Jemena Gas Networks (NSW) Ltd

Revised 2025-30 Access Arrangement Proposal

Attachment 4.1

Capital expenditure

Table of contents

List of tables

List of figures

List of appendices

Overview

Our Initial 2025 Plan identified three key investment drivers for the 2025-30 period –

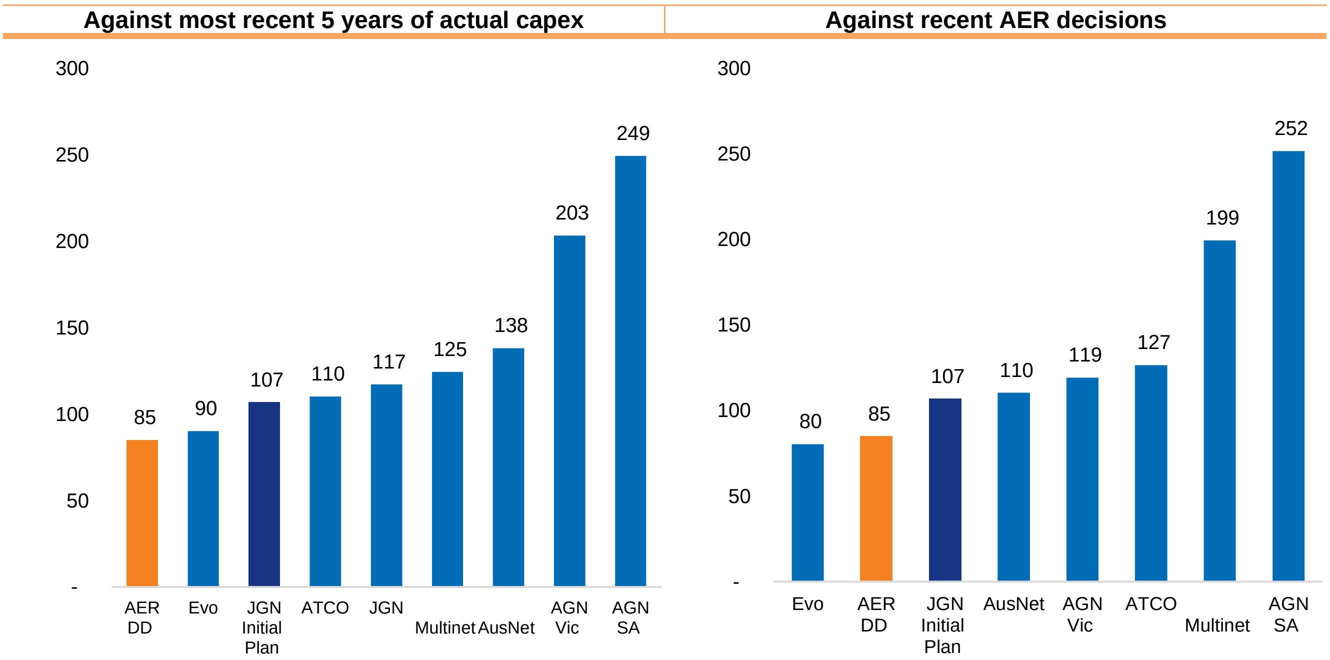
- to connect customers and provide access to our network (consistent with regulatory obligations and customer expectations),
- play our role in reducing emissions (e.g. by enabling renewable gas), and
- to keep our ageing network safe and reliable for as long as our customers need us to.

Despite already being one of the most capital efficient energy networks – gas or electricity – regulated by the AER and with many elements of our network reaching end-of-life, our Initial 2025 Plan proposed capex of $832.5 million, $80.2 million (9%) less than the 2020-25 period. We proposed a very lean program to ensure our plan was affordable and capable of acceptance by the AER.

The AER's draft decision accepted the bulk of our proposal only raising concerns with a small number of elements. However, the non-acceptance of these elements has an outsized impact on our program reducing capex by 20% to $670.1 million.

The combination of our very lean proposal with such a large reduction by the AER results in one of the lowest capex allowances ever set. It is significantly lower than the allowances for all other gas distribution businesses (except for Evoenergy[1]) and significantly lower than actual capex currently being incurred by all Australian gas businesses as shown in Figure OV–1 on a net capex per customer basis.

Figure OV–1: AER's draft decision net capex per customer allowance benchmarked ($2025)



Such a low allowance is insufficient for a network of our scale, age and condition. Not only is the accepted program insufficient to maintain the safety and integrity of our network – the AER's adjustments of our cost estimates mean that we will be unable to deliver all approved projects. Constraining capex to within the AER's draft decision allowance would result in unacceptable safety risks to the community as well as breaches to our safety and technical regulatory obligations. This is inconsistent with the first of the two components of the NGO.

Further, it will prevent us from facilitating 6.7 PJs of renewable gas – essential to deliver 0.4% and 1.0% of the emissions reductions needed to achieve the Australian and NSW government's 2030 emission reduction targets.

[1] A much younger, smaller network built using modern materials and limited new connections.

This is not consistent with achieving a lower emissions energy future for our customers. This is inconsistent with the second of the two components of the NGO.

While we are concerned with the draft decision allowance, we have identified areas where we can accept the AER's draft decision and reduced capex by $12.0 million:

- Digital metering – where the AER did not support our proposal to roll-out 8,000 digital meters to customers with difficult to access meters reducing meter replacement capex by $3.8 million. As requested, we have also removed $5.6 million of ICT capex related to digital meters.[2]
- Data logger batteries – where the AER applied an updated forecast (lowering meter replacement capex by $2.2 million) based on what we provided in the information request process.
- Defective metering – where the AER made an alternative forecast based on historical capex, reducing meter replacement capex by $0.5 million.

However, are unable to accept the AER's draft decision in respect of connecting renewable gas, the scope factor allowance included in our cost estimates, our planned meter replacement forecast volumes and our project to replace obsolete end-of life equipment at Tempe Pressure Reduction Station (PRS). Accepting these reductions would compromise the safety and integrity of our network as well as our ability to meet our regulatory obligations and reduce emissions.

We have made no changes to these elements of our 2025 Plan. Instead, we provide further information to address the AER's concerns. A summary is provided in Figure OV–1, with further detail on scope factor allowance, metering and Tempe PRS provided in sections 1, 2, 2.3.2, respectively.

Table OV–1: Elements of the AER's draft decision we do not accept

Draft Decision	Further information provided
Renewable Gas	
The AER did not accept our forecast of $80.8 million due to concerns around the economic value of these projects given potential alternative uses for biomethane feedstock.	We have updated our analysis to take into account the AER's feedback by considering a counterfactual where feedstock is used for electricity generation. We found that our program continues to provide net economic benefits to customers in the order of $3.35 billion. This program is included in connections capex.
Scope Factor Allowance	
The AER did not accept the inclusion of an adjustment for scope risk in our cost estimates, totalling $43.1 million across all projects. It considered individual project-level cost variations will balance out across our investment portfolio.	Contrary to the AER's hypothesis, project level scope risk does not balance out at the portfolio level. This is well known and recognised by the Association for the Advancement of Cost Engineering (AACE), AEMO (who make similar adjustments in the Integrated System Plan) and others.[3] We provide 10-years of evidence that our cost estimates are exceptionally accurate *only* when scope factor allowance is included. We also note that our cost estimation methodology has been unchanged for 10 years, has been reviewed and accepted by two separate technical engineering consultants and accepted by the AER in two previous decisions. Accordingly, we have retained the inclusion of the scope factor allowance across our project cost estimates (included for all network projects and affecting most capex categories).

2 The AER also asked that we provide information on the volume and cost of meters that need to the replaced in the absence of this program. We have made no adjustment as this is not necessary as our digital metering program was costed up on an incremental basis.

3 See section 1.3.1.

Draft Decision	Further information provided
Planned meter replacement	
The AER did not accept our planned meter replacement forecast ($67.1 million) substituting an alternative forecast based on a historical average ($29.4 million), a cut of $37.7 million.	We provide evidence demonstrating that our forecasting assumptions around meter accuracy (for meters which have not yet been tested) are exceptionally optimistic – and in turn our forecast is lower than reasonable alternative forecasting approaches. For example, our Initial 2025 Plan assumes residential gas meters will continue to be accurate until 35-years of age. This is significantly longer than: • Assumptions applied by all other Australian gas distribution businesses and approved by the AER or the ERA (18 – 25 years). • What we had and the AER assumed for the 2020-25 period (25 and 25.02 years respectively) • Applying a similar approach, but with updated information, to what we applied in our 2020 Plan and the AER applied in its final decision (30 years or 28.29 years). We are not aware of any gas business globally operating gas meters to 35 years of age. In contrast, the AER's approach of taking a historical average does not take into account the age-profile of our meters, their mechanical nature, available test data or Australian good industry practice and in turn is not consistent with Rule 74.[4]
Tempe PRS	
The AER did not accept our proposal to replace end-of-life equipment at Tempe PRS at a cost of $5.7 million, and suggested that we consider updating our CBA analysis for the economic value resulting from increased safety and integrity that arises by replacing it.	We provide further information on how the functionality, safety and reliability of our network cannot be maintained without the project. Operating a high-pressure facility (supplying 50,000 customers, including 61 industrial customers) to failure puts the community and our employees at risk, will lead to a 25-day outage, is not consistent with Australian standards and will breach our regulatory obligations. We have updated our economic analysis to value emissions benefits and apply a more realistic (but still very conservative) value of reliability. This shows that our preferred option provides the highest economic value – even without quantifying the primary drivers of the project (safety, integrity and compliance). We note that requiring a positive net economic value is not consistent with the Rules, past AER decisions, the decisions of other economic regulators, the views of technical engineering consultants previously relied on by the AER, safety regulators, our technical regulatory requirements or accepted Australian gas industry practice. Our Tempe PRS project is included in facilities and pipes capex.

We have also made several updates to our Revised 2025 Plan to align with:

- 2024 meter accuracy results – we found that two lots of meters tested at 30 years of age did not pass their accuracy tests and must be replaced to comply with our regulatory requirements. In our Initial 2025 Plan we had assumed that these meters would be accurate until 35 years of age. This increased our forecast by $13.7 million.

