Jemena Gas Networks (NSW) Ltd

2025-30 Access Arrangement Proposal

Attachment 6.1

Operating expenditure

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Overview

Chapter 6 of Jemena Gas Networks (NSW) Ltd's (**JGN**) 2025 Plan sets out the forecast operating expenditure (opex) requirements for the 2025 Plan Period. The purpose of this document is to provide additional information on our historical and forecast opex requirements, including an explanation of how we have developed our opex forecast for our reference services for the 2025 Plan period. It explains how the feedback that we have received from our customers has informed the development of our opex forecast. It seeks to demonstrate that the opex forecast is prudent, efficient and compliant with the National Gas Rules (**NGR**).

Customers have told us that issues of affordability – particularly in a context of rising inflation – continue to be front-of-mind and challenging. They want us to ensure gas remains affordable for customers in the longer term whilst we transition to a renewable gas and environmentally friendly market.

We are committing to keeping opex per customer constant over the 2025 Plan period. This is despite increases in Information and Communication Technology (**ICT**) costs due to transferring some costs from capex to opex and for new capacity requirements, investments required to comply with new emissions reporting requirements, the purchase of Australian Carbon Credit Units (**ACCUs**) to comply with Safeguard Mechanism requirements, and investing in new initiatives to support customers experiencing vulnerability.

We forecast our opex using the AER's preferred forecast method, 'base, step, trend'. The method forecasts future opex using a base year – where the operating costs are representative of the efficient costs necessary to operate and maintain the network, and to meet regulatory obligations. According to recent analysis by Competition Economists Group (**CEG**), who we engaged to benchmark our performance against our peers, we continue to benchmark well in relation to opex, capital expenditure (**capex**) and our total costs.

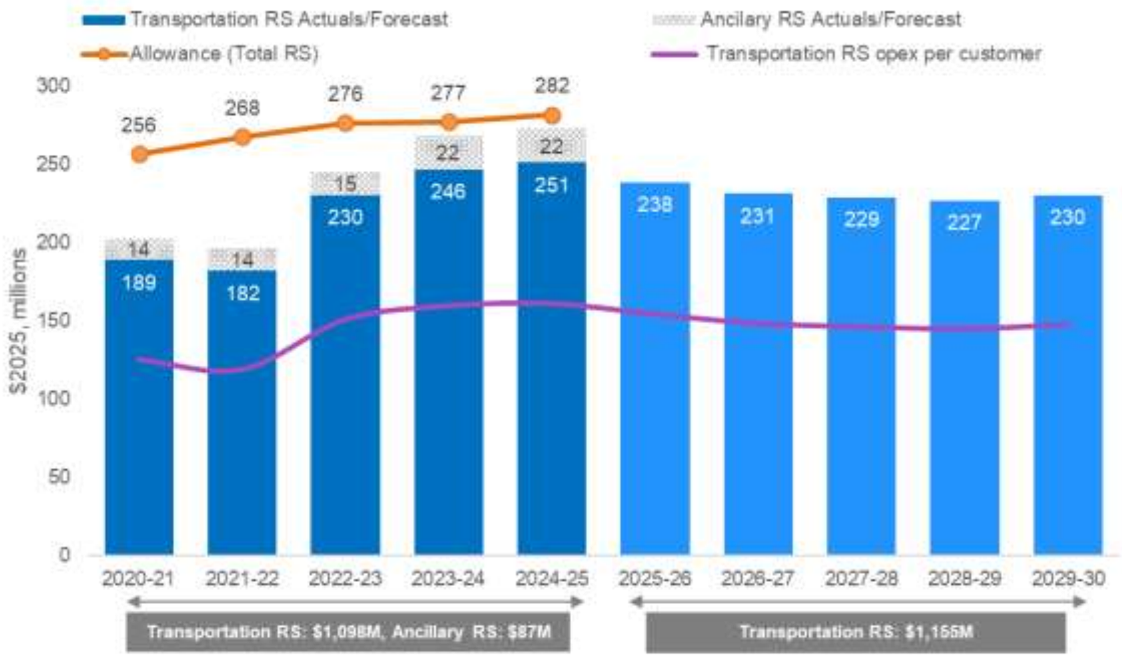
Whilst most of our opex is generally recurrent in nature, funding the regular operations required to deliver reliable network services, we have some step changes for new regulatory obligations, an increase in expected pipeline integrity management measures, major external factors outside our control associated with our ICT spend, costs for providing support for customers experiencing hardship/vulnerability and reducing our emissions as strongly supported by stakeholder engagement outcomes. Our step changes are discussed in *JGN-Att 6.2-Opex step change justification*.

We have also used specific forecasts for items that the base year opex does not provide a reasonable basis with which to forecast future opex requirements. We have done so for costs associated with UAG, government levies, Safeguard Mechanism costs and debt raising costs.

From 1 July 2025 our current reference service will be split into Transportation Reference Service (**Transportation RS**) and Ancillary Reference Services (**Ancillary RS**). This opex attachment deals with opex associated with our Transportation RS. In the 2020-25 period, both Transportation RS and Ancillary RS opex were forecasted using the base, step, trend approach. After separating these two services, Ancillary RS costs are forecasted separately based on a bottom-up cost build-up of individual services, which is discussed in *JGN-Att 7.2-Ancillary reference service cost build up approach*.

Table OV–1 shows our total opex for Transportation RS and Ancillary RS over the 2020-25 and 2025-30 periods, and the AER total opex allowance for the 2020-25 period.

Figure OV–1: Total opex, current and forecast period ($2025, million)



As can be seen from Figure OV–1 above, our total forecast opex for the 2025 Plan period is $1,155M, inclusive of debt raising costs. Our forecast opex for our Transportation RS and Ancillary RS over the 2025 Plan period is around 9% lower than our allowance for the 2020 Plan period. When comparing Transportation RS opex, our forecast opex is about 5% higher compared to what we expect to incur in the current 2020-25 period.

Despite our forecast increase in opex, opex per customer is constant over the 2025 Plan period.

The drivers of the increase in Transportation RS opex over the 2025-30 period compared to 2020-25 period is largely due our opex step changes for the transition to cloud-based and other ICT services ($15M), emissions measurement ($21M), pipeline integrity management ($28M), legislative requirements pertaining to emissions reporting ($4M) and safeguard mechanism compliance ($10M), offset by assumed productivity improvements of $24M (which will be challenging for us to achieve).

We undertook a thorough assessment to determine that our forecast opex represents the amount that is required to meet our obligations and customers' expectations efficiently, and to promote the long-term interests of our customers.

Structure of this attachment

This attachment is focussed on Transportation RS and is structured as follows:

- Section 1 presents and explains JGN's Transportation RS opex forecast
- Section 2 provides an overview of what we have heard from our customers and how we have incorporated their feedback into our 2025 Plan
- Section 3 describes JGN's operating cost categories
- Section 4 provides an overview of our current period opex performance
- Section 5 provides an overview of our opex forecasting approach
- Section 6 explains why our proposed base year is relevant starting point for setting our recurrent opex forecasts, including our benchmarking performance. This section also explains the adjustments made to the base year opex for removal of Ancillary RS opex, Software as a service (**SaaS**) and information technology related project opex.

- Section 7 explains our approach for trending the base opex
- Section 8 provides an overview of our Transportation RS step changes (which are set out in more detail in *JGN-Att 6.2-Opex step change justification*), and
- Section 9 explains estimation of our specific cost forecasts such UAG, government levies, and safeguard mechanism.

Unless otherwise stated, all financial numbers in this document are presented in real 2025 dollars.

List of opex attachments

Table OV–1: List of opex attachments

Attachment	Name	Author
5.5	Input cost escalation	Oxford Economics
6.1	Operating expenditure	JGN
6.2	Opex step change justification	JGN
6.3M	Operating expenditure forecasting model	JGN
6.4	Relative efficiency and forecast productivity growth of JGN	CEG
6.5	Cost allocation methodology	JGN
6.6	Debt transaction costs and PTRM timing benefits	JGN
6.7	Unaccounted for gas	JGN
6.8	UAG report	Frontier Economics
6.9M	Estimated UAG rates	Frontier Economics
6.10M	Safeguard mechanism reporting model	JGN
6.11M	Climate reporting model	JGN

1. Our opex forecast for the transportation reference service

Opex is a major component of our building block costs, accounting for approximately 40% of JGN's total cost of service over the 2025 Plan period. Table 1–1 details our forecast opex over the 2025 Plan period for our Transportation RS. The forecast opex model is provided in *JGN-Att 6.3M-Operating expenditure forecasting model*.

