FINAL DECISION
Jemena Gas Networks (NSW) Ltd
Access Arrangement 2015−20

Overview

June 2015

AUSTRALIAN
ENERGY
REGULATOR

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Note

This overview forms part of the AER's final decision on Jemena Gas Networks' 2015–20 access arrangement. It should be read with all other parts of the final decision.

The final decision includes the following documents:

Overview

Attachment 1 – services covered by the access arrangement

Attachment 2 – capital base

Attachment 3 – rate of return

Attachment 4 – value of imputation credits

Attachment 5 – regulatory depreciation

Attachment 6 – capital expenditure

Attachment 7 – operating expenditure

Attachment 8 – corporate income tax

Attachment 9 – efficiency carryover mechanism

Attachment 10 – reference tariff setting

Attachment 11 – reference tariff variation mechanism

Attachment 12 – non-tariff components

Attachment 13 – demand

Contents

Shortened forms

Shortened form	Extended form
AER	Australian Energy Regulator
capex	capital expenditure
CAPM	capital asset pricing model
CCP	Consumer Challenge Panel
Code	National Third Party Access Code for Natural Gas Pipeline Systems
CPI	consumer price index
DRP	debt risk premium
ERP	equity risk premium
JGN	Jemena Gas Networks (NSW) Ltd (ACN 003 004 322)
MRP	market risk premium
NGL	national gas law
NGO	national gas objective
NGR	national gas rules
opex	operating expenditure
PPI	partial performance indicators
PTRM	post-tax revenue model
RAB	regulatory asset base
RBA	Reserve Bank of Australia
RFM	roll forward model
RIN	regulatory information notice
RPP	revenue and pricing principles
SLCAPM	Sharpe-Lintner capital asset pricing model
WACC	weighted average cost of capital

1 Our final decision

The Australian Energy Regulator (AER) is responsible for the economic regulation of covered gas pipelines in all states and territories except Western Australia.

The National Gas Law (NGL) and National Gas Rules (NGR) provide the regulatory framework under which we operate. Most relevantly, they set out how we must assess an access arrangement revision proposal and make our decision.

The National Gas Objective (NGO) sits at the centre of the NGL and NGR. The NGO is to promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas.[1]

Jemena Gas Networks (NSW) Limited (JGN) operates the largest gas distribution network in NSW. This is our final decision on JGN's proposed revisions to its access arrangement for the 2015–20 period.[2] It includes our final decision on the reference tariffs and terms and conditions that apply to services provided through JGN's distribution pipelines.[3]

Under the NGL, JGN must submit revisions to its access arrangement to us for approval.[4] The central component of JGN's proposal is the amount of revenue JGN proposes to recover from consumers over the 2015−20 access arrangement period.[5] We must assess JGN's proposal, using the NGR's detailed rules. The NGR address a range of components of proposed revenue. We must decide whether to accept JGN's proposal. If we do not accept that JGN's proposal complies with the requirements of the NGR, we must substitute an alternative amount of revenue that we are satisfied does comply. We must undertake this assessment and make this decision in a manner that will or is likely to contribute to the achievement of the NGO and, where appropriate, contribute to the greatest degree.

As with other covered pipelines, we regulate JGN's reference tariffs, and through this, its revenue. We do not regulate JGN's costs. JGN must then decide how best to use the revenue it recovers through reference tariffs in providing pipeline services and fulfilling its obligations. This provides incentives for service providers, such as JGN, to operate their businesses efficiently and, in the long run, at least cost to consumers. It also provides incentives for service providers to innovate and invest in response to changes in consumer needs and productive opportunities.[6] This is consistent with

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1 NGL, s. 23.

2 NGR, r. 62.

3 This decision includes the revisions we propose under r. 64(1) of the NGR, noting that under r. 64(3) we are not required to consult on these, and a final decision under r. 64(4).

4 NGL, s. 132.

5 NGR, r. 72(1)(m).

6 Hansard, SA House of Assembly, 9 February 2005 p. 1452, Hansard, SA House of Assembly, 9 April 2008 pp. 2884 and 2885.

economic efficiency principles. It also means that the person who is best able to manage a risk generally carries that risk. To the extent that JGN incurs costs above what we assess to be efficient, these will be recovered from JGN's shareholders and not its customers. Consumers should not pay more than necessary for safe and reliable gas services.

JGN submitted its proposal in June 2014. In November 2014 we made a draft decision and, in February 2015, JGN submitted a revised proposal. We also received submissions from various stakeholders on JGN's initial and revised proposals as well as our draft decision.[7]

This overview, together with its attachments, constitutes our final decision on JGN's revised proposal. The overview provides a summary of our final decision and its constituent components. It sets out the issues we covered, the conclusions we made, and how those conclusions were reached. We also explain why we are satisfied our decision contributes to the achievement of the NGO to the greatest degree and why we do not consider that JGN's revised proposal contributes to the NGO to a satisfactory degree. In our attachments we set out detailed analysis of the components that make up JGN's revised proposal and our decision on each of them.

1.1 Decision

Our final decision is that JGN can recover $2229 million ($nominal) from consumers over the 2015–20 access arrangement period. Figure 1 illustrates our overall decision.

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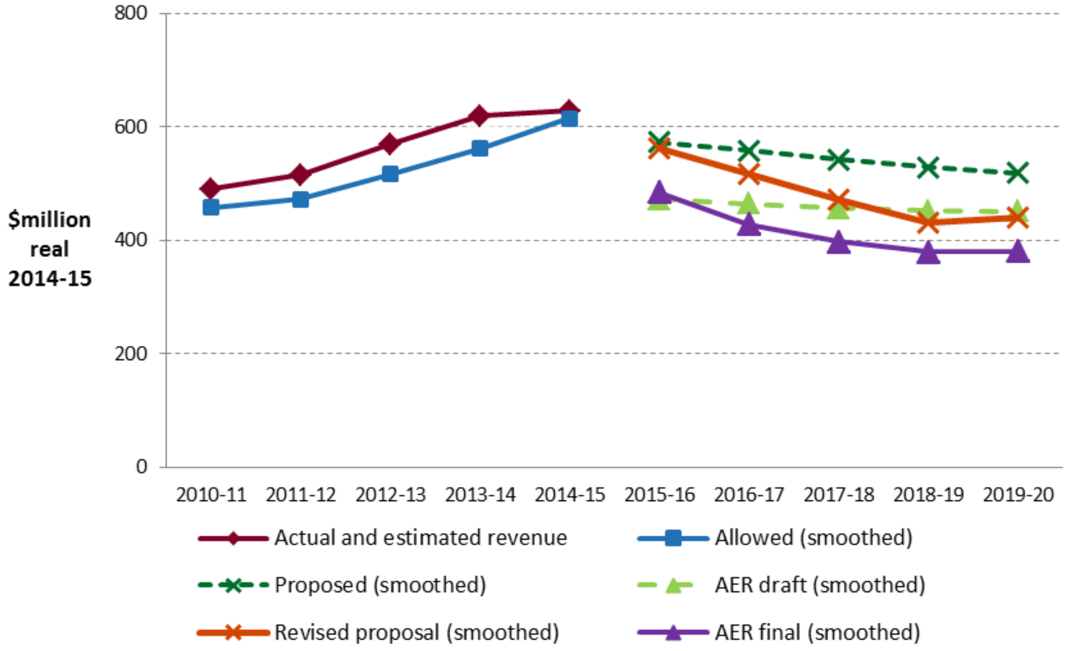
7 See appendix A for a list of submissions.

Figure 1 JGN's past total revenue, proposed total revenue and AER total revenue allowance ($ million, 2014–15)



Source: AER analysis.

Table 1 shows the estimated impact of our final decision on the average JGN customer's annual gas bills over the 2015–20 access arrangement period, compared with what was proposed.[8]

In NSW, gas distribution charges represent approximately 50 per cent of a customer's average annual gas bill.[9] If all other components of a customer's bill remain constant, and the lower distribution charges flowing from our final decision for JGN are passed through to customers, we would expect the average annual gas bills for residential and small business customers on JGN's network to reduce over the 2015–20 access arrangement period. Table 1 presents the indicative impact of the final decision on average annual gas bills in JGN's distribution area. It estimates the indicative impact for both residential and small business customers, and compares our decision against JGN's revised proposal.