- Implementation of a new abolishment service charge – we have included $900,000 capex to be incurred 2025-26 to support the implementation for adding a new abolishment service charge as discussed in section 9.6 of our Revised 2025 Plan.

- Our Revised 2025 Plan Demand forecast – where connections have been updated based on 2024 actuals and the latest Housing Industry Association (HIA) data. These changes increase connections capex by $6.0 million.

4 Which requires forecasts to be arrived at on a reasonable basis and to represent the best forecast possible in the circumstances.

- 2023-24 RIN data – as our connection and metering unit rates[5] are based on a 4-year average of the most recent RIN data available. This increased our connections and metering forecast by $5.5 million each.

- Our revised approach to Picarro – reducing the number of vehicles require and in turn other capex by $0.2m.

- 2023-24 actual inflation in the connections forecast model. In making this update we also identified an inflation calculation error which we corrected.[6] Together these changes increased our forecast by $9.5 million.

- Other updates – latest escalators, updated inflation (applied to our project cost estimates) and the calculation of overheads based on the revised program. Collectively these updates, which affect most categories of capex, reduced capex by $5.2 million.

Overall, we have reduced gross capex forecast in our 2025 Plan by $12.0 million by accepting elements of the AER's draft decision. However, this has been offset by an increase of $34.8 million driven by updated inputs now available. We have made no change to any project, or forecasting methodology to increase our forecast. A comparison of our forecast at the category level is shown in Table OV–2.

Table OV–2: Comparison of JGN's proposed 2025-30 capex to AER's draft decision ($2025, $M)

	JGN's 2025 Plan	AER's draft decision	Revised 2025 Plan
Connections	354.8	273.9	372.5
Meter replacement	158.6	110.8	171.1
Facilities and pipes	117.0	97.6	114.5
IT	45.9	45.9	40.9
Augmentation	15.1	13.5	14.8
Mains replacement	62.5	52.9	61.2
Other[7]	54.6	53.1	53.9
Overheads	23.7	22.5	26.4
Gross total	**832.5**	**670.1**	**855.2**
Contributions	15.9	16.1	17.1
Disposals	2.6	2.6	2.6
Net total	**813.9**	**651.5**	**835.6**

5 As well as programs forecast based on a straight 4-year average of historical costs.

6 Specifically, Sheet calc|inflation row 11, the index between real mid-year and nominal mid-year. This has been flagged in purple in our revised plan Connections capex forecast model.

7 Other includes property, fleet and SCADA (the system which controls our network).

1. Scope factor allowance

This section provides background to our inclusion of a scope factor allowance in our cost estimates and the AER's concerns as set out in its draft decision. We then set out additional information to address these concerns and demonstrate why forecast capex meets the conforming capex criteria (Rule 79), has been arrived at a reasonable basis and represents the best forecast possible in the circumstances (Rule 74).

1.1 Initial 2025 Plan

In 2014, as part of our preparation for the 2015-20 Access Arrangement review, we asked Evans & Peck to review our cost estimation methodology. Evans & Peck found:[8]

- Our cost estimation approach (including the cost estimation methodology) was appropriate given that we are consistently unable to comprehensively forecast the final scope of a project. This can only occur once additional design, site investigation and consultation work has been completed.
- Taking into account of our historical project estimates and outturn costs,[9] an average scope allowance of between 17.8% and 22.8% would be reasonable and consistent with good industry practice.
- Diversification across multiple projects does not reduce cost-uncertainty as scope-risk is one sided in nature.

Given these findings, we applied our methodology to produce cost estimates for the 2015-20 Access Arrangement review. This included the transparent application of a scope factor allowance of 10% on labour and 30% on contractor costs.

The AER, and its consultant Sleeman Consulting, accepted our project cost estimates and raised no concerns with our cost estimation methodology.[10]

We applied the same cost estimation methodology in our 2020-25 Access Arrangement review. Through the information request process,[11] the AER queried our approach to including scope factor allowance and sought data comparing our previous cost estimates and actual expenditure. This data again showed that our initial estimates (excluding the scope risk component) underestimated outturn costs[12] and that including a scope risk allowance was required to ensure that our cost estimates were close to outturn costs.

The AER's consultant, Zincara, on the basis of the data provided, accepted our project estimates with risk factors as a whole and generally found our cost estimating process to be efficient.[13] The AER again accepted the cost estimates produced by our methodology for the 2020-25 period.

For the 2025-30 period we transparently[14] applied the exact same approach used (and approved by the AER) for the last 10 years.

8 See here. Submitted to the AER as part of the 2015-20 Access Arrangement review.

9 Data set make up of 82 projects. The total stage 2&3 estimates for these projects were $91.8m ($Real 2010) compared to outturn costs of $115.0 ($Real 2010), 25% higher.

10 AER 2014, D*raft decision Jemena Gas Networks (NSW) Ltd Access Arrangement 2015-20 Attachment 6: Capital Expenditure*, Available here and to Sleman Consulting, 2014 Jemena Gas Networks 2015 Access Arrangement Submission, Review of Capex Forecasts for Capacity Development and Facilities Renewal and Replacement, Report to Australian Energy

11 See Information Request 24.

12 By 22% overall.

13 Zincara 2019, *Access Arrangement 2019 JGN Capital Expenditure Review,* see here. Zincara did request updated cost estimates for some projects. Where possible these were provided and reviewed by Zincara in its subsequent report (see here).

14 Scope factor amounts were reported as Risk in each Project Cost Estimation Output with the basis for the calculation (10% on internal labour and 30% on contractor costs) set out in *JGN – RIN – 4.3 Jemena Infrastructure Cost Estimation Methodology*.

1.2 Draft decision

The AER's draft decision did not accept the inclusion of a scope factor allowance in our cost estimates, noting:[15]

> *We do not consider it efficient to apply additional capex to a portfolio of projects to account for forecasting error. We are not satisfied that the risk allocation is efficient under NGR, r. 79(1)(a). We consider that while some individual projects may incur costs above forecast, other projects will cost less than forecast. On this basis, variations on individual projects will tend to balance out over the portfolio.*
>
> *We may allow a contingency for a given program where JGN identifies a specific risk factor, with a high probability that would increase the cost of a project, but which is nevertheless difficult to forecast. In its initial proposal, JGN has not identified such factors for specific projects. We invite JGN to provide further justification for its risk allowance.*

1.3 Revised 2025 Plan

We do not consider that characterising scope factor allowance (risk) as '*additional capex to a portfolio of projects to account for forecasting error'* is accurate. This implies that we have included line items, or a separate allowance, to account for general forecasting error. This is not the case.

We include a scope factor allowance in our early cost estimates for each project. The purpose of this adjustment is to account for scope risk inherent in our circumstances – being required to produce accurate unbiased cost estimates before undertaking site surveys, condition assessments or producing detailed designs. This factor is based on historical differences between early cost estimates and outturn costs and is calibrated to be accurate at the portfolio level. The inclusion of the scope factor allowance is required to produce the best forecast possible in the circumstances, consistent with Rule 74.

As requested by the AER, we have compiled further justification for the inclusion of a scope-factor allowance in our project cost estimates. Specifically, we outline that:

- Project level variations do not balance out across our capex portfolio.
- It is widely recognised by Association for the Advancement of Cost Engineering (AACE) and others[16] that initial estimates are both inaccurate and underestimate outturn costs. To counteract this bias, it is good industry practice to adjust early cost estimates. A transparent example is AEMO's inclusion of an 'unknown risk factor' in the development of its 2024 Integrated System Plan.
- Analysis of our early cost estimates and outturn costs indicate that a scope factor allowance is required to produce accurate cost estimates but that overall, our cost estimates inclusive of the scope factor allowance are remarkably accurate.
- Rule 74 requires that forecasts and estimates are arrived at on a reasonable basis and must represent the best forecast or estimate possible in the circumstances. For this Rule to be met, in a manner consistent with good industry practice, a scope factor allowance must be included.

Given the evidence above, together with the advice of two separate technical engineering consultants previously engaged by the AER and 10 years of existing AER regulatory precedent, we consider that scope factor allowances should continue to be applied. Accordingly, we have made no changes to our cost estimates in our Revised 2025 Plan.

[15] AER 2024, *Draft decision, Jemena Gas Networks (NSW) access arrangement 2025 to 2030 Attachment 15 – Capital Expenditure,* p. 20.

[16] See section 1.3.1.

1.3.1 Project level variations do not balance out at the portfolio level.

Good Industry Forecasting Practice

Early (concept) cost estimates, are uncertain and likely to underestimate outturn costs. This is due to “known unknowns” and “unknown unknowns” due to the low level of project definition as well as systematic (undiversifiable) risks. This is recognised by the AACE cost classification system – a system required by the AER’s Regulatory Information Test guidelines for investments above $103 million[17] – which has larger accuracy bands for early cost estimates.[18] The upper band is materially higher than the lower cost band indicating the asymmetric nature of these risks.