Table 1–1: Forecast Transportation RS opex for 2025-30 period

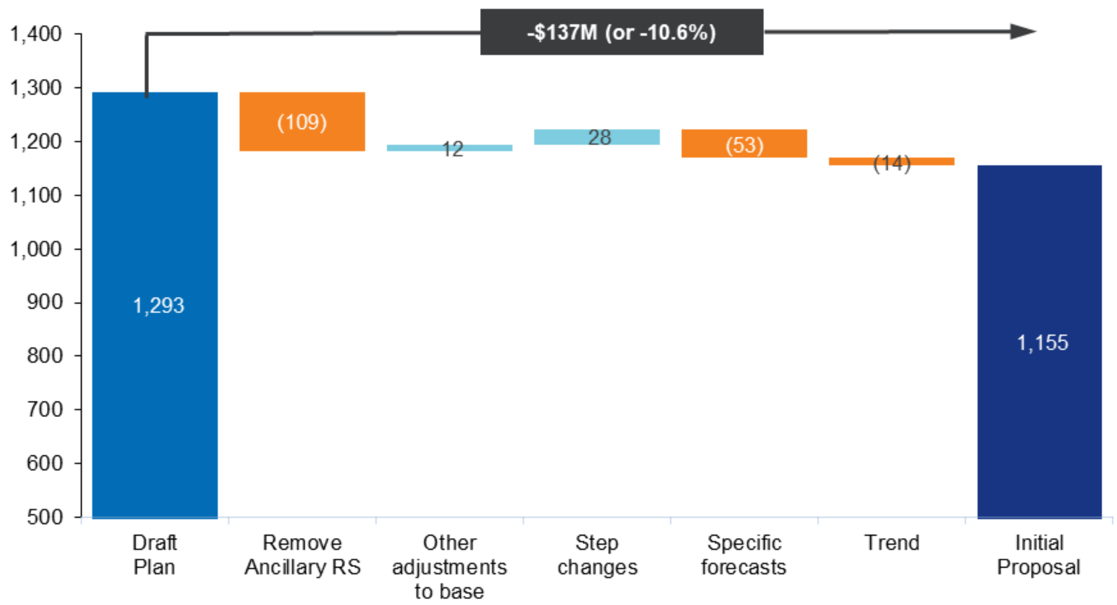
Category	Description	Total forecast opex ($M)
Establish efficient base year	Our proposed base year is 2023-24. The estimated base year opex before removing Ancillary RS is $268M. This estimate will be updated in our reviewed proposal in January 2025 to reflect the full year actual audited costs.	1,342
Adjust base year opex	We have made adjustments to the base year opex to: • remove category specific forecasts in the base year • remove costs relating to Ancillary RS to reflect the separation of Ancillary RS from 1 July 2025 • re-allocate SaaS implementation costs from capex to opex in line with the AER's guidance[1] • include the project costs associated with establishing and implementing new ICT cloud based service capacity • account for the increment from base year to final year in the model.	-458
Estimate trend	We have trended the efficient base forward by applying rate of changes. This includes: • Output growth (customer number and line length) of $19M • Price growth (labour) of $19M • Ongoing productivity improvements of 0.86% per annum, which equates to a reduction of $24M over 5 years	14
Develop category specific forecasts	We have developed specific forecasts for items where base year costs are not representative of the costs we expect to incur. This includes: • UAG $146M • Licence fees and government levies $21M • Safeguard Mechanism costs $10M • Debt raising costs $10M	187
Forecast step changes	We have proposed the following step changes: • Support for customers experiencing vulnerability $3M • ICT services $15M • Climate change reporting $4M • Emissions measurement (Picarro) $21M • Pipeline Integrity Management program ('pig and digs') $28M	70
Total		**1,155**

[1] In April 2021, the International Financial Reporting Interpretations Committee (IFRIC) released a guidance note requiring SaaS implementation costs treated as opex. When the 2020-25 allowances were determined for JGN in April 2020, these costs were classified as capex. To ensure our reported actuals and allowances are comparable based on consistent accounting treatments, the AER provided guidance for us to continue applying the old accounting treatment (i.e. capitalising SaaS implementation costs) for the current regulatory period 2020-25 and apply the new accounting treatment from the 2025-30 period. We have adjusted our opex and capex accordingly in our expenditure in line with the AER's guidance for both the 2020-25 and 2025-30 periods.

1.1 Changes from our Draft 2025 Plan

In our Draft 2025 Plan, our forecast opex was $1,293M over 2025-30 period for Transportation RS and Ancillary RS, compared with our proposed $1,155M for Transportation RS in the 2025 Plan. This results in a difference of $137M. After excluding the impact of Ancillary RS, our proposed opex is $28M lower than the Draft 2025 Plan. Figure 1–1 shows a comparison between our Draft 2025 Plan and our 2025 Plan.

Figure 1–1: Opex forecast between Draft 2025 Plan and 2025 Plan ($2025, million)



This is a result of the following key changes since we published our Draft 2025 Plan:

1. Our Draft 2025 Plan included opex for our total reference services, that is, for our Transportation RS and Ancillary RS. To be consistent with the AER's preferred treatment of Ancillary RS, we have backed out Ancillary RS opex from base opex based on an estimate of what we expect to incur in our base year. This results in a difference of $109M between the Draft Plan and Initial Proposal. These forecasts will be updated once we have actual opex available for our base year of 2023-24.

2. The inclusion of a base year adjustment on incremental ICT project costs based on the AER's feedback through the Early Signal Pathway engagement.

3. Increase in our step changes of $28M, including a new step change on pipeline integrity management and an increase in emissions measurement activities.

4. Reduction in specific forecasts driven by lower cost of unaccounted for gas (**UAG**) due to update of gas price from AEMO.

5. Updated estimates on output growth, labour escalation and productivity adjustments based on external experts forecasts from CEG and BIS Oxford.

2. What we have heard from our customers

To understand the needs and expectations of our customers, and to ensure that our opex proposals for the 2025-30 period have been informed by them, we have undertaken an extensive engagement program which we discuss in chapters 2 and 3 of our 2025 Plan. The engagement program was designed to understand customer expectations and values regarding the future role of gas and allowed opportunity for customers to provide recommendations and preferences on a range of initiatives -some of them require opex funding - that has informed the development of our 2025 Plan.

When considering their recommendations and preferences, customers were mindful of the values they had agreed on – including the values of CALD and Youth customers - which was a key element to the Customer Forum process to ensure their recommendations balanced the diverse views of customers.

These customer Values are:

- **Affordability:** ensuring gas remains affordable for customers in the long term.
- **Safety**: safety needs to remain a given with no additional risk introduced.
- **Reliability**: “gas should come on whenever I want it to”.
- **Planning for the future:** one clear message came through on the topic of planning for the future, to act now, rather than delaying action and working towards a net zero future including renewable gas options.
- **Fairness:** ensuring that future customers do not carry the cost burden of current customers who have higher gas demand or leave the network earlier than others and that the impact of our decisions is considered across the wide diversity of customers in our network.
- **Access or choice:** retaining choice for individuals, and diversity in the energy supply.

Guided by these Values, the Customer Forum made six recommendations - outlined in chapter 3 of our 2025 Plan – which cover the following initiatives:

- Renewable gas strategy for supporting customers
- Renewable gas reliability and safety
- Renewable gas advocacy and communication
- Affordability
- Vulnerability
- Regulatory response options.

Our opex proposals for the 2025-30 period have considered feedback garnered from the engagement program to ensure our initiatives align with what customers’ value and the Customer Forum recommendations. A key theme throughout Customer Forum deliberations and the boarder engagement program has been **Affordability**. In line with this customer value, we are committed to keeping opex per customer relatively constant over the 2025-30 period and we will continue to operate efficiently to ensure the provision of affordable gas network services which is demonstrated by our independent productivity analysis discussed in section 7.2.

In terms of the initiatives considered by the Customer Forum that support Affordability, 92% of participants agreed that we should do more to support customers experiencing vulnerability which includes more communications, especially to include diverse groups by translating materials that cater for this diversity and increasing our involvement in key community programs. This sentiment was shared by other customer segments we engaged including Small Business Customers. Aligned with this customer expectation, we propose a total of $2.7M to enhance customer support for customers experiencing vulnerability which we discuss in *JGN-Att 6.2-Opex step change justification*.

In developing our opex for the 2025 Plan, customer values associated to **Reliability** and **Safety** have been a key focus area. Our pipeline integrity management opex of $28M - referred to as 'pigs and digs' – will support safety and compliance activities that are necessary to avoid risk of failure in our high pressure pipes and sustain network reliability. Our ICT opex step change of $15M includes cost related to supporting maintenance and ongoing operational activities required to sustain the safe and reliable functionality of our network. We discuss these step changes further in *JGN-Att 6.2-Opex step change justification*.

Throughout our engagement with customers, they consistently expressed their desire for us to prioritise safety. Given the critical safety implications of preventative measures and the potential risks to us if the program is not carried out correctly, we decided that seeking customer input on our approach to pipeline integrity management would not be appropriate. Presenting customers with options for varying levels of pigging activities would be disingenuous, as we are not willing to consider alternative programs or options that could compromise safety. This approach aligns with our engagement objectives, which include building trust and fostering collaboration with customers in formulating our 2025 Plan. We believe that maintaining the integrity of our pipeline system is a non-negotiable aspect of our operations, and we remain committed to upholding the highest safety standards.

Another key value that came through the customer engagement program was **Planning for the Future** and taking action towards a net zero future. Our opex forecast includes provision for emissions reduction reporting of $3.6M and the purchase of ACCUs to meet Safeguard Mechanism requirements, forecast at $10M. The Safeguard Mechanism is the Australian Government's policy that aims to reduce emissions for facilities by establishing a greenhouse gas emission threshold which we discuss in section 10.4

Following the publication of our Draft 2025 Plan we held a recall session with our Customer Forum (Forum 8), and including some members of the Key Voices groups, to test the overall support of the Draft 2025 Plan and whether our proposals aligned with the Customer Forum's recommendations in a balanced manner. In Customer Forum 8, we reminded participants of Picarro's role in supporting a targeted approach to mains replacement, and also discussed its role in helping us reduce our carbon emissions. Customer Forum participants expressed strong support for us investing in Picarro to enable us to reduce network emissions - 94% of the Customer Forum supported the proposal. In line with customer expectations, our opex proposal for the 2025-30 period has forecast a cost of $21M to invest in Picarro technology which will enable us to more accurately detect leaks in our network and adopt a more proactive approach to asset management when planning for the future. This step change is further discussed in *JGN-Att 6.2-Opex step change justification*.

3. Operating cost categories and cost allocation

3.1 Operating cost categories for our reference service

We incur opex by undertaking a range of activities to maintain and support our network. These activities include ongoing network maintenance, such as inspections, repairs, and emergency response for unplanned outages or incidents. We also incur opex in network planning and design, customer service, field operations, and corporate support, such as ICT.

Figure 3–1: Our opex categories for our reference service

Operating expenditure categories
Repairs and maintenance
Marketing and retail incentives[2]
Debt raising
Unaccounted for gas
Government levies
Other operating expenditure

Appendix A includes an overview of each opex cost category.[3]

3.1 Cost allocation for our services

The JGN Cost Allocation Methodology[4] (**CAM**) governs how costs are allocated to the Reference, Non-reference and Non-Pipeline Services provided by means of the JGN network, in accordance with rule 93(2) of the NGR. The CAM has been applied to report reference services costs separately—that is, non-reference services costs are excluded from the opex forecast.

[2] We note that consistent with customer feedback, our proposed marketing costs included in marketing and retail incentives over the 2025 Plan period are forecast to be on promoting use of renewable gas. Further, any funding of marketing costs will be from our opex base year; that is, we are not proposing additional step changes for marketing activities.

