake and penetration of renewable gases versus the extent of government-directed or market-led progress to decarbonisation.

Figure 5-1: Projected customer numbers and gas consumption



5.2 Cost forecast

Based on the long term demand forecasts, we forecasted the costs required from 2026 to 2050 for the four future scenarios. These cost projections are split into capital expenditure (capex) and operating expenditure (opex). The capex is further split into connections, stay-in-business, and renewable gas investments. Opex is split into business as usual (**BAU**) costs forecasted by base-step-trend approach, and decommissioning costs when the network faces significant decline in customer numbers. The results are depicted in Figure 5-2.

In both the Electric Hare and Electric Tortoise scenarios, expenditure declines rapidly as customers disconnect from our gas network. Connections capex (in lighter green), stay-in-business capex (in blue) and BAU opex (in purple) reduce as our network shrinks, while decommissioning expenditure (in orange) ramps up over time. These projections contrast with the Big Hydrogen and Market Hydrogen scenarios, whereby expenditure largely continues at current levels, with some investment needed for hydrogen readiness (in dark green).

Figure 5-2: Projected expenditure

The FoG model also projects how JGN's RAB will grow under each scenario. This is shown in Figure 5-3, with investment broken down by regulatory periods. The RAB profiles over the 2026 to 2050 period for the electrification scenarios differ noticeably from those for the hydrogen scenarios. The electrification scenarios have the RAB reducing by about half in real terms, which compare to the relatively stable projections for the two hydrogen scenarios.

Importantly, under the electrification scenarios, despite capex reductions in all categories in 2030-50, the unrecovered RAB at 2050 remains high, with a large portion attributed to investment prior to 2025 (i.e., the dark blue area). This highlights the significant asset stranding risks we face without any accelerated depreciation especially when our customer base diminishes. For example, the unrecovered RAB in 2050 is $1.9B in Electric Tortoise and $1.7B in Electric Hare, representing more than half of our 2025 RAB of $3.8B (all numbers are presented in Real $2025).

Figure 5-3: Projected RAB

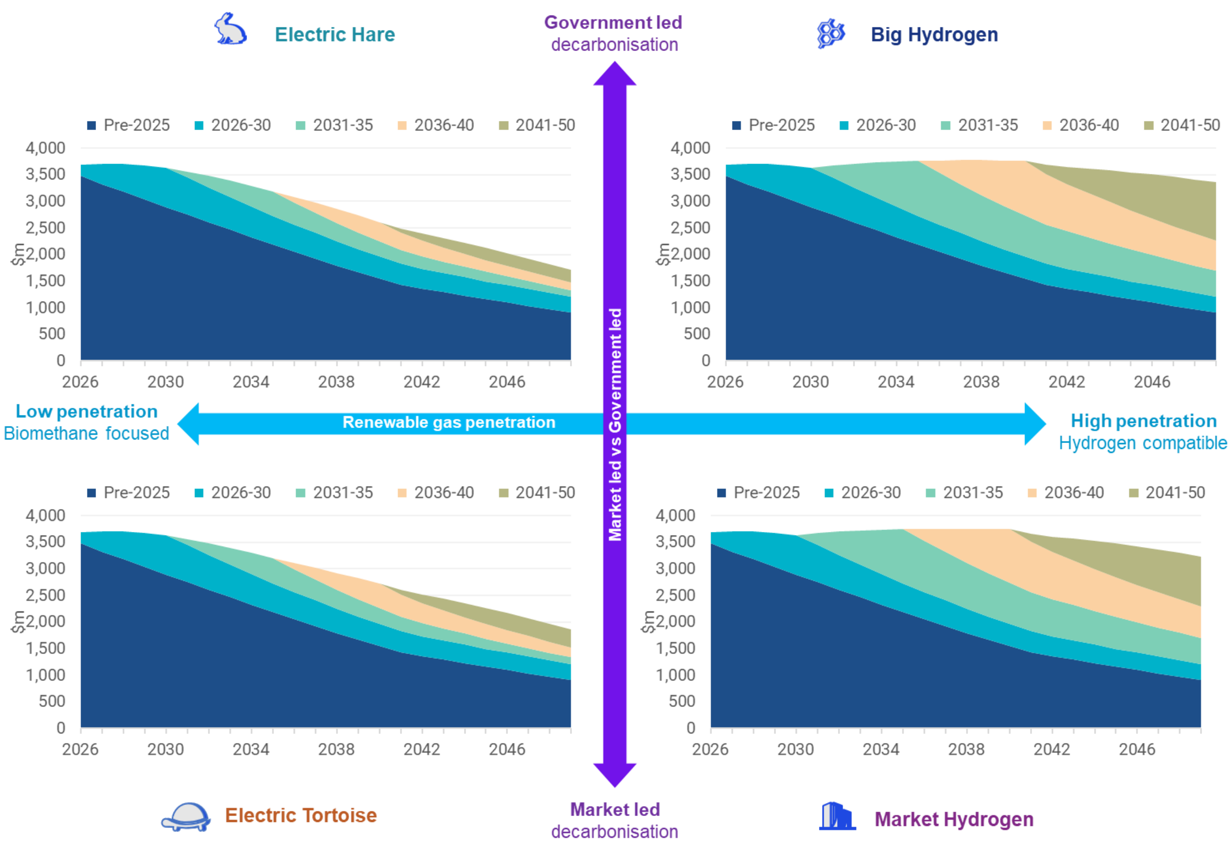
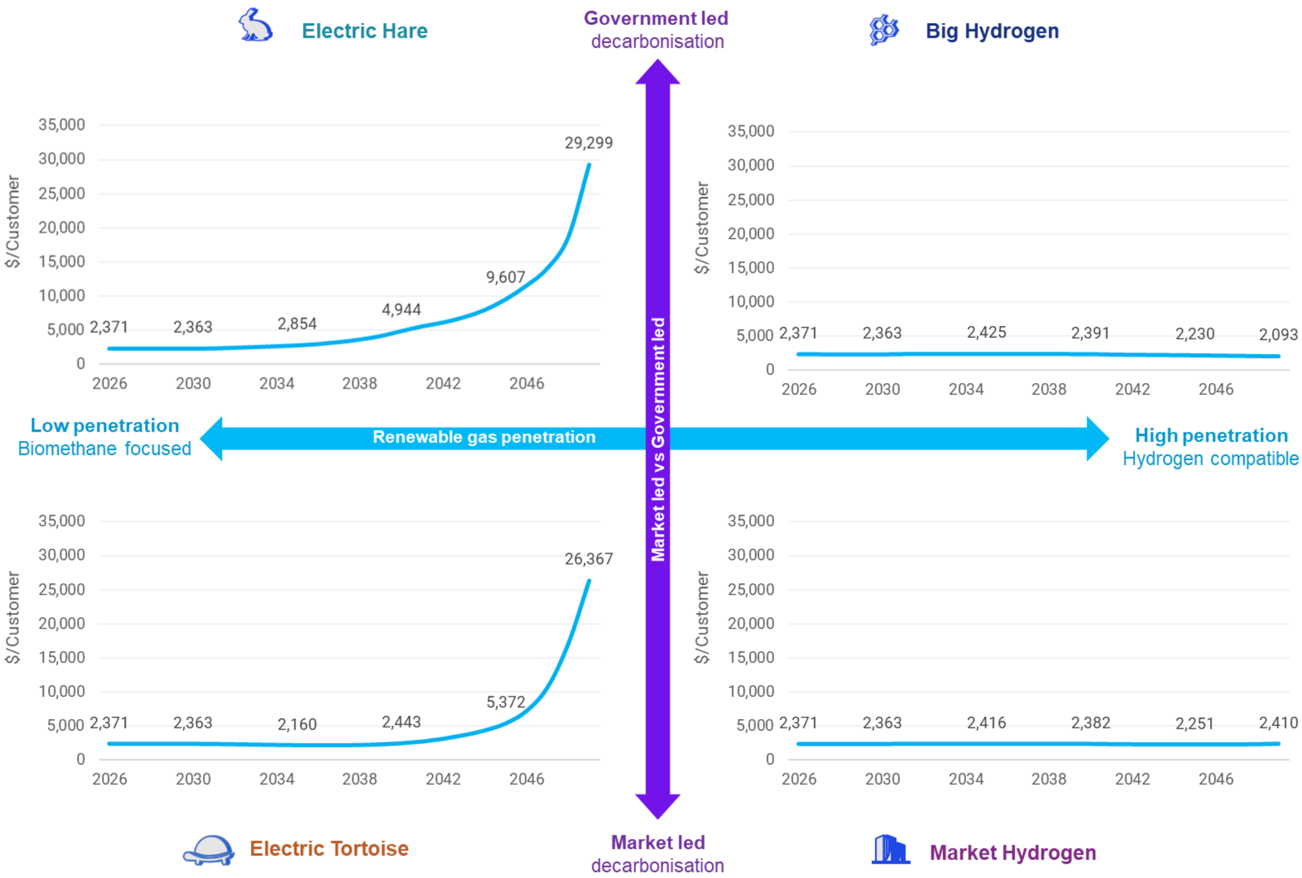