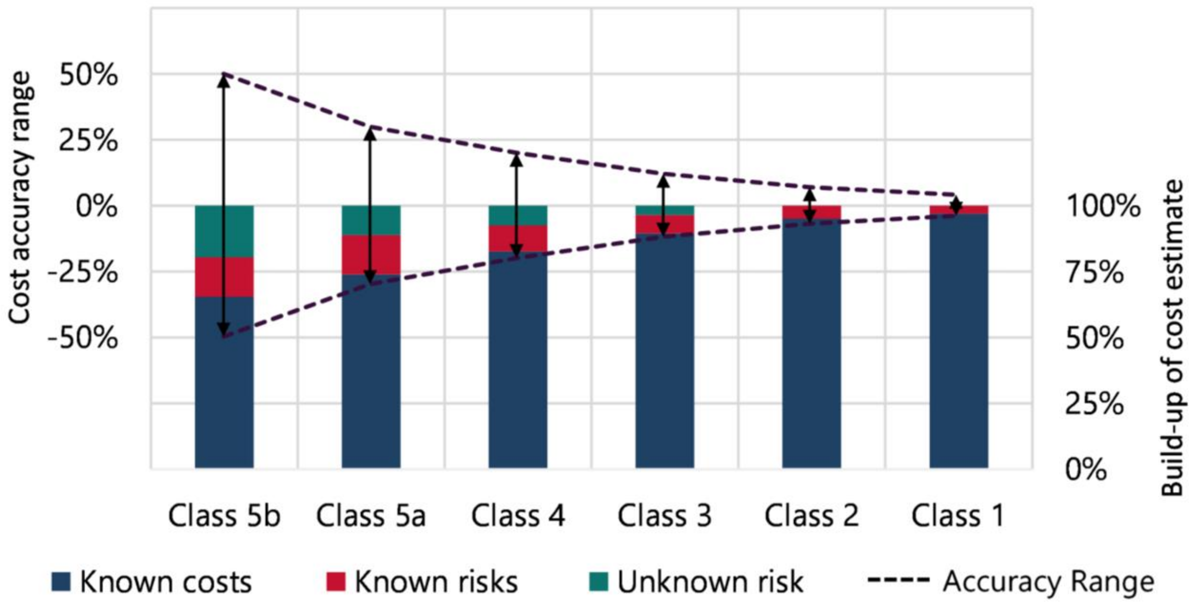
Table 1–1: AACE expected accuracy range by estimate class[19]

	Class 5	Class 4	Class 3	Class 2	Class 1
High	+30% to +100%	+20% to +50%	+10% to +30%	+5% to +20%	+3% to +15%
Low	-20 to -50%	-15% to -30%	-10% to -20%	-5% to -15%	-3% to -10%

AEMO applies scope factor allowances (unknown risk factors) in the 2024 ISP

In preparing the Integrated System Plan,[20] AEMO recognised the impact of project definition on both cost estimate uncertainty and the downward bias in cost estimates. This is shown by AEMO’s diagram in Figure 1–1[21] which shows that over time, as project definition increases, known and unknown risks fall away but known costs increase.

Figure 1–1: AEMO’s Cost estimate summary breakdown from Class 5b to Class 1



[17] The AER’s RIT-D/RIT-T guidelines require this classification system to be applied where the estimated capital costs of the preferred option exceed $103 million. Otherwise, the RIT-D/RIT-T must identify the alternative cost estimation system and explain why this alternative system is more appropriate or suitable See section 3.5A.1 of the AER’s RIT-D and RIT-T guidelines here and here.

[18] A similar concept is the ‘Cone of Uncertainty’ here on page 38.

[19] AACE *Cost Estimate Classification System – As applied in engineering, procurement and construction for the pipeline transportation infrastructure industries.* Sample available here.

[20] The Integrated System Plan is a whole-of-system plan that provides an integrated roadmap for the development of the National Electricity Market (NEM).

[21] AEMO 2023, *2023 Transmission Expansion Options Report for the Integrated System Plan,* p.25 Available here.

Given the asymmetric uncertainty in early cost estimates, AEMO applies an 'unknown risk factor' to uplift the point cost estimate by up to 30% for Class 5b estimates and up to 15% for Class 5a estimates.[22] This factor is based on a GHD study of the progression of 22 recent major project elements that found that on average Australian TNSPs increased their early-stage Class 5b cost estimates by ~30%. The change was driven by scope and technology risks (these risks drove the highest variations), productivity and labour cost risks, plan procurement risks and project overhead risks.

The approach taken by AEMO (and GHD) is conceptually identical to the approach we undertook 10 years ago with Evans & Peck.

Applying a scope factor allowance, in the same manner as we have historically and AEMO has for the ISP, is good industry practice. Other examples include:

- Seattle Public Utilities Allowance for indeterminates[23]
- The South Australian Department of Planning, Transport and Infrastructure Estimating Manual which includes "contingency allowances" (noting again differences in terminology) for strategic options which range from 10 – 42%.[24]
- Washington Statement Department of Transportation Cost Estimating Manual for projects.[25]

Analysis of our historical cost estimates indicates that a scope factor allowance is required and that overall our cost estimates are remarkably accurate

To provide the AER with confidence that our cost estimation methodology produces the best cost estimates in the circumstances, we have compared our 2020 Plan cost estimates against outturn costs for completed projects.

The results are shown in Figure 1–2 which shows the cost estimates and outturn costs for 16 projects (amounting to $65.8 million in outturn costs). Actual costs are 1.63% less than our cost estimates including scope factor allowance. If the scope factor allowance had not been included our cost estimates would have been 19% below outturn costs.

This analysis indicates that the scope factor allowance is required to produce accurate estimates, overall our cost estimates are remarkably accurate, and that it is not the case that individual project cost variations balance out at the portfolio level.

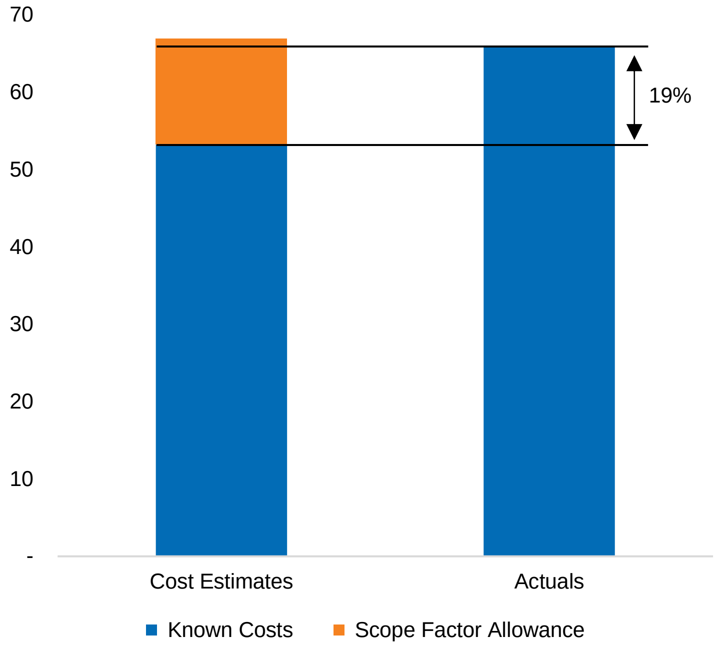
22 Cost estimates evolve from Class 5 to Class 1 as scope definition matures. AEMO defines Class 5b estimates as concept level scope without site-specific review or TNSP input and Class 5a estimates as those which include high level site-specific review and TNSP input. AEMO 2023, *2023 Transmission Expansion Options Report for the Integrated System Plan,* p.21 Available here.

23 Seattle Public Utilities 2017, *2017 Cost Estimating Guide*, p.7. Available here.

24 Department of Planning, Transport and Infrastructure 2022, Estimating Manual, p. 53 Available here.

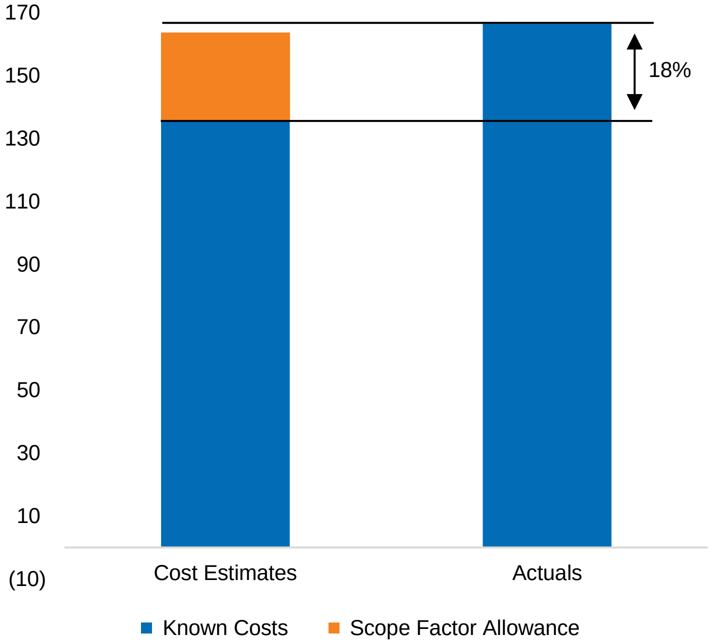
25 Washington State Department of Transportation 2015, *Cost Estimating Manual for Projectrs,* p.7-1 Available here.

Figure 1–2: Comparison of 2020 Plan cost estimates versus available actuals ($2025)



We expanded our analysis to included data from an additional 35 projects[26] to provide a total data set of $166.5 million. Again, the results show that our cost estimation methodology produces very accurate cost estimates at the portfolio level. Outturn costs are 1.65% above early cost estimates which include scope factor allowance. If we did not include a scope factor allowance, then we would have underestimated costs by 18%. This is shown Figure 1–3 below.

Figure 1–3: Expanded data set: cost estimates versus actuals ($2025)



[26] Estimates which either formed part of our 2015 Plan or, the initial estimate for projects not included in one of our Plans.

1.3.2 Including a Scope Factor Allowance is required to meet the requirements of Rule 74

Rule 74 requires that:

(1) Information in the nature of a forecast or estimate must be supported by a statement of the basis of the forecast or estimate.

(2) A forecast or estimate:

(a) must be arrived at on a reasonable basis; and

(b) must represent the best forecast or estimate possible in the circumstances

The current circumstances is the need to prepare a capex forecast up to the end of 2029-30 – which is about six years into the future (noting that our cost estimates were produced around 9-12 months ago).

Good industry practice is for works to define the project to occur at each 'gate'. This allows our cost estimates to move from Class 5 to Class 3 at Gate 3 – when we make a final investment decision.

Preparing an Access Arrangement forecast requires cost estimates to be produced well before we have undertaken site surveys, condition assessments of our assets or produced detailed designs. Accordingly, our Access Arrangement cost estimates are AACE Class 5 estimates.

Given our circumstances, and the consistent downward bias in our early cost estimates and our overall forecasting accuracy, the best forecast includes a scope factor allowance.

Disallowing scope factor allowance on the basis of a prima facie case that costs even out over a portfolio of spend, is not reasonable given:

1. cost estimation theory indicates that early cost estimates have systemic (undiversifiable) risks;
2. good industry practice; and
3. our evidence that this does not occur.

Lastly, we note that it is theoretically possible to undertake preparatory work ahead of an Access Arrangement process to improve scope definition for cost estimation processes, however, this would be inefficient as this work would need to be repeated again before the project proceeds given that much of this information will become out-of-date. In turn this approach would not be consistent with Rule 79(1)(a).