[3] Rule 72(1)(a) of the NGR.

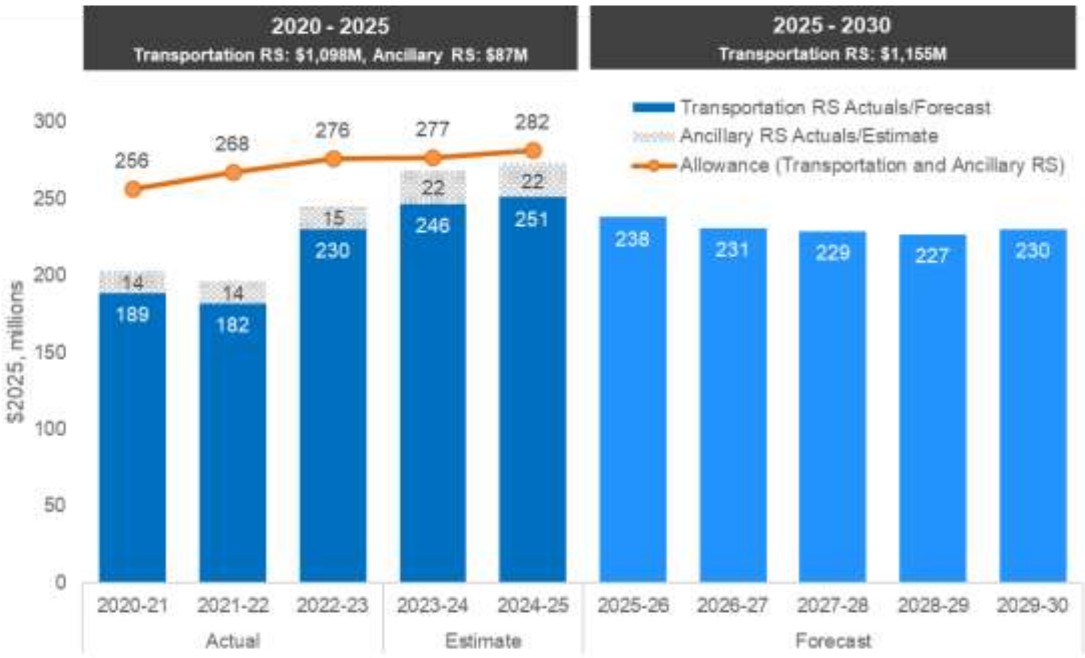
[4] JGN-Att 6.5-Cost Allocation Methodology.

4. Overview of current period performance

Over the 2020 Plan period, our reference service includes both Transportation RS and Ancillary RS and our opex allowance was based on the total reference services. We expect to incur $1,185M of opex consisting of $1,098M Transportation RS and $87M Ancillary RS. This is $135M or 10% below the allowance approved by the AER.

Figure 4–1 shows our actual and estimated opex spend against the AER allowances over the 2020 Plan period for our current reference services (Transportation RS and Ancillary RS), and our forecast opex for Transportation RS.

Figure 4–1: JGN actual and forecast opex over 2020-30 ($2025, million)



The underspend is largely driven by the following factors:

- Prior to 2021-22, JGN implemented a transformation program to simplify business processes and lower operating costs. This resulted in a sustained reduction in our opex cost base and partially offset the impact of a change in our capitalisation policy to expense all corporate overheads.
- Over the 2020-22 period, many operational activities were temporarily halted by the impact of repeated COVID-19 lockdowns. This included meter reading and a range of inspection and maintenance activities. These activities have since returned to normal levels from 2022-23.
- During 2021 and 2022, prolonged wet weather caused by the La Nina weather event resulted in significant flooding across NSW impacting operational activities.[5] However, following these flooding events, spending in emergency repairs and maintenance, as a result of water entering pipelines, resulted in increased costs to undertake repairs in 2023 and 2024.[6]
- Partially offsetting the reductions to opex, was a material increase in UAG replenishment costs in 2022-23 and 2023-24. The increase in UAG costs was due to significant spikes in wholesale gas prices following the European energy crisis in 2021-22 and the conflict between Russia and Ukraine. Despite the significant increase in the UAG costs, we were able to operate below the opex allowance approved by the AER.

5 In March 2021, following months of prolonged wet weather, a series of floods affected large parts of the east coast of NSW, including Sydney. It was the most significant flood event in 60 years in parts of the state, and the Australian Government declared many parts of the east coast a natural disaster zone. This was followed by further flooding in February 2022.

6 Costs to relight households were also incurred following the significant gas outage in Bathurst, when an APA pipeline delivering gas to our Bathurst network suffered damage during flooding, resulting in a loss of gas supply to the area.

4.1 Analysis of opex by category

Rule 72(1)(a)(ii) of the NGR requires the Access Arrangement Information to provide actual opex by category over the current 2020 Plan period. Our historical opex is provided in Table 4–1, with a comparison against the AER approved costs. Further details on our historical category level opex are provided in Annual RIN table F4.

Table 4–1: Allowed opex compared with actuals and estimated costs (excl. debt raising costs) ($2025, million)

		Actual 2020-21	Actual 2021-22	Actual 2022-23	Estimate 2023-24	Estimate 2024-25	Total 2020-25
Controllable opex	2020 AA allowance	212.7	225.6	232.2	232.3	237.4	**1,140.2**
	Actual/estimate	166.7	160.2	186.1	189.3	193.6	**896.0**
Specific forecasts							
Government levies	2020 AA allowance	5.8	5.8	5.8	5.8	5.8	**29.2**
	Actual/estimate	5.7	4.2	4.8	4.6	4.6	**23.9**
UAG	2020 AA allowance	35.8	33.9	36.1	36.7	36.2	**178.8**
	Actual/estimate	30.3	31.7	53.9	74.4	74.6	**264.9**
Total costs (excl. debt raising costs)	**2020 AA allowance**	**254.3**	**265.4**	**274.2**	**274.9**	**279.4**	**1,348.2**
	Actual/Estimate	**202.7**	**196.1**	**244.8**	**268.3**	**272.8**	**1,184.7**

Analysis of variances between allowed and actual opex by opex category is set out in Table 4–2 below.

Table 4–2: Analysis of variance between allowed and actual opex

Opex category	Analysis of variance from AER allowance
Controllable opex	
Repairs and maintenance	Many operational activities were halted during the COVID-19 period and prolonged wet weather 2020-22 period. Following this, increased spending in emergency repairs and maintenance has resulted in increased costs in 2022-23. This is anticipated to continue in 2023-24. However, prior to 2021-22, JGN implemented a transformation program to simplify business processes and lower operating costs. This has resulted in an overall positive variance against allowance.
Marketing and retail incentives	The transformation program implemented prior to 2021-22 and the change in marketing strategy resulted in a sustained reduction in our marketing costs resulting in a positive variance against allowance.
Other opex	The transformation program implemented prior to 2021-22 resulted in a sustained reduction in our opex cost base resulting in a positive variance against allowance.
Specific forecasts	
Government levies	Government levies have remained fairly consistent throughout the period with actuals tracking marginally below allowance.
Unaccounted for gas	The UAG costs have been higher since 2022-23 due to higher wholesale gas prices and is expected to remain higher than the allowance in the period to 2024-25 resulting in an overall negative variance against allowance.
Debt raising	The debt raising costs are reported as 0 because they have been held at JGN's parent company level and not allocated to individual assets such as JGN.

4.1.1 Unaccounted for gas costs

As part of our contractual arrangements with network users, we procure gas to replenish the difference between the measured quantities of gas entering and leaving the network in delivering our Transportation RS – this difference is known as UAG. During the current period we have purchased gas for UAG through a competitive tender process.

Our opex allowance for the 2020 Plan period included forecast UAG costs, based on:

- forecast volume market and demand market consumption
- the approved target rates of UAG
- the cost of replacement gas.

A UAG incentive applies in the 2020 Plan period to provide a continuous incentive for us to minimise the rate of UAG. This means that if the actual rate of UAG is above (or below) the target UAG rate then we under (or over) recover our actual UAG costs:

- the UAG incentive is based on efficient annual target rates of UAG
- the efficient level of UAG is represented as two different UAG target rates – one applies to daily metered customer withdrawals and the other to gas received to supply non-daily metered customers
- we are compensated for variations in total market volumes and the wholesale costs of purchasing UAG (which remain outside of our control) through an automatic annual adjustment
- a two year lag is applied to cost recovery, removing reliance on forecast gas receipts.

Over the 2020 Plan period, we expect to exceed our UAG allowance due to:

- paying higher wholesale prices compared with the AER's allowance in the 2020 Plan period
- overall, we delivered more gas than forecast in the AER's UAG allowance.