Figure 5-4 shows how the RAB per customer is projected to change over the 2026 to 2050 period. For the two electrification scenarios, customer numbers decline faster than the RAB, leading to a significantly ramp up in RAB per customer by 2050. It indicates that, without accelerated depreciation, the cost burden on future generations are disproportionately higher than current generations, leading to significant intergenerational equity issues.

Figure 5-4: Projected RAB per customer

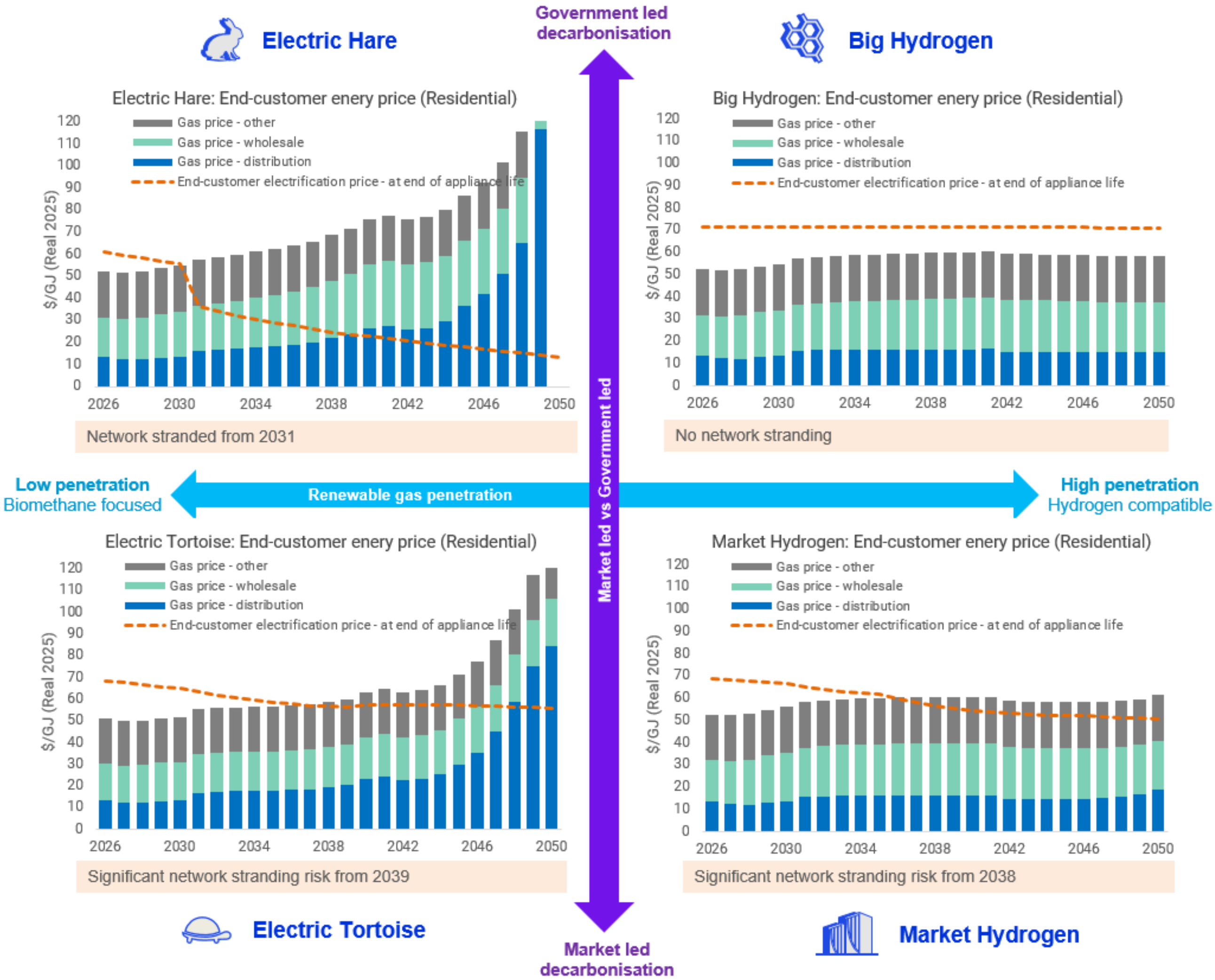


5.3 Impact on customers

Our FoG model derives the average network bill customers would pay over the 2026–50 forecast period by combining the long term demand outlook with the building block revenue required to maintain and operate our network. The model converts this network bill into a $/GJ charge and adds other key price components (i.e. wholesale, transmission, and retail) to derive the end-customer gas price. Figure 7-5 shows how this end-customer gas price (the sum of the bars) is then compared to the equivalent price of electrification for customers opting to switch to electricity (orange lines).

When gas price exceeds that of electrification, the risks of asset stranding of our network increase significantly. In three out of the four future scenarios below, gas price increase above the price of electrification before 2040, highlighting the level of stranding risks without any mitigation.

Figure 5-5: End-customer energy prices for residential customers



Our FoG analysis has enabled us to assess the four scenarios and understand impact on price stability, affordability and equity outcomes over the forecast period. Key observations include:

- Under the **Electric Hare** and **Electric Tortoise** scenarios there is a significant increase in the network gas bill as more customers disconnect from the network. With a diminishing customer base, the costs of maintaining the gas network are shared among fewer customers, leading to a substantial rise in customer bills towards the end of the forecasting period. Customers remaining on our gas network may be constrained with affordability challenges associated with costs required to retrofit their property and purchase new electric appliances. Other customers might be restricted in their ability to electrify, for example renters, or residential apartment blocks that share centralised gas hot water heating.

- In the **Electric Hare** scenario, gas remains competitive until 2030. Beyond that, the cost to electrify homes significantly reduces due to assumed government subsidies that contribute to the purchase of electric appliances. The customer base starts to decrease significantly driving up gas prices for customers remaining on the gas network. This can lead to asset stranding for us and our customers' gas appliances, and intergenerational inequity issues.

- In the **Electric Tortoise** scenario, gas loses competitiveness from 2039 as electrification costs continue to decline gradually. This means more customers switch to electricity when replacing household appliances leaving customers who find it harder to transition to electrification experiencing an increase in gas prices. Like the Electric Hare scenario this can result in asset stranding and intergenerational inequity issues.

- Under the two hydrogen scenarios—**Market Hydrogen** and **Big Hydrogen**—gas network bills remain relatively stable over time due to the retention of a larger customer base. The gas network bill for Market Hydrogen shows a slight upward trend from 2046 onward, with some customers reverting to electricity when an increase in the hydrogen blend requires upgrades to household gas appliances.
- Under the **Big Hydrogen** scenario, the viability of renewable gas keeps gas prices lower compared to electricity which in turn retains a higher number of customers. The gas network remains viable with lower asset stranding risks and overcomes intergenerational inequity concerns by ensuring a more equitable recovery of our assets.

Overall, in three out of the four scenarios, the price of electrification becomes lower than the gas price at some point before 2040, implying that customers are more likely to electrify in the longer term. This introduces substantial asset stranding risk for our network, which if not properly mitigated, will discourage further investments necessary for the network's safe and reliable operation, limit choice of fuel and flexibility for customers who remain on the gas network, and create intergenerational inequity issues associated with the inequitable recovery of our asset base. This reinforces why we have considered potential asset stranding risk mitigation initiatives as part of our future of gas analysis.

5.4 Effectiveness of our mitigation initiatives

Using our FoG model, we can examine the mitigation initiatives discussed in section 2.3. While some of these initiatives place an upward pressure on customer’s bills in the next five-year period, they will help provide greater stability to prices over the longer term. These initiatives are not mutually exclusive and are often complementary to each other.

We engaged with the Advisory Board on these mitigation initiatives and how they affect customer outcomes under the four future scenarios. That analysis is captured in a handbook prepared specifically for the Advisory Board, and included as *JGN - Att 2.5 - Appendix C to KPMG Advisory Board Report*. Overall, our future of gas analysis has shown that the earlier we start to address the risks presented by the energy transition, the smoother the pathway to net zero will be. In this session, the Advisory Board endorsed our mitigation initiatives to be taken to customer engagements.