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8 JGN updated its proposed revenue numbers after the submission of its revised proposal. JGN, *Submissions on draft decision, Attachment N - updated appendix 10.1 - JGN revenue forecast model*, 27 March 2015.

9 IPART, *Changes in regulated retail gas prices from 1 July 2014*, June 2014, p. 7.

Table 1 Indicative impact of final decision—residential and small business customers ($nominal)

	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20
JGN revised proposal						
Residential annual gas bill[a]	$1,042	$1,021	$991	$963	$937	$955
Annual change in distribution bill component —residential		–$21 (–2.1%)	–$30 (–2.9%)	–$28 (–2.8%)	–$26 (–2.7%)	$18 (+2.0%)
Small business annual gas bill[a]	$5,021	$4,918	$4,775	$4,640	$4,514	$4,603
Annual change in distribution bill component—small business		–$103 (–2.1%)	–$143 (–2.9%)	–$134 (–2.8%)	–$126 (–2.7%)	$89 (+2.0%)
AER final decision						
Residential annual gas bill[a]	$1,042	$946	$905	$887	$878	$887
Annual change in distribution bill component—residential		–$96 (–9.2%)	–$41 (–4.4%)	–$18 (–2.0%)	–$9 (–1.0%)	$9 (+1.0%)
Small business annual gas bill[a]	$5,021	$4,559	$4,359	$4,274	$4,230	$4,274
Annual change in distribution bill component—small business		–$462 (–9.2%)	–$200 (–4.4%)	–$86 (–2.0%)	–$44 (–1.0%)	$44 (+1.0%)

Source: AER analysis; JGN, *Submissions on draft decision, Attachment N - updated appendix 10.1 - JGN revenue forecast model*, 27 March 2015.

a The 2014–15 annual gas bill was calculated based on IPART, *Fact sheet – Removing carbon costs from regulated gas prices*, 15 August 2014. The 2015–16 to 2019–20 annual gas bills were calculated from this starting point, applying each year the weighted average price change (CPI–X) to the distribution charge component. All other components of the bill are assumed to be held constant.

Other factors also affect a customer's annual gas bill, such as the wholesale price of gas.[10] In section 2.5 we model the potential impact of our final decision on customer gas bills if we also allow for forecast increases in the wholesale gas price.[11]

1.2 Contribution to achievement of the NGO

We are satisfied that the price path and total revenue approved in our final decision contribute to the achievement of the NGO to the greatest degree. Our price path and total revenue reflect the efficient, sustainable costs of providing network services in JGN's operating environment. Our final decision also reflects the key drivers of efficient costs facing JGN. For the reasons set out below and in our attachments, we consider our decision will promote the efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers, as required by the NGO.

10 The broad components of the customer bill are wholesale gas costs, transmission costs, distribution costs (JGN's component) and retail margins. There may also be carbon related costs.

11 We do not regulate wholesale gas prices, and these are also outside JGN's control.

The key drivers of costs facing a service provider are:[12]

- its accumulated network investment (reflected in the size of its capital base)
- its expected growth in network investment (reflected in its capital expenditure (capex) program net of capital returned to the shareholders through depreciation)
- its financing costs (interest on borrowings and a return on equity to shareholders)
- its operating expenditure (opex) program (the cost of operating and maintaining its network)
- its taxation cost (taxable income at the corporate tax rate adjusted for the value of imputation credits).

From one access arrangement period to the next, the pressures on each of these drivers may change. For example, in periods of high demand growth, a service provider would expect to need a larger capex program. Similarly, during periods of high interest rates, a service provider would expect to pay more in financing costs.

The most important factor we see impacting on JGN's costs in the 2015−20 period is an improved investment environment, which translates to lower financing costs necessary to attract efficient investment.

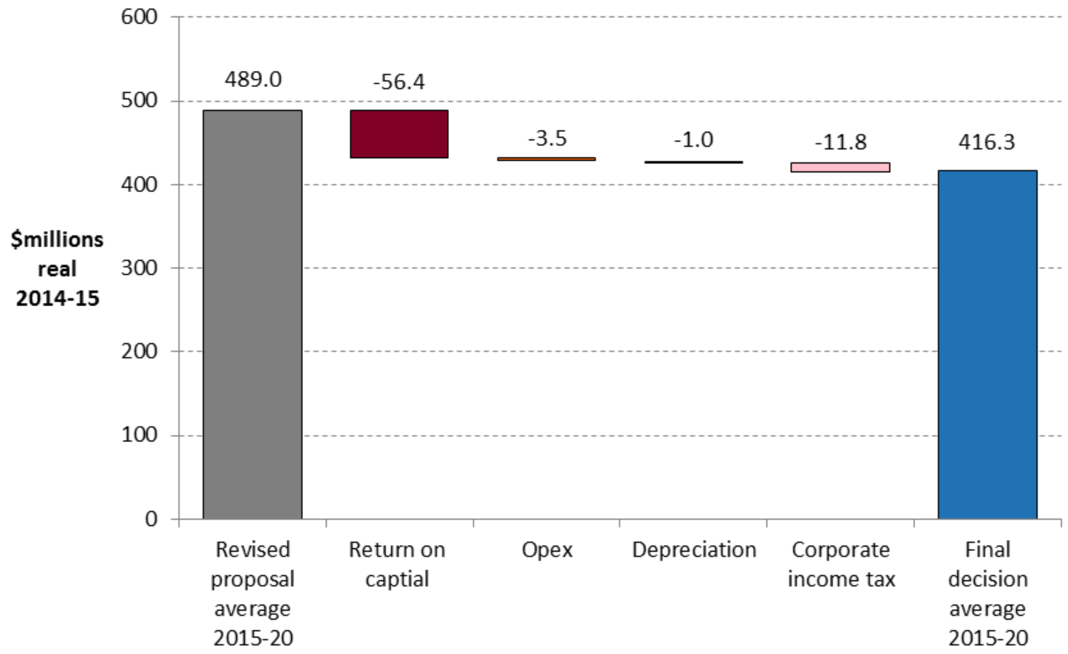
This is reflected throughout our final decision and impacts the different components of our decision to varying degrees. At the total revenue level it indicates that a prudent operator of JGN's network—acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services—would need materially less revenue than JGN has proposed for the 2015−20 access arrangement period.

In our final decision we consider that JGN's revised proposal does not reflect the factors impacting on its cost drivers to a satisfactory extent. As a consequence, we consider that JGN has proposed to recover more revenue from customers than is necessary for the safe and reliable operation of its network. It follows that we consider that JGN's revised proposal does not contribute to the achievement of the NGO to a satisfactory degree.

Figure 2 illustrates the key differences (in terms of constituent components, or building blocks, making up total revenue) between our decision and JGN's revised proposal.

12 How these key cost drivers impact total revenue is further explained in section 2 of this overview.

Figure 2 AER's final decision on building block costs ($ million 2014–15)



Source: AER analysis; JGN, *Submissions on draft decision, Attachment N - updated appendix 10.1 - JGN revenue forecast model*, 27 March 2015

For reasons outlined in our attachments and later in this overview, our final decision differs from JGN's revised proposal in a number of ways. However, the component of our decision that has had the greatest impact on the total revenue requirement and that drives most of the revenue gap between us and JGN is the rate of return.

1.2.1 Rate of return

The rate of return provides a service provider with revenue to service the interest on its borrowings and to give a return on equity to shareholders. The allowed rate of return is a key determinant of allowed revenue.

The rate of return must be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the service provider in respect of the provision of reference services.[13] The NGR refer to this requirement as the allowed rate of return objective.

Our final decision is for a rate of return of 5.41 per cent (nominal vanilla[14]) for 2015–16 compared to JGN's proposed rate of return which was 7.06 per cent.[15] For the rest of the access arrangement period, we will update the rate of return annually.

13 NGR, r. 87(3).

14 The nominal vanilla rate of return formula combines a post-tax return on equity and pre-tax return on debt, for consistency with other building blocks.

We set out our approach to determining the allowed rate of return in the rate of return guideline (Guideline) we published in December 2013.[16] This Guideline is not binding. However, a service provider must provide reasons to justify any departure from the Guideline[17]. JGN has proposed we depart from the Guideline. However, we are not satisfied that there are sufficient grounds to justify doing so.