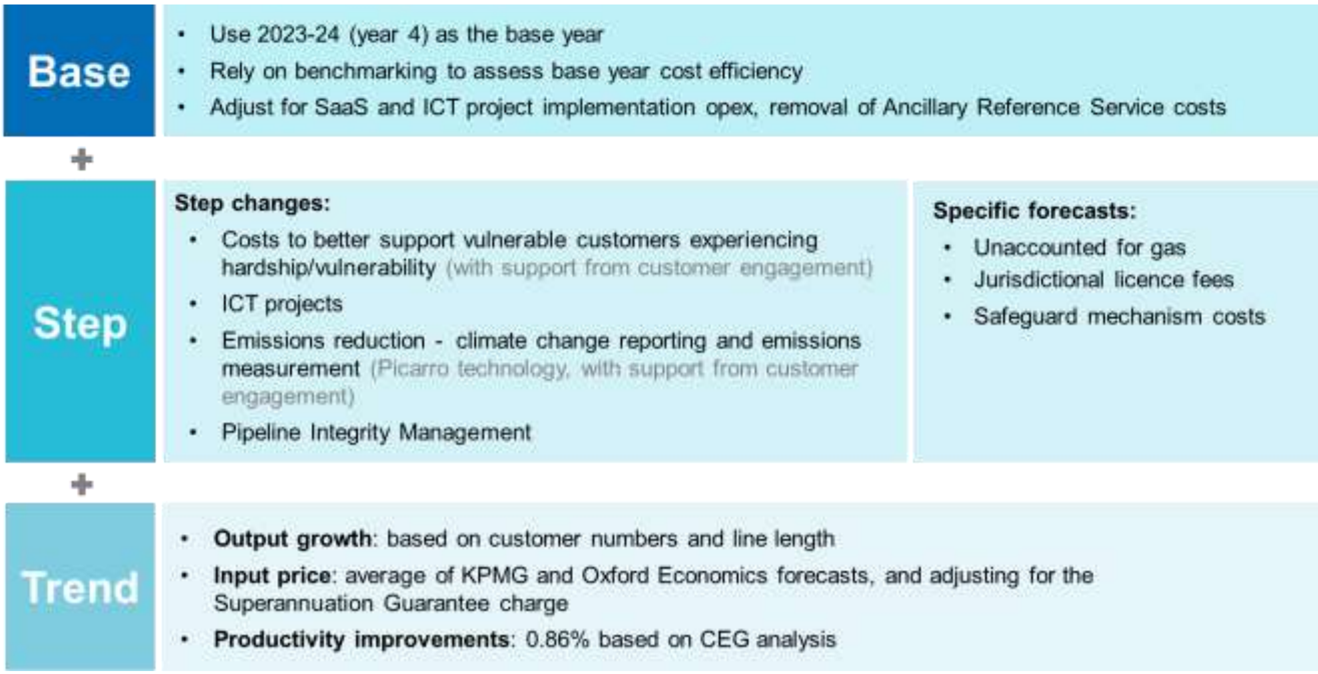
A more detailed discussion of UAG, including JGN's UAG performance over the current 2020 Plan period and our management of UAG is contained within *JGN-Att 6.7-Unaccounted for gas*.

5. Overview of our forecasting approach

In developing our 2025 Plan, we have forecast our opex (as shown in Figure 5–1) using the AER's preferred forecast method, base - step - trend for our Transportation RS. The method forecasts future opex using a base year (2023-24) – where the operating costs are representative of the efficient costs necessary to operate and maintain the network, and meet regulatory obligations.

The base year opex is adjusted to remove Ancillary RS costs, category specific forecasts, non-recurrent ICT opex and SaaS implementation costs which are now treated differently based on the International Financial Reporting Interpretations Committee guidance note. Once the adjustments to the base year opex have been made these costs are trended forward to account for changes in output growth, input price, and expected productivity improvements. We then add costs that are not reflected in our base opex, including step changes and specific forecasts.

Figure 5–1: Our opex forecasting approach for Transportation Reference Service



We undertook a comprehensive assessment to ensure that our forecast opex is efficient, represents the amount that is required to meet our obligations and customers' expectations, and to promote the long term interests of our customers.

6. Establishing an efficient base year

6.1 Selection of base year

We are proposing to use the penultimate year in the current 2020 Plan period, 2023-24, as the base year. It will be the most recent year for which our actual opex information will be available when the AER makes its Final Decision for our 2025-30 period. We consider that the operating costs in 2023-24 best represent the efficient costs necessary to operate and maintain the network, and meet our regulatory and legal obligations in regard to safety, reliability, security, and the environment, consistent with rule 91(1) of the NGR.

As shown in section 7.2 below, CEG's benchmarking analysis demonstrates that JGN continues to be one of the most efficient gas distribution network in Australia and that our proposed base year (2023-24) opex is an efficient basis to forecast our Transportation RS opex for the 2025-30 period.

We have also made the following adjustments to our 2023-24 expenditure to ensure it is representative of efficient and recurrent Transportation RS opex:

- Remove category specific forecast opex that are in 2023-24 opex (UAG, licence fees and government levies)
- Remove Ancillary RS opex to ensure separation of Transportation RS and Ancillary RS opex in line with unbundling of our reference services
- Adjust for SaaS implementation costs to be treated as opex going forward
- Adjust for movements in our non-recurrent ICT project opex associated with project implementation
- Adjust for movements in provisions in accordance with the AER's preferred approach.

Table 6–1 sets out the adjustments we have made to our base year opex.

Table 6–1: Derivation of base opex before trending ($2025, million)

Opex category	2025$M
Estimated 2023-24 opex for our reference services (Transportation RS and Ancillary RS)	268.3
Base year adjustments:	
Remove Ancillary RS	(21.9)
Adjust for SaaS costs (see section 6.3.1)	2.5
Adjust for net Non-recurrent ICT project implementation costs (see section 6.3.2)	2.4
Remove category specific forecasts and movements in provisions	(79.2)
Increment from base year (2023-24) to final year (2024-25)	4.5
Base opex before trending	**176.7**

6.2 Benchmarking of our operating expenditure

When compared to other gas utilities in Australia and New Zealand, we have consistently benchmarked well in terms of the costs and efficiency of the services we provide. According to CEG's benchmarking analysis (see *JGN-CEG-Att 6.4-Relative efficiency and forecast productivity growth of JGN*), who we engaged to benchmark our performance against our peers, we continue to benchmark well in relation to opex, capital inputs and our total costs. Economic Insights in its report for us in 2019 also made similar conclusions.[7]

[7] Economic Insights, Relative efficiency and forecast productivity growth of JGN, April 2019.

CEG conducted analysis based on data from eight Australian and four New Zealand gas distribution businesses (**GDBs**) by examining the relative opex efficiency of JGN compared to other GDBs using productivity indices, econometrics analysis and partial performance indicators:

- **Productivity indices** – a productivity index measures the relationship between multiple outputs and inputs, enabling comparison of productivity levels and trends over time and between GDBs. It provides indications on how efficiently a firm uses opex and capital inputs to produce its outputs. CEG has compared JGN's total factor productivity (**TFP**) and partial factor productivity (**PFP**)[8] trends against the productivity trends of the other GDBs measured over time. CEG has also analysed JGN's productivity levels against other Australian GDBs measured using multilateral TFP (**MTFP**). The TFP approach considers how productivity has changed over time but not relative to other GDBs, whereas the MTFP approach enables the comparison between GDBs.
- **Econometric analysis** – measures whether JGN is efficient in its use of opex inputs relative to the efficient production frontier. CEG applied opex cost functions to estimate the relationship between opex and several output variables, environmental variables and time. It derived efficiency scores and coefficients of various outputs to provide estimates of the output weights and productivity improvements in the trend component of our opex forecast.
- **Partial performance indicators (PPI)** – PPI measures the relationship between opex (as the input) and individual outputs to measure opex efficiency. PPIs offer a general indication of the comparative performance of GDBs in delivering specific outputs. It is often used as a supplementary method to other more sophisticated benchmarking approaches, as it doesn't account for interrelationships between multiple inputs and outputs.

6.2.1 Productivity indices

CEG conducted the analysis on productivity indices following the same approach as Economic Insights in 2019 for our 2020-25 AA[9]. This analysis includes both TFP/PFP and MTFP/MPFP measures. The TFP and PFP indices provide the change in productivity trends over time, whereas the MTFP and MPFP indices provide a comparison of the relative efficiencies between GDBs.

CEG's analysis shows that JGN has the fastest rate of productivity improvements across 8 Australian and 4 New Zealand GDBs on opex. JGN is also in the top 3 of all GDBs on MTFP and MPFP measures[10]. The results are summarised in Figure 6–1 below.

Figure 6–1: Summary of JGN's results on productivity indices

8 The partial performance indicators analysed by CEG are analogous to those published by the AER for electricity distribution businesses.

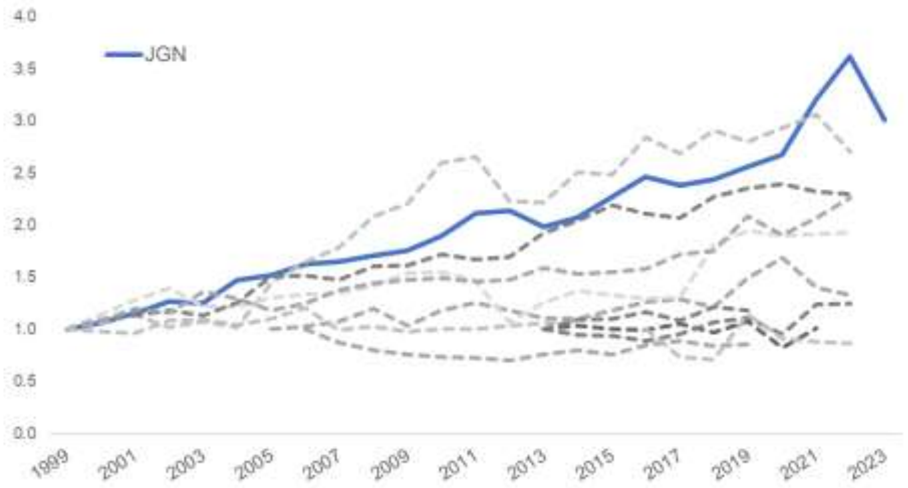
9 Economic Insights, Relative efficiency and forecast productivity growth of JGN, April 2019.

10 Opex PFP and Opex MPFP include 12 GDBs in the analysis (8 Australian and 4 New Zealand GDB) whereas Capital PFP, TFP, Capital MPFP and MTFP include only 7 Australian GDBs. This is because data on capital inputs are not available for all 4 New Zealand GDBs and 1 Australian GDB.

Comparison of productivity growth (TFP and PFP)

Figure 6–2 below shows the change in opex PFP over time for the GDBs measured. JGN's index is presented as the blue solid line below while other networks are presented as grey dotted lines. In 2023, JGN's output per dollar of opex is approximately 3.0 times the base level measured in 1999. This is achieved by a 41% reduction in real opex with a 77% increase in outputs between 1999 and 2023. This is the fastest rate of increase in productivity of any GDB measured since 1999. It indicates that JGN is the top performer on opex productivity improvements.