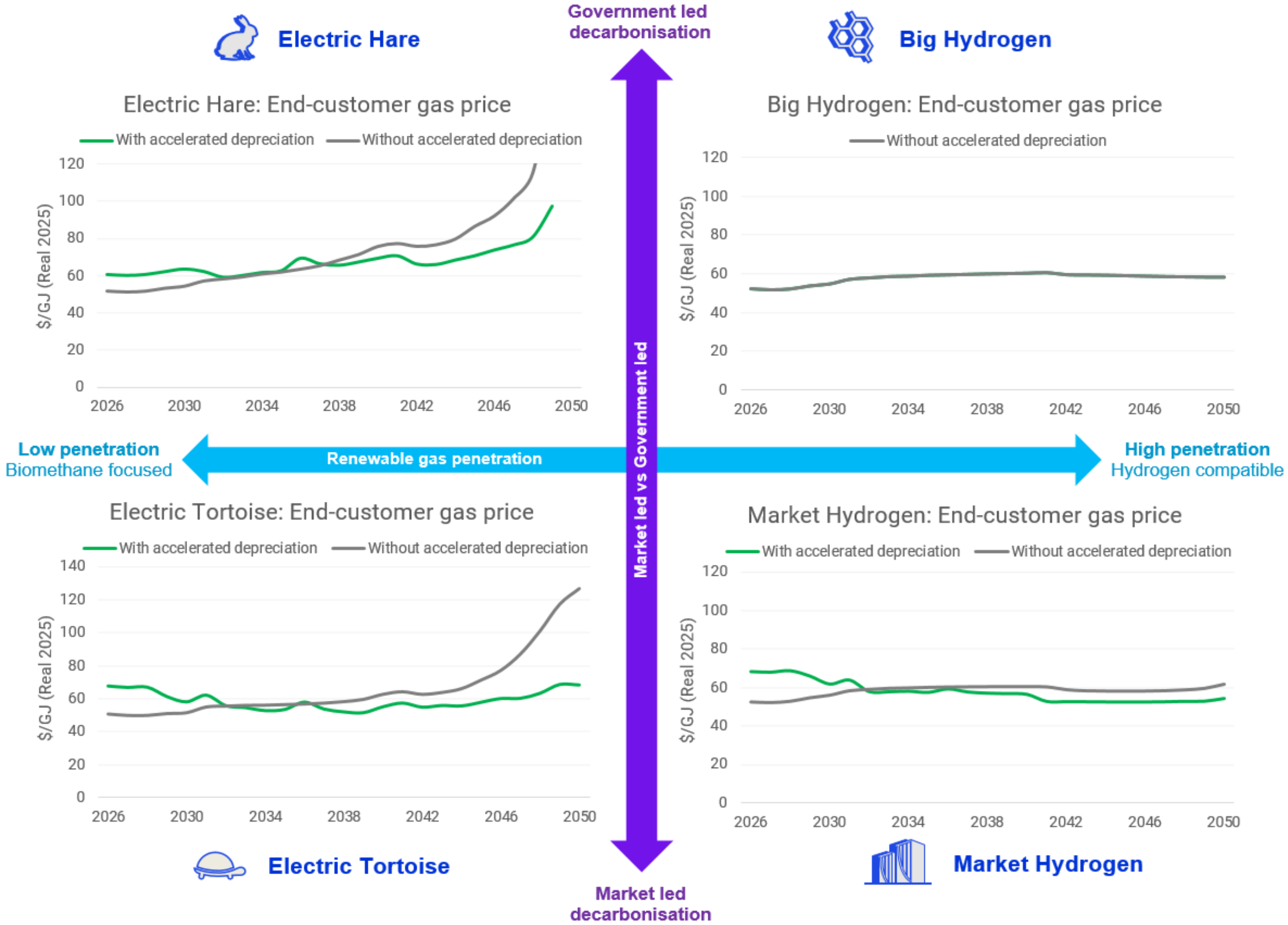
The next sub-sections consider four key responses that we have incorporated into our 2025 plan.

5.4.1 Accelerate capital recovery

Consistent with Crew and Kleindorfer 1992 paper, one of the most important mitigation initiatives is accelerated depreciation. The importance of capital recovery when technological change and competitive entry are occurring in the utility space is paramount. We tested a range of accelerated capital recovery or depreciation profiles across the four scenarios and assessed its impact on customers.

