# Jemena Gas Networks (NSW) Ltd

## 2020-25 Access Arrangement Proposal

Attachment 6.1

Operating Expenditure

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# Abbreviations

| | |
|---|---|
| A&O | Administration and overheads |
| AA | Access Arrangement |
| AEMO | Australian Energy Market Operator |
| AER | Australian Energy Regulator |
| bppa | Basis points per annum |
| CAM | Cost allocation methodology |
| DAE | Deloitte Access Economics |
| DNSP | Distribution network service providers |
| DRC | Debt raising costs |
| ECA | Energy Consumers Australia |
| ECM | Efficiency Carryover Mechanism |
| EI | Economic Insights |
| EWON | Energy and Water Ombudsman NSW |
| JEN | Jemena Electricity Networks (Vic) Ltd |
| JGN | Jemena Gas Networks (NSW) Ltd |
| MTFP | Multilateral Total Factor Productivity |
| NER | National Electricity Rules |
| NGR | National Gas Rules |
| O&M | Operating & Maintenance |
| OH&S | Occupational Health and Safety |
| opex | Operating expenditure |
| PIAC | Public Interest Advisory Centre |
| PTRM | Post Tax Revenue Model |
| RAB | Regulatory Asset Base |
| RY | Regulatory Year |
| SGSPAA | SGSP (Australia) Assets Pty Ltd |
| UAG | Unaccounted for gas |
| WPI | Wage Price Index |

# Overview

Chapter 6 of our 2020 Plan sets out our forecast operating expenditure (**opex**) requirements. 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 pipeline services for the next Access Arrangement (**AA**) period, which runs from 1 July 2020 to 30 June 2025. 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 relevant provisions of the National Gas Rules (**NGR**).

The document is structured as follows:

- This overview summarises Jemena Gas Networks (NSW) Ltd's (**JGN's**) opex forecasts for the next AA period, and the key changes to our forecast since we published our Draft 2020 Plan
- Section 1 provides an overview of what we have heard from our customers, and how we have incorporated this into our plans. It also includes a response to the feedback we have received on the opex forecasts in our Draft 2020 Plan
- Section 2 describes JGN's operating cost categories
- Section 3 provides an overview of our current period opex
- Section 4 provides an overview of our opex forecasting approach
- Section 5 explains and justifies our base year opex forecast, including our benchmarking performance
- Section 6 explains and justifies our approach for trending the base year
- Section 7 discusses step changes
- Section 8 explains and justifies the other elements of our opex forecast that we have prepared using specific (or bottom-up) forecasting approaches
- Section 9 presents and explains JGN's opex forecast

Unless otherwise stated, all financial numbers in this document are presented in real 2020 dollars.

## Our opex forecast

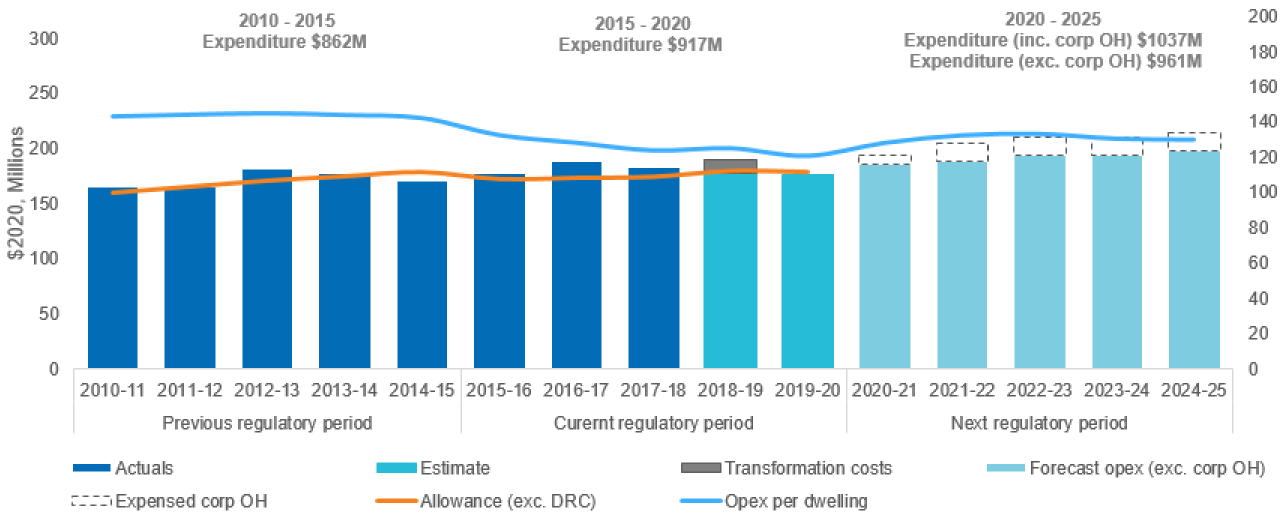
Opex is a major component of our building block costs, accounting for approximately 44% of JGN's total cost of service over the 2020-25 AA period. Table OV–1 details our forecast opex over the 2020-25 AA period. The forecast opex model is provided in Attachment 6.2.

**Table OV–1: Opex forecast, including debt raising costs, 2021 to 2025 ($2020, $M)**

| | 2020-21 | 2021-22 | 2022-23 | 2023-24 | 2024-25 | Total |
|---|---|---|---|---|---|---|
| **Total Opex** | 196.0 | 207.2 | 212.9 | 213.0 | 216.8 | 1,045.9 |

Although our total opex will increase over the 2020-25 AA period, we expect that our operating costs per dwelling will remain in line with the 2015-20 AA period (see Figure OV–1).

**Figure OV–1: Historical and forecast opex 2010-11 to 2024-25 ($2020, $M, exc. DRC)**




Notes - DRC = Debt raising costs, OH = Overheads

Our forecast opex for the 2020-25 period represents an efficient level of expenditure required to deliver the safe, reliable and cost-effective gas services that our customers have told us they want. It will enable us to continue to:

- deliver safe, reliable and cost-effective services through investment in maintenance programs that manage risk and meet customer service requirements
- respond to emergencies so that we minimise supply disruptions
- operate our call centres and customer touch points
- market gas for the continued utilisation of our network
- manage Jemena as a corporate entity and regulated business, to meet our legal and regulatory obligations
- replenish efficient levels of unaccounted for gas (**UAG**)

We believe that our opex forecast is the best forecast possible in the circumstances and that it is arrived on a reasonable basis. It reflects the costs of a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services. This is because our opex forecast:

- is based on the Australian Energy Regulator's (**AER**) preferred base, step and trend approach
- is supported by Economic Insights's (**EI**) review of JGN's base year efficiency and technical productivity
- includes sustainable benefits of lower costs from our transformation program and ongoing productivity savings factored into our forecast opex.