2. Metering

This section provides background to our planned meter replacement program forecast and the AER's concerns as set out in its draft decision. We then set out additional information to address these concerns and demonstrate why our forecast has been arrived at a reasonable basis and represents the best forecast possible in the circumstances (Rule 74).

2.1 Initial 2025 Plan

Gas meter failure modes

Gas meters are mechanical devices which wear over time. Key failure modes include:

- Corrosion and damage to the meter bodies as meters are located in damp environments (e.g. gardens, bushes, coastal areas) or near driveways and lawn, making them susceptible to impacts from lawnmowers, cars, trailers, etc. We also see failures due to insect damage.
- Unreadable indexes due to moisture ingress or damage (such as UV) to the clear plastic.
- Wear to internal mechanical components (e.g. pistons, gears), gaskets and seals. Over time, these components may deteriorate leading to gear mechanical failure, inaccurate index calibration and even gas bypass or leaks.
- Wear to the diaphragm which inflates and deflates as gases pass through. The diaphragm is made up of flexible materials which degrade, wear and lose elasticity with age leading to inaccurate readings.

Meter replacement programs

As a result, meters reach end-of-life when they either fail[27] or no longer meet regulatory performance requirements.[28] Accordingly, we have two distinct meter replacement programs.

The first is our defective program where we replace a meter which no longer operates, is unreadable or is unsafe. These meters are identified by our meter readers (when the meter cannot be read or is damaged or in a unsafe condition), customers (often due to the smell of gas or strange clicking / whirring sounds) or by our systems as a result of successive reads of no consumption.

The second is our planned program where we replace meters which are no longer sufficiently accurate to meet regulatory performance requirements. Inaccurate meters either:

- <u>Over record consumption</u> resulting in customers paying for more gas than they consume.
- <u>Under record consumption</u> resulting in customers paying for less gas than they consumed. The gas they consume but is not metered then forms part of Unaccounted for Gas (UAG) and is paid for by all customers through our opex allowance.

Either way inaccurate meters lead to unfair outcomes for our customer base as a whole. Inaccurate meters also have market impacts, for instance as retailers relying on our meter data for billing.

We identify inaccurate meters by undertaking periodic testing of each 'lot' of meters. For our smaller meters (mostly used for residential customers) these tests commence at 15 years of age (the design life of mechanical meters) and, if they pass, periodically at mostly 5-year internals.[29] Visual field inspections do not identify inaccurate meters.

[27] Failing to operate or the index degrading to a point where it can no longer be read.

[28] NMI R 137 Gas Meters

[29] Depending on metering performance, in some circumstances we may only be able to extend the life of a meter by 1 or 3 years.

For our larger industrial and commercial meters, as we use a mix of new and refurbished meters and given the larger volumes of gas these customers use, we replace these meters at shorter intervals.[30]

Replacing either a defective or inaccurate meter is unquestionably prudent and efficient, and in turn meets the conforming capex criteria.[31]

Previous AER decisions

For our 2020 Plan, based on test data available at the time, we forecast that smaller meters would pass their first two tests (at 15 and 20 years) but would fail their 25-year test. In making this forecast we recognised that some meters would fail at 15 and 20 years and some would pass at the 25-year mark but considered that as a whole this was the best forecast possible in the circumstances.

The AER did not accept this forecast and instead relied on a forecast prepared by Zincara based on its analysis of performance by meter type. As with our forecast, Zincara aimed to produce the best possible forecast at the portfolio level.[32] A comparison of our forecasting assumptions and Zincara's are shown in Table 2–1.

Table 2–1: 2020-25 forecast pass rate[33]

Test	JGN 2020 Plan	AER Final Decision (Zincara)
15-years	100% (Pass)	89%
20-years	100% (Pass)	89%
25-years	0% (Fail)	40%
30-years	0% (Fail)	0%

We note that Zincara's assumptions for tests at the 25-year mark were based on an analysis of failure data at the meter type level as shown in Table 2-2. The overall objective was to produce a forecast which took into account the age profile of our meters fleet.

Table 2–2: Zincara 2020-25 25-year forecast pass rate assumptions

Meter type	AER / Zincara forecast pass rate
Email 602 JF JG	100%
Email 610	35%
Email 602 JX JZ	49%
ABB DS5	16%
Toyo	0%
Overall	**40%**

30 25 years for our medium I&C meters (>10m^3/hr and ≤25m^3/hr). Our larger turbine and rotary meters we generally replace at 5 and 10 years, unless possible to extend to 7 or 15 years using throughput analysis.

31 For completeness, this is because 1) It would be incurred by a prudent service providing acting efficiently, in accordance with accepted good industry practice (Rule 79(1)(a). 2) It is justified on the basis of being necessary to maintain the integrity of services and to comply with a regulatory obligation or requirement and to maintain our capacity to meet levels of demand for services existing at the time the capex is incurred (noting that our service includes meter related services and meter reading) (Rule 79(1(b)). 3) Meter reading is part of the reference service and costs are allocated to the reference service (Rule 79(1)(c)).

32 Zincara 2020, *AER Access Arrangement 2020 JGN Capital Expenditure Review Stage 2 Report,* p .83. Available here.

33 Zincara 2020, *AER Access Arrangement 2020 JGN Capital Expenditure Review Stage 2 Report,* Appendix A. Public version available here. 15 and 20 year test percentage based on a forecast of 48,000 meters out of 220,759 meters to be tested. 25-year test data as shown in the table on page 84. 30-year assumption on page 80.

Zincara's forecast assumption resulted in an expected average meter life of 25.02 years – almost exactly the same as we had forecast (25 years).[34] These alternative assumptions resulted in a planned replacement volume 13% below what we had forecast.[35]

Zincara (and in turn the AER) accepted our forecast for the planned replacement of I&C meters.

Our 2025 Plan forecasting assumptions

In preparing our 2025 Plan, we considered the latest information available on our meters' performance. We also took into account the performance against our past forecasting assumptions – where we had assumed that smaller meters would fail at 25 years but had performed better.

Our default position has been to forecast that meters will not pass the next life-extension due, unless we have sufficient evidence otherwise. For our 2025 Plan this would have meant preparing a forecast based on smaller meters failing at 30 years – 5 years longer than we had previously assumed.

However, given past forecasting performance and our desire to put forward a forecast the AER could accept (noting the AER's adjustment for the current 2020-25 period) we instead assumed that our smaller meters would continue to be accurate until they reach 35 years of age – 10 years longer than we had assumed in our 2020 Plan. This is 40% longer than both we and Zincara had previously forecast.

Table 2–3: Residential meter forecasting assumptions

Meter Age	2020 Plan	AER 2020-25 Final Decision	2025 Plan
15	100% Pass – 5 years	89% Pass – 5 years	100% Pass – 5 years
20	100% Pass – 5 years	89% Pass – 5 years	100% Pass – 5 years
25	0% Pass	40% Pass – 5 years	100% Pass – 5 years
30	0% Pass	0% Pass	100% Pass – 5 years
35	N/A	N/A	No test
Expected life	**25 years**	**25.02 years**	**35 years**

Assuming that a gas meter will remain accurate until age 35 is extraordinarily optimistic, given meters are un-serviced mechanical devices. We assume that our gas meters will continue to be accurate for 20 years beyond their design life (more than twice their design life of 15 years).

To put this into context, the average age of Australian registered motor vehicle (a serviced mechanical machine) is 11.40 years.[36] The bestselling Australian cars in the early 1990s (the same vintage as our meters) were the Ford Falcon, Holden Commodore and Mitsubishi Magna. Only a small number of these vehicles are still in regular use.

Our forecasting assumption is materially longer than applied by other Australian gas distribution businesses and approved by the AER or ERA. As shown in Table 2–4, other businesses typically assume that smaller meters will receive a single 5-year life extension followed by a 3- and 1-year life extension with an expected life of either 18 or 25 years. In contrast, we are forecasting four 5-year life extensions – an expected life of 35 years.

[34] Applying Zincara's forecasting assumptions results in a meter having a 11% probability of a 15 year life, a 10% probability of a 20 year life, a 48% probability of a 25 year life and a 32% probability of a 30 year life. When summed this results in a weighted average life of 25.02 years.

[35] 257,410 rather than 294,272 meters to be replaced. See Zincara 2020, *AER Access Arrangement 2020 JGN Capital Expenditure Review Stage 2 Report,* p .85. Available here.

[36] Department of Infrastructure, Transport, Regional Development, Communications and the Arts, *Road Vehicles Australia*, January 2024, p.1. Available here.

Table 2–4: Gas distribution businesses and economic regulator views of gas meter life extensions

Gas distribution business	Forecasting assumptions	Economic Regulator
ATCO[37]	**2025-29 Access Arrangement** • One unknown meter type: 25 years • Older meters: 18 years.	Accepted by the ERA
AGIG[38]	**2023-28 Access Arrangement** New meters: • 15 years – 5-year extension • 21 years – 3-year extension • 24 years – 1-year extension • 25 years – fail. Refurbished meters: • 15 years – 3-year extension • 19 years – 1-year extension • 20 years – fail I&C meters – 15-year replacement. No field life extensions, except in a small number of cases.	Accepted by the AER
AusNet[39]	**2023-28 Access Arrangement** Not public – but known to the AER. **2018-22 Access Arrangement** • 5-years – AL 425 tested for the first time. • 3 years: New and Refurbished meters (except AL425 and Email 610) tested for the first time. Any meter type previous gained a 5-year extension. • 1 year: Any meter type that previously gain a 3 year extension. • Failed. All meter families excluded from in-service compliance testing, any meter type previously gained a 1 year extension, all Email 610 meters tested at the end of their initial in-service compliance testing life. I&C meters – 15-year replacement. No field life extensions.	Accepted by the AER

We are not aware of any gas business globally which extends the lives of their meters to 35 years.

Given this extraordinarily optimistic forecasting assumption underpinning the bulk of our metering forecast and with the limited data we have to date we also assumed that:

- Defective meter replacement rates will rise.
- We will not test meters at 35-years, as given the defective rates we have seen so far, it will not be prudent undertaking accuracy tests at 35-years. This may change based on failure performance data. For the purpose of this forecast we did not include meter testing costs for 35-year-old meters as we consider that this is the best forecast in the circumstances consistent with Rule 74.