Figure 6–2: Opex PFP index comparison



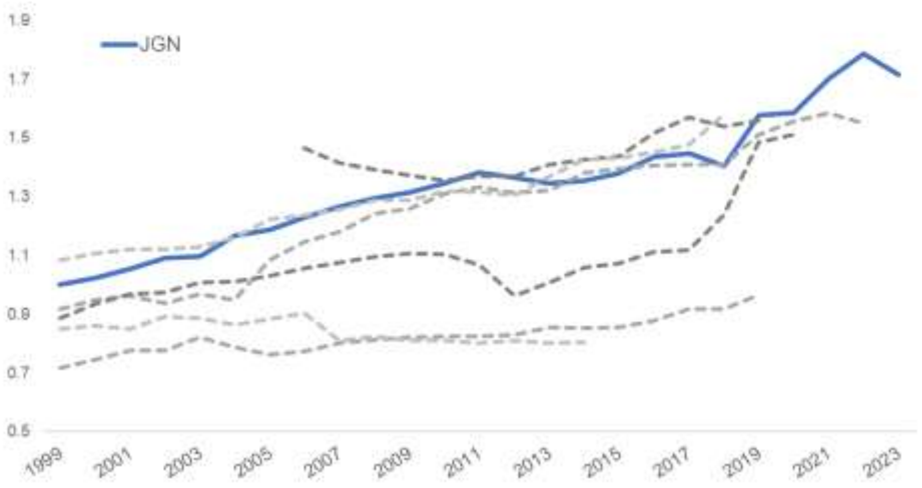
Source: CEG *(Note that data for all GDBs, apart from JGN, is available to 2022 at the time of the analysis)*

JGN also has the fastest growth in TFP, representing productivity on total costs, and the third highest growth on capital PFP between 1999 and 2023. More details are included in CEG's report in *JGN-CEG-Att 6.4: Relative efficiency and forecast productivity growth of JGN*.

Productivity comparison between networks (MTFP and MPFP)

CEG's analysis on MTFP index in Figure 6–3 shows that JGN is the most efficient network on total cost from 2019 onwards. JGN is also consistently among the most efficient firms throughout 1999 to 2023. It is evident that JGN has been the top performer on delivering services with efficient costs on both opex and capex.

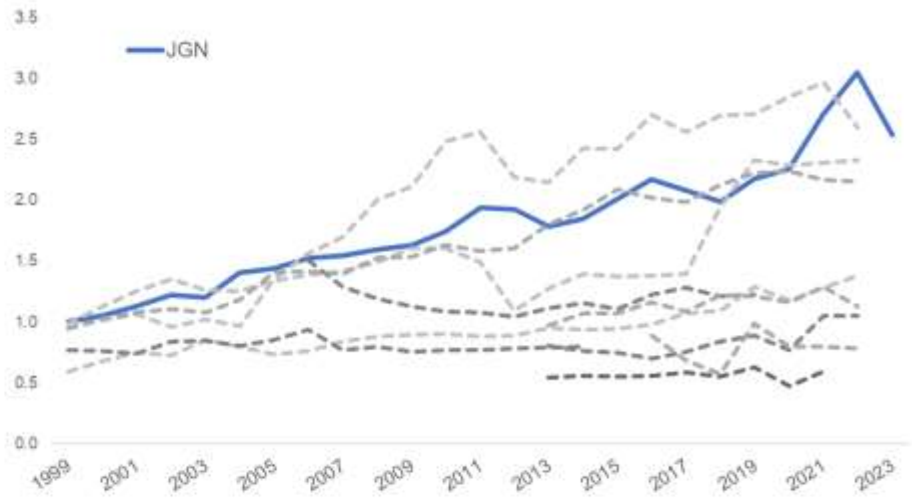
Figure 6–3: MTFP index comparison



Source: CEG

Figure 6–4 below shows JGN's opex MPFP performance against other networks. It highlights that JGN consistently ranks in the top three among other networks from 1999 to 2023.

Figure 6–4: Opex MPFP index comparison



Source: CEG

6.2.2 Econometric analysis

CEG undertook econometric modelling based on the same model specifications of Economic Insights' 2019 report for us in the 2020-25 Access Arrangement. It adopted two econometric models, Feasible Generalised Least Squared (**FGLS**) and Stochastic Frontier Analysis (**SFA**). It is conducted based on Australian and New Zealand GDB's data from 2000 to 2022.

CEG's analysis concludes that JGN's efficiency score on historical average opex is 0.84, higher than the industry average score (0.72) of all GDBs. When assessing the efficiency of the latest year where data is available (i.e. 2022), JGN is the most efficient network with an efficiency score of 0.98 compared to the industry average score of 0.80. These findings suggests that JGN is efficient and does not require an adjustment to its base year opex.

Similar to Economic Insights' benchmarking analysis in 2019, the coefficients derived from the econometric analysis can be used to estimate the outputs, output weights and productivity adjustments in forecasting the 'trend' component of our opex for 2025-30. These estimates are outlined below:

- The estimated average rate of technical change or 'frontier shift' is 0.86% per annum (expressed as a rate of productivity growth), which is higher than the 0.74% per annum in JGN's 2020-25 opex forecast and higher than the 0.5% per annum commonly applied in electricity distribution determinations. In an uncertain future that may result in our customer base declining it will be challenging for JGN to achieve this level of productivity growth.
- The estimated output weights for the two outputs used are: (i) customer numbers, 48.6%; and (ii) mains length, 51.4%[11].

6.2.3 Partial performance indicators

JGN has one of the lowest opex per customer across Australian and New Zealand gas networks. Figure 6–5 below shows that JGN is consistently below the industry average on opex per customer over the long period (2011-22) and short period (2018-22). The blue bar represents our historical average opex per customer and the green bar represents our 2022-23 opex per customer (the latest year where JGN's actual opex is available). It shows that JGN's most recent (2022-23) opex per customer is lower than our historical average as well as the industry average (grey line).

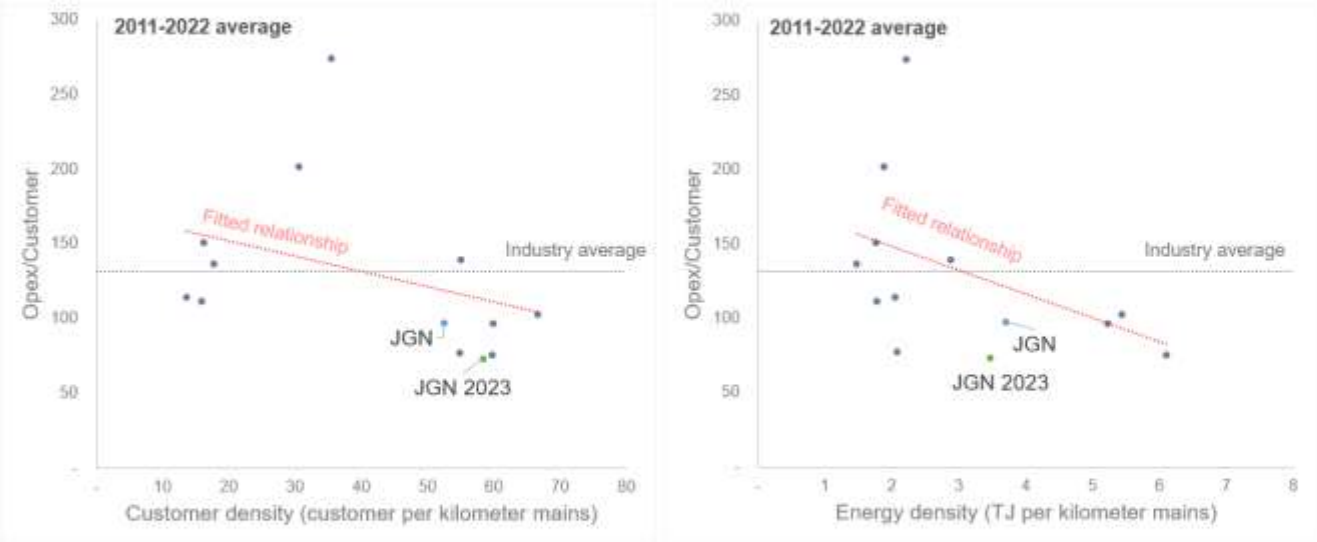
[11] These estimates are consistent with Economic Insights' 2019 estimates of 49.4% for customer numbers and 50.6% for mains length.

Figure 6–5: Historical average opex per customer ($2022)

Source: CEG

When we compare the opex per customer with GDBs with similar customer density and energy density in Figure 6–6 below, both JGN's historical average and 2022-23 opex per customer is lower than other networks with similar densities. Additionally, JGN's opex per customer is below the predicted level (red line) for a firm with JGN's network density; that is, JGN's level of opex is efficient relative to average industry level when accounting for customer density and energy density.

Figure 6–6: Opex per customer conditional on network density ($2022)



Source: *JGN-CEG-Att 6.4-Relative efficiency and forecast productivity growth of JGN*

6.2.4 CEG conclusion

CEG's independent analysis outlined above strongly supports that JGN is operating efficiently. This outcome provides evidence that JGN's level of operating costs is efficient. Consequently, we consider that our 2023-24 base year opex provides an efficient basis to forecast our opex for the 2025 Plan period.

6.3 Adjustments to base year opex

We have adjusted our base year costs:

- to remove Ancillary RS to reflect the splitting of our haulage reference service into Transportation RS and Ancillary RS from 1 July 2025. Consequently, this opex attachment deals with opex associated with our Transportation RS and we provide details of our Ancillary RS cost build up in *JGN-Att 7.2-Ancillary reference services cost build up approach*
- to remove SaaS implementation costs, which are currently treated as capex for regulatory purposes for consistency with the AER's treatment of them in the CESS and ECM. SaaS costs will be treated as opex in the 2025-30 period and therefore we add them back to base opex resulting in a net zero impact
- for the net movement in ICT non-recurrent project implementation costs
- to remove costs that we develop category specific forecasts for.

Table 6–2 sets out the adjustments we have made to our base year.

Table 6–2: Base year adjustment ($2025, million)

Description	Total opex base year adjustment
Remove Ancillary RS opex from our 2023-24 base year (see JGN-Att *7.2-Ancillary reference services cost build up approach*)	(21.9)
SaaS costs provided as capex allowance (see below)	2.5
Net movement in non-recurrent ICT project opex (see below)	2.4
Remove costs that we develop category specific forecasts for	(79.2)
Net adjustment to base year opex	**(96.2)**

6.3.1 SaaS implementation costs

In April 2021, the International Financial Reporting Interpretations Committee released a guidance note requiring SaaS implementation costs be treated as opex. When the 2020-25 allowances were determined for JGN in April 2020, these costs were classified as capex. Other distribution networks also face similar issues. The AER in its 2024 final determination for Ausgrid notes –[12]

SaaS implementation costs have historically been treated as capital expenditure in revenue determinations. However, in April 2021, the International Financial Reporting Standards Foundation (IFRSF) clarified that in most cases, a business utilising SaaS services:

• does not control the software being configured or customised, and

• that those configuration and customisation activities do not create a resource that is controlled by the business, separate to the software, from which the business then has the power to obtain a future economic benefit.