## Changes since our Draft 2020 Plan

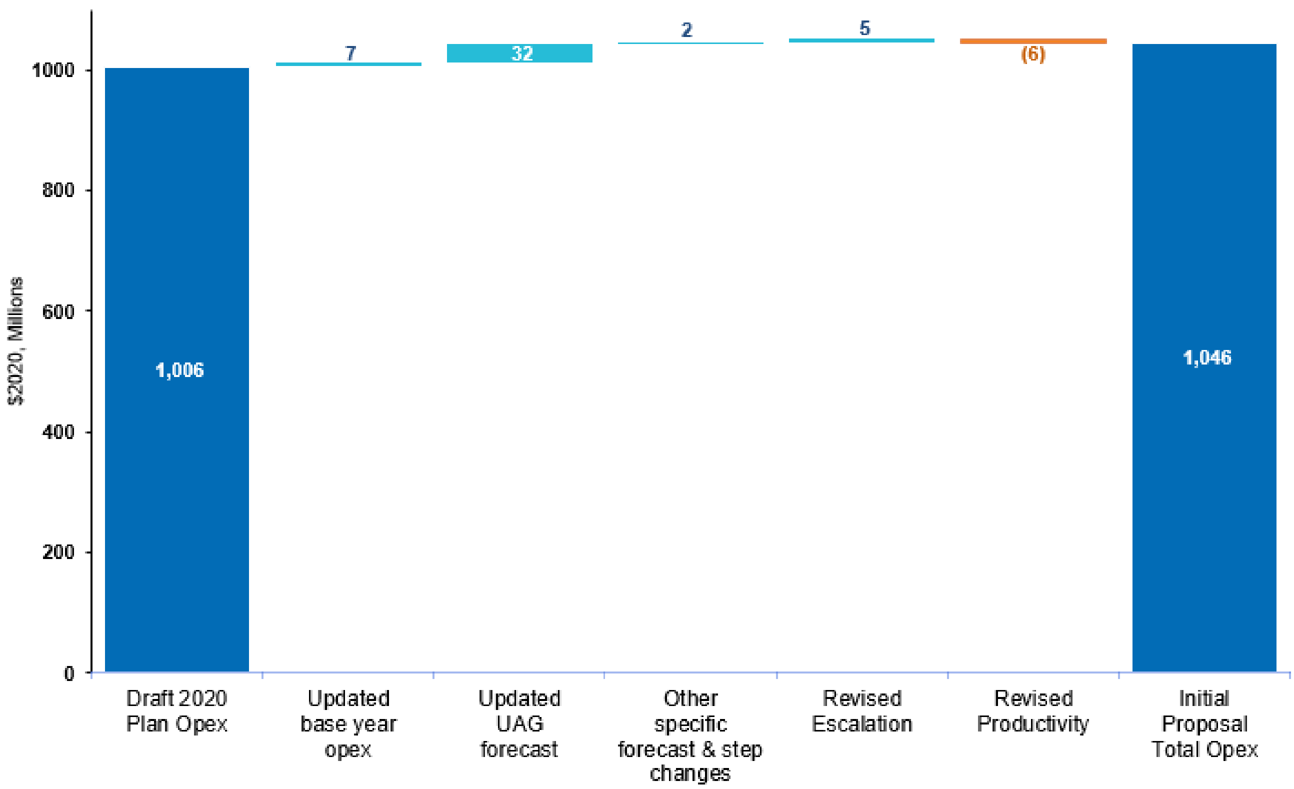
In our Draft 2020 Plan, our forecast opex was $1,006M over the 2020-25 AA period. This was $40M lower than our proposed opex forecast for the 2020-25 AA period. This is a result of the following key changes since we published our Draft 2020 Plan:

- An updated estimate of base year opex – the updated estimate reflects more up to date information on our actual opex in 2018-19. Our revised base year forecast is based on eight months of actuals and four months of estimated data. Our Draft 2020 Plan was based on a full year forecast for 2018-19 (see section 5.3).

- A change in methodology to forecast trend escalation – the Draft 2020 Plan forecast trend escalation was based on previous AER decisions for Victorian gas businesses. In line with feedback that we received from the AER at the deep dive we held on our Draft 2020 Plan,[1] we have reviewed our approach to forecasting trend escalation. Our revised method is based on an econometric analysis by EI (see section 6).
- An updated productivity target, also based on the econometric analysis by EI (see section 6.4).
- An update of the specific forecast on debt raising costs – based on expert advice from Competition Economist Group (**CEG**).
- An update to our forecast UAG costs – we have updated the UAG target rates based on latest data and the revised forecast of demand, which has resulted in an increase in our forecast UAG costs (see section 8.1).
- An update to forecast pigging and inspection related costs based on our latest business forecast.

These changes are summarised in Figure OV–2.

**Figure OV–2: Changes in our opex forecast since our Draft 2020 Plan**




[1] On 19 February 2019, we held a deep dive workshop on our Draft 2020 Plan with the AER, the Consumer Challenge Panel and a number of customer advocates that are members of our JGN Customer Council. Following the deep dive we had discussions with the AER on our approach to forecasting trend escalation, which led us to modify the approach we had adopted in the Draft 2020 Plan.

## List of opex attachments

**Table OV–2: List of opex attachments**

| Attachment | Name | Author |
|---|---|---|
| 6.1 | Operating expenditure | JGN |
| 6.2 | Operating expenditure forecasting model | JGN |
| 6.3 | Pigging costs roll-forward model | JGN |
| 6.4 | Relative efficiency and forecast productivity growth of JGN | Economic Insights |
| 6.5 | Cost allocation methodology | JGN |
| 6.6 | Debt transaction costs and PTRM timing benefits | CEG |
| 6.7 | Unaccounted for gas | JGN |
| 6.8 | Independent review of JGN's UAG | Howard Wright Gas Measurement |
| 6.9. | UAG report | Frontier Economics |
| 6.10 | Estimated UAG rates | Frontier Economics |
| 6.11 | Independent review of JGN's UAG calculation | KPMG |

# 1. What we have heard from our customers

## 1.1 Results from our engagement with our customers

Throughout our engagement program, our customers told us that they value and expect a safe and reliable gas service. They also told us that they are satisfied with the current levels of service that we provide, and that it is important that we provide common minimum levels of service to our customers, irrespective of where they are located across our network. Our opex forecast has been developed to ensure that we can continue to provide our customers with the level of service that they expect—we are not proposing to increase or decrease existing service levels.

Recognising that affordability is a key issue for our customers, we are committed to delivering a number of initiatives which are aimed at improving our cost competitiveness, both now and into the future. This includes delivering a transformation program to reduce our opex, and a commitment to deliver ongoing productivity improvements. The initiatives are explained in more detail in Section 5.3.

Our customers also told us that they enjoy and value the benefits of natural gas, and that they want to continue using it the future. They supported us taking appropriate actions now to respond to uncertainty around the long-term future of gas. This includes taking action to ensure the long-term price competitiveness of gas, by reducing the growth in our asset base. Aligning our regulatory practice to our accounting practice to expense all of our corporate overheads will help us achieve this, and will improve fairness across generations, by better aligning the recovery of costs with the realisation of benefits.

As outlined in Chapter 2 of our 2020 Plan, in March 2019 we held a fourth deliberative forum with a group of customers from across NSW. This forum followed three previous forums held throughout 2018, where we sought inputs and feedback from our customers to help shape our plans for the 2020-25 period. The purpose of the fourth forum was to provide customers who had been involved in our engagement program with an overview of our Draft 2020 Plan, to ensure that we had accurately captured and reflected their feedback in our Draft 2020 Plan. During the forum, our customers confirmed, with 90% either strongly or moderately agreeing, that our Draft 2020 Plan was in the long term interest of customers (see Attachment 2.1 for details). Additionally, our customers confirmed that we had accurately captured their preferences for us to maintain current levels of service.

## 1.2 Responses to our Draft 2020 Plan

In addition to the feedback from our customers on our Draft 2020 Plan, we also received written submissions from the Public Interest Advisory Centre (**PIAC**)[2] and Energy Consumers Australia (**ECA**).[3] The feedback that we received in relation to our opex forecast, together with our response, is included in the following table.

**Table 1–1: Summary of submissions on our Draft 2020 Plan**

| Author | Topic | Feedback | How we are responding |
|---|---|---|---|
| ECA | Service levels | The ECA provided support for the initiatives included to ensure that current levels of safe and reliable service provision will be maintained into the future. | We are committed to continuing to provide our customers with a safe and reliable gas service into the future, and we consider that our opex proposal will ensure that we are able to deliver on this commitment whilst also ensuring that our services remain cost-effective. |

2 PIAC, *Submission to Jemena Gas Networks' Draft 2020 Plan*, 21 March 2019 (available on https://yournetwork.jemena.com.au/draft-2020-plan/documents)

3 Energy Consumers Australia, *Jemena Gas Networks Draft 2020 Plan Submission*, March 2019 (also available at the above link)