Prevailing market conditions for debt and equity heavily influence the rate of return. In our draft decision we pointed out that financial conditions have improved markedly since our 2010 final decision, resulting in a lower rate of return. This meant that our draft decision contained an indicative (placeholder) rate of return of 6.80 per cent, which was markedly lower than the 10.43 per cent rate of return adopted for the previous access arrangement period. Since our draft decision, interest rates have fallen further and financial market conditions have continued to ease. This means that the cost of debt and the returns required to attract equity are lower than when we made our draft decision. We consider these factors should be reflected in the final approved rate of return. This has led to our final decision rate of return of 5.41 per cent.

On a more technical level, there are several key differences between our final decision and JGN's revised proposal in relation to the rate of return:

- Whether to gradually transition between approaches to estimating the return on debt, as we have decided, or to use a hybrid transition which combines a gradual transition for the base rate component of the return on debt and a backwards looking debt risk premium, as JGN has proposed. JGN's revised proposal on this matter is a departure from its (initial) access arrangement proposal. The NGR state a service provider may submit amendments in its revised access arrangement proposal. The NGR requires "the amendments must be limited to those necessary to address matters raised in the access arrangement draft decision unless the AER approves further amendments."[18] We do not consider the NGR permit JGN to depart from its (initial) access arrangement proposal on this matter.[19] This is because in the draft decision we accepted this aspect of JGN's (initial) access arrangement proposal and we have not approved JGN making further amendments to its access arrangement on this matter.[20]
- Whether to determine the averaging period and choice of data series to estimate the return on debt by running a separate process every year during the access arrangement process, as JGN proposed, or to determine these matters upfront at

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15 JGN's revised proposal contained indicative values based on an indicative averaging periods for risk free rate and return on debt. On 27 March 2015 JGN provided submissions that updated its approach using values derived from its proposed averaging periods. JGN's proposed rate of 7.06 per cent is from JGN, *Submission on draft decision–Attachment M: updated appendix 7.15–rate of return forecast model*, 27 March 2015.

16 AER, *Rate of Return Guideline*, December 2013: http://www.aer.gov.au/node/18859

17 NGR, r. 72(g).

18 NGR, r.60(1)–(2).

19 NGR, r.60(1)–(2).

20 AER, *Draft decision–JGN access arrangement 2015–20–Attachment 3: Rate of return*, November 2014, pp.100–101.

the start of the access arrangement period as we set out in the Guideline and have decided here.

- Whether to give weight to indicators of the return on equity that we do not consider to be robust and which other regulators do not use, as JGN has proposed, or to adopt a standard and commonly adopted approach to estimating the return on equity, as we have decided.

The Guideline (and this decision) marks a departure from the approach we used in previous regulatory decisions to estimating the return on debt and the return on equity. For the return on debt, we have used a gradual, forward-looking transition to do so. We set out this transition in the Guideline. Our approach to setting the return on debt received broad support amongst many stakeholders, including JGN in its (initial) access arrangement proposal.[21] Notwithstanding our position that the NGR do not allow JGN to submit a revised proposal in respect of the approach to the transition to the trailing average for debt, the subsequent evidence provided by JGN in support of its new position does not convince us that we should depart from the approach in our Guideline in this final decision.[22] For the return on equity, the evidence before us indicates that employing our approach is generally expected to lead to a rate of return that achieves the allowed rate of return objective.

1.3 Assessment of options under the NGO

The NGR recognise that there may be several decisions that contribute to the achievement of the NGO. Our role is to make a decision that we are satisfied contributes to the achievement of the NGO to the *greatest* degree.[23]

For at least two reasons, we consider that there will almost always be several decisions that might contribute to the achievement of the NGO. First, the NGR requires us to make forecasts, which are predictions about unknown future circumstances. As a result, there will likely always be more than one plausible forecast. Second, there is substantial debate amongst stakeholders about the costs we must forecast, with both sides often supported by expert opinion. As a result, for several components of our decision there may be several plausible answers or several point estimates from within a range. This has the potential to create a multitude of potential overall decisions. In this decision we have approached this from a practical perspective, accepting that it is not possible to consider every possible permutation specifically. Where there are several plausible answers, we have selected what we are satisfied is the best outcome under the NGL and NGR.

In many cases, our approach results in an outcome towards the end of the range of options materially favourable to JGN (for example, our choice of equity beta). While it

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21 For example, TasNetworks, *Revenue proposal*, June 2014; JGN, *2015–20 access arrangement information*, 30 June 2014, p.92; JGN, *2015–20 access arrangement*, 30 June 2014, page 15.

22 See Attachment 3 - Rate of Return.

23 NGL, s. 23(1)(b)(iii).

can be difficult to quantify the exact revenue impact of these individual decisions, we have identified where we have done so in our attachments. Some of these decisions include:

- selecting the top of the range for the equity beta
- setting the return on debt by reference to data for a BBB broad band credit rating, when the benchmark is BBB+
- the cash flow timing assumptions in JGN's revenue model.

We set out our detailed reasons in the attachments. They demonstrate that the components making up our decision comply with the NGR's requirements. At an overall level our decision reflects the factors set out above, which indicate that JGN should recover less revenue from customers than it has proposed or recovered in recent years. Our decision reflects these at both the individual component and overall revenue levels.

Given our approach, we are satisfied that our decision will or is likely to contribute to the achievement of the NGO to the greatest degree.

1.4 Structure of the overview

The remainder of this overview is structured as follows:

- Section 2 sets out our final decision on JGN's revenue
- Section 3 sets out the key components making up our final decision on JGN's revenue
- Section 4 sets out our decision on the incentive schemes that will apply to JGN
- Section 5 explains our views on the regulatory framework
- Section 6 outlines the process we undertook in reaching our final decision.

2 Total revenue requirement

The total revenue requirement is a forecast of the efficient cost of providing gas distribution services over the access arrangement period.

Tariffs are derived from the total revenue requirement *after* consideration of demand for each tariff category. JGN operates under a weighted average price cap.[24] This means the tariffs we determine (including the means of varying the tariffs from year to year) are the binding constraint across the 2015–20 access arrangement period, rather than the total revenue requirement in this final decision.[25]

2.1 The building block approach

We have employed the building block approach to determine JGN's total revenue. The building block costs, illustrated in Figure 3, include:[26]

- a return on the capital base (return on capital)
- depreciation of the capital base (return of capital)
- the estimated cost of corporate income tax
- increments or decrements resulting from incentive schemes such as the efficiency carryover mechanism[27]
- forecast opex.

Our assessment of capex directly affects the size of the capital base and therefore the revenue generated from the return on capital and return of capital building blocks.

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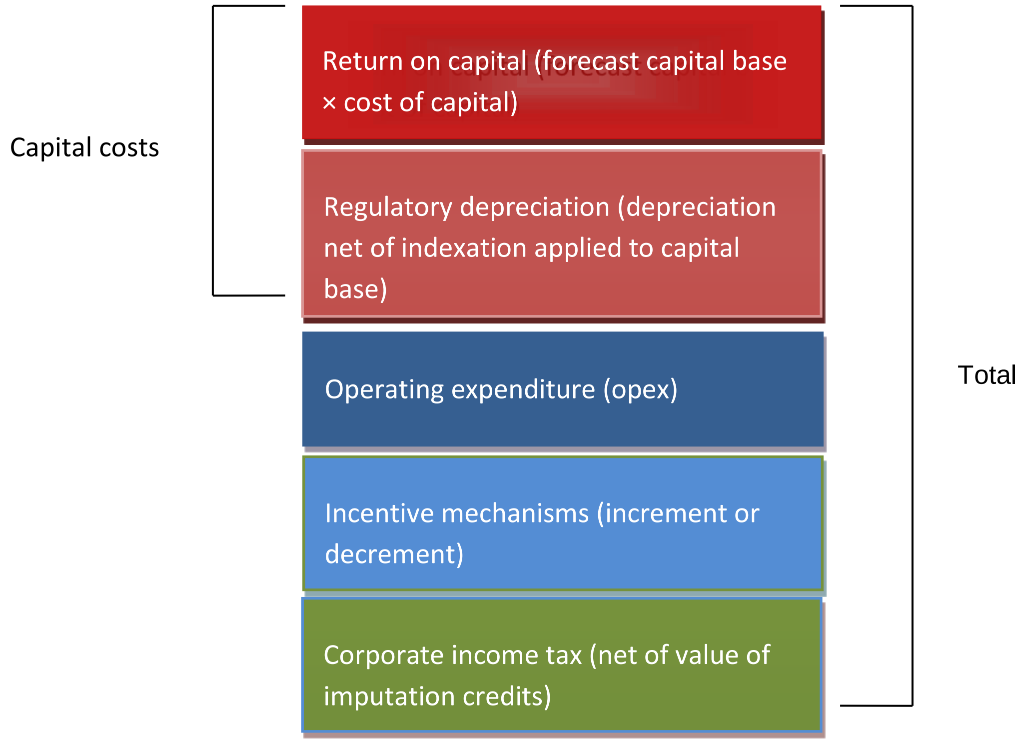
24 JGN, *Revised access arrangement proposal, Appendix 10.1 Revenue model - updated*, February 2015.