The IFRSF consequently determined that these SaaS implementation costs should more accurately be expensed as opposed to being capitalised.

To ensure our reported actuals and allowances are comparable based on consistent accounting treatments, the AER provided guidance for us to continue applying the old accounting treatment (i.e. capitalising SaaS implementation costs) for the current 2020-25 period and apply the new accounting treatment from the 2025-30 period. We have adjusted our opex and capex accordingly in line with the AER's guidance by removing the SaaS implementation costs in 2020-25 period from opex, which includes $2.5M in our base year, and added them to

[12] AER's final decision Ausgrid, Attachment 6 Operating expenditure | Final Decision – Ausgrid Distribution determination 2024–29

our capex. This will ensure that there is no unintended consequence to the incentive schemes revenue from CESS and ECM for the 2020-25 period. Going forward these costs will be treated as opex from the 2025-30 period. Therefore, we have added back the SaaS implementation costs to the adjusted base year opex, resulting in a net zero impact to our base year opex.

6.3.2 Non-recurrent ICT project implementation costs

When implementing new non-recurrent ICT capacity, we incur implementation costs to establish, and if necessary, customise, ICT cloud services. These costs comprise SaaS, Infrastructure as a Service (IaaS), and Platform as a Service (PaaS) which we classify as non-recurrent ICT project opex. We note that whilst the costs relate to non-recurrent projects, the activity of implementing new non-recurrent ICT capacity is recurring in nature but the level of project activity is expected to fluctuate between regulatory periods.

Our approach to estimating the non-recurrent ICT project opex has been to consider the costs of implementing any non-recurrent projects over the 2025 Plan. We have set out in *JGN-Att 5.4-Technology plan* our proposed non-recurrent ICT projects over the 2025-30 period. Table 6–3 summarises the estimated non-recurrent project opex costs associated with these projects, and the net adjustment we have made to our 2023-24 base year opex to provide an opex allowance for the estimated net increase in costs over the 2025-30 period.

Table 6–3: Forecast non-recurrent ICT project opex

Non-recurrent ICT sub-categorisation	Project name	2023$M	2025$M
Maintaining existing services, functionalities, capability, and/or market benefits	SAP Upgrade	6.97	7.4
	Gas Retail Market Settlement – Major Application Lifecycle	0.29	0.3
Complying with new/altered regulatory obligations / requirements	Data Foundations and Governance	2.04	2.2
	Enterprise Content Management Uplift	4.78	5.1
	Cybersecurity Program	7.10	7.6
	Contract Lifecycle Management	0.99	1.1
New or expanded ICT capability, functions, and services	Asset Investment Planning	1.00	1.1
	Network Management Advanced Analytics	4.02	4.3
	Chronic No Access Digital Metering pilot	1.24	1.3
	Works Management Extend Phase	2.99	3.2
Total non-recurrent ICT project opex 2025-30 (a)		**31.42**	**33.5**
Average annual non-recurrent ICT project opex 2025-30 (b=a/5)			6.7
Less non-recurrent ICT project opex in base year (c)			-4.3
Net increase in base year opex for non-recurrent ICT project opex (b)-(c)			**2.4**

As shown in Table 6–3, we are forecasting a total net adjustment of $2.4M per annum to our base year for non-recurrent ICT project opex.

7. Trending the base year opex

7.1 Rate of change in opex

Once the base year opex has been adjusted it is trended to ensure the costs remain in line with expected changes in input (labour/material) costs, the level of output/activity and productivity. This is also referred to as rate of change:

Annual real rate of change = (1+Δ input cost growth) x (1+Δ output growth) x (1-Δ productivity growth) - 1

Where,

- **Price change (input cost growth) trend** – is the expected change in our real cost of inputs, such as labour and materials, over the 2025 Plan period, which are primary inputs to our opex program. We applied zero real escalation to non-labour costs consistent with the AER's standard practice.
- **Output growth trend** – this captures the incremental cost of the expected change in the level of our activity over the period, as measured by our customer numbers and mains length.
- **Productivity growth trend** – this is the expected reduction in our costs over the period due to developments in technology and other factors that enable us to provide our reference service at a lower cost. We have adopted the productivity trend estimated independently by CEG – see *JGN-CEG-Att 6.4-Relative efficiency and forecast productivity growth of JGN*.

We have applied these three adjustments to our base opex for the 2025 Plan period. Table 7–1 shows the forecast rate of change for 2025-30.

Table 7–1: Forecast rate of change (%)

	2025-26	2026-27	2027-28	2028-29	2029-30	2025-30 Average
Price change trend	0.87%	0.61%	0.57%	0.66%	0.71%	0.68%
Output growth trend	0.84%	0.73%	0.64%	0.57%	0.44%	0.65%
Productivity adjustment	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%
Total opex rate of change	**0.85%**	**0.47%**	**0.34%**	**0.36%**	**0.29%**	**0.46%**

Table 7–2 shows the forecast opex trend over the 2025 Plan period. These costs will increase our opex by $14.5M or 1.6% of base opex in the 2025 Plan period.

Table 7–2: Forecast opex trend ($2025, million)

	2025-26	2026-27	2027-28	2028-29	2029-30	2025-30 Total
Price change trend	1.5	2.8	3.9	5.0	5.8	19.0
Output growth trend	1.6	2.7	3.7	5.0	6.3	19.2
Productivity adjustment	(1.5)	(3.1)	(4.7)	(6.4)	(8.0)	(23.8)
Total opex rate of change	**1.5**	**2.3**	**2.9**	**3.6**	**4.1**	**14.5**

We discuss each of the rate of change components below.

7.2 Price change

Our base year opex reflects the current prices of our inputs, which comprise labour and non-labour items, such as materials.

We have applied the AER's standard approach of using a weighted average of forecast labour and non-labour cost growth to determine our overall input cost growth adjustment.

We adopted the AER's approach of taking the average of two state-specific utilities industry wage price index growth forecasts as the labour cost escalation. This includes estimating the average real labour escalator forecasts from Oxford Economics (see *JGN-Oxford Economics-Att 5.5-Input cost escalation*) and KPMG's real wage price index (**WPI**) forecast for the NSW utilities' industries commissioned by the AER.[13]

In addition to this we apply an uplift for the Superannuation Guarantee charge (**SGC**) given that it is not included in the wage price index. Oxford Economics highlighted in its report that:

> *Note that the wage price index measure does not include the Superannuation Guarantee charge (SGC). As the SGC is in effect a labour on-cost, in terms of escalating wage costs over the forecast period, the full annual 0.5% for the SGC therefore needs to be added to the forecast increases in the WPI for each of the years from FY24 to FY26.*

Therefore we have adjusted the labour escalation of 2025-26 by 0.5% (see *JGN-Oxford Economics-Att 5.5-Input cost escalation*).

We use the benchmark weighting of 62% for labour and 38% non-labour to our opex costs as adopted by the AER in its 2023 final decision to Victorian gas distribution businesses. Table 7–3 shows our forecast input cost over the 2025 Plan period.

Table 7–3: Forecast input cost growth 2025-30

	2025-26	2026-27	2027-28	2028-29	2029-30	Total
KPMG real labour forecast (A)	0.65%	0.85%	0.93%	0.95%	0.95%	
Oxford Economics real labour forecast (B)	1.17%	1.11%	0.90%	1.18%	1.35%	
Superannuation guarantee increases (C)	0.50%	-	-	-	-	
Average real labour forecast (D = (A+B)/2+C)	1.41%	0.98%	0.91%	1.07%	1.15%	
Labour contribution to price growth trend (E)	62.00%	62.00%	62.00%	62.00%	62.00%	
Adjusted real labour forecast (F=D x E)	0.87%	0.61%	0.57%	0.66%	0.71%	
Real other forecast (G)	-	-	-	-	-	
Price growth trend (F+G)	0.87%	0.61%	0.57%	0.66%	0.71%	
Input cost growth (2025$M)	1.5	2.8	3.9	5.0	5.8	19.0

The AER has recognised in its past regulatory decisions that using a labour (or wage) price index, as we propose, builds in some assumed labour productivity. We have not sought to quantify this, but it adds to our proposed productivity savings that are discussed in section 8.4.

13 See AER draft decision Endeavour Energy opex and AER draft decision Ausgrid opex. The draft decisions refer to KPMG, Wage Price Index Forecasts, 18 August 2023, p. 38. We note that the KPMG forecasts are placeholder values and will be updated by the AER in its draft decision to JGN.

7.3 Output growth

We have forecast output weights based on econometric analysis by CEG (see *JGN-CEG-Att 6.4-Relative efficiency and forecast productivity growth of JGN*), as outlined in section 7.2.2 above. Our base opex reflects the cost of delivering current outputs and services. This element of the rate of change reflects that our opex activities (and associated costs) will grow in line with our customer base and the length of pipeline we need to maintain.

We have applied the AER's standard approach to determine the forecast changes in outputs by using internally consistent forecasts growth in customer numbers (as estimated by Core Energy, see *JGN-Core Energy-Att 8.2-Demand Forecast Report*) used for demand forecast and line length. We have calculated the impact on opex by multiplying the forecast increase in each output measure by the corresponding output weights, determined by CEG from econometric analysis, which are customer numbers (48.6%) and mains length (51.4%). The results are detailed in Table 7–4. This translates to a 0.44% to 0.84% annual increase in opex due to output growth over the 2025-30 period.