| Author | Topic | Feedback | How we are responding |
|---|---|---|---|
| ECA | Operating expenditure efficiencies/ productivity | The ECA confirmed its support for JGN's proposed opex efficiencies, noting they were consistent with long term consumer interest. The ECA noted it would like further justification that the 0.5% target in the Draft 2020 Plan is still appropriate and consistent with regulatory precedent. | JGN reconfirms its commitment to deliver ongoing productivity savings and we have updated our productivity target to 0.74% per annum, in line with our updated method to forecast trend escalation. This target is supported by the results of econometric analysis by Economic Insights, and is in line with comments made by the AER in its Final Decision on '*Forecasting productivity growth for electricity distributors'* (dated 8 March 2019). See section 6.4 for more detail. |
| PIAC | | PIAC welcomes JGN's commitment to deliver opex savings of 0.5% p.a. over the 2020-25 period. | |
| ECA | Rebate schemes | The ECA noted that JGN should consider opportunities to incentivise greater and continued usage of the network. This includes more tiering of tariff arrangements and rebates schemes on gas appliances. | As noted in Section 6.1 of our 2020 Plan, rebate schemes are an important part of our marketing program. Our rebate schemes are focused on promoting greater utilisation of our network which benefits all JGN customers by placing a downward pressure on our network charges. In contrast to PIAC's concerns about whether gas distributors should spend any money on marketing, the results of our rebate program demonstrate that it is in our customers long term interests to continue to grow the network and its utilisation (see section 1.2.1 for more information on our rebate program). More information on our tariff arrangements is included in Attachment 4.1. |
| PIAC | | PIAC expressed concern regarding the use and implementation of rebates and incentives to encourage the purchase or replacement of gas appliances, noting that households may choose to purchase lower-efficiency gas appliances because of the rebates. | |
| ECA | Expensing corporate overheads | The ECA would like more explanation on why expensing corporate overheads previously capitalised is in consumers' interests when it will increase charges in the short term. | As discussed in section 5.4, this change in treatment will ensure that we retain alignment with our accounting practices, and recognises that the nature of corporate overheads has changed in recent years. Although there is a short term upward impact on revenue, this is within the context of overall network price reductions. We consider that this change is in the long term interests of consumers as it helps to reduce RAB growth. It is also consistent with customer feedback that we should consider fairness in the context of existing and future customers—expensing these overheads will ensure better alignment of cost recovery with the realisation of customer benefits arising from this expenditure. |

| Author | Topic | Feedback | How we are responding |
|---|---|---|---|
| ECA | Transformation program | The ECA requested further clarification on the savings in labour costs assumed in base year. | As noted in section 5.3 we are currently forecasting that the transformation program will deliver ongoing benefits of approximately $8M per annum. These savings will be derived from a reduction in both labour and non-labour costs. We are currently forecasting a reduction of $8M in controllable opex[4] between 2017-18 and 2018-19, which reflects savings delivered as part of the transformation program. |

### 1.2.1 Appliance rebates

Our gas appliance cash back program seeks to drive increased usage and penetration of our network. Rebates are only paid where new gas points are fitted—this might be from an additional appliance or by replacing electric appliances. Since 2015, we have invested $5M in cash backs which has generated 130,000GJ of incremental load annually. The rebate program has a payback period of 2.5 years. This means that all JGN customers benefit in the form of lower bills.

Our cash back program is primarily targeted at renovators and those considering their appliances and fuel mix, with renovators accounting for approximately half of claimants.

Gas appliances can often be more expensive than their electric counterparts, and therefore the cash back aims to provide some parity between upfront costs, so that customers can consider the overall benefits of the product in terms of its efficiency and ongoing running costs. This is particularly the case for gas heating which accounts for 37% of rebate claims, where systems typically cost $10-$15k to install.

To ensure that the incremental load is not inefficient for our customers, we work closely with manufacturers that produce and promote highly efficient five, six and seven star (equivalent) systems.

Throughout our customer engagement program, we heard that our customers want us to continue making gas available to those who want it, and to do what we can to lower bills. Our appliance rebate program is directly aligned to this customer feedback.

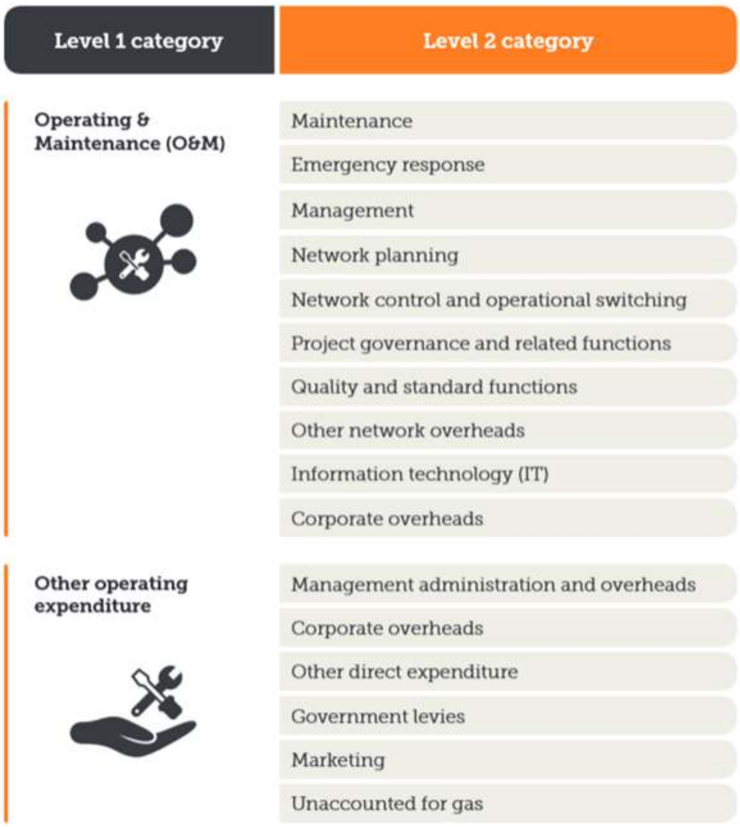
4 Controllable costs exclude UAG and government levies.

# 2. Operating cost categories and cost allocation

## 2.1 Operating cost categories

Our operating costs can be split into two high level categories (consistent with the AA RIN): operating & maintenance (**O&M**) and other operating expenditure. A breakdown of these operating cost categories is shown in Figure 2–1.

**Figure 2–1: Operating cost categories**




Appendix A includes an overview of each of the opex categories.

## 2.2 Cost Allocation

The JGN Cost Allocation Methodology[5] (**CAM**) governs how costs are allocated within JGN. It includes allocation of costs to the reference service and non-reference services provided by means of the JGN network, in accordance with Rule 93(2) of the NGR. The CAM has been applied to remove non-reference services related opex from our base year opex—that is, it is excluded from the opex forecast presented in this attachment.[6]

[5] This is included as Attachment 6.5 of the AA proposal

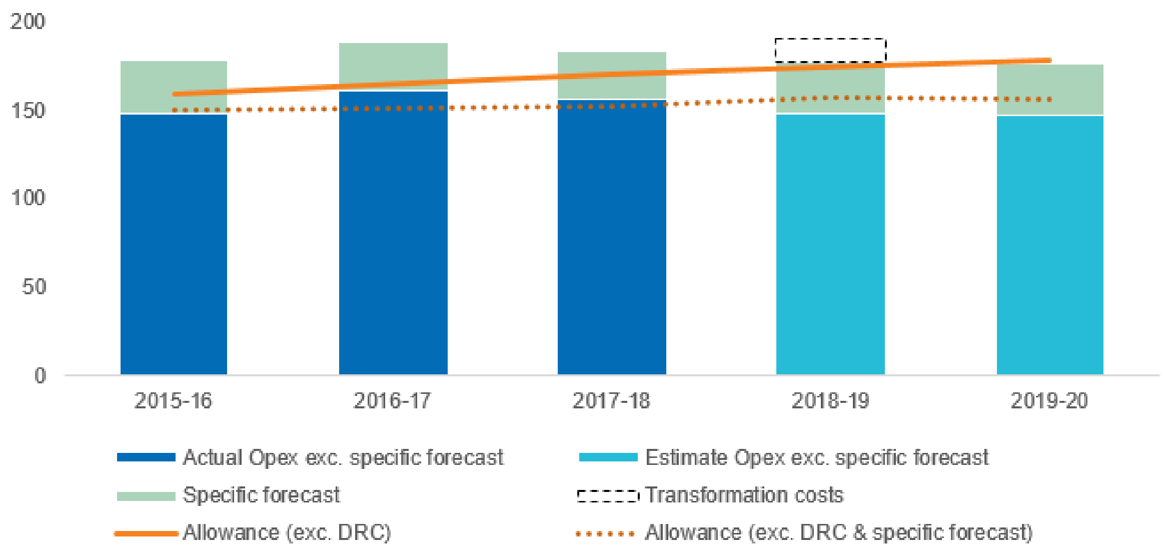
[6] Non-reference service opex is reported in RIN Attachment 6 (Historical templates) table E20.2.2 Non-reference services. In RY18, non-reference service opex was $105.67k ($nominal).

# 3. Overview of current period performance

Over the current period, we expect to incur $917M of opex, which is $40M more than the allowance of $877M (this excludes debt raising costs) approved by the AER. The two major drivers of this overspend are higher UAG costs and costs associated with our transformation program (identified by the dotted area for the 2018-19 year in Figure 3—1).

It also shows that our opex has tracked the AER's allowances relatively closely, once the impact of UAG and transformation costs are excluded.