37 Economic Regulation Authority 2024, Draft decision on revisions to the access arrangement for the Mid-West and South-West Gas Distribution Systems, Attachment 4: Regulatory Asset Base, p.30 Available here.

38 AGIG 2022, Attachment 9.8 Meter Replacement Plan, Final Plan 2023/24 – 2027/28, p.24 Available here.

39 2023-28 Access Arrangement: Forecasting assumptions not public but available to the AER see here. 2018-22 Access Arrangement: AusNet Gas Services, *Gas Access Arrangement Review 2018-2022, Appendix 6G: Meter Management Strategy – Public, Appendix A*, Available here.

2.2 Draft Decision

The AER did not accept our planned meter replacement forecast stating that:

> *We consider a lower forecast of capex is appropriate for: … proactive replacements of aging meters that were based on incomplete or unavailable data*

It later explains:[40]

> *We do not accept JGN's proposed $67.1 million program for the proactive replacement of aged meters for both residential and commercial and industrial customers. We are not satisfied that proactive replacement of meters prudent under NGR, r. 79(1)(a). We are not satisfied proactive replacement of meters is efficient under NGR, r. 79(1)(a), and there is insufficient evidence that the expenditure is required to maintain and improve the safety of services NGR, r. 79(2)(c)(i) or comply with regulatory obligations or requirements NGR, r.79(2)(c)(i). We have included an amount of $29.4 million, which is more in line with historical spending. JGN has assumed that when certain families of meters pass 35 years of age, the failure rate will increase exponentially. This assumption has driven JGN's strategy to proactively replace meters over 35 years old. We do not consider JGN has provided evidence supporting such an increase in failure rates. JGN has not been able to provide sufficient data to support the assumption, particularly because sample sizes of meters older than 35 years is small.*
>
> *As we do not accept the proactive replacement of all meters older than 35 years, we have allowed for increased sample testing and sample replacement in the alternative forecast to facilitate increased reactive replacement of older meters. JGN's proposal repeats a similar end of life scenario for meters from the 2020-2025 access arrangement proposal. At that time, JGN forecast end of life failures increasing to an unacceptable level at 30 years which we did not accept in the access arrangement review for the same reasons.*

2.3 Revised 2025 Plan

Our concerns with the AER's draft decision

In developing our 2025 Plans, we aim to ensure that what we propose is not only consistent with the Rules but capable of acceptance by the AER. As part of this, we seek to genuinely consider and adjust our forecast as necessary to respond to feedback provided by the AER.[41] However, in considering the AER's draft decision we have identified two issues.

The first is that the AER's draft decision is premised on several material misunderstandings (outlined in section 2.3.2) of our proposal. The most significant is the mischaracterisation of our 2025 Plan as a similar repeat of the approach taken in our 2020 Plan.

This is not accurate. The opposite is true. Our 2025 Plan did not just reflect latest test data but also took into account 2020–25 outperformance as well as the AER's final decision for 2020-25. This resulted in our 2025 Plan adopting exceptionally optimistic forecasting assumptions. Making further adjustments to further reduce our forecast would double count the adjustment we have already made.

The second issue is that the AER's alternative forecast is based on a historical average. Moving to a historical average for volumes (we already apply a historical average for unit rates) would mean not taking into account the age profile of our meters, the mechanical nature of gas meters, available test data, or the more conservative forecasting approaches applied by other businesses (and accepted by the AER and the ERA) to replace meters at around 18-25 years (rather than at 35 years as we proposed). This approach is not consistent with Rule 74,

[40] AER 2024, *Draft decision, Jemena Gas Networks (NSW) access arrangement 2025 to 2030 (1 July 2025 to 30 June 2030) Attachment 5 – Capital Expenditure, pp.17-18* Available here.

[41] We did this at initial proposal stage by considering prior AER decisions for all businesses.

which requires forecasts to be arrived at on a reasonable basis and to represent the best forecast possible in the circumstances.

New information now available

Since lodging our Initial 2025 Plan, we have received calendar year 2024 accuracy test results. Although our 2025 Plan assumed all meters would pass their 15-, 20-, 25- and 30-year tests, two lots of meters failed their 30-year tests. This is unsurprising given that our forecasting assumptions are exceptionally optimistic.

Table 2–5: 2024 Test results versus 2025 Plan assumptions

Test	2024 Test results		2025 Plan	
Meter Age	Pass	Fail	Pass	Fail
15	5	-	5	-
20	5	-	5	-
25	-	-	-	-
30	-	2	2	-
35	-	-	-	-

Additionally, since lodging our 2025 Plan, 2023-24 cost data is now also available.

Our revised proposal

Given our concerns with the AER's draft decision, we have not adjusted our forecasting methodology. Instead, we provide further information to:

- Outline how extraordinarily optimistic forecasting assumptions are. In particular, we outline the material differences between our 2020 Plan (and the AER's final decision for 2020-25) and our 2025 Plan.
- Clarify misunderstandings related to the basis of our forecast and the drivers of our forecast.

We have also updated our meter replacement forecast to incorporate the latest test data now available. The latest meter test data indicates that an additional 20,648 meters will need to be replaced over the 2025-30 period. We have also updated our unit rates to reflect that 2023-24 data is available (as our forecasting methodology is based on a 4-year average of actual costs). These changes are required to ensure that our forecast remains the best possible in the circumstances, consistent with Rule 74.

As with any other element of our Revised 2025 Plan, we would like to again extend our offer to take the AER or any of their technical advisors through any aspect of our forecast in more detail, including our meter forecast volume model.

2.3.1 Our optimistic forecasting assumptions

Our Initial 2025 Plan implemented extraordinarily optimistic forecasting assumptions which reflected the latest accuracy test data available, as well as current period out-performance and the AER's draft decision for the 2020-25 period. These assumptions are materially more optimistic than those applied in our 2020 Plan and the AER's final decision for 2020-25.

Residential meters

Table 2–6 compares our Revised 2025 Plan forecasting assumptions to:

- A simplified approach based on the approach taken by all other Australian gas distribution businesses – and approved by either the AER or ERA. In simplifying the forecasting assumptions, we made the forecast more optimistic (as shown by a comparison with Table 2–4).
- An approach 'similar' to our 2020 Plan – but with the expected life extended from 25 years to 30 years.
- An approach similar to what the AER set for the 2020-25. We made two changes. First to apply an 89% pass rate to the 25-year test (rather than 40%) and a 40% pass rate to the 30-year test (rather than 0%).

The table shows that our Revised 2025 Plan is 26% lower what we would have forecast if we applied a similar approach to our 2020 Plan. This adjustment is larger than the 13% adjustment the AER made to our Revised 2020 Plan. Our Revised 2025 Plan is also materially lower than what would be forecast if we applied the same approach applied by other businesses (and approved by the AER / ERA).

It also shows how the AER's draft decision methodology in using a historical average and not taking into account meter age profile data represents a departure from its previous approach and the approach taken by all other businesses.

Table 2–6: Comparison of forecasting approaches ($2025)

Meter Age	Revised 2025 Plan	Other businesses (and approved by the AER / ERA)	Similar to 2020 Plan	Approach similar to the AER 2020-25 Final Decision	AER draft decision
15	100% Pass – 5 years	100% Pass – 5 years	100% Pass – 5 years	89% Pass – 5 years	Does not use meter age profile information
20	100% Pass – 5 years	100% Pass – 5 years	100% Pass – 5 years	89% Pass – 5 years	
25	100% Pass – 5 years	0% Pass	100% Pass – 5 years	89% Pass – 5 years	
30	100% Pass – 5 years	0% Pass	0% Pass	40% Pass – 5 years	
35	No test	0% Pass	0% Pass	0% Pass	
Expected life	**35 years**	**25-years**	**30 years**	**28.39 years**	**N/A**
Expenditure	**$62 million**	**$99 million**	**$82 million**	**$69 million**	**$28 million**

We are not aware of any other gas distribution business in the world which has extended the life of gas meters to 35 years.

I&C meters

As with our residential gas meters, we applied exceptionally optimistic forecasting assumptions. The approach on I&C meters is different, however, for three main reasons:

1. Higher volumes of gas mean the consequences of inaccuracy are materially larger, as shown by Table 2–7.

2. These meters are larger, often more complex mechanical devices.
3. Where possible we use refurbish meters rather than purchasing new ones. While this reduces overall costs it also means that several components of a meter are likely to be significantly older.

Table 2–7: Gas throughput and wholesale value by segment ($2023)

Meter Age	Typical meter type	Annual volume of gas (GJ)	Wholesale value[42]
Residential	Diaphragm	15 GJ (typical)	$229
Commercial	Diaphragm / rotary	500 GJ (typical)	$4,891
Industrial	Rotary / turbine	115,874 GJ (average)	$1,438,000

We also note that other Australian gas distribution businesses do not undertake field life extensions for I&C meters. For large diaphragm meters (>10m³/hr but ≤25m³/hr), Table 2-8 outlines the various approaches that have been adopted by the AER, our 2020 Plan (as adopted by the AER) and our Revised 2025 Plan.

Table 2–8: Comparison of forecasting approaches for larger diaphragm meters ($2025)

Meter Age	Revised 2025 Plan	Approach taken by other businesses (and approved by the AER / ERA)[43]	AER draft decision
15	100% Pass – 5 years	No Test	Does not use meter age profile information
20	100% Pass – 5 years		
25	No test		
Expected life	**25 years**	**15-years**	**N/A**
Expenditure[44]	**$22 million**	**$45 million**	**$2 million**

Similarly, we do not undertake field life extensions of our larger diaphragm meters (>25m³/hr), rotary and turbine meters given the high volumes of gas they measure and their failure mechanisms. Instead, we changeover our rotary and turbine meters at 5 and 10 year intervals.

For our smaller diaphragm meters (≤10m³/hr) similar in size to our residential meters, we assume that they will have an expected life of 35 years. However, for our larger diaphragm meters we have adopted more conservative assumptions of a life of 25-years given their greater importance of meter accuracy for the larger volumes of gas.

2.3.2 Misunderstandings of our metering forecast

In reviewing the AER's draft decision we have identified a series of material misunderstandings related to the basis of our forecast, what drives metering expenditure, the nature of the evidence provided and how our forecast differs to our previous forecast in addition to the AER's previous decision for the 2020-25 period. To assist the AER, we provide clarifications below in Table 2–9.