Table 7–4: Forecast output growth 2025-30

	2025-26	2026-27	2027-28	2028-29	2029-30	Total
Customer Numbers	1.19%	0.92%	0.74%	0.61%	0.49%	
Main length	0.52%	0.55%	0.55%	0.54%	0.40%	
Forecast output growth	0.84%	0.73%	0.64%	0.57%	0.44%	
Forecast output growth ($2025M)	1.6	2.7	3.7	5.0	6.3	19.2

7.4 Productivity

CEG estimated JGN's opex technical productivity as part of the econometric analysis. We have forecast the productivity adjustment based on CEG's estimate.

CEG's econometric models use industry level data to establish a robust estimate of productivity growth in gas networks. The estimated average rate of technical change derived by these models was then applied to the opex forecast as an annual rate of productivity growth.

CEG's analysis indicates that an efficient gas network business is expected to achieve productivity improvements averaging 0.86% per annum. This is higher than:

- 0.74% per annum productivity growth forecast for JGN's current 2020-25 period
- 0.5% per annum opex productivity growth factor the AER applies to electricity networks
- -1.1% to 0.2% per annum opex productivity growth factor in the AER's final decisions for VIC gas distribution networks in 2023.

We have incorporated this productivity adjustment into our opex forecast. We believe this will be a challenging forecast to achieve for JGN in the 2025-30 period especially with uncertainty around future of gas demand. The reduction in opex arising from this forecast productivity gain is passed directly through to our customers and reflects JGN's commitment to efficiently managing our business. These savings will translate into a reduction of $24M over the 2025-30 period.

Table 7–5 sets out our forecast productivity adjustments for the 2025 Plan period.

Table 7–5: Forecast productivity adjustment 2025-30 ($2025, million)

	2025-26	2026-27	2027-28	2028-29	2029-30	Total
Productivity adjustment	(1.5)	(3.1)	(4.7)	(6.4)	(8.0)	(23.8)

8. Opex step changes

Step changes are costs we incur in undertaking new activities or meeting new obligations that are not part of our base year costs.

Our proposed step changes set out in Table 8–1 reflect the outcome of an extensive review of our opex requirements for the 2025 Plan period, informed by customer priorities and preferences, reflecting good industry practices, our regulatory obligations associated with emissions reporting, and external factors outside our control with regards to the timing of safety preventative measures and for our ICT expenditure.

Table 8–1: Forecast opex step changes ($2025, million)

Step change	Driver	2025-26	2026-27	2027-28	2028-29	2029-30	Total
Support for customers experiencing vulnerability	Reflects accepted good industry practice supported by customer engagement	0.53	0.53	0.53	0.53	0.53	2.66
ICT services – recurrent opex for new projects	Major external factor outside JGN's control	0.76	2.26	3.75	3.93	4.34	15.04
Emissions reduction – Climate change reporting	New regulatory obligation	0.78	0.71	0.71	0.71	0.71	3.61
Emissions measurement (Picarro leak detection services)	Reflects accepted good industry practice supported by consumer engagement	4.17	4.14	4.16	4.16	4.16	20.80
Pipeline Integrity Management program ('pigs and digs')	Reflects accepted good industry practice and major external factor outside JGN's control	9.30	3.14	4.08	4.03	7.58	28.13
Total		**15.54**	**10.78**	**13.23**	**13.36**	**17.32**	**70.25**

These step changes are further discussed in *JGN-Att 6.2-Opex step change justification*.

9. Category specific forecasts

We have used specific forecasts for items where the base year opex does not provide a reasonable basis on which to forecast expenditure requirements for the 2025 Plan. We include these as category specific forecasts instead. These are discussed below.

9.1 Our category specific forecasts for our reference service

Table 9–1 sets out our category specific forecasts for the 2025 Plan, which we discuss in detail below.

Table 9–1: Category specific forecasts 2025-30 ($2025, million)

	2025-26	2026-27	2027-28	2028-29	2029-30	Total
Unaccounted for gas	36.1	32.8	27.8	25.1	24.1	145.8
Licence fees and government levies	4.3	4.3	4.3	4.3	4.3	21.3
Safeguard Mechanism requirements	2.2	2.3	2.1	2.0	1.9	10.4
Debt raising costs	2.0	2.0	2.0	1.9	1.9	9.7
Total	**44.5**	**41.3**	**36.1**	**33.2**	**32.1**	**187.2**

9.2 Unaccounted for gas

As previously explained, we procure gas to replenish the difference between the measured quantities of gas entering and leaving our gas network – this difference is known as UAG. UAG is calculated as the difference between the measured quantity of gas entering the network system (receipts) and metered gas deliveries (withdrawals). We buy gas to replenish the difference, usually through a competitive tender process. We are not proposing any changes to the arrangements for dealing with UAG from those that apply in the 2020-25 period – this includes both the basis for calculating the efficient UAG opex forecast and the UAG incentive scheme.

The total cost of UAG is a product of the volume of UAG and the replacement cost of gas purchased by JGN to replace UAG. Our efficient UAG opex forecast is calculated based on the product of the following three parameters for each market segment:

- Total gas deliveries – we have relied on demand forecasts prepared by the specialist energy forecaster Core Energy. We have provided its independent expert report at *JGN - Core Energy - Att 8.2 - Demand Forecast Report* that details its forecasts.
- Our proposed target rate (loss rate) of UAG – we have relied on loss rate forecasts prepared by Frontier Economics. We have provided its independent expert report and forecasts in *JGN - Frontier Economics-Att 6.9M - Estimated UAG rates*.
- Cost of replacement gas – we have relied on the gas price forecasts developed as part of AEMO's 2024 Gas Statement of Opportunities (GSOO).

We estimate that our total UAG costs over the 2025-30 Plan period will be $146M. A more detailed discussion on UAG and our proposed UAG target rates is included in *JGN - Att 6.7 - Unaccounted for gas*.

We propose to continue to apply the current UAG incentive that applied over the 2020-25 period to provide an incentive for us to minimise the rate of UAG. This means that if the actual rate of UAG is above (or below) the target UAG rate then we under (or over) recover our actual UAG costs:

- the UAG incentive is based on efficient annual target rates of UAG represented as two different UAG target rates – one applies to daily metered customer withdrawals and the other to gas received to supply non-daily metered customers

- we are compensated for variations in total market volumes and the wholesale costs of purchasing UAG (which remain outside of our control) through an automatic annual adjustment
- a two year lag is applied to cost recovery, removing any reliance on forecast gas receipts.
- An automatic adjustment for UAG currently applies to each year's annual tariff variation for demand and price variations from forecast (see *JGN - Att 10.1 - Pricing* for details). The tariff variation notice includes a true-up of the UAG costs on a t-2 basis. This true up accounts for differences in gas receipts and the cost of gas to that assumed in the allowance, as both of these are outside JGN's control.

9.3 Government levies

Government levies comprise annual licence and authorisation fees paid to the NSW Government and other authorities and mains' taxes paid to local government councils. These include:

1. License fees - The Gas Supply Act 1996 (NSW) allows the Energy Minister to set licence fees for companies that distribute gas. These fees depend on how much the NSW government spends on overseeing each company. The Independent Pricing and Regulatory Tribunal (**IPART**) calculates these costs and suggests the appropriate fees to the NSW Treasurer. We pay licence fees in respect of the five pipeline licences that we hold for the pipelines that make up our trunk network and an authorisation fee in respect of the reticulator's authorisation that we hold for the remainder of our gas network. The fees are paid on invoices raised by the NSW Department of Planning and Environment for pipeline licence fees (as provided in the Pipelines Act), and by IPART for the authorisation fee (as provided in the Gas Supply Act).
2. Local government taxes - Local governments are authorised to charge mains' taxes under section 611 of the Local Government Act 1993 (NSW). The charges are calculated as a percentage of the amount of revenue that we derive in the relevant local government area and amounts paid are subject to independent review.
3. Ombudsman fees - Section 11A of the Gas Supply Act 1996 provides that it is a condition of our reticulator's authorisation that we are a member of the NSW energy ombudsman scheme. As a result, we pay annual fees to the Energy and Water Ombudsman NSW (**EWON**).

We have based our opex forecasts for these government levies based on the historical average of the fees that we have paid over 2021-24, which we consider is a good proxy for what we should incur on an average basis over the 2025-30 period for these costs.

These levies are subject to a true-up through our reference tariff variation mechanism (see *JGN-Att 10.1-Pricing*). This is because these costs can vary from year to year and are outside of our control.

9.4 Safeguard mechanism requirements

The Safeguard Mechanism, part of the National Greenhouse and Energy Reporting (**NGER**) scheme, is an Australian Government policy aimed at reducing emissions from facilities, including JGN, by establishing greenhouse gas emission thresholds. The Safeguard Mechanism sets baselines for the maximum allowable net greenhouse gas emissions from a facility. Facilities with a baseline of 100,000 tonnes of carbon dioxide equivalent emissions per year are required to report their emissions and energy data annually to the Clean Energy Regulator.

The intent of the Safeguard Mechanism rule change is for safeguard facilities to reduce emissions by 43% by 2030 and net zero by 2050.[14] Facilities with emissions exceeding their baseline must manage their excess emissions, for instance by acquiring and surrendering Australian Carbon Credit Units (**ACCUs**).

The Safeguard Mechanism, a new obligation under the NGER, introduces compliance costs not reflected in our base year opex and are beyond our control. Although we have provided our best estimate of the cost to purchase ACCUs, the actual costs are highly uncertain. As a result, we have classified ACCU costs associated with the Safeguard Mechanism as a category-specific forecast, which is excluded from our Efficiency Carryover Mechanism.

[14] See Clean Energy Regulator, 3 May 2024, Safeguard Mechanism [online], accessed via this link.

We believe this approach aligns with rule 91(1) of the NGR and ensures that we incur costs as a prudent, efficient service provider, adhering to accepted good industry practice and the National Gas Objective (**NGO**).

The estimated costs for us to purchase ACCUs for Safeguard Mechanism compliance averages to approximately $2M per annum. The forecast ACCUs are based on forward trade price projections. Our tariffs will be adjusted over the 2025-30 Plan period using the tariff variation mechanism to ensure that we only recover the costs that we incur and pass on any benefits we receive through the Safeguard Mechanism.