**Figure 3—1: Historical opex versus allowance 2015-16 to 2019-20 ($2020, $M)**




Notes - DRC = debt raising costs

## 3.1 Analysis of opex by category

Rule 72(1)(a)(ii) requires the Access Arrangement Information to provide actual opex by category over the current AA period. Our historical opex is provided in Table 3–1, with a comparison against the AER approved costs. Analysis of variances between allowed and actual opex is set out in Table 3–2.

**Table 3–1: Allowed opex compared with actuals and JGN's currently estimated and forecast outcomes (excl. debt raising costs ($M, $2020)**

| | | Actual 2015-16 | Actual 2016-17 | Actual 2017-18 | Estimate 2018-19 | Forecast 2019-20 | Total 2015-20 |
|---|---|---|---|---|---|---|---|
| Operating and maintenance | 2015 AA allowance | 125.0 | 125.9 | 127.7 | 136.8 | 135.9 | **651.3** |
| | Actual/estimate | 124.9 | 136.6 | 130.3 | 137.7 | 123.9 | **653.4** |
| Non-operating expenditure (excluding specific forecasts) | 2015 AA allowance | 25.3 | 25.4 | 24.5 | 20.5 | 20.6 | **116.3** |
| | Actual/estimate | 23.7 | 25.0 | 25.8 | 23.7 | 23.6 | **121.9** |
| **Specific forecasts** | | | | | | | |
| Government levies | 2015 AA allowance | 4.4 | 4.4 | 4.4 | 4.4 | 4.4 | **21.8** |
| | Actual/estimate | 6.1 | 5.2 | 4.6 | 4.8 | 4.8 | **25.6** |
| Unaccounted for gas (**UAG**) | 2015 AA allowance | 17.5 | 17.6 | 17.5 | 17.5 | 17.6 | **87.7** |
| | Actual/estimate | 23.5 | 21.9 | 22.4 | 24.1 | 24.1 | **116.1** |
| **Total costs** | **2015 AA allowance** | **172.2** | **173.2** | **174.2** | **179.2** | **178.4** | **877.1** |
| | **Actual/Estimate** | **178.2** | **188.7** | **183.2** | **190.3** | **176.4** | **916.9** |

(1) Amounts allowed are adapted from the 2015 AA "AER Final decision JGN distribution access arrangement – opex model – June 2015.
(2) Amounts incurred are JGN's actuals to 2015-16 to 2017-18, its estimate for 2018-19 and its forecast for 2019-20.

**Table 3–2: Analysis of variance between allowed and actual opex**

| Opex category | Analysis of variance |
|---|---|
| Operating and maintenance (O&M) | Overspend due to:<br>• Increase in corrective maintenance activities, mainly around pipework and facilities<br>• Higher volume, and associated cost, of disconnection and reconnections (recoverable via an ancillary charge) than forecast in the final decision allowance<br>• Transformation program costs are estimated to be $13M (in RY19). These costs were not included within the allowance, but will deliver sustainable opex reductions in future by reducing base year costs. |
| Non-operating expenditure (excluding UAG and Government levies) | A number of offsetting items account for the variance between the allowance and actual expenditure. These include:<br>• Higher volume of ancillary activities provided (special meter reads) than forecast in the final decision<br>• Higher expenditure on commercial activities to support growth in new connections, associated with greater network growth than forecast in allowance<br>• Rationalisation of marketing programs to reduce marketing expenditure, to offset increases in opex in other areas |
| Government levies | Overspend due higher than forecasted government levies for the current AA period. |
| UAG | Overspend is due to actual volumes being greater than forecast and the variation in wholesale gas prices, both of which are subject to annual automatic adjustment arrangements. Overspend in RY19-20 also due to the actual level of UAG (as a percental of total receipts) being greater than the target rate of UAG (%) allowed for in the AER's Final Decision for the 2015-20 period. See section 3.1.2 for details. |

### 3.1.1 Transformation program

In 2018-19 we expect to incur approximately $13M in opex associated with transforming our business. This transformation program commenced in 2018, and will deliver benefits of approximately $8M per annum, primarily in the form of reductions in labour costs.

More information on our transformation program is provided below, in section 5.3.

### 3.1.2 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 – this difference is known as UAG. We buy gas through a competitive tender process.

Our opex allowance for the 2015-20 period included forecast UAG costs, based on the product of:

- the total gas receipts
- the approved target rate of UAG
- the cost of replacement gas.

A UAG incentive applies in the 2015-20 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 current period, we expect to exceed our UAG allowance. This is due to a number of different drivers, namely:

- The price of gas: Our forecast opex allowance for the 2015-20 period assumed a wholesale gas price of $9.20/GJ[7], whereas in fact we have paid (on average) [redacted]. This higher wholesale price accounts for [redacted] of our expected $28.4M overspend against the AER's allowance in the 2015-20 period.
- The volume of UAG: over the 2015-20 period, we delivered more gas than forecast in the AER's UAG allowance. In addition, there was an increase in the percentage of UAG due to a change in the metering station at Wilton, which delivers flows into JGN from the MSP. These two factors accounted for [redacted] of our expected overspend in UAG opex.

A more detailed discussion of UAG, including JGN's UAG performance over the current AA period and our management of UAG is contained within Attachment 6.7. In addition, Attachment 6.8 includes an independent review of JGN's UAG performance by Howard Wright Gas Measurement Pty Ltd, and Attachment 6.11 includes a report by KPMG, which has undertaken an independent validation of JGN's UAG calculation method.

7 The allowance was $8.25/GJ in real $2014.

# 4. Overview of our forecasting approach

## 4.1 Forecasting method

We have developed our opex forecast using the AER's preferred forecast method, the *base, step and trend approach*. Additionally, we have also used *specific year-by-year forecasts* for the opex cost categories where base year costs are not representative of the costs that we will incur on these categories in the future.

We forecast our opex in five broad steps:

- **Step one:** we establish the efficient base year, having regard for our current and historical costs. We discuss this step in section 5.
- **Step two:** we adjust this base year for the following: non-recurrent costs; costs that we forecast other than using the base, step and trend approach; and the expensing of corporate overheads. We also discuss this in section 5.
- **Step three:** we trend the base year forward over the forecast 2020-25 AA period, considering expected changes in real labour input costs, network growth and productivity gains. We discuss this in section 6.
- **Step four:** we add in a step change of pigging and inspection costs due to a proposed change in the treatment of these costs—these costs were previously capitalised. We have also included a negative step change to account for the corporate overheads that are capitalised in the first half-year of 2020-21. We discuss this in section 7.
- **Step five:** we add in specific forecasts for items where base year costs are not representative of the costs we expect to incur. We have developed specific forecasts for the following items: UAG, government levies, and debt raising costs. These items are discussed in section 8.

## 4.2 Key inputs and assumptions underlying JGN's opex forecast

Sections 5 to section 8 describe and substantiate the key inputs and assumptions underlying JGN's opex forecast, including the basis of the specific forecasts.

These sections should be read in conjunction with Attachment 6.2, our opex forecasting model.

# 5. Establishing an efficient base year

## 5.1 Efficiency of base year

The purpose of the base year in the base, step and trend approach is to provide a reasonable starting point for our prudent and efficient opex forecast that reflects our on-going requirements to maintain the quality, safety and reliability of our gas network and our pipeline services during the 2020-25 AA period.

We have used 2018-19 as our base year because 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 2020-25 period (expected in May 2020). Using the penultimate year of our 2015-20 period continues the standard approach that the AER has applied in its recent regulatory decisions, including for our 2015-20 AA period, where it has deemed it appropriate to use revealed costs to set opex forecasts
- is consistent with the AER's guidance, where it notes *"if a network service provider (NSP) operated under, and responded to, an effective incentive framework, actual past expenditure should be a good indicator of the efficient expenditure the NSP requires in the future*"[8]. As we have noted we have operated under the ECM during the 2015-20 AA period.
- incorporates opex reductions that we have and are expecting to realise over the current 2015-20 period, including benefits from the transformation program (discussed in section 5.3).
- is representative of our underlying, current operating conditions in the 2015-20 and 2020-25 AA periods
- is supported by EI analysis as being efficient and suitable for use as base year.

We have estimated our 2018-19 opex because we have not had time to confirm our final actual opex for the year before submitting our AA proposal to the AER in June 2019. We will update our base year with our actual 2018-19 opex in our Revised Proposal, which we will submit to the AER in January 2020.