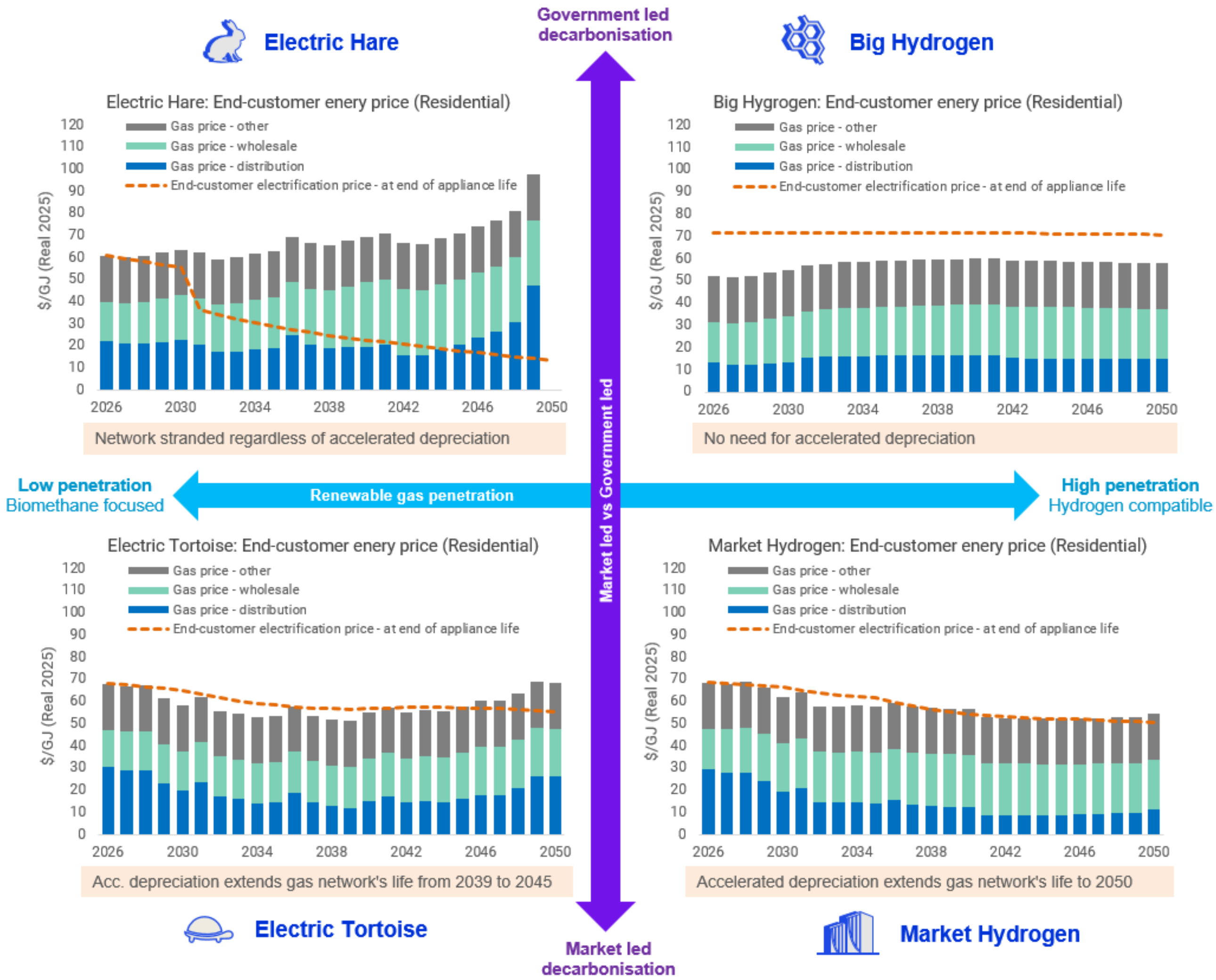
We found that although accelerated depreciation increases customer bills in the short term, it significantly lowers them over the horizon out to 2050, supporting overall price stability. The logic is that accelerating depreciation when there is a larger customer base to share the cost helps to reduce the cost burden on remaining customers in the long term. In all scenarios, accelerated depreciation provides more stable long-term prices and improves the intergenerational equity of customers utilising the gas networks. This is illustrated in Figure 5-6, which compares the residential end-customer gas price across four scenarios with (in green) and without (in dark grey) accelerated depreciation.

Figure 5-6: End-customer gas prices for residential customers



Accelerated depreciation initiative keeps the end-customer gas prices competitive for longer period when compared to the cost of electrifying. This is illustrated in Figure 5-7 and shows that with accelerated depreciation the gas prices (i.e., the stacked bars) align closely and often sit below the electricity price (the dotted line) across all scenarios, except for Electric Hare.

Figure 5-7: Comparison of residential end-customer gas and electricity prices with accelerated depreciation



We consider accelerated depreciation for our customer engagements and the 2026-30 regulatory proposal further in section 5.5.

5.4.2 Invest in renewable gas connections

Supporting renewable gas connections means that customers can access cleaner and more environment friendly gas. This is important for Australia to meet its environmental commitments. As the supply of renewable gas grows, it will require support of a competitive network such as JGN to sustain the uptake and provide fuel diversification. We discuss our proposal to support renewable gas connections in *JGN - Att 4.1 - Emissions reduction program* and *JGN - Att 5.1 – Capital expenditure*.

It is important for JGN to accelerate depreciation now so it can provide a lower network transportation cost in future for renewable gas suppliers. The two initiatives – accelerating depreciation and connection to renewable gas source are not mutually exclusive – but in fact are intertwined. Accelerating depreciation now can help us to lower our asset base in the future and keep network prices lower for renewable gas suppliers even as customer numbers drop. This works because we currently have a large customer base to spread network costs across and only a few renewable sources connected that would be impacted.

Accelerating depreciation now We can lower our future asset base and keep network prices

One possible way to rewrite the sentence in two sentences is:
We can lower our future asset base by speeding up depreciation now. This will help us offer more competitive network prices to renewable gas suppliers, even if we lose some customers over time as more renewable sources are connected.

5.4.3 Change asset management approach

In developing our capital program, we have explored opportunities to defer investment and make trade-offs that slow the growth in our asset base. By using digital tools to better understand the condition of our assets we can prioritise which assets need replacement and which assets we can work harder through more maintenance. Through this approach we can reduce main replacements expenditure over the 2025 Plan period without compromising on safety and network reliability. Replacing assets in a targeted manner reduces our capital expenditure and growth of our regulatory asset base. This in turn can reduce our stranding asset risk for new investments.

We discuss our proposed changes to our asset management approach in *JGN - Att 5.1 – Capital expenditure*.

5.4.4 Change connections policy

We have proposed changes to our connections policy so that more customers are required to make an up-front contribution if they wish to connect to our network. Such a change, if approved by the AER, would help to reduce the growth in our asset base and lower asset stranding risks.

We discuss our proposed changes to the connection policy in *JGN - Att 5.1 – Capital expenditure*.

5.5 Analysis on accelerated depreciation

We engaged with the Advisory Board and received their endorsement to pursue the accelerated capital recovery mitigation initiative in JGN's customer engagements. We derived customer bill impacts of accelerated depreciation initiative, and to effectively illustrate the trade-offs between short-term and long-term impacts on customers.

This analysis was used in our consultation with our Customer Forum, our Draft 2025 Plan, and ultimately our final 2025 Plan.

The sections below explore:

- how accelerated depreciation can improve our ability to recovery our efficient costs and lower stranding risk
- how different levels of depreciation affect projected gas customer bills
- how delaying accelerated depreciation can increase price volatility and push up bills for future generations.

5.5.1 Cost recovery risk

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

5.5.2 Balancing long-term and short-term price impacts

We use the FoG model to test how different levels of accelerated depreciation affect projected gas bills. This was important for our broader engagement with customers and other stakeholders.