25 Where actual demand across the 2015–20 period varies from the demand forecast in the access arrangement, JGN's actual revenue will vary from the revenue allowance in this final decision. In general, if actual demand is above forecast demand, JGN's actual revenue will be above forecast revenue, and vice versa.

26 NGR, r. 76.

27 We did not apply an efficiency carryover mechanism to JGN in the 2010–15 access arrangement period.

Figure 3 The building block approach for determining total revenue



Section 3 summarises our decision by building block and provides our high level reasons and analysis. The attachments provide a more detailed explanation of our analysis and findings.

In this section 2 we set out our decision on JGN's total revenue requirement and the tariffs derived from that total revenue requirement.

2.2 Final decision

We do not approve JGN's revised proposal for a total revenue requirement (smoothed) of $2605.2 million ($nominal) for its reference, negotiated and other services.[28] Based on our assessment of the building block costs, we determine a total revenue requirement of $2229.0 million ($nominal, smoothed) for JGN over the 2015–20 access arrangement period.[29] We are satisfied that this amount meets the requirement of rule 76 of the NGR. This amount includes revenue for the reference service of $2218.1 million ($nominal) and $11.0 million ($nominal) for negotiated and other services. This total smoothed revenue requirement means we have approved 85.6 per cent of JGN's revised proposal over the 2015–20 access arrangement period (taking

28 From this amount, $11 million relates to negotiated and other services. JGN updated its proposed total revenue requirement after the submission of its revised proposal. JGN, *Submissions on draft decision, Attachment N - updated appendix 10.1 - JGN revenue forecast model*, 27 March 2015.

29 This is calculated by smoothing the total unsmoothed building block revenue requirement of $2487.9 million ($nominal).

into account JGN's 27 March submission on its revised proposal, which put forward changes to the smoothed revenue requirement).[30]

We do not approve JGN's revised proposed 2015–16 tariffs, which imply a weighted average decrease in nominal tariffs of 4.1 per cent.[31] Nor do we approve its 2016–20 tariff path, which is for a nominal decrease of 5.9 per cent each year from 2016–17 to 2018–19 and a nominal increase of 4.4 per cent in 2019–20.[32] As a result of our lower total revenue requirement and higher demand forecast, our final decision is for a nominal decrease in weighted average tariffs in the first four years of the access arrangement period. After factoring in our inflation forecast of 2.6 per cent per annum, this means a nominal decrease of:

- 18.4 per cent in 2015–16[33]
- 9.8 per cent in 2016–17
- 4.6 per cent in 2017–18
- 2.5 per cent in 2018–19.

Nominal prices then increase in line with inflation for the final year, 2019–20.

We accept that some aspects of JGN's revised proposal are consistent with the requirements of the NGR. However, we have not approved all elements, and so have not approved JGN's access arrangement proposal as a whole.[34]

Our final decision on JGN's revenue requirement by building block costs for each year of the 2015–20 access arrangement period, its total revenue after equalisation (smoothing) and the X factors for use in the tariff variation mechanism are set out in Table 2.

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30 JGN updated its revised proposed total revenue requirement after the submission of its revised proposal. JGN, *Submissions on draft decision, Attachment N - updated appendix 10.1 - JGN revenue forecast model*, 27 March 2015

31 These figures assume inflation of 2.55 per cent, in line with JGN's revised proposal.

32 JGN updated its proposed tariff path (X factors) after the submission of its revised proposal. JGN, *Submissions on draft decision, Attachment N - updated appendix 10.1 - JGN revenue forecast model*, 27 March 2015.

33 This final decision establishes 2015–16 prices directly, rather than referencing a change from 2014–15 prices. Hence, this is an indicative figure only, principally because of changes in the composition of tariff classes.

34 NGR, r. 41(2).

Table 2 AER's final decision on JGN's smoothed total revenue and X factors for the 2015–20 access arrangement period ($million, nominal)

Building block	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Return on capital	167.0	174.9	182.2	188.4	192.9	905.4
Regulatory depreciation	66.6	79.0	92.2	103.0	88.1	428.9
Operating expenditure	162.6	167.7	173.0	182.5	186.3	872.0
Corporate income tax	5.8	6.9	9.1	11.4	9.1	42.4
Building block revenue – unsmoothed	**402.0**	**428.5**	**456.5**	**485.2**	**476.3**	**2248.6**
Building block revenue – smoothed	**497.4**	**450.3**	**429.6**	**419.6**	**432.2**	**2229.0**
X factor[a]	20.43%[b]	12.00%	7.00%	4.90%	0.00%	n/a
Inflation forecast	2.55%	2.55%	2.55%	2.55%	2.55%	n/a
Nominal price change[c]	–18.40%	–9.76%	–4.63%	–2.47%	2.55%	n/a

Source: AER analysis; JGN, *Submissions on draft decision, Attachment N - updated appendix 10.1 - JGN revenue forecast model*, 27 March 2015

n/a not applicable.

a Under the CPI–X form of control, a positive X factor is a decrease in price (and therefore revenue).

b The X factor for 2015–16 is indicative only; the final decision establishes 2015–16 tariffs directly, rather than referencing a change from 2014–15 tariffs.

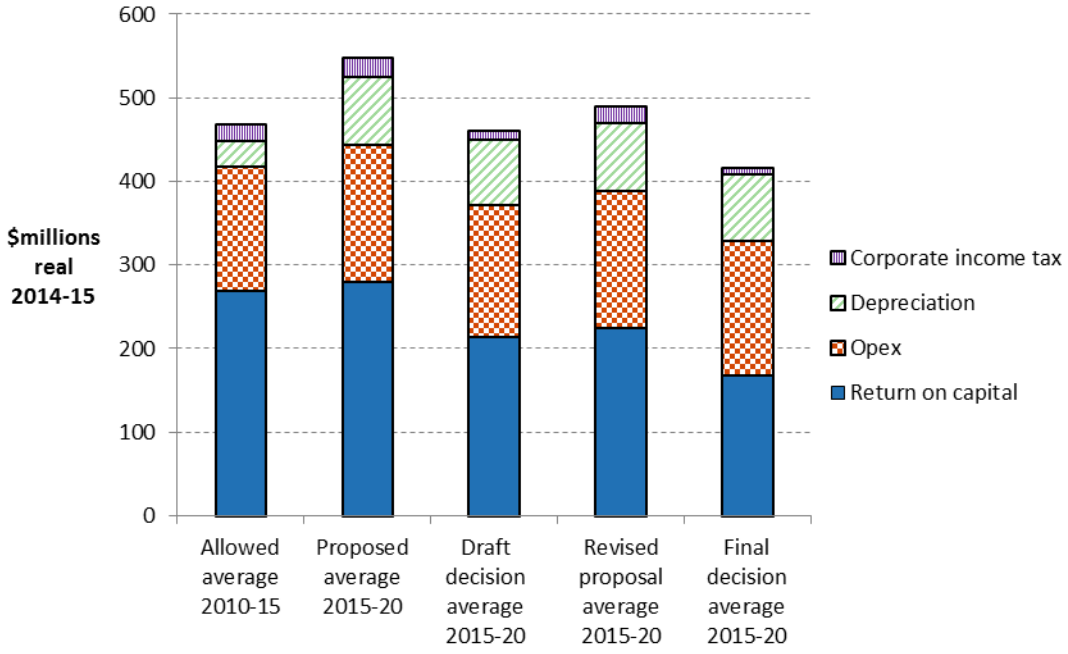
c The mathematical formula for a nominal price change under the CPI–X form of control is [(1+CPI)*(1–X factor)] – 1.

Sections 2.3, 2.4 and 2.5 focus on the derivation of total revenue from the building block components, the derivation of smoothed revenue and tariffs, and the derivation of indicative bill impacts.