We consider that our current and estimated 2018-19 opex is prudent and efficient because:

- the opex data is current and will be audited in the RY19 update of the AA RIN;
- our opex and total costs benchmark efficiently when compared with other gas distribution businesses (**GDB**), as discussed in section 5.2

## 5.2 Benchmarking

Unlike the National Electricity Rules (**NER**), the NGR do not require the AER to conduct economic benchmarking, or to rely on benchmarking results, in assessing GDBs' opex proposals. The AER does not prepare an annual benchmarking report of GDBs, as it does for electricity distribution network service providers (**DNSP**).

While we do not believe that benchmarking should be used deterministically to set opex allowances, it is a tool that combines various techniques to inform whether a GDB's base opex is efficient to apply a revealed cost approach.

We commissioned an independent report from EI (included as Attachment 6.4) to benchmark JGN against other Australian and New Zealand gas distribution businesses using AER's preferred benchmarking techniques, including:

- Productivity index numbers - these techniques use a mathematical index to determine the relationship between multiple outputs and inputs, enabling comparisons of productivity levels over time and between networks. These include multilateral total factor productivity (**MTFP**) and multilateral partial factor productivity (**MPFP**).

[8] AER, Expenditure Forecast Assessment Guideline for Electricity Distribution, Nov 2013, p 42

- Econometric opex cost function models - these model the relationship between opex (as the input) and outputs to measure opex efficiency. These include using stochastic frontier analysis (**SFA**) and feasible generalized least square (**FGLS**).
- Partial performance indicators (**PPI**) - These model the relationship between opex (as the input) and individual outputs to measure opex efficiency. For example - opex per customer relative to customer density, opex per mains km relative to customer density, etc.

### 5.2.1 Results of benchmarking analysis

EI's key findings in relation to JGN's performance based on the various benchmarking techniques are:

- JGN's MTFP and opex MPFP were amongst the highest for the latest available years. The MTFP and MPFP analysis indicate that JGN is a relatively efficient performer in its use of both opex and capital inputs.
- Econometric analysis concludes that JGN's estimated efficiency score of 0.93 is higher than the average efficiency score (0.86) of all 14 GDBs in the sample. It is one of several firms clustered on or about the efficient frontier. These findings suggests that JGN does not have any material inefficiency and does not require an adjustment to its base year opex.
- In regard to the PPI opex-related measures, when differences in customer density are controlled for, JGN is reasonably efficient in terms of opex per customer, and it has average levels of opex per km of network.
- In terms of PPI asset cost measures, JGN is close to average in terms of asset cost per customer and has relatively higher asset cost per kilometre of mains. These comparisons are influenced among other things by asset age, original network asset valuations, and various factors not controlled-for which influence the quantity of assets per customer, and hence asset cost per customer.
- In terms of total cost measures, JGN's total cost per customer is close to the sample average when differences in customer density are controlled for, whereas its total cost per km is slightly higher than the sample average. Once again, qualification is necessary because the wide variation in GDBs' total cost per km may suggest that unobserved differences in local conditions are important determinants of these costs.

Other key EI findings from the econometric analysis are that:

- The estimated average rate of technical change or 'frontier shift' is 0.74% per annum (expressed as a rate of productivity growth), which is higher than the 0.5% per year recently assessed by the AER for electricity distribution[9]
- The estimated output index weights for the two outputs used in EI's preferred econometric model are: (i) customer numbers, 49.4%; and (ii) mains length, 50.6%.

EI's full report is provided in Attachment 6.4.

Our strong productivity performance provides robust support for the efficiency of our opex forecast. The result demonstrates that JGN invests in opex programs at lowest sustainable cost and in accordance with good industry practice, promoting the long term interests of our customers.

## 5.3 Transforming our business to reduce our cost base

To ensure that gas remains a competitive and sustainable fuel both now and into the future, we must strive continually to improve our cost efficiency. We are currently implementing a business-wide transformation program, which aims to reduce our operating-cost base so that we can achieve sustainable operating-cost reductions over the longer term. The program demonstrates our commitment to continuous improvement in operational efficiency, and will assist us in reducing network charges for our customers over the 2020-25 period.

9 AER, "Forecasting productivity growth for electricity distributors", March 2019, page 10

This program commenced in 2018, and we expect that it will deliver benefits of approximately $8M per annum, or $39M over the 2020-25 period. The cost reductions achieved through this program will be well in excess of the expected implementation costs of approximately $13M.

The key focus areas of the transformation program are:

- Optimisation of corporate activities and improvements to customer service
- Procurement and contract renegotiation
- Salary restructuring
- Increase gas field forecast productivity

We believe that these benefits should be incorporated into our base year (2018-19) for the purpose of forecasting our opex requirements over the 2020-25 AA period. This means that we will bear the ongoing costs and risks of the program—only if our initiatives actually deliver the anticipated lower future opex will we realise the intended benefits.

Our proposal includes a positive efficiency carryover amount in our Efficiency Carryover Mechanism (**ECM**) reflecting the one off adjustment made to the base year (2018-19). Under the ECM customers will pay the implementation costs for the transformation program over the next period, but will receive the full and ongoing benefits of the program (expected to be $39M over 2020-25 period and $8M per annum thereafter). Once base year is completed, our auditors will undertake an external review and validation of these costs.

As discussed in section 6.4, in addition to these benefits of our transformation program, we are also volunteering to achieve significant ongoing productivity savings throughout the 2020-25 AA period.

## 5.4 Changing treatment of our corporate overhead costs

Corporate overheads are costs associated with corporate functions that are necessary to provide our reference service. We have typically capitalised approximately 40% of corporate overheads up to, and including, the 2015-20 period. From 1 January 2021 our accounting treatment of corporate overheads will be to expense these costs.

We are changing the treatment of these corporate overheads for regulatory purposes as well so that, from 1 January 2021, all of these costs will be expensed to ensure alignment between accounting and regulatory treatment of costs. It is also aligned with the treatment of these costs in the Cost Allocation Methodology adopted by Jemena Electricity Networks (Vic) Ltd (**JEN**), which was approved by the AER in May 2019.[10]

Recognising that we do not earn a rate of return on opex, this change in treatment of these costs will benefit customers in the longer term, as it will result in a lower asset base. The effect of this change is to increase our opex base year by $16.8M per annum or $75.8M in total—only half the annual amount (i.e. $8.4M) will apply in 2020-21, as the change in approach will be in effect from 1 January 2021.[11]

This change reduces our capex by the same amount and so does not reflect any change in our overall cost or efficiency.

## 5.5 Other base year adjustments

We need to adjust our base year to remove any costs where the base year is not representative of our recurrent costs in the forecast period.

[10] AER Final Decision, Jemena Electricity Networks (Vic) Ltd Revised Cost Allocation, May 2019

[11] The capitalisation adjustment in 2020-21 is described as a 'step change' in the opex model

In addition to the adjustments for our transformation program costs and corporate overhead charges, we have removed costs for items we have forecast using specific forecasts (see Table 5-1 below). These activities are government levies, UAG. They are discussed in section 7.

**Table 5–1: Forecast base year adjustments ($2020, $M)**

| | 2018-19 |
|---|---|
| Estimated base year opex | 190.3 |
| Less transformation program costs | -13.1 |
| Add opex associated with expensing corporate overheads | 16.8 |
| Less opex on items forecast using specific forecast (government levies, UAG, debt raising costs) | -29.0 |
| **Adjusted base year opex** | **165.1** |
| Final year adjustment[1] | -0.8 |
| **Adjusted base opex before trending** | **164.3** |

(1) It is the AER's standard practice to take the increment of opex allowance from base year to final year as an estimate of the actual incremental opex from base year to final year

# 6. Trending the base year

## 6.1 Total trend

The base, step and trend approach adjusts the base year for the expected rate of change over the 2020-25 period. In its recent decisions, including for our 2015-20 AA period, the AER has defined three components of rate of change adjustments to the base year.

- **Input cost trend** – this is the expected change in our real cost of inputs, such as labour and materials, over the period, which are primary inputs to our opex program.
- **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 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. This is an additional stretch target that we are volunteering, over and above the benefits of our transformation program.

The trending of our base year opex is determined by the following rate of change relationship:

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

We have applied these three adjustments to our base year forecast for the 2020-25 period. Table 6-1 shows the impact on our opex forecast.