The long-term analysis in section 5.4.1 shows that the accelerated deprecation needed to make gas more competitive is between $1.55–2.38 billion (Real 2025) over the 2026–30 period. It translates into increases to 2024-25 residential bills of between $141 to $228 (Real 2025) per year, or 56–91%.

Our customers have told us that affordability is important for them. Conscious of this, we capped the accelerated depreciation options that we engaged on with them to $300–700 million (Real 2025) over the 2025–30 period. That range translates into a much lower price impact; ranging from $5 (Real 2025) more per year on average compared to 2024-25 if $300 million (Real 2025) is adopted to $51 (Real 2025) on average if $700 million (Real 2025) is adopted.

Figure 5-13 shows how we narrowed our accelerated depreciation options (in orange area) down from what is needed to keep gas competitive (in blue bars) across the four scenarios. Figure 5-14 then compares the average annual bills over the 2025–30 period that would result from applying a range of options from no accelerated depreciation to high accelerated depreciation.

The analysis on accelerated depreciation options for $300–700 million were presented to our customers in Customer Forum 5 and 6 in July and August 2023. Our customers voted on the accelerated depreciation in Forum 5 and the result was: 44% of the group voted $300m, 44% voted $500m and 12% voted $700m. In Forum 6, when considering all mitigation initiatives as a package, most customers voted in favour of the $300m option. We provide more details of our engagement in section 3.4.3 of *JGN - Att 7.3 - Depreciation approach*.

Figure 5-13: Narrowing our accelerated depreciation options

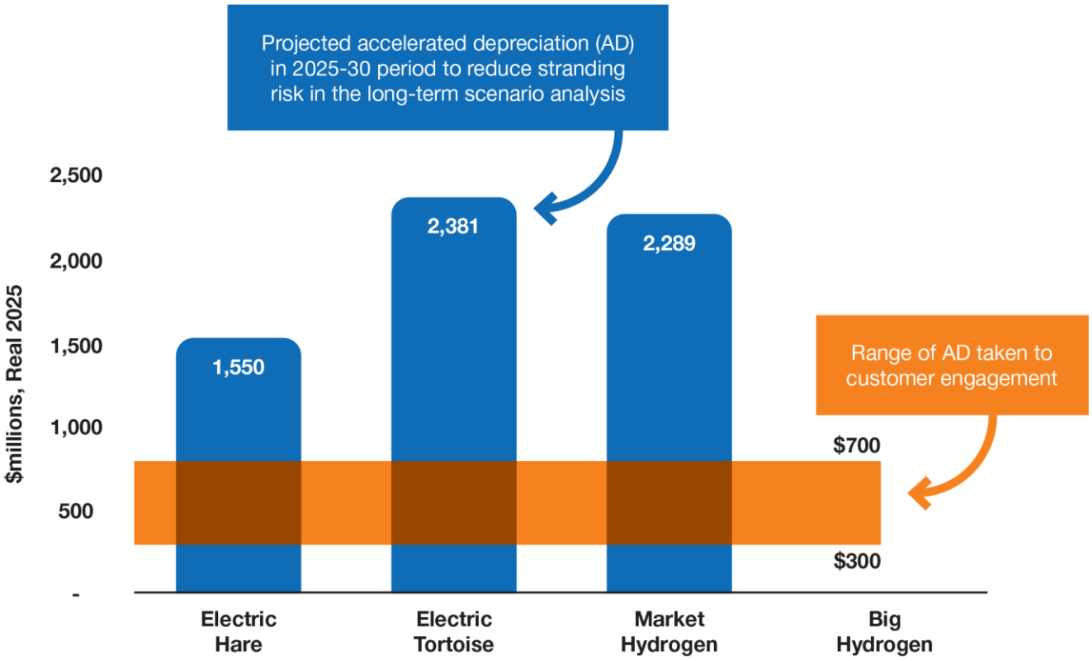
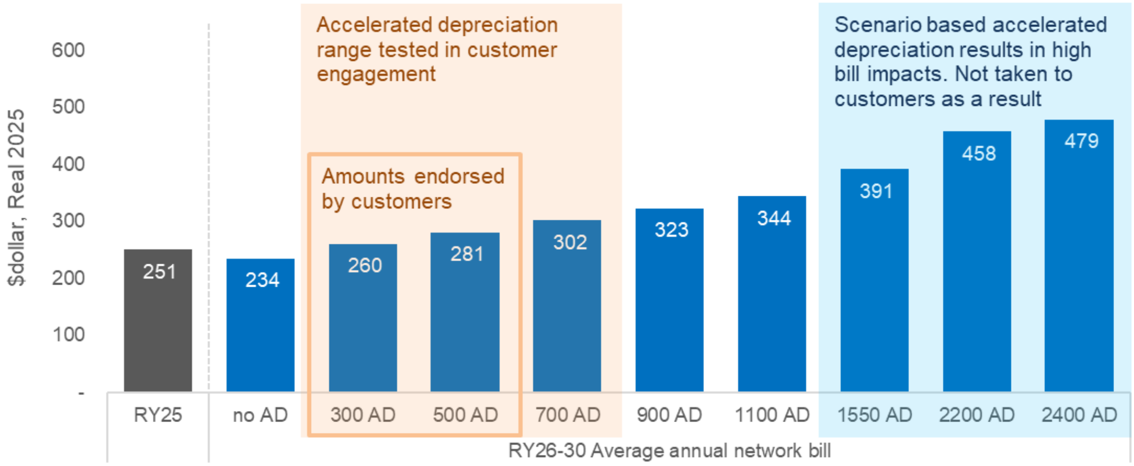


Figure 5-14: Average network bills under alternative accelerated depreciation options