2.3 Total revenue

Figure 4 compares the average annual building block revenue from our final decision against that proposed by JGN for the 2015–20 access arrangement period, as well as the approved average amount for the 2010–15 access arrangement period. It shows the relative size of each building block component, and illustrates that the most significant change is the reduction in the return on capital allowance.

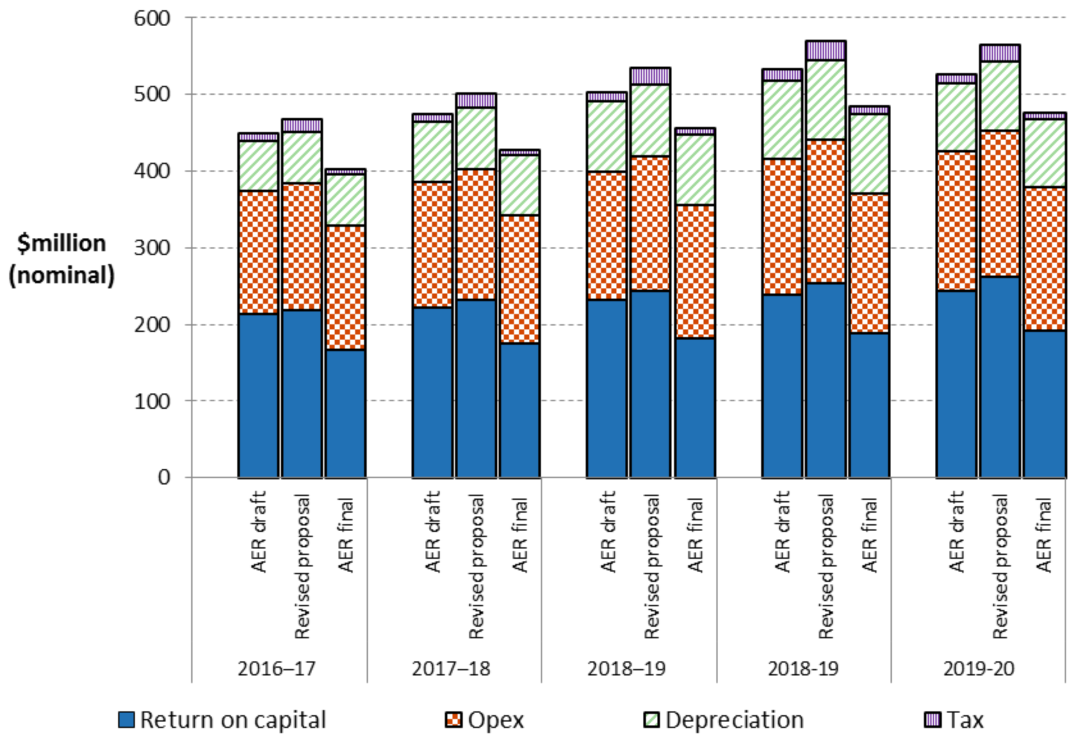
Figure 4 AER's final decision average annual revenue (unsmoothed) compared with JGN's revised proposal average annual revenue and approved average annual revenue for 2010–15 ($ million, 2014–15)



Source: AER analysis, JGN, *Submissions on draft decision, Attachment N - updated appendix 10.1 - JGN revenue forecast model*, 27 March 2015.

Figure 5 shows the effect of our final decision adjustments on JGN's revised proposal building blocks for the 2015–20 access arrangement period. It shows our final decision will reduce JGN's proposal for the return on capital, opex and tax building blocks.

Figure 5 AER's final decision and JGN's proposed building block revenue (unsmoothed) ($million, nominal)



Source: AER analysis, JGN, *Submissions on draft decision, Attachment N - updated appendix 10.1 - JGN revenue forecast model*, 27 March 2015

2.4 Smoothed revenue and tariff path

After our assessment of JGN's total unsmoothed revenue, we need to determine the smoothed revenue profile across the five year access arrangement period. JGN operates under a weighted average price cap as its tariff variation mechanism.[35] This means we determine the weighted average price change each year such that the net present value of unsmoothed and smoothed revenue is equal across the entire period.[36] This weighted average price change is labelled the 'X factor'. The mechanics of the tariff variation mechanism are addressed in attachment 11.

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35 The access arrangement decision directly sets 2015–16 tariffs; so the first year X factor (often called P_0) is indicative only. It is calculated by comparing the total revenue arising from using 2015–16 quantities and 2014-15 prices against the total revenue arising from using 2015–16 quantities (which includes some changes to tariff classes) and 2015–16 prices. For years two to five, the X factors are the binding means of adjusting prices (under the weighted average price cap tariff variation mechanism).

36 We have used a vanilla WACC form to undertake this smoothing, instead of the pre-tax WACC proposed by JGN. As noted in the draft decision, we considered this issue in conjunction with a broader review of the standard PTRM template used by all electricity network service providers. Using the vanilla WACC aligns JGN with our standard approach and reflects the appropriate basis for adjusting smoothed revenue across years. AER, *Draft decision, Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20, Overview*, November 2014, p. 26 (footnote 54);

Table 3 presents our final decision X factors, and compares them to JGN's proposal, our draft decision and JGN's revised proposal.[37]

Table 3 Weighted average price change across the access arrangement period (X factors) – comparison of JGN and AER positions (per cent)

	2015–16	2016–17	2017–18	2018–19	2019–20
Real price change (X factor)[a]					
JGN proposal	4.00%[b]	2.71%	2.71%	2.71%	2.71%
AER draft decision	23.44%[b]	2.09%	2.09%	2.09%	2.09%
JGN revised proposal	6.50%[b]	8.27%	8.27%	8.27%	–1.84%
AER final decision	20.43%[b]	12.00%	7.00%	4.90%	0.00%
Nominal price change (CPI–X)					
JGN proposal	–1.56%	–0.23%	–0.23%	–0.23%	–0.23%
AER draft decision	–21.49%	0.41%	0.41%	0.41%	0.41%
JGN revised proposal	–4.12%	–5.93%	–5.93%	–5.93%	4.44%
AER final decision	–18.40%	–9.76%	–4.63%	–2.47%	2.55%

Source: AER analysis, JGN, *Submissions on draft decision, Attachment N - updated appendix 10.1 - JGN revenue forecast model*, 27 March 2015.

a Under the CPI–X form of control, a positive X factor is a decrease in price (and therefore revenue). For example, an X factor of 12.00 per cent in 2016–17 means a real price decrease of 12.00 per cent that year. After consideration of inflation (estimated at 2.55 per cent) this becomes a nominal price decrease of 9.76 per cent. The mathematical formula for a nominal price change under the CPI–X form of control is [(1+CPI)*(1–X factor)] – 1.

b The X factor for 2015–16 is indicative only; the final decision establishes 2015–16 tariffs directly, rather than referencing a change from 2014–15 tariffs.

In broad terms, JGN’s revised proposal was for tariff decreases for the first four years of the period, with a small tariff increase in year five.[38] The largest tariff decreases were targeted to the three middle years of the five year period, in order to offset predicted increases in the wholesale gas prices in those years. Since the unsmoothed building block costs are generally increasing across the period, such a tariff path meant

and AER, *Final decision, Amendment, Electricity transmission and distribution network service providers, Post-tax revenue models (version 3)*, 29 January 2015, pp. 17–18.

37 In JGN's revised proposal, the X factors for 2016–17, 2017–18, and 2018–19 were 8.24 per cent (not 8.27 per cent). JGN updated its proposed X factors after the submission of its revised proposal. JGN, *Submissions on draft decision, Attachment N - updated appendix 10.1 - JGN revenue forecast model*, 27 March 2015.