**Table 6-1: Forecast rate of change (%)**

| | 2020-21 | 2021-22 | 2022-23 | 2023-24 | 2024-25 |
|---|---|---|---|---|---|
| Input cost trend (%) | 0.44% | 0.63% | 0.71% | 0.69% | 0.63% |
| Output growth trend (%) | 1.68% | 1.47% | 1.38% | 1.37% | 1.41% |
| Productivity adjustment (%) | -0.74% | -0.74% | -0.74% | -0.74% | -0.74% |
| Total opex rate of change (%) | **1.38%** | **1.35%** | **1.36%** | **1.32%** | **1.30%** |

Table 6–2 shows the forecast rate of change adjustments, excluding inflation, over the 2020-25 period. These costs will increase our opex by 4.1% in 2020-25 period compared to our base opex. We explain and justify each of these forecasts in the following sub-sections.

**Table 6–2: Forecast rate of change ($2020, $M)**

| | 2020-21 | 2021-22 | 2022-23 | 2023-24 | 2024-25 | Total |
|---|---|---|---|---|---|---|
| Input cost trend | 0.7 | 1.8 | 2.9 | 4.1 | 5.2 | 14.7 |
| Output growth trend | 2.8 | 5.3 | 7.7 | 10.2 | 12.8 | 38.7 |
| Productivity | -1.2 | -2.5 | -3.8 | -5.2 | -6.6 | -19.4 |
| **Total opex trend** | **2.3** | **4.5** | **6.8** | **9.1** | **11.3** | **34.0** |

## 6.2 Input cost trend

Our base year opex reflects the current prices of our inputs, which comprise labour and non-labour items, such as materials. The base, step and trend approach allows for our adjusted base year opex to be varied to account for forecast real changes in input costs.

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 have developed our opex forecast on the assumption that our real labour costs will increase but that our other non-labour input costs will not change in real terms (i.e. they will move in accordance with inflation).

Our input cost adjustments are based on forecast real price increases for labour of between 0.44% and 0.71% per annum for the 2020-25 period, as detailed in Table 6–3. This reflects:

- The average of real labour escalator forecasts from BIS Oxford and Deloitte Access Economics (**DAE**). We have relied on a forecast by BIS Oxford Economics (see Attachment 5.5) and have relied on DAE's real wage price index (**WPI**) forecast for the NSW utilities' industries commissioned by the AER[12]. We have used these as proxies for our labour costs over the 2020-25 period.
- Our assumption about the relative weighting of 59.7% for labour and 40.3% non-labour to our opex costs, which is the benchmark weightings in AER's 2017 Economic Benchmarking report[13] and applied to electricity businesses in the AER's recent decisions.[14]

**Table 6–3: Forecast input cost growth 2020-25**

| | 2020-21 | 2021-22 | 2022-23 | 2023-24 | 2024-25 | Total |
|---|---|---|---|---|---|---|
| BIS Oxford real labour forecast (A) | 1.27% | 1.50% | 1.69% | 1.61% | 1.41% | |
| Deloitte Access Economic real labour forecast (B) | 0.20% | 0.60% | 0.70% | 0.70% | 0.70% | |
| Average real labour forecast (C = (A+B)/2) | 0.73% | 1.05% | 1.20% | 1.16% | 1.06% | |
| Labour contribution to Price growth trend (D) | 59.70% | 59.70% | 59.70% | 59.70% | 59.70% | |
| Adjusted real labour forecast (E=D x C) | 0.44% | 0.63% | 0.71% | 0.69% | 0.63% | |
| Real other forecast (F) | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | |
| Price growth trend (E+F) | **0.44%** | **0.63%** | **0.71%** | **0.69%** | **0.63%** | |
| **Input cost growth ($M, 2020)** | **0.7** | **1.8** | **2.9** | **4.1** | **5.2** | **14.7** |

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 6.4 and the savings from our transformation program discussed in section 5.3.

## 6.3 Output growth trend

Our adjusted base year opex reflects the current outputs that we deliver via our services. The base, step and trend approach allows for varying the adjusted base year opex to account for forecast changes in outputs. This is because many of our opex activities (and associated costs) will grow in line with our customer base and the length of pipeline we need to maintain.

12 Deloitte Access Economics , Labour Price Growth Forecasts prepared for the AER, 28 February 2019 Section 3.2.4, page 37

13 Economic Insights, Economic Benchmarking Results for the Australian Energy Regulator's 2017 DNSP Benchmarking Report, 31 October 2017, pp. 1–2.

14 AER, Ausgrid 2019-24 - Draft decision - Attachment 6 - Operating expenditure - November 2018, page 37; AER, Essential Energy 2019-24 - Draft decision - Attachment 6 - Operating expenditure - November 2018, page 27; AER, Endeavour Energy 2019-24 - Draft decision - Attachment 6 - Operating expenditure - November 2018, page 31.

We have applied the AER's standard approach to determine the forecast changes in outputs. We have calculated the impact on opex by multiplying the forecast increase in each output measure by the corresponding output weights, determined by EI from econometric analysis, which are customer numbers (49.4%) and mains length (50.6%).

The results are detailed in Table 6–4. This translates to a 1.37% to 1.68% annual increase in opex due to output growth over the 2020-25 period.

**Table 6–4: Forecast output growth 2020-25**

| | 2020-21 | 2021-22 | 2022-23 | 2023-24 | 2024-25 | Total |
|---|---|---|---|---|---|---|
| Customer Numbers | 1.88% | 1.53% | 1.43% | 1.41% | 1.44% | |
| Mains length | 1.49% | 1.40% | 1.34% | 1.34% | 1.38% | |
| **Forecast output growth** | **1.68%** | **1.47%** | **1.38%** | **1.37%** | **1.41%** | |
| **Forecast output growth ($M, 2020)** | **2.8** | **5.3** | **7.7** | **10.2** | **12.8** | **38.7** |

## 6.4 Productivity

As noted in section 5.2, JGN commissioned EI to estimate JGN's opex technical productivity.[15] EI'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.

EI's analysis indicates that an efficient gas network business is expected to achieve productivity improvements averaging 0.74% per annum. This compares to the 0.5% per annum opex productivity growth factor supported by the AER in its Final Decision on '*Forecasting productivity growth for electricity distributors*', dated 8 March 2019: [16]

> *"Gas distribution and sectoral labour productivity growth estimates and forecasts both rely on relatively long datasets and both yield similar results that lend support to an opex productivity growth factor of 0.5 per cent per year."*

We have incorporated a 0.74% per annum opex productivity growth forecast into our opex forecast. This reduction in opex arising from forecast productivity gains 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 $19M over five years. These productivity gains will be in addition to the transformation program savings already built in to our base year opex forecast.

Table 6–5 details our forecast productivity adjustments for the 2020-25 period.

**Table 6–5: Forecast productivity adjustment 2020-25 ($2020, $M)**

| | 2020-21 | 2021-22 | 2022-23 | 2023-24 | 2024-25 | Total |
|---|---|---|---|---|---|---|
| Productivity adjustment | -1.2 | -2.5 | -3.8 | -5.2 | -6.6 | -19.4 |

15 Economic Insights, *Relative Efficiency and Forecast Productivity Growth of Jemena Gas Networks, Report prepared for Jemena Gas Networks*, 24 April 2019 (included as Attachment 6.4)

16 AER, "Forecasting productivity growth for electricity distributors", March 2019, page 10

# 7. Step changes

The base, step and trend approach allows for changes to costs, which could either be positive or negative, but are not reflected in the base year opex.

These changes could be due to external factors such as new regulatory obligations, legislative impacts or outcomes from customer engagement. These changes could also be a result of internal factors such as efficient trade-offs between capex and opex (for example, where demand management is used as a substitute for capex), where these are not captured in our efficient base year or trend escalation.

We are proposing two step changes for the next regulatory period which includes a negative step change to ensure that the cost of expensing corporate overheads for the first year 2020-21 is not overstated and a positive step change to expense future pigging costs that are currently capitalised. To the extent that we do in fact incur any other step changes over this period in addition to these two, we will need to achieve offsetting cost savings (except in the case of pass through events).[17]

**Table 7–1: Forecasts step changes 2020-25 ($2020, $M)**

| | 2020-21 | 2021-22 | 2022-23 | 2023-24 | 2024-25 | Total |
|---|---|---|---|---|---|---|
| Pigging and inspection costs | 0.0 | 0.0 | 3.3 | 1.3 | 3.1 | 7.7 |
| Negative corporate overheads | -8.4 | 0.0 | 0.0 | 0.0 | 0.0 | -8.4 |
| **Total** | **-8.4** | **0.0** | **3.3** | **1.3** | **3.1** | **-0.7** |

## 7.1 Pigging and inspection costs

We use an intelligent pipeline inspection tool, commonly referred to as a 'pig' to inspect the thickness of pipeline walls from the inside. Pigging a pipeline provides a detailed picture of its condition, allowing us to identify the locations of any damage and to correct material defects over time. We hire the equipment to undertake these inspections, but we undertake the work ourselves. This approach is cheaper, over time, than conducting spot checks of our pipelines.