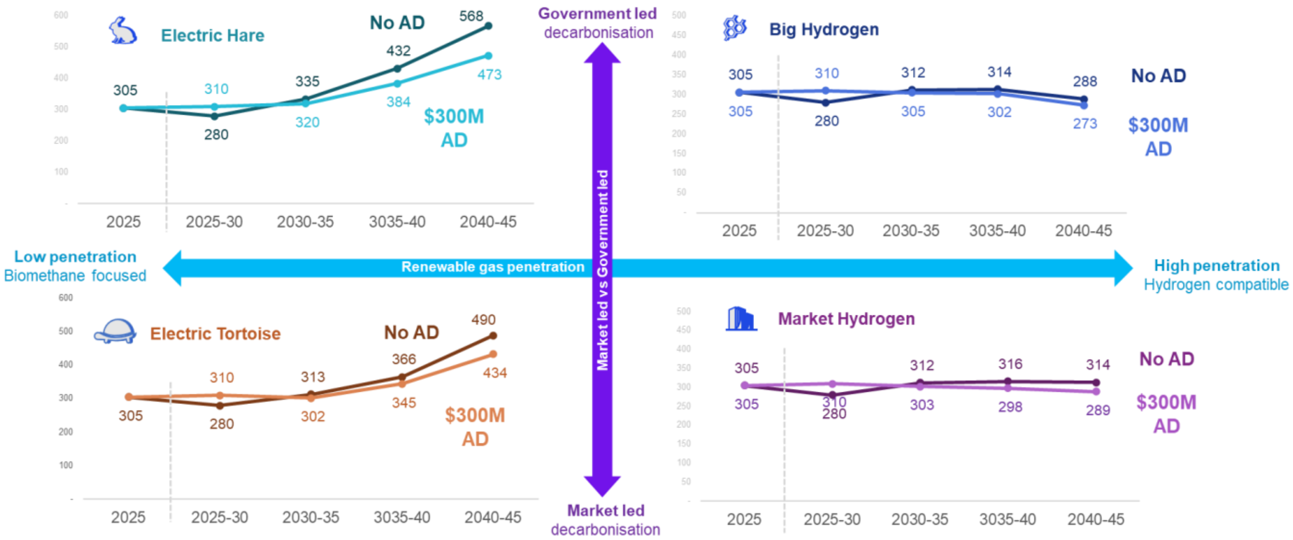


We published our 2025 Draft Plan in February 2024 with an accelerated depreciation proposal of $300m supported by our customers. Through consultations of our 2025 Draft Plan, we received feedback from our Advisory Board with concerns on not presenting a ‘do nothing’ or zero accelerated depreciation option for customers. In response to this feedback, we undertook a further customer engagement session (Customer Forum 8) in March 2024 with a focus on presenting the outcome of zero accelerated depreciation and comparing it with the $300-700m acceleration options.

Our analysis shows how accelerated depreciation of $300 million, $500 million, and $700 million affected projected gas bills across all four scenarios compared to no acceleration. These projections are shown in Figure 5-15, Figure 5-16, and Figure 5-17, respectively, and compared to the projected bills that would apply if there was no accelerated depreciation. The impacts are then summarised in Figure 5-18. It shows that the higher the amount of depreciation over the 2025–30 period, the lower the projected bills in subsequent periods.

In this customer forum, 84% of customers voted in support of accelerating depreciation of $300m or above. We provide details about the engagement outcome in section 3.4.3 of *JGN - Att 7.3 - Depreciation approach*.

Figure 5-15: Impact of $300M in accelerated depreciation[13]



13 The bills represent the average network bill for a residential customer consuming 15GJ per annum (dollar, real 2025). The 2046–50 period has been intentionally been left out of the charts to make it easier to visualise the bill impact of alternative accelerated depreciation amounts.

Figure 5-16: Impact of $500M in accelerated depreciation[13]

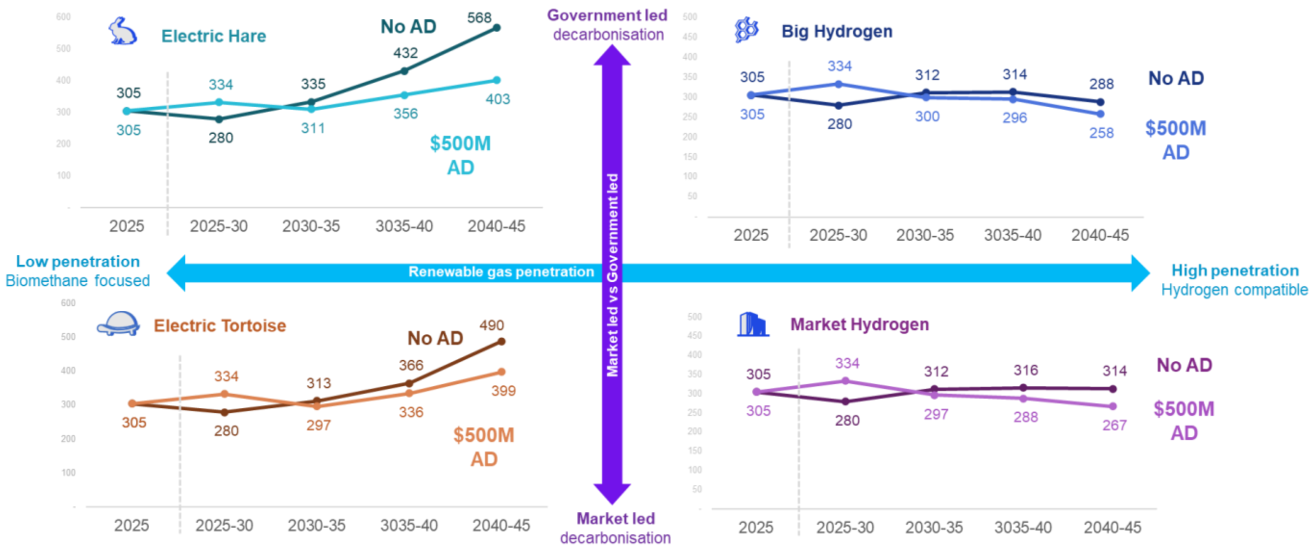


Figure 5-17: Impact of $700M in accelerated depreciation[13]