38 JGN also suggested that an alternative tariff path with a decrease in the fifth year would also be acceptable. JGN, *Response to the AER's draft decision and revised proposal*, February 2015, p. 112.

that JGN would over-recover revenue in the earlier years and then under-recover in later years of the 2015–20 access arrangement period.[39]

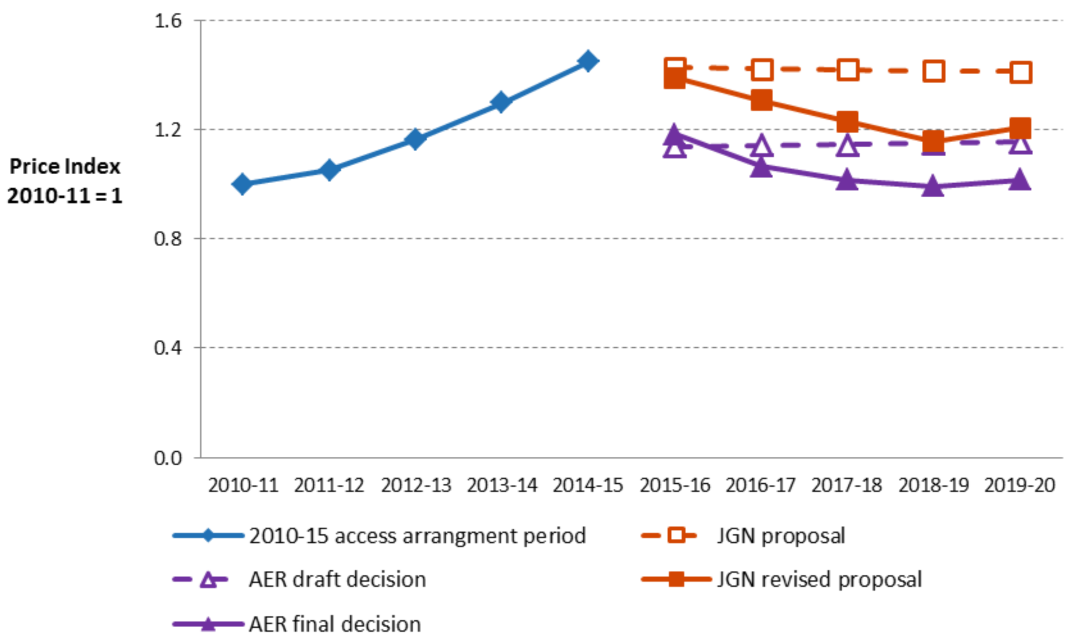
Our final decision tariff path produces lower total smoothed revenue than JGN's proposal, in line with our reductions to total unsmoothed revenue. This tariff path maintains tariff decreases in the first four years, as did JGN's revised proposal, but the decreases are larger in the earlier years of the period. In year five, tariffs increase slightly in nominal terms, though at a smaller rate than under JGN's revised proposal.

Figure 6 sets out a nominal index that shows indicative changes in JGN's distribution charges across the 2010–20 period. This index is calculated using the approved X factors from JGN's 2010–15 access arrangement, and then for 2015–20 the X factors from different sources:[40]

- JGN's proposal and revised proposal
- the AER's draft decision and final decision.

This provides a broad overall indication of the average tariff path across this period.

Figure 6 Indicative reference tariff paths for JGN's reference services from 2010 to 2020 (nominal index)



Source: AER analysis, JGN, *Submissions on draft decision, Attachment N - updated appendix 10.1 - JGN revenue forecast model*, 27 March 2015; AER, *Access arrangement information for JGN's NSW gas distribution networks, 2010–2015, Further amended with regard to mine subsidence expenditure*, September 2011, p. 26.

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39 In JGN's revised proposal, the difference between unsmoothed and smoothed revenue in 2019–20 was 11.8 per cent.

40 It uses inflation outcomes for the 2010–14 period, and estimated inflation from 2014–20.

We are satisfied that our final decision tariff path for JGN's 2015–20 access arrangement period achieves revenue equalisation as required by rule 92(2) of the NGR. It reflects our balanced consideration of a number of competing objectives, because the tariff path:

- Adjusts smoothed revenue downward in the first few years of the access arrangement period, to better reflect the unsmoothed building block costs. Closer alignment of tariffs and costs aids the achievement of the NGO and the revenue and pricing principles, including through providing a price signal that facilitates efficient use of natural gas services.[41]
- Retains significant decreases in the middle years of the access arrangement period to mitigate forecast increases in the wholesale gas prices in these years.[42] This means there will be less movement in final retail prices (which reflect the net impact of decreases to distribution tariffs and increases in wholesale gas prices) in keeping with the customer preferences expressed in JGN’s revised proposal.
- Aligns the final year unsmoothed and smoothed revenues, within 10 per cent. All else being equal, this minimises price shocks at the start of the next access arrangement period, an objective endorsed in JGN’s revised proposal as being in customer’s interests.[43]

Our tariff path retains elements of JGN’s proposed tariff path:

- We have had regard to JGN’s submission that smoothing should take into account end consumer impact (retail prices).[44] This aligns with our draft decision position that minimising consumer price shocks is desirable.[45] We acknowledge the uncertainty around forecast wholesale gas prices themselves, and their effect on retail prices.[46] Our final decision price path includes real decreases in the affected years to help mitigate the expected impact of wholesale gas price rises on consumers.[47]
- We have had regard to JGN’s submission that we should allow a greater difference between unsmoothed and smoothed revenue in the final year.[48] In JGN’s revised proposal, smoothed revenue in 2019–20 was 12 per cent below the unsmoothed

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[41] NGL, ss. 23, 24.

[42] We recognise there is uncertainty around the exact timing of these increases, and this is discussed further below.

[43] JGN, *Response to the AER's draft decision and revised proposal*, February 2015, p. 110.

[44] JGN, *Response to the AER's draft decision and revised proposal*, February 2015, pp. 108–110.

[45] AER, *Draft decision, Jemena Gas Networks (NSW) Ltd, Access arrangement 2015–20, Overview*, November 2014, pp. 30–31.

[46] JGN’s revised proposal (and consultation with customers) is predicated on equal wholesale gas price increases in 2016–17, 2017–18 and 2018–19, each directly impacting retail prices in that year. In contrast, JGN’s demand forecast predicts the same total increase and direct effect on retail prices but in just two years, 2016–17 and 2017–18.

[47] One particular point of uncertainty is whether wholesale gas price increases will increase retail prices in 2018–19. Our tariff path still includes a real decrease in distribution tariffs to mitigate such a rise in 2018–19, but the decrease is of smaller magnitude than that in JGN's revised proposal.

[48] JGN, *Response to the AER's draft decision and revised proposal*, February 2015, pp. 108–110.

building block requirement for that year. All else equal, this means tariffs will need to increase at the start of the next access arrangement period. JGN has committed to smoothing this increase across the next access arrangement period,[49] but the magnitude of the required increases is still of concern.[50] On balance, our final decision constrains the difference between unsmoothed and smoothed 2019–20 revenues to be within 10 per cent.[51]

2.5 Indicative impact of distribution charges on annual gas bills

Distribution charges are just one component of the customer's annual gas bill, which also includes wholesale, transmission and retail charges.

To estimate the effect of our final decision on annual gas bills, we begin with the determined weighted average price change (X factors), which provides the indicative change in distribution charges.[52] For customers on JGN's network, distribution charges account for approximately 50 per cent of the annual gas bill.[53] To calculate the impact of our final decision on customers' gas bills we assume that our changes to distribution charges are passed through to customers. In section 1.1, above, we isolated the impact of our final decision by holding all other components of the retail bill constant. Table 1 in that section shows the change in annual gas bills for residential and small business customers in this case.

However, forecast increases in the wholesale gas price are expected to flow through to customer bills during the 2015–20 access arrangement period. We do not regulate wholesale gas prices, and these are also outside JGN's control. Below, we have included JGN's forecast impact of changes in the wholesale price of gas in our modelling of end customer bill impact.[54] While we acknowledge the uncertainty around forecasts of the wholesale gas price, this approach preserves comparability with JGN's revised proposal. The indicative bill impact therefore presents the combined impact of

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49 JGN, *Response to the AER's draft decision and revised proposal*, February 2015, pp. 108–110. Note that the current access arrangement period submission costs are relevant to the comparison, since the following period submission costs will be included in the smoothing for the next period.

50 As a rough indicator, such a difference would require real increases of approximately 7 per cent every year of the next access arrangement period. This would have a larger impact on residential retail prices (approximately 3.5 per cent increases every year for five years) than the expected wholesale gas price increases in the 2015–20 access arrangement period (approximately 3 per cent increases every year for three years). This broad comparison is based on figures from the 2015–20 access arrangement period (particularly the discount rate and rate of change of unsmoothed building blocks).

51 In our draft decision, we constrained this difference to be within 3 per cent.

52 This process is discussed in more detail in AER, *Draft decision, Jemena Gas Networks (NSW) Ltd, Access arrangement 2015–20, Overview,* November 2014, pp. 29–31.