Undertaking these inspections is necessary to satisfy our safety management requirements, which are described by the Australian Standard AS/NZS 2885.3 – Operations and Maintenance of Gas pipelines.

The costs of pigging do not include the resultant works that may be required on our pipelines and therefore may not necessarily result in extending the lives of our pipelines. This is because, once the pigging is undertaken, we still need to undertake validation or integrity digs to confirm any repair works. It is only after this point that we may repair the pipelines if we assess the damage discovered through the pigging to be unacceptable.

We are proposing to expense the costs of pigging from 2020-21 onwards, which we have capitalised in the current AA period.

We have based our pigging and inspection opex forecast on our actual historical expenditure (ie. cost per pigging run and frequency)[18] Pigging costs are included within Attachment 6.3.[19]

We believe that classifying pigging and inspection costs as opex more accurately reflects the nature of our activities. This will increase our forecast opex by $7.7M over the 2020-25 period. These costs will be offset by equal reductions in our capex, so there is no change in our overall costs or efficiency.

17 We note that the capitalisation adjustment in 2020-21 that is detailed in section 5.4 is described as a 'step change' in the opex model.

18 Refer to AA RIN Attachment 15 (Document index), "Capex document matrix" worksheet, for details of the six in line inspections (pigging) and integrity dig projects planned for the 2020-25 period.

19 See 'Inputs|Projects' worksheet

**Table 7–2: Forecasts for pigging and inspection costs 2020-25 ($2020, $M)**

| | 2020-21 | 2021-22 | 2022-23 | 2023-24 | 2024-25 | Total |
|---|---|---|---|---|---|---|
| Pigging and inspection costs | 0.0 | 0.0 | 3.3 | 1.3 | 3.1 | 7.7 |

## 7.2 2020-21 Negative corporate overheads

As discussed in section 5.4, our accounting and regulatory treatment of corporate overheads will change from 1 January 2021. Since this change will occur half way through the 2020-21 regulatory year, we need to expense these previously capitalised overheads for only half the year. Since we have added a full year of corporate overheads to 2020-21 as an adjustment to our base year costs, it is important that we net off a half-year of costs so that our customers do not pay more than what is required by this change.

**Table 7–3: Forecasts for negative corporate overheads 2020-25 ($2020, $M)**

| | 2020-21 | 2021-22 | 2022-23 | 2023-24 | 2024-25 | Total |
|---|---|---|---|---|---|---|
| Negative corporate overheads | -8.4 | 0.0 | 0.0 | 0.0 | 0.0 | -8.4 |

# 8. Specific forecasts

Some opex categories are better suited to being forecast using approaches other than the base, step and trend approach because past costs may not be representative of future costs, or a benchmark approach may be preferable.

We have used several specific or bottom-up approaches to forecasting our UAG costs, government levies, and debt raising costs. We have used alternative approaches to the base, step and trend approach for these costs categories to ensure that the forecast is representative of our future costs or benchmark costs (e.g. in the case of debt raising costs).

This method of forecasting opex for these costs is consistent with our opex allowance for the 2015-20 period.

## 8.1 Unaccounted for gas

As explained in Section 3.1.2, 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. We buy gas for this purpose through a competitive tender process.

We are not proposing any changes to the arrangements for dealing with UAG from those that apply in the 2015-20 period – this includes both the basis for calculating the efficient UAG opex forecast and the UAG incentive scheme.

The efficient level of UAG is determined based on two market segments – one applies to daily metered customer withdrawals (referred to as the 'Demand Market') and the other to gas received to supply non-daily metered customers (referred to as the 'Tariff Market'). 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 Attachment 8.2 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 Attachment 6.9 and 6.10.
- Cost of replacement gas – [redacted]

A more detailed discussion on UAG and our proposed UAG target rates is included in Attachments 6.7 to 6.11.

An automatic adjustment for UAG currently applies to each year's annual tariff variation for demand and price variations from forecast (see Attachment 4.1 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. However, if the actual UAG rate is above (below) the target rate of UAG, JGN will under (over) recover its actual UAG costs (ie JGN bears this risk).

## 8.2 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.

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 the

20 [redacted]

pipeline licence fees (as provided in the Pipelines Act), and by the Independent Pricing and Regulatory Tribunal (**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 we derive in the relevant local government area and amounts paid are subject to independent review.

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 each of these Government levies on the costs that we will pay (or expect to pay) to each Government agency in 2018-19, holding this constant in real dollar terms.[21] Our specific forecast is based on our best estimate of what we should incur on an annual basis for these costs (assuming we are invoiced in a prompt manner).

These levies are subject to a true-up through our reference tariff variation mechanism (see Attachment 4.1 of our AA proposal). This is because these costs can vary significantly from year to year. We note that this is a two-way pass through and so it has been common for us to make refunds to customers in some years while in other years we have recovered additional costs.

## 8.3 Debt raising costs

We incur debt raising costs each time we raise 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**)
- 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, and with the AER's recent decisions, including for the 2015-20 period.

Attachment 6.6, which is a report by Competition Economists Group (**CEG**) explains how these debt raising costs have been estimated.

## 8.4 Summary of our specific forecasts

Table 8–1 details our forecasts for the 2020-25 period for the above three cost categories of other opex.

[21] For IPART, we have based the forecast on the most recent invoice received (in RY18).

**Table 8–1: Forecasts for other cost categories 2020-25 ($2020, $M)**

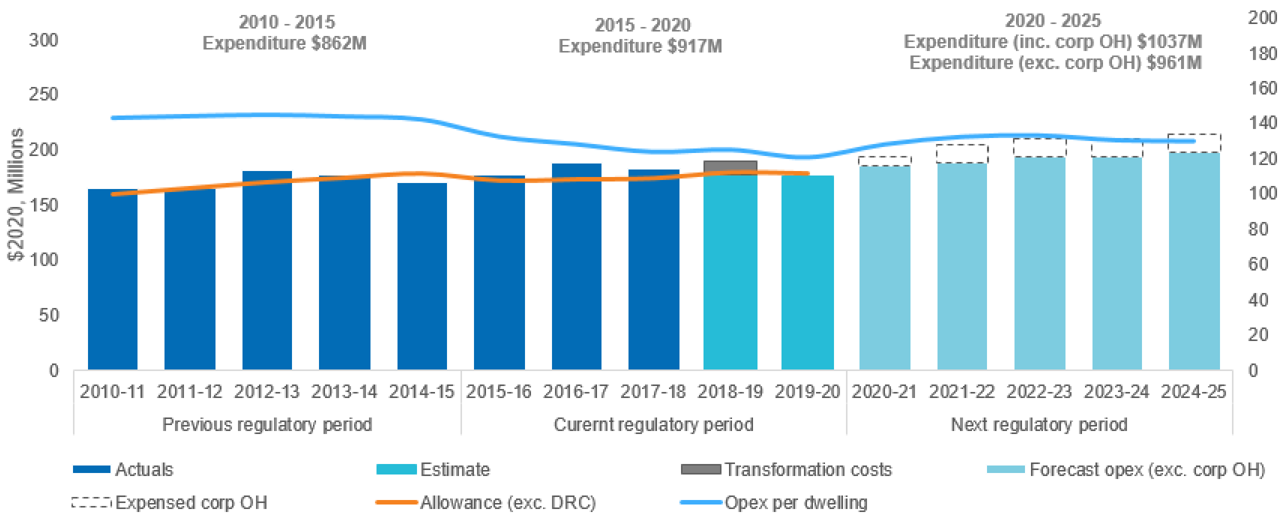
| | 2020-21 | 2021-22 | 2022-23 | 2023-24 | 2024-25 | Total |
|---|---|---|---|---|---|---|
| UAG | 31.2 | 31.6 | 31.7 | 31.6 | 31.4 | 157.5 |
| Government levies | 4.8 | 4.8 | 4.8 | 4.8 | 4.8 | 24.2 |
| **Total (exc. DRC)** | **36.0** | **36.5** | **36.6** | **36.4** | **36.2** | **181.7** |
| Debt raising costs | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 9.3 |
| **Total (inc. DRC)** | **37.9** | **38.3** | **38.4** | **38.3** | **38.1** | **191.0** |