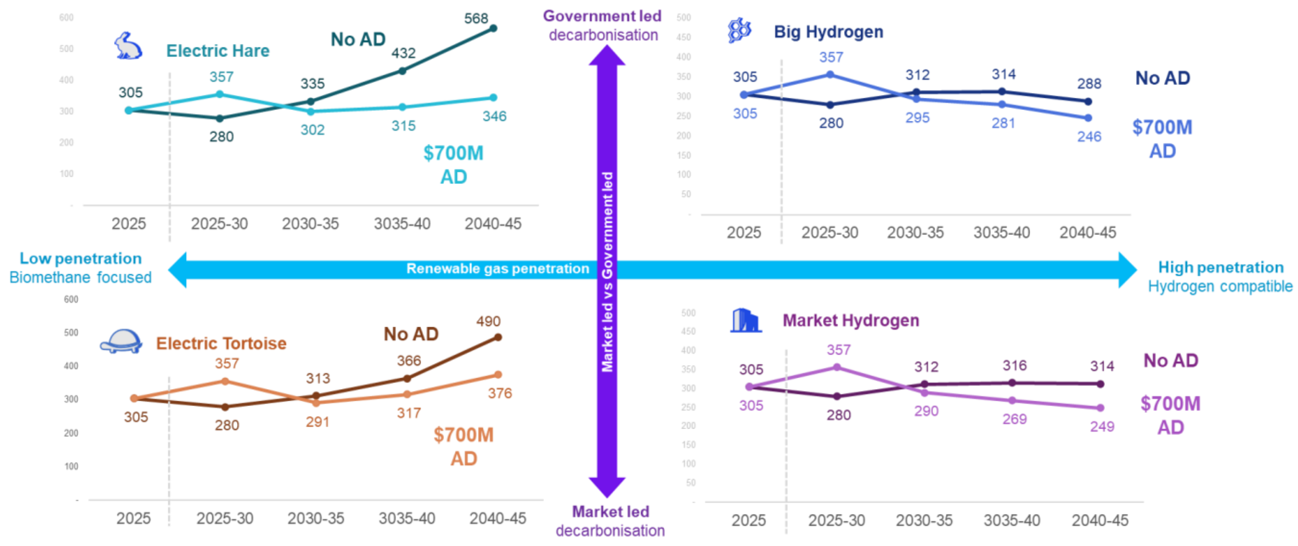
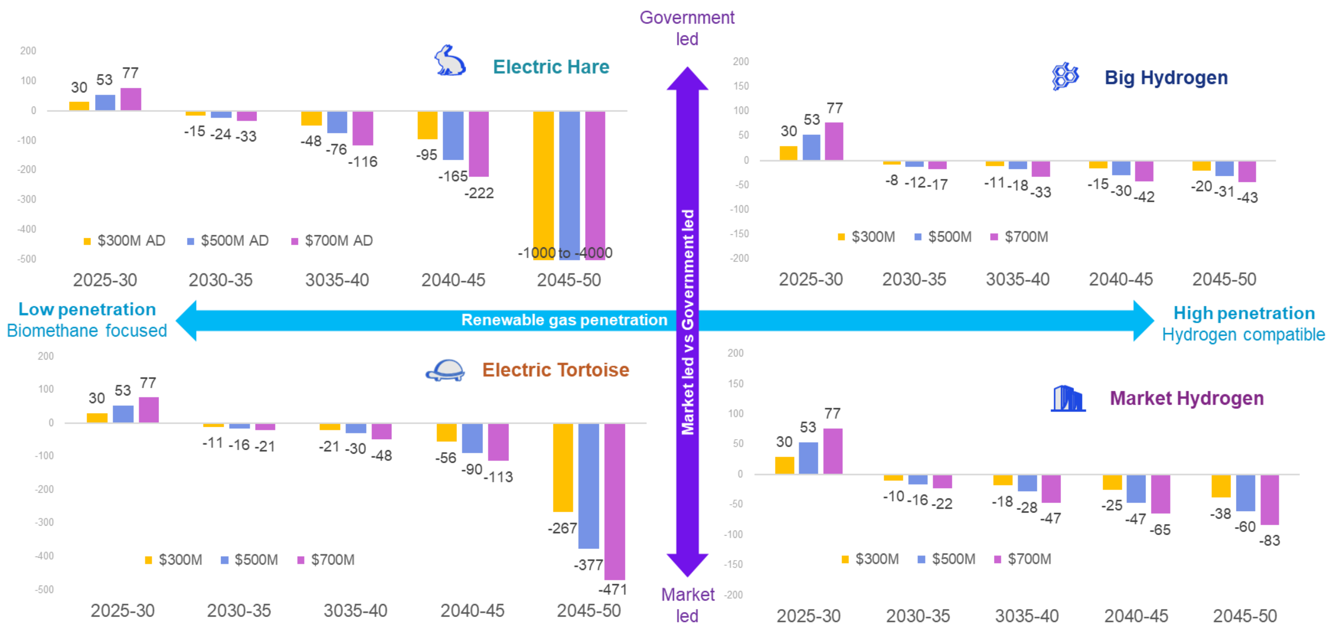


Figure 5-18: Incremental bill impact for $300M to $700M accelerated depreciation



5.5.3 Impact of delaying accelerated depreciation

Delaying accelerated depreciation is expected to increase gas bills in future years. This is because we are effectively deferring that capital recovery to a period when there are fewer gas customers, leading to a higher amount of capital recovery per customer.

We tested the delaying option using the FoG model by comparing the $300 million accelerated depreciation option in FY26–FY30 period considered above with a five year delay in FY31–FY35 period. As shown in Figure 5-19, across all scenarios, this led to more volatile projected bills, with lower bills over the FY26–FY30 period offset by higher bills over the FY31–FY35 period.

Figure 5-19: Impact of delaying $300 million in accelerated depreciation by 5 years[13]