53 IPART, *Changes in regulated retail gas prices from 1 July 2014*, June 2014 p. 17.

54 We have adopted wholesale gas price forecast presented in JGN's revised access arrangement proposal. JGN, *Revised access arrangement proposal*, February 2015, pp. xx–xxi and pp. 107–110. Note that figure OV-2 (on page xxi) shows JGN's forecast wholesale gas prices increasing in 2015–16, 2016–17 and 2017–18. This appears to be in error, as JGN forecasts the increases to occur one year later than this.

forecast changes to the distribution and wholesale components of the bill.[55] We assume that other components of the retail gas bill remain constant.

Table 4 presents the indicative impact of our final decision and potential wholesale gas price increases for residential customer annual gas bills in JGN's distribution area over the 2015–20 access arrangement period.

Table 4 Indicative impact of final decision and potential wholesale gas price increases—residential customers ($nominal)

	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20
JGN revised proposal						
Residential annual gas bill[a]	$1,042	$1,021	$1,021	$1,023	$1,026	$1,044
Annual change in JGN's distribution bill component		–$21	–$30	–$28	–$26	$18
Annual change in wholesale gas price bill component		$0	$30	$30	$30	$0
Total change in residential annual gas bill (distribution and wholesale)		**–$21 (–2.1%)**	**$0 (0.0%)**	**$2 (+0.2%)**	**$3 (+0.3%)**	**$18 (+1.8%)**
AER final decision						
Residential annual gas bill[a]	$1,042	$946	$934	$946	$967	$976
Annual change in JGN's distribution bill component		–$96	–$41	–$18	–$9	$9
Annual change in wholesale gas price bill component		$0	$30	$30	$30	$0
Total change in residential annual gas bill (distribution and wholesale)		**–$96 (–9.2%)**	**–$12 (–1.2%)**	**$12 (+1.3%)**	**$21 (+2.2%)**	**$9 (+0.9%)**

Source: AER analysis; JGN, *Submissions on draft decision, Attachment N - updated appendix 10.1 - JGN revenue forecast model*, 27 March 2015; JGN, *Appendix 03.02 Core Energy models and supporting spreadsheets - revised JGN demand and customer forecast*, February 2015.

a The 2014–15 annual bill was calculated based on IPART, *Fact sheet – Removing carbon costs from regulated gas prices*, 15 August 2014. The 2015–16 to 2019–20 annual bills were calculated from this starting point, applying each year the weighted average price change (CPI–X) to the distribution charge component, and JGN's forecast increase to the wholesale gas price component. All other components of the bill are assumed to be held constant.

55 In our modelling of the indicative retail bill impact we use the information from IPART, *Fact sheet – Removing carbon costs from regulated gas prices*, 15 August 2014 to derive the starting annual bill in 2014–15. We escalated the forecast distribution network bill component based on the weighted average price change using the CPI–X formula each year. We escalated the wholesale gas bill component based on JGN's forecast year-on-year increases in the wholesale gas price. We kept all other components of the retail bill constant.

Table 5 presents the indicative impact of our final decision and potential wholesale gas price increases on small business customer annual gas bills in JGN's distribution area over the 2015–20 access arrangement period.

Table 5 Indicative impact of final decision and potential wholesale gas price increases—small business customers ($nominal)

	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20
JGN revised proposal						
Small business annual gas bill[a]	$5,021	$4,918	$4,987	$5,065	$5,151	$5,240
Annual change in JGN's distribution bill component		–$103	–$143	–$134	–$126	$89
Annual change in wholesale gas price bill component		$0	$212	$212	$212	$0
Total change in small business annual gas bill (distribution and wholesale)		**–$103 (–2.1%)**	**$69 (+1.4%)**	**$78 (+1.6%)**	**$86 (+1.7%)**	**$89 (+1.7%)**
AER final decision						
Small business annual gas bill[a]	$5,021	$4,559	$4,571	$4,698	$4,867	$4,911
Annual change in JGN's distribution bill component		–$462	–$200	–$86	–$44	$44
Annual change in wholesale gas price bill component		$0	$212	$212	$212	$0
Total change in small business annual gas bill (distribution and wholesale)		**–$462 (–9.2%)**	**$12 (+0.3%)**	**$127 (+2.8%)**	**$169 (+3.6%)**	**$44 (+0.9%)**

Source: AER analysis; JGN, *Submissions on draft decision, Attachment N - updated appendix 10.1 - JGN revenue forecast model*, 27 March 2015; JGN, *Appendix 03.02 Core Energy models and supporting spreadsheets - revised JGN demand and customer forecast*, February 2015.

a The 2014–15 annual bill was calculated based on IPART, *Fact sheet – Removing carbon costs from regulated gas prices*, 15 August 2014. The 2015–16 to 2019–20 annual bills were calculated from this starting point, applying each year the weighted average price change (CPI–X) to the distribution charge component, and JGN's forecast increase to the wholesale gas price component. All other components of the bill are assumed to be held constant.

These are high-level indicative estimates only, and the specific impact of our final decision on annual gas bills for different types of customers will vary depending on the reference tariff structure and customer's consumption level. Changes to other components of the annual gas bill will also affect the actual bill outcomes. In particular, the timing and extent of any increase in the wholesale gas price is uncertain, and this may have a substantial impact.

3 Key elements of the building blocks

The components of our decision include the building blocks we use to determine the revenue JGN may recover from its customers.

In setting our overall revenue for JGN of $2248.6 million ($nominal, unsmoothed) for the 2015–20 period we:

- apply relevant tests under the NGR, the assessment methods and tools developed as part of our Better Regulation guidelines[56] (see section 6.1). We also considered information provided by JGN, the Consumer Challenge Panel (CCP), consultants and stakeholder submissions.
- considered our overall revenue decision against section 23 of the NGL, including the constituent decisions and the interrelationships we discussed in sections 1 and 4.

The following section summarises our decision by building block and provides our high level reasons and analysis. The attachments provide a more detailed explanation of our analysis and findings.

3.1 Capital base

The capital base roll forward is the value of JGN's assets that are used to provide gas distribution network services. These assets include pipelines, meters, land, buildings, plant and vehicles. The capital base is the value on which JGN earns a return on capital, representing the return on the funds (capital) invested in the business. The capital base is also the basis for calculating depreciation, which represents the return of capital back to investors over time. As such, the capital base is an important input to the determination of JGN's total revenue.

We are required to make a decision on JGN's:[57]

- opening capital base as at 1 July 2015, which reflects the capital base roll forward over the 2010–15 access arrangement period[58]
- projected capital base over the 2015–20 access arrangement period.

Attachment 2 sets out the detailed reasons for our final decision on JGN's capital base.

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56 http://www.aer.gov.au/Better-regulation

57 NGR, rr. 72, 77, 78 and 90.

58 The term 'roll forward' means the process of carrying over the value of the capital base from one regulatory year to the next. The opening capital base value for a regulatory year within the access arrangement period is rolled forward by indexing it for inflation, adding any conforming capex, and subtracting depreciation and other possible factors (for example, disposals or customer contributions). Following this process, the AER arrives at a closing value of the capital base at the end of the relevant year.

We approve JGN's revised proposed opening capital base of $2980.2 million ($nominal) at 1 July 2015.[59]

Table 6 sets out our final decision on the roll forward of JGN's capital base across the 2010–15 access arrangement period, and shows the derivation of the opening capital base.

Table 6 AER's final decision on JGN's capital base roll forward for the 2010–15 access arrangement period ($million, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Opening capital base	2312.7	2456.6	2611.2	2697.1	2801.5
Net capex at start of year	76.2	82.8	63.5	69.7	123.0
Indexation of assets	63.4	78.8	59.0	75.9	50.2
Net capex at end of year	78.3	85.4	64.9	71.6	125.1
Depreciation	–74.1	–92.4	–101.4	–112.7	–124.0
Closing capital base	**2456.6**	**2611.2**	**2697.0**	**2801.5**	**2975.8**
Adjustment for 2009–10 capex					4.4
Opening capital base at 1 July 2015					**2980.2**

Source: AER analysis; JGN, *Submissions on draft decision, Attachment N - updated appendix 10.1 - JGN revenue forecast model*, 27 March 2015.