Notes - DRC = debt raising costs

# 9. Our opex forecast

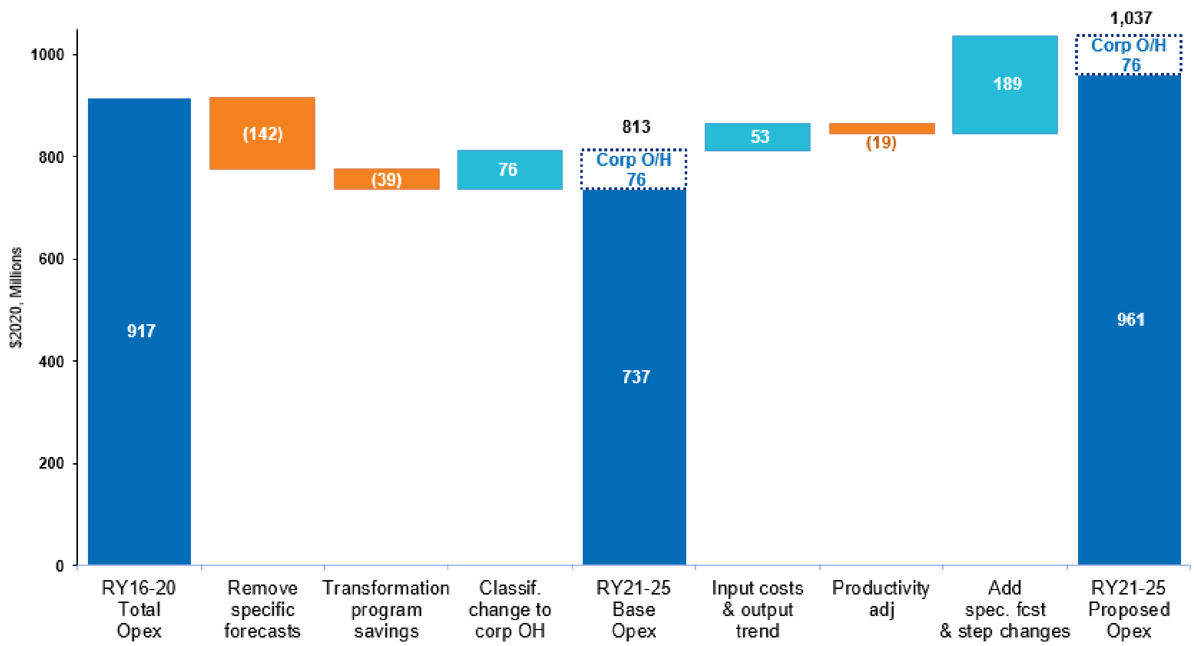
Our forecast opex (excluding debt raising costs) for the 2020-25 AA period is $1,037M, which is approximately $120M greater than our actual and estimated opex for the 2015-20 AA period (see Figure 9–1). This increase is driven by increases in specific forecasts and the expensing of capitalised corporate overheads. Taking only JGN's controllable opex[22] and excluding the impact of previously capitalised pigging costs and corporate overheads, our forecast opex will be $9M lower over the 2020-25 period than for our actual and estimated controllable opex for the 2015-20 period.

**Figure 9–1: Historical and forecast opex 2010-11 to 2024-25 ($2020, $M, exc. DRC)**




Notes - DRC = Debt raising costs, OH = Overheads

**Figure 9–2: Comparison of 2015-20 to 2020-25 Opex ($2020, $M, exc. DRC)**




Notes - DRC = Debt raising costs, O/H = Overheads

22 Controllable opex excludes category specific forecasts of UAG and government levies

Notes - DRC = Debt raising costs, OH = Overheads

**Figure 9–2** shows that the difference between our opex in the 2015-20 and 2020-25 periods is due to:

- an additional $48M on specific forecasts and step changes, primarily driven by UAG and the reclassification of pigging and inspection costs
- $39M in savings arising from the transformation program, equivalent to $7.7M per annum
- the change in treatment of the corporate overheads from 1 January 2021. This adds $75.8M to opex, which is comprised of $8.4M in 2020-21 and $16.8M per annum between 2021-22 and 2024-25
- adding $53.3M for input cost and scale escalation
- deducting $19.4M for the assumed ongoing productivity.

Table 9–1 provides a build-up of each component of our base, step and trend opex forecast for the 2020-25 period. It also includes the opex that is forecast using other approaches.

**Table 9–1: Opex forecast for 2020-25 AA period ($2020, $M, exc. DRC)**

| | | | 2020-25 period | | | | | |
|---|---|---|---|---|---|---|---|---|
| Category | 2018-19 | 2019-20 | 2020-21 | 2021-22 | 2022-23 | 2023-24 | 2024-25 | 2020-25 Total |
| Estimated base year opex | 190.3 | 176.4 | 176.4 | 176.4 | 176.4 | 176.4 | 176.4 | 882.2 |
| Less transformation program costs | -13.1 | | | | | | | |
| Additional opex associated with expensing corporate overheads | | | 16.8 | 16.8 | 16.8 | 16.8 | 16.8 | 84.2[23] |
| Less opex on items forecast using specific forecast (government levies, UAG, debt raising costs) | -29.0 | -29.0 | -29.0 | -29.0 | -29.0 | -29.0 | -29.0 | -144.8 |
| **Adjusted Base Opex** | **148.3** | **147.5** | **155.9** | **164.3** | **164.3** | **164.3** | **164.3** | **813.2** |
| Trending the base opex | | | 2.3 | 4.5 | 6.8 | 9.1 | 11.3 | 34.0 |
| Specific forecasts | | | 36.0 | 36.5 | 36.6 | 36.4 | 36.2 | 181.7 |
| Step changes | | | -8.4 | 0.0 | 3.3 | 1.3 | 3.1 | -0.7 |
| **Total** | | | **194.2** | **205.3** | **211.0** | **211.1** | **215.0** | **1036.6** |

[23] Total expensing of previously capitalised corporate overheads is $75.8M in total after accounting for negative step change of -$8.4M in 2020-21 (to account for the first half of the 2020-21 where the corporate overheads are still capitalised).

# Appendix A
# Overview of operating expenditure categories

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# A1. Operating and maintenance (O&M)

## A1.1 Maintenance

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.

## A1.2 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. Throughout our customer engagement process, our customers told us that they want us to retain our current levels of responsiveness during emergencies.

## A1.3 Management

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

## A1.4 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.

## A1.5 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 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.

## A1.7 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.

### A1.8 Other network overheads

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

### A1.9 Information Technology (IT)

Expenditure on IT relates to the provision and management of IT infrastructure and services. These costs include salaries and other employee-related expenses, procurement of software and hardware, maintenance support costs, telecommunication costs, procurement of external advice and system support costs. Insufficient funding for IT services will impact the provision of critical back-office support to network operations and JGN's ability to safely and properly manage network assets and staff.

### A1.10 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, and other corporate head office activities or departments.

## A2. Non-operating expenditure

### A2.1 Management administration and overheads

JGN's management administration and overheads (**A&O**) relate to the commercial activities of JGN's regulated business and allows JGN to meet its legal and regulatory obligations. This includes expenditure on activities related to developing marketing strategy, managing customer relationships and performing market analysis and research for both residential and business customers, preparation and management of regulated tariffs and strategy development, existing and new contract negotiations.

### A2.2 Corporate overheads

These include items such as property taxes and utilities.

### A2.3 Other direct expenditure

This relates to JGN's cyclical and special meter readings and associated staff employee costs.

### A2.4 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 Attachment 4.1).

## A2.5 Marketing

As discussed in Section 6.1 of our 2020 Plan, JGN has a marketing program that promotes natural gas as a fuel of choice. The program offers incentives to customers to install new natural gas appliances in their households while also driving new economic connections. The marketing function is critical to encouraging gas consumption and new economic connections to our network, to lower average networks prices in the long-term interests of customers.

## A2.6 Unaccounted for gas

JGN incurs costs replenishing gas that is lost, or unaccounted for, during distribution through the network. Under its Reference Service Agreement, JGN is responsible for the supply of gas in order to replenish UAG.

A UAG cost pass through event currently applies to each year's annual tariff variation for demand and price variations from forecast (see Attachment 4.1).

## A2.7 Debt raising costs

The SGSPAA Group incurs costs when it raises funds, both debt and equity, 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.