42 Based on $12.92/GJ for residential and commercial and $12.41/GJ for industrial. Based on ACIL Allen Natural Gas Price Step Change forecast for 2025 published as part of the 2024 GSOO. Available here.

43 See Table 2–4.

44 Planned meter replacement costs (RAF). Does not include the costs to replace sample tested meters (RA2).

Table 2–9: Misunderstandings of our metering forecast

Misunderstanding	Clarification
JGN proposes a proactive end-of-life replacement programs for aged meters, both residential and C&I.	We do not proactively replace aged meters. We have a defective meter program to replace meter failures (when meters cease to operate, unsafe or cannot be read) on a reactive basis and a planned program to replace meters which do not meet regulatory accuracy requirements based on the life extension tests.
JGN has assumed that when certain families of meters pass 35 years of age, the failure rate will increase exponentially. This assumption has driven JGN's strategy to proactively replace meters over 35 years old.	Our planned replacement program is not driven by defective failure rates. It is driven by meters failing to meet regulated accuracy requirements.[45]
JGN has assumed that when certain families of meters pass 35 years of age, the failure rate will increase exponentially. This assumption has driven JGN's strategy to proactively replace meters over 35 years old. We do not consider JGN has provided evidence supporting such an increase in failure rates. JGN has not been able to provide sufficient data to support the assumption, particularly because sample sizes of meters older than 35 years is small.	Exponential failure rate data has been observed and was presented in our Initial 2025 Plan.[46] This data is not assumed. Failure rate data does not drive our planned replacement program. This program is driven by forecast meter accuracy. Given the preliminary defective data available, we assume that it would not be prudent or efficient to undertake accuracy testing at 35 years old and have not included any capex for accuracy tests at the 35-year mark. We note that this is not a decision, but a forecasting assumption based on the data currently available to us.[47]
As we do not accept the proactive replacement of all meters older than 35 years, we have allowed for increased sample testing and sample replacement in the alternative forecast to facilitate increased reactive replacement of older meters.	Increased sample testing and sample replacement does not "*..facilitate increased reactive replacement of older meters."* Sample testing is used to identify whether meters are sufficiently accurate and can continue to be used. We also note that in its draft decision, the AER did not accept our proposed increase in our reactive defective gas meter replacement program on the basis of no statistical evidence in increase in failure rates for meters 30 years or older. In our assumption model, we have not accounted for any replacements due to life extension test failures before 35 years. We believe that assuming older meters will be replaced at 35 years represents the most optimistic scenario. This approach is intended to balance out any potential replacements that might be required prior to reaching the 35-year mark.
JGN's proposal repeats a similar end of life scenario for meters from the 2020-2025 access arrangement proposal. At that time, JGN forecast end of life failures increasing to an unacceptable level at 30 years which we did not accept in the access arrangement review for the same reasons.	This is not correct: • Our Initial 2025 Plan did not include a similar end of life scenario for meters as we had proposed in our 2020 Plan. • Our 2020 Plan forecast that meters would not pass the 25-year test – not 30 years. • While the AER did not accept our forecast, it applied a forecast with a weighted average expected life of 25.02 years – very similar to what we had proposed.[48]

45 NMI R 137 Gas Meters

46 See Figure 4.3 of Attachment 5.1 of our Initial 2025 Plan, available here.

47 If defective failure rates fall, we may test meters at 35-years. We will make this decision once we have seen further failure data. We also note that while, at this stage are not forecasting that these meters will be sufficiently accurate at 35-years, it may be possible that some of these meter's lives can be extended. However, we expect that the number of these life extensions will be below the number of meters which will not pass their 15, 20, 25 or 30 year life extension tests.

48 See section 2.1

3. Tempe PRS obsolescence project

This section provides background to our inclusion of our Tempe PRS project and the AER's concerns as set out in its draft decision. We then set out additional information to address these concerns and demonstrate why forecast capex meets the conforming capex criteria (Rule 79).

3.1 Initial 2025 Plan

Over the current 2020-25 regulatory period, we commenced replacing aged end-of-life components at our high-pressure gas facilities. These components are critical to the ongoing function, safety and reliability of our network.

The original focus of our program was on the obsolete electrical instrumentation and control (E&I) equipment. This program was considered by the AER and its engineering consultant Zincara as part of the 2020-25 Access Arrangement review.

Zincara concurred that there is a need to replace ageing assets to ensure that facilities and pipes meet the requirements of industry standards and safety regulations.[49] Zincara considered our program to be prudent and recommended acceptance.[50] On the basis of this advice, the AER found that our program met the conforming capex criteria as the expenditure was justified and required to maintain safety, reliability, to meet minimum pressure obligations and existing levels of demand.[51]

Our program for the upcoming 2025-30 period, focusses on our older sites with end-of-life mechanical components. This includes our Tempe PRS which supplies 50,000 customers (including 61 demand customers) and will be 54 years old by the end of the 2025-30 period. At Tempe the pneumatic pressure control valves are obsolete and can no longer be refurbished by being machined back to specification. As a result, the valves will, at some point, functionally fail and be inoperable unless replaced.

The requirement to replace these valves provides an opportunity to simplify the stations. In particular, we identified that moving from pneumatic valves to Gorter style valves and regulators allows us to shift to a modern station design. This approach has several benefits:

- Reduced capex – due to removing the need for air power systems and a reduction in associated E&I components. At Tempe, the simplified approach costs $5.35 million ($2023), which is less than the like-with-like option cost of $5.97 million ($2023).
- Reduced ongoing opex – by about $10k per year due to lower facility complexity.
- Reduced fugitive emissions – in the order of 0.77 TJ of fugitive emissions or 338 tCO_2e per year per site.

We also considered the economic benefits of avoided costs of asset failure and improved energy reliability using very conservative assumptions. We did not quantify safety, compliance with regulatory obligations or emissions reduction benefits. The results for Tempe PRS are shown in Table 3–1.

49 Zincara 2019, *Access Arrangement 2019 JGN Capital Expenditure Review Prepared for the AER, p*.85 Available here.

50 Zincara 2019, *Access Arrangement 2019 JGN Capital Expenditure Review Prepared for the AER, section 7.2.6, 7.6.2, 7.6.3 and* Available here.

51 AER 2019, *Draft Decision Jemena Gas Networks (NSW) Ltd Access Arrangement 2020 to 2025* Attachment 5 Capital Expenditure, p.5-32. Available here.

Table 3–1: Initial 2025 Plan Tempe PRS Project NPV (Millions, $2025, discounted)

	Option 1. Status Quo	Option 2. Replace Like for Like	Option 3. Simplify facility operating configuration
Avoided cost at asset failure	-	0.2	0.3
Improved energy reliability	-	1.8	2.3
Emissions		*Not quantified*	
Safety		*Not quantified*	
Regulatory Obligations		*Not quantified*	
Integrity		*Not quantified*	
Economic benefits	**-**	***2.0***	***2.6***
Capex	-	4.8	4.3
Opex	-	-0.7	-1.2
Costs	**-**	***4.1***	***3.1***
Net Economic Benefits	**-**	**-2.2**	**-0.6**

It is important to note that, due to changes in good industry practice, standards and regulatory requirements, it is not possible to replace mechanical components of our facilities without also replacing the associated obsolete E&I equipment.

This is not only for practical reasons. We cannot modify facilities and retain equipment which does not adhere to current standards. In particular, we need to install residual current devices on electrical circuits and E&I equipment certified to operate in hazardous areas under the Australian National Ex Certification Scheme (ANZEx Scheme) or the International Electrotechnical Commission Ex Scheme (IECEx Scheme). The current E&I equipment was installed prior to the establishment of these schemes and has not been certified.

Gas pipelines around Australia are undertaking similar programs. For example, the Goldfields Gas Pipeline – a pipeline commissioned in 1996 – is undertaking a program to replace end-of-life components at its facilities, including its control systems and valve actuators. As with our program key considerations include the obsolescence of components, difficulty finding spares, criticality of this high-pressure facility infrastructure and compliance with modern standards and regulatory requirements (such as the IECEx Scheme).[52]

EMCa, a technical consultant (who the AER also relies on from time to time), reviewed the GGP's proposal and considered that the program of work complies with the conforming capex criteria in the Rules.[53] On this basis, the ERA concluded that end of life capex meets the conforming capex criteria set out in the NGR.[54]

52 GGP 2023, *Reliability and maintenance Program* p.10 Available here.

53 EMCa 2024, *Review of technical aspects of GGT Access Arrangement 2025-29,* p.46. Available here.

54 Economic Regulation Authority, *Draft decision on revisions to the access arrangement for the Goldfields Gas pipeline, Attachment 4: Regulatory capital base.* p. 27 Available here.

3.2 Draft decision

The AER accepted all of our obsolescence projects, expect for Tempe PRS. In the case for Tempe, the AER was concerned that we did not select the option with the highest net present value – 'Maintain Status Quo (no investment)' – stating that:[55]

> *We note that JGN, when choosing from the options in the business case, did not select the option with the highest net present value. The option with the highest net present value was not replacing certain mechanical equipment. JGN did not otherwise establish that another option (that is, an option other than that with the highest net present value) was prudent and efficient. Consequently, we do not consider JGN selected the most efficient project. We have not included this capex in our alternative estimate. We are not satisfied the Tempe PRS Facilities Obsolescence project is prudent and efficient under NGR, r. 79(1)(a), and there is insufficient evidence that the expenditure is required to maintain and improve the safety of services NGR, r. 79(2)(c)(i) or comply with regulatory obligations or requirements NGR, r. 79(2)(c)(i).*

Based on this, the AER concluded that there is insufficient evidence that the expenditure is required to maintain and improve the safety of services or to comply with regulatory obligations or requirements. The AER noted:[56]

> *We consider that, if JGN considers a project will improve matters such as safety and integrity, it should identify an economic value for the increased safety and integrity and include it in its cost benefit analysis model. This would allow it to demonstrate whether the project was efficient and in the interests of its customers.*

3.3 Revised 2025 Plan

The AER's draft decision is premised on the view that capex can only meet the conforming capex criteria if economic analysis demonstrates that undertaking the project has positive NPV. The AER suggests that it will only take into account safety and integrity benefits of a project if these benefits can be quantified and included in economic analysis.