Our approach to developing the estimated Safeguard Mechanism cost is consistent with the NGER requirements which is to determine:

1. The target baseline emissions which is a combination of an industry-average and JGN-specific emissions estimate, adjusted by a factor that declines by 4.9% p.a.
2. JGN's expected emissions based on the cumulative forecast emissions from distribution, transmission, fleet, and water bath heaters.
3. JGN's excess emissions being the difference between the target baseline and JGN's expected emissions.
4. JGN's forecast ACCU costs – while there is significant variability among various forecasts, our estimate is based on forward trade price projections from Demand Manager.

We have set out in section 3.2 of *JGN-Att 4.1-Emissions reduction program* more detail on how JGN's baseline emissions are calculated and on the forward ACCU prices.

Table 9–2 sets out our estimate for our Safeguard Mechanism cost over the 2025 Plan.

Table 9–2: Safeguard Mechanism costs 2025-30

	2025-26	2026-27	2027-28	2028-29	2029-30	Total
Target baseline (tCO2e) (1)	324,477	317,919	314,771	309,636	294,965	
JGN's expected emissions (tCO2e) (2)	390,507	386,143	374,445	364,079	346,142	
Excess emissions (tCO2e) (3=2-1)	66,030	68,223	59,673	54,443	51,177	
Forecast ACCU costs ($/tCO2e)[15] (4)	$31.27	$32.39	$33.41	$34.30	$35.21	
Cost of carbon credits ($) (3x4) (2023$M)	$2.1	$2.2	$2.0	$1.9	$1.8	$9.9
Cost of carbon credits ($2025, million)	**$2.1**	**$2.3**	**$2.1**	**$2.0**	**$1.9**	**$10.4**

9.5 Debt raising costs

We incur debt raising costs each time we raise to fund our capital investments or refinance debt. These may include arrangement fees, legal fees, company credit rating fees and other transaction costs. The AER's practice has been to allow gas network service providers to recover efficient direct debt raising costs by adding an allowance for them to the opex forecast.

Consistent with standard regulatory practice, we propose estimating these costs for a benchmark efficient entity with the same characteristics as our network, including:

- calculating the benchmark bond size
- determining the number of bond issues needed to rollover the benchmark debt share (60%) of the regulatory asset base (**RAB**)

[15] Demand Manager, Certificate Prices, accessed 3 October 2023, https://www.demandmanager.com.au/certificate-prices/ .

- amortising the upfront debt issuance costs incurred using our nominal vanilla rate of return over a ten-year period
- expressing the debt issuance costs in basis points per annum (**bppa**) as an input into the Post Tax Revenue Model (**PTRM**)
- multiplying the rate by our projected RAB to determine the debt raising cost allowance.

This method is consistent with the AER's PTRM handbook, which requires benchmark debt raising costs.

We engaged an expert consultant, CEG, to estimate the debt raising costs for JGN's 2025-30 period based on the AER's approach in its recent decisions, excluding any allowance for the cost to the issuer of discounting the issue price relative to market value of the bond.

The AER in it's most recent decisions for NSW distribution networks stated that[16]:

> *In arriving at this decision, we [The AER] apply the approach from our final decision for SA Power Networks. That is, we use updated Bloomberg data to inform the 'arrangement fee' component of debt raising costs and Chairmont's updated estimates [in 2019] for the remaining components.*

CEG found that the estimates in the AER's decisions for NSW networks on 30 April 2024 used an upfront arrangement fee of 49.0 bp. However, by updating the Bloomberg data based on AER's stated approach, the upfront arrangement fee would be 51.4 bp. We encourage the AER to review the calculations in CEG's report submitted as part of our proposal (*JGN - CEG - Att 6.6 - The cost of arranging debt issues - 20240611*).

Based on CEG's recommendation, we have adopted a debt raising cost of 8.55 bppa in our proposal with the updated arrangement fee.

[16] AER, Draft Decision Ausgrid Electricity distribution Determination 2024–29 – Attachment 3 Rate of return, September 2023

Appendix A
Overview of opex categories for our reference service

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A1. Overview of opex categories for our reference service

This appendix set out details of JGN's opex categories.

Operating expenditure categories
Repairs and maintenance
Marketing and retail incentives
Debt raising
Unaccounted for gas
Government levies
Other operating expenditure

A1.1 Repairs and maintenance

A1.1.1 Maintenance

The expenditure incurred by JGN in relation to maintenance activities and is not capital expenditure.

Maintenance consists of operational repairs and maintenance of the distribution system including high, medium and low pressure assets as well as testing, investigation, validation and correction costs not involving capex.

Maintenance includes both:

- routine maintenance—recurrent/programmed activities undertaken to maintain assets, performed regardless of the condition of the asset. Activities are predominantly directed at discovering information on asset condition and are undertaken at intervals that can be predicted
- non-routine maintenance—activities predominantly directed at managing asset condition or rectifying defects (excluding emergency call-outs). The timing of these activities depends on asset condition and decisions on when to maintain or replace the asset.

A1.1.2 Emergency response

Emergency response involves immediate operations and/or repairs necessary to restore failed components to an operational state where supply has been, or is in imminent threat of being, interrupted or where assets have been damaged or rendered unsafe by a breakdown. This reflects customer expectations for a responsive network service that must be supported by sufficient emergency response funding.

A1.2 Marketing and retail incentives

The expenditure incurred by JGN in marketing the use of gas as an energy source and the potential future of Renewable Gas (**RG**) in the network helping to lower network emissions and maintain a cost-effective energy supply for network customers.

JGN has a marketing program that aims to raise awareness and educate customers about RG amongst residential, business, and commercial customers, and the potential future for JGN in helping to lower emissions via increased supply of RG, including biomethane and renewable hydrogen, whilst continuing to support customers' fuel choice to manage usage and costs to the network customer base.

The marketing program algins with customer expectations that JGN should have more of a public presence and communicate on the future of renewable gases. The Customer Forums Recommendation 3 (see below) showed how participants acknowledge this view.

Recommendation 3 – renewable gas advocacy and communication

- Jemena needs to have a more public presence and speak up in the media.
- Speak with the Federal and local government and councils about Renewable gas advocacy and planning for the future.
- Educate all stakeholders to ultimately reduce the numbers of customers leaving gas over safety concerns. Recognising everyone's knowledge varies, so supply more information so there isn't any misinformation when educating everyone.
- To communicate with their customers on the future of renewable gas with a personable approach, so that customers don't abandon the company. This could include cost comparison between electricity and gas.
- Communicate that the option of bio-methane is an environmentally friendly solution.

Source: JGN - BD Infrastructure - Att 2.2 - Customer forum engagement report, page 19

A1.3 Debt raising costs

The transaction costs (expenditure) incurred by JGN in relation to raising debt instruments for investment into the gas distribution network.

The SGSPAA Group incurs costs when it raises debt funds to spend on JGN's capital program. These costs are maintained at a group level. Debt raising costs are incurred each time debt is rolled over and may include underwriting fees, legal fees, company credit rating fees and other transaction costs.

A1.4 Unaccounted for gas (UAG)

JGN incurs costs replenishing gas that is lost, or unaccounted for, during distribution through the network. UAG is measured as the difference between the quantity of gas metered as having been injected into JGN's gas distribution network and the quantity of gas metered as having been delivered to customers.

Under our Reference Service Agreement, JGN is responsible for the supply of gas in order to replenish UAG. For the 2025-30 period we are proposing that this accountability is contained in our Access Arrangement. A UAG cost pass through event currently applies to each year's annual tariff variation for demand and price variations from forecast (see *JGN-Att 10.2-Cost pass through mechanism*).

A1.5 Government levies

Government levies comprise annual licence and authorisation fees paid to the NSW Government and other authorities and mains taxes paid each year by JGN to local government councils.

JGN pays licence fees in respect of the five pipeline licences that it holds for the pipelines that make up the trunk and an authorisation fee in respect of the reticulator's authorisation it holds for the remainder of the network. The fees are paid on invoices raised by the NSW Department of Planning & Environment for the pipeline licence fees (as provided in the Pipelines Act), and by IPART for the authorisation fee (as provided in the Gas Supply Act).

Local governments are authorised to charge mains taxes under section 611 of the Local Government Act 1993 (NSW). The charges are calculated as a percentage of the amount of revenue that JGN derives in the relevant local government area and amounts paid are subject to independent review.

A licence fee annual administrative adjustment applies to each year's annual tariff variation for variations from forecast (see *JGN-Att 10.1-Pricing*).

A1.6 Other operating expenditure

A1.6.1 Network overheads

A1.6.1.1 Network Management

This category includes costs related to the general management of the JGN network business, including management and support staff.

A1.6.1.2 Network planning

Network planning involves developing visions, strategies and plans for the development of the JGN network. This includes functions such as demand forecasting, network analysis, preparation of planning documentation and area plans, as well as management directly associated with these functions. Importantly, this excludes planning costs for specific projects, which are directly attributed to the relevant projects.

A1.6.1.3 Network control and operational switching

This includes control room operations and staff, management of field crews, dispatch operators, associated support staff, as well as management directly associated with these functions.

A1.6.1.4 Project governance and related functions

Project governance and related functions includes all costs associated with the approval and management control of network projects or programs. This includes the cost of functions such as project management offices, works management, project accounting or project control groups where these costs are indirectly charged to specific projects or programs.

A1.6.1.5 Quality control and standard functions

This expenditure is for the management of the quality and reliability of supply and associated functions. It also includes all functions associated with developing, maintaining and complying with network technical standards, service standards or quality of supply standards, as well as:

- network records—developing and maintaining network records such as information in geographic information systems, network outage information, network capacity/ratings and network loading records
- asset strategy—developing and maintaining strategies for the ongoing management of network assets. It excludes network planning strategy development and maintenance that is part of the network planning function, as well as network operational strategy development and maintenance that is part of the network control function.

A1.6.1.6 Other network overheads

This includes expenditure on other activities such as training, occupational health and safety functions, property & procurement activities, network billing and customer service and call centre activities.

A1.6.2 Corporate overheads

This includes corporate support and management services by the corporate office that cannot be directly identified with specific operational activity. Corporate overhead costs typically include those for executive management, legal and corporate secretariat, human resources, finance, information technology, regulation and other corporate head office activities or departments.

A1.6.3 Other direct expenditure

This relates to JGN's cyclical and special meter readings and associated staff employee costs, and pipeline integrity management activities.