The Rules set out that capex meets the conforming capex criteria if it is:[57]

- Prudent and efficient "such as would be incurred by a prudent service provider acting efficiently in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services in a manner consistent with the achievement of the national gas objective." This Rule is clear that efficiency and prudency is to be considered in context rather solely on the basis of quantitative economic analysis which cannot consider all factors (e.g. good industry practice, regulatory requirements, etc.).

- Justified on the basis of being necessary to maintain the safety of services, maintain the integrity of services, comply with regulatory obligations or to maintain capacity to meet levels of demand for services. We note that while expenditure can be justified if the overall economic value is positive **this is not required** – it is only one of seven possible grounds.

Accordingly, the requirement for economic analysis and a positive NPV for a project to be considered conforming capex is not consistent with the Rules. Not only is this approach a departure from previous AER decisions it is also inconsistent with other regulators' practice, views of two technical engineering consultants previously relied on by the AER, safety regulators, our technical regulatory requirements and Australian gas industry practice.

---

55 AER 2024, *Draft decision, Jemena Gas Networks (NSW) access arrangement 2025 to 2030 (1 July 2025 to 30 June 2030) Attachment 5 – Capital Expenditure, p.* 20 Available here.

56 AER 2024, *Draft decision, Jemena Gas Networks (NSW) access arrangement 2025 to 2030 (1 July 2025 to 30 June 2030) Attachment 5 – Capital Expenditure, p.* 20 Available here.

57 Rule 79(1). The third criterion is for capex to be properly allocated (and we have correctly allocated costs associated with Tempe PRS to transportation reference services).

We maintain that our Tempe PRS project is required to maintain the functionality, safety, integrity and reliability of our network and meets the conforming capex criteria. We provide further details on the implications of not undertaking the Tempe PRS project below.

Given the AER's focus, we have reviewed our economic analysis. We have now quantified the emissions reduction benefits of the project and updated our estimate of the value of energy reliability with more realistic, yet still very conservative, assumptions. Our updated analysis indicates that our proposed project results in the highest NPV ($31.5 million) of all options considered.

We have not quantified the benefits of maintaining the safety, integrity, or compliance with regulatory obligations – the primary drivers of the project. This means that the calculated NPV materially understates the economic and customer value of the project.

3.3.1 Functionality, safety and reliability of our network cannot be maintained without the Tempe PRS project

The AER has identified that in the Options Analysis we submitted, Maintain Status Quo (Option 1) has the highest NPV. This NPV of this option is $0.6 million higher than our preferred option. However, it does not address the identified need (to maintain facility operation) and has a treated risk rating of high.

Maintain status quo is the option where we operate a critical high-pressure facility with obsolete, degraded end-of-life equipment. There is no ability under this option, via different maintenance approaches or otherwise, to maintain the functionality of the installed equipment and in turn the ongoing safe operation of the facility.[58] The installed equipment will, at some point, fail and become inoperable. This will result in either:

- Failure of a pressure control valve – resulting in a lost functionality and control of our significant portion of our network which supplies to 10 PJ a year (11% of total volume of gas transport by our network) to 50,000 customers, including 61 large demand customers. This would result in either:
  - Loss of supply – This will require a (high cost) reactive replacement followed by restoration of supply via a 'relight' which, based on recent experience, would take about 25 days to complete.[59] This may also lead to plant damage (potentially permanently shutting down a business), product damage or a material loss in production. All three outcomes could lead to a material loss in customer income.
  - Over pressurisation – leading to uncontrolled release of gas (with associated safety and environmental consequences), damage to our downstream assets, and/or end-user appliances. A recent example is the 2018 Merrimack Valley overpressure event which resulted in one fatality, 21 serious injuries, damage to 131 structures, and 5 homes destroyed.[60]
- Failure of the E&I and earthing systems resulting in injury or death to personnel maintaining our assets.

Failure of Tempe PRS triggers the activation of the NSW Natural Gas Supply Disruption Plan under the State Emergency Plan.[61]

Letting a facility degrade such that it is no longer reliably functional is not consistent with AS2885.3 (the Australian Standard for High Pressure Pipeline Systems). This standard requires us to operate pipelines within their design parameters to ensure safe operation. In turn, this approach is not consistent with our Safety and Operating Plan and the *Gas Supply (Safety and Network Management) Regulation* 2022 (NSW).[62]

58 As noted in the Options Analysis we have been able to extend the lives of the pressure control valves by through period refurbishment, machining back to specification, to ensure continued operation. These valves can no longer be machined back to specification.

59 Following the 2022 incident on APA's Lithgow to Young Gas Pipeline, we restored gas supply to 12,000 customers in Bathurst over 6 days. This indicates that we can restore about ~2,000 customers a day. Accordingly, losing 50,000 customers will take about 25 days.

60 See here for a summary.

61 NSW Natural Gas Supply Disruption Plan, December 2024.

62 Part 2, Clause 7.

This outcome is clearly not consistent with the achievement of the NGO and does not meet the goals of conforming capex criteria. E.g. operating a high-pressure gas facility to failure is not in accordance with accepted good industry practice.

3.3.2 The conforming capex criteria does not require quantitative economic analysis to demonstrate that a capex achieves the highest NPV

Rule 79(1) sets out that conforming capex is capex which is 1) prudent and efficient 2) justified and 3) properly allocated. This criteria does not require quantitative economic analysis to be met.

Prudent and efficient

The first requirement is that capex:[63]

> *...must be such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services in a manner consistent with the achievement of the national gas objective;*

This Rule is clear that efficiency must be considered in the context of accepted good industry practice, achieving lowest sustainable cost and the achievement of the national gas objective.

It is not 'efficient' to select an approach which provides the highest NPV if this approach is not prudent, consistent with good industry practice and does not achieve the lowest sustainable cost of providing services in a manner consistent with the national gas objective.

In the case of Tempe PRS, a high-pressure gas facility operating in the community and supplying 50,000 customers including 61 large demand customers, running the facility to fail Is not consistent with:

- the actions of a prudent – which means acting with or showing care and thought for the future, sensible, careful – service provider.
- good industry practice – running a high-pressure facility to failure is not consistent with Australian standards or practice by any reasonable or prudent service provider in Australia or otherwise.
- the NGO, given the implications for the safety, reliability, quality, security of supply and emissions.

Justified

Rule 79(2) outlines that capex can be justified for several reasons. These include if necessary to maintain and improve the safety of services, maintain the integrity of services; comply with a regulatory obligation; or to maintain capacity to meet levels of demand for existing services.

While capex can be justified on the basis of an overall positive economic value (Rule 79(2)(a)) this does not preclude capex being justified on another basis.

The Rules do not require capex to have a positive economic value. They do not require this as it would result in unworkable, nonsensical outcomes.

For instance, it would require that we conduct economic analysis to determine whether expenditure to comply with a regulatory obligation meets the conforming capex criteria. This approach would run counter to the AER Chair's view that "*Compliance with the law is not a matter of choice.*"[64]

Requiring a positive NPV would also lead to a bias against expenditure required to maintain the safety and integrity of our network – especially for low consequence high probability events for which there is limited data. This approach is generally inconsistent with technical and safety related regulatory regimes.

63 Rule 79(1)(a).

64 AER Chair Clare Savage speech *Protecting consumers through the energy transition.* Available here.

3.3.3 Established regulatory practice

In addition to being inconsistent with the Rules, requiring a preferred option to have the highest economic value of all considered options is not consistent with:

- Previous AER decisions on earlier stages of this same program of works.
- Decisions by other Australian economic regulators operating under the (largely) same NGR.
- The views of two technical engineering consultants both previously engaged by and relied on by the AER (EMCa and Zincara).
- Our regulatory requirements and Australian standards which require us to maintain the functionality of the pipeline and to reduce safety risks to as low as reasonably practicable (ALARP).[65]
- International regulatory practice in respect of safety. For instance, the UK's Health and Safety Executive (HSE) is clear that "*A CBA* [cost benefit analysis] *cannot be used to argue against the implementation of relevant good practice, unless the alternative measures are demonstrated unequivocally to be at least as effective.*"[66] We note that maintaining the functionality of high pressure facilities is good practice and that operating to failure cannot be demonstrated as at least as effective.
- The Regulatory Investment Test in the National Electricity Rules (NER) and the AER's Guidelines. The purpose of this process is to identify the "credible option" – defined to be an option which addresses the identified need – that maximises the present value of the net economic benefit. The status quo approach we include in our options analysis (and selected by the AER in its draft decision) does not address the identified need to maintain the safety, integrity and reliability of our network and, in turn, is not a "credible" option as per the NER.[67]
- The views of our customers who have told us that safety needs to remain a given with no additional risk introduced.
- Common practice in the Australian gas network industry.[68]

3.3.4 Quantifying the reliability consequences demonstrates that undertaking the project has the highest NPV

Given the AER's preference for quantitative economic analysis, we have reviewed our analysis and made two changes to:

- Quantify the emissions reduction benefits of the project.
- Update our estimate of the value of energy reliability with more realistic, yet still very conservative, assumptions.

These changes result in our preferred option having the highest NPV of $31.4 million, even before the primary drivers of the project – to maintain the safety, integrity and functionality of the project are considered.

65 AS/NZS 2885 Part 6 Pipeline Safety Management

66 Health and Safety Executive Cost Benefit Analysis (CBA) checklist. Available here.

67 We note that in our Options Analysis we labelled status quo as a credible option; however, it is not a 'credible option' as defined in the National Electricity Rules.

68 EMCa 2024, *Review of technical aspects of GGT Access Arrangement 2025-29,* p.46. Available here.

Table 3–2: Updated Tempe PRS Project Incremental NPV ($2025, millions, discounted)

	Option 1. Status Quo	Option 2. Replace Like for Like	Option 3. Simplify facility operating configuration
Avoided cost at asset failure	-	0.3	0.3
Improved energy reliability	-	33.9	33.9
Emissions	-	-	0.3
Safety		*Not quantified*	
Regulatory Obligations		*Not quantified*	
Integrity		*Not quantified*	
Economic benefits	**-**	***34.2***	***34.5***
Capex	-	4.8	4.3
Opex	-	-0.7	-1.2
Costs	**-**	***4.1***	***3.1***
Net economic benefits	**-**	**30.1**	**31.4**

Emissions reduction

Currently, Tempe PRS uses natural gas to power the control values. This gas is then vented to the atmosphere resulting in 338 tCO2e emitted annually.[69] Changing the station configuration removes the need for instrument gas and eliminates these emissions. This benefit is only realised in *Option 3 Simplify facility operating configuration*.

Applying the Ministerial Council of Energy Value of Emissions to the avoided emissions gives a present value of this reduction of $0.3 million.

Improved energy reliability

As outlined above, no prudent service provider would ever run a high-pressure gas facility which supplies 50,000 customers, including 61 demand customers, to failure. Accordingly, there is limited data to use to quantify the probability and consequence of a failure event.

As flagged in our response to IR009, we initially applied very conservative assumptions. We were satisfied with these assumptions as the primary driver of the project is to keep our network safe, functional and to comply with Australian Standards and our regulatory obligations.

However, given the AER's focus on quantitative analysis we have reviewed our assumptions as outlined in Table 3–3.

[69] This is based on 20,000 SCM, consistent with Information Request IR006.

Table 3–3: Change to economic assumptions around reliability

Aspect	Initial Proposal	Updated analysis	Comment
Probability of failure	Status Quo: 5% Replace like for like: 1.5% Simply station configuration: 0.5%	Status Quo: 2.5% increasing 2.5% per year Replace like for like: 0.1% Simply station configuration: 0.1%	Updated.
Duration of failure	2.7% (10 days)	2.7% (10 days)	No change. We note recent experience indicates that we can relight about 2,000 customers a day which indicates that an unplanned loss of supply a Tempe would take about 25 days to restore.
Energy at risk	10,000 TJ	10,000 TJ	No change.
Value of unserved energy	~$20 /GJ	$100 /GJ	Updated. Using the value of wholesale gas is too low.

The first change is to update the probability of failure. We have changed these percentages as:

- Operating a critical high-pressure facility to failure will result in failure. It's a matter of when not if. Accordingly, we have updated the risk from a static 5% to initially 2.5% then increasing by 2.5% each year.
- The historical rate of failure of a functional station is very low. We have not had a valve failure at any of our ~120 our high-pressure facilities in the last 10 years. Accordingly, we have reduced the probability to 0.1%.

The second change is to the value of unserved energy. We originally applied a value of ~$20/GJ as an estimate of the wholesale price of gas. This is very conservative as:

- The retail price consumers pay is closer to $50/GJ.[70] This indicates that consumers value the supply of gas to be *at least* $50/GJ.
- In electricity, the AER's 2023 value of customer reliability (VCR) is $34.32/kWh for a residential customer in Suburban NSW[71] which is about 89 times higher than the AER's 2022-23 default market offer (DMO) prices for electricity of $0.38/kWh.[72]
- Converting the AER's 2023 VCR for electricity to gas would give a value of $9,533/GJ.
- Applying the ratio between the VCR and the DMO to the retail price of gas would give a value of $4,292/GJ.[73]

70 As at December 2024 the two best plans for our network on Energy Made Easy for a home with medium gas usage was $850 (Sumo Assure Residential Gas) and $860 (AGL Residential Value Saver) – on a per GJ basis these plans work out to be $48/GJ.

71 See here.

72 Based on the DMO Price of $1,512 for annual usage of 3,900 kWh for a residential customer without a controlled load on the Ausgrid network. See Table 2.1 here.

73 Applying the scaling factor of 89 to $48/GJ.

- The AER's VCR for business customers, many of which are supplied by our Tempe PRS, is much higher ranging from $52.20/kWh commercial, to $74.79/kWh (industrial) to $138.34/KWh (industrial using more than 10 MVA at peak times.) Converting these figures to GJ gives an indicative value of 14,500/GJ to $38,428/GJ. These values are not unreasonable given that a no gas scenario could lead to plant damage (potentially permanently shutting down a business), product damage or a material loss in production. All three outcomes could lead to a material loss in income.

We have updated our analysis to apply a value of reliability of $100/GJ ($2023). We note that this value remains extremely conservative given the figures above – but given the criticality of Tempe PRS – it still has a material impact on the economic analysis.

4. Summary of proposed revisions to Initial Proposal AA

As outlined in our Revised 2025 Plan, we have accepted the AER's draft decision with response to the CESS mechanism. The specific changes to the Access Arrangement are detailed below.

Table 4-1: Explanation of proposed relevant revisions to the Initial Proposal AA

Clause	2020 AA reference	2025 AA reference	Summary of proposed change
Capital expenditure incentive mechanism			
CESS mechanism	13.1(b)(v)	13.1(b)(v)	Clause 13.1(b) is proposed to be amended by reverting to the original drafting and deleting the proposed exclusion of renewable gas connection expenditure from the CESS mechanism.
CESS mechanism	13.1(f)	13.1(f)	Clause 13.1(f) is proposed to be amended consistent with the AER's decision to apply a tiered approach to sharing of underspend in incentive schemes.
CESS mechanism	**13.1(l)**	**13.1(l)**	**Clause 13.1(l) is proposed to be amended consistent with the AER's decision to apply a tiered approach to sharing of underspend in incentive schemes.**

Appendix A
"Capital expenditure by asset class"

Jemena
bringing energy to life

A1. Capital expenditure by asset class

Below we set out capital expenditure by asset class over the earlier access arrangement period.

Table 4–1: Gross capital expenditure by asset class over the earlier 2020-25 Access Arrangement Period ($2025)

Asset class	2020-21	2021-22	2022-23	2023-24	2024-25
Trunk Wilton-Sydney	-	-	0.77	0.06	-
Trunk Sydney – Newcastle	0.01	0.11	0.56	0.29	0.22
Trunk Wilton-Wollongong	-	-	0.02	0.05	0.65
Contract Meters	1.18	1.26	0.80	3.09	1.91
Fixed Plant – Distribution	9.08	6.25	1.62	9.34	25.08
HP Mains	9.43	16.33	29.75	10.54	25.83
HP Services	2.59	1.34	0.78	0.99	1.40
MP Mains	34.37	41.46	28.36	28.25	31.65
MP Services	71.44	58.00	65.82	59.97	54.49
Meter Reading Devices	2.82	1.63	2.72	4.83	1.35
Country POTS	0.02	0.18	0.39	0.06	-
Tariff Meters	33.70	24.86	28.25	30.94	31.66
Computers – IT Infrastructure	1.59	1.75	3.24	3.22	0.18
Fixed Plant	0.31	0.48	0.78	0.36	-
Furniture	-	-	-	-	-
Land	0.17	-	-	-	-
Low value assets	-	-	-	-	-
Mobile Plant	1.68	1.43	5.22	(2.99)	1.07
Vehicles	5.26	3.10	4.44	4.89	2.09
Leasehold Improvements (SL)	0.30	0.53	2.76	1.34	-
Buildings (SL)	0.06	0.19	0.66	0.06	5.68
Software – Inhouse (SL)	18.19	11.22	15.51	13.79	18.31
Total	**192.19**	**170.11**	**192.45**	**169.10**	**201.56**

Appendix B
Updates to RIN response

Jemena
bringing energy to life

B1. Update to RIN response

Clause 1.3.5 of the reset RIN requires us to update our response to sections 4.3.1 and 4.3.2 of the notice. This is provided below (in addition to the information provided as part of our 2023-24 RIN response).

Table B1–1: Updated response to RIN requirement 4.3.1 and 4.3.2.

Requirement	Response
4.3.1 For total capital expenditure expected to be incurred in the current access arrangement period, provide: (a) a comparison of the total expenditure, disaggregated by expenditure category or driver, to the total forecast capex allowed for the current access arrangement period; (b) an explanation of the drivers of differences noted in response to section 4.3.1 (a), for example the impact of efficiency gains, major new projects, project deferrals or rescoping, changing regulatory obligations, asset age, or other factors; (c) a list of projects deferred in the current access arrangement period and included in the forecast capex for the forthcoming access arrangement period, and the rationale for the deferral.	(a) We provide an updated comparison of total capital expenditure by driver in Table B1-2 below. (b) Our Initial 2025 Plan, *JGN – Att 5.1 – Capital expenditure* and *JGN – Att 5.4 – Technology Plan* provides an explanation of the differences by driver. The only difference between our Initial and Revised 2025 Plan is an update for 2023-24 RIN data. This update does not change the explanations already provided. (c) There is no change to the list of projects deferred as set out in Table 4.1 of *JGN - RIN - Att 1 - Written response - 20240628* provided as part of our Initial 2025 Plan.
4.3.2 For forecast capex for the forthcoming access arrangement period, provide: (a) a comparison of the total forecast expenditure by category or driver to the total capital expenditure expected to be incurred in the current access arrangement period; (b) an explanation of the drivers of differences noted in response to section 4.3.2 (a), for example the impact of expected efficiency gains, major new projects, project deferrals or rescoping, changing regulatory obligations, asset age, or other factors	(a) See Table B1-2 below. (b) The explanation of material differences between capital expenditure expected to be incurred in the current and forecast period is provided in our Initial 2025 Plan (specifically JGN – *Att 5.1 – Capital expenditure* and *JGN – Att 5.4 – Technology Plan*). As noted in the overview of this document, the difference between our Initial and Revised 2025 Plans are due to accepting the AER's draft decision in respect of several areas (digital metering, data loggers and defective meters) and updating inputs (connections forecast, metering accuracy test data, inflation etc.)

Table B1–2: Capex over 2020-25 and 2025-30 (Gross, $2025 millions)

	2020-25			2025-30	
	Allowance	Initial 2025 Plan: Actual / forecast	Revised 2025 Plan: Actual / forecast	Initial 2025 Plan	Revised 2025 Plan
Connections	528.0	474.3	488.6	281.8	302.7
Emissions: reducing our emissions	41.0	33.3	34.6	59.5	58.2
Emissions: facilitating renewable gas	-	5.9	5.9	83.4	81.6
Stay in business: Metering	152.2	112.3	117.5	169.4	177.1
Stay in business: Excluding Metering	227.3	206.7	190.1	198.0	194.7
ICT	119.2	80.1	79.7	40.3	40.9
Total	**1,067.7**	**912.7**	**916.4**	**832.5**	**855.2**
Total (Excluding ICT)	**948.5**	**832.6**	**836.7**	**792.1**	**814.4**