We do not approve JGN's revised proposal for its projected capital base across the 2015–20 access arrangement period, and therefore do not approve its revised proposed closing capital base. This is a consequence of our decision not to approve JGN's revised proposed inputs to the projected capital base—forecast net capex and forecast depreciation.[60] Instead, we determine a closing capital base of $3567.6 million ($nominal) as at 30 June 2020. Table 7 shows the derivation of this closing capital base.

59 JGN updated its proposed capital base projection after the submission of its revised proposal. JGN, Submissions on draft decision, *Attachment N - updated appendix 10.1 - JGN revenue forecast model*, 27 March 2015.

60 We approve JGN's proposal to use forecast depreciation to roll forward the capital base across 2015–20 at the next access arrangement decision.

Table 7 AER's final decision on JGN's projected capital base for the 2015–20 access arrangement period ($million, nominal)

	2015–16	2016–17	2017–18	2018–19	2019–20
Opening capital base	2980.2	3133.0	3262.6	3387.8	3481.6
Net capex at start of year	108.3	103.0	107.4	97.1	85.9
Indexation of assets	78.8	82.5	85.9	88.9	91.0
Net capex at end of year	111.1	105.6	110.1	99.6	88.1
Depreciation	–145.4	–161.5	–178.2	–191.8	–179.0
Closing capital base	**3133.0**	**3262.6**	**3387.8**	**3481.6**	**3567.6**

Source: AER analysis.

3.2 Rate of return (return on capital)

The return on capital provides a service provider with revenue to service the interest on its borrowings and give a return on equity to shareholders. The return on capital building block is calculated as a product of the rate of return and the value of the capital base.[61]

The NGR set out that the allowed rate of return must be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the service provider in respect of the provision of gas pipeline services. The NGR refers to this requirement as the allowed rate of return objective.[62]

We have determined an allowed rate of return of 5.41 per cent (nominal vanilla[63]). We have not accepted JGN's proposed 7.06 per cent return in its revised proposal.[64] In accordance with the Guideline, we will update the rate of return annually.[65]

Our rate of return and JGN's proposed rate of return is set out in Table 8.

61 NGR, r. 87(1).

62 NGR, r. 87(3).

63 The nominal vanilla rate of return formula combines a post-tax return on equity and pre-tax return on debt, for consistency with other building blocks.

64 JGN's revised proposal contained indicative values based on an indicative averaging periods for risk free rate and return on debt. On 27 March 2015 JGN provided submissions that updated its approach using values derived from its proposed averaging periods. JGN's proposed rate of 7.06 per cent is from JGN, *Submission on draft decision–Attachment M: updated appendix 7.15–rate of return forecast model*, 27 March 2015.

65 NGR, r. 87(9)(b).

Table 8 AER's final decision on JGN's rate of return (nominal)

	AER previous decision (2010–15)	JGN revised proposal (2015–16)[a]	AER final decision (2015–16)	Return over 2015–20 access arrangement period
Return on equity (nominal post–tax)	11.05%	9.83%	7.1%	Remains constant (7.1%)
Return on debt (nominal pre–tax)	10.02%	5.22%	4.28%	Updated annually
Gearing	60%	60%	60%	Remains constant (60%)
Nominal vanilla WACC	10.43%	7.06%	5.41%	Updated annually as return on debt is updated
Forecast inflation	2.60%	2.50%	2.55%	Remains constant (2.55%)

Source: AER analysis; Jemena Gas Networks, *Access arrangement: JGN's NSW gas distribution networks 1 July 2010–30 June 2015, Amended by order of the Australian Competition Tribunal*, June 2011; JGN, *Submission on draft decision–Attachment M: updated appendix 7.15–rate of return forecast model*, 27 March 2015.

a JGN's revised proposal contained indicative values based on an indicative averaging periods for risk free rate and return on debt. On 27 March 2015, JGN provided submissions that updated its approach using values derived from its proposed averaging periods. JGN's proposed rate of 7.06 per cent is from JGN, *Submission on draft decision–Attachment M: updated appendix 7.15–rate of return forecast model*, 27 March 2015.

Our approach

All NGR requirements relating to the rate of return are subject to the overall rate of return achieving the allowed rate of return objective.[66] The NGR recognise that there are several plausible answers that could achieve the allowed rate of return objective. We agree with stakeholders that predictability of outcomes in rate of return issues would materially benefit the long term interests of consumers.[67]

We developed our approach prior to the submission of this regulatory proposal. As required by the rate of return framework, in December 2013 we published the Guideline.[68] The Guideline was designed through extensive consultation and involved effective and inclusive service provider and consumer participation.[69]

We have considered JGN's departures from the Guideline. However, we are not satisfied that JGN's proposed departures would satisfy, or would better satisfy, the rate of return objective, compared with the approach we proposed in the Guideline.

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66 NGR, r. 87(2).

67 ENA, *Response to the Draft Rate of Return Guideline of the AER*, 11 October 2013, p. 1; AER, *Better regulation: Explanatory statement Rate of Return Guideline, Appendices*, December 2013, Appendix I, Table I.4, pp. 185−186.

68 NGR, r. 87(13).

69 http://www.aer.gov.au/node/18859

Return on debt

Previously, we used an 'on-the-day' approach to determine the return on debt. This is the approach that several Australian regulators continue to use. However, in this decision and consistent with the Guideline, we have decided to gradually transition from the on-the-day approach to the trailing average approach to estimate the return on debt.[70] This is consistent with the approach most stakeholders supported during the Guideline development process.

In its (initial) access arrangement proposal, JGN agreed with our Guideline approach to transition from the on–the–day to trailing average approach. However, in its revised proposal JGN departed from its initial proposal and submitted that we should use a different, hybrid, transition approach. We do not agree with JGN's new position in its revised proposal. Our reasons are set out in attachment 3.

We are satisfied that a gradual, forward looking transition to a trailing average approach results in a return on debt that contributes to the rate of return objective. In particular, this approach takes account of any impacts on a benchmark efficient entity or customers that might arise as a result of changing the methodology that is used to estimate the return on debt. This includes impacts that occur across access arrangement periods. In particular, a gradual, forward looking transition:

- has regard to the impact on a benchmark efficient entity of changing the method for estimating the return on debt
- promotes efficient financing practices consistent with the principles of incentive based regulation
- provides a benchmark efficient entity with a reasonable opportunity to recover at least the efficient financing costs it incurs in financing its assets. And as a result it:
    - promotes efficient investment, and
    - promotes consumers not paying more than necessary for a safe and reliable network
- avoids a potential bias in regulatory decision making that can arise from choosing an approach that uses historical data after the results of that historical data are already known
- avoids practical problems with the use of historical data as estimating the return on debt during the global financial crisis is a difficult and contentious exercise.

70 The 'on-the-day' approach estimates the allowed return on debt based on prevailing interest rates at the start of the access arrangement period. At the next access arrangement decision, the allowed return on debt is reset based on prevailing interest rates at the start of the new access arrangement period. The 'trailing average' approach estimates the allowed return on debt based on interest rates averaged over a moving historical period. Each year, prevailing interest rates from each new year are added to the trailing average, and interest rates from the last year of the trailing average 'fall out' of the trailing average.

Return on equity

We consider that the Sharpe–Lintner Capital Asset Pricing Model (SLCAPM) is the superior financial model in terms of estimating expected equity returns. We have therefore adopted this model as our foundation model. The expert evidence before us also indicates that, on balance, employing our foundation model approach and using the SLCAPM as the foundation model is expected to lead to a rate of return that achieves the allowed rate of return objective.[71] JGN proposed a weighted average of four models — SLCAPM, Black CAPM, Fama French Model (FFM), and Dividend Growth Model (DGM). Our view is that the returns on equity ranges derived from these models do not necessarily assist us to perform our task.

We also evaluated our point estimate from the SLCAPM against other information. The critical allowance for an equity investor in a benchmark efficient entity is the allowed equity risk premium (ERP) over and above the estimated risk free rate at any given time.[72] Our estimate of the ERP for the benchmark efficient entity is 4.55 per cent which is within the range of other information available to inform the return on equity (see Figure 7). A detailed explanation of our findings on return on equity and this figure can be found attachment 3.

Our approach to determining the return on equity involves considering all of the information before us, through a six step process as set out in the Guideline (foundation model approach). This includes detailed consideration of a number of financial models for determining the return on equity.[73] Considering all of this material helps inform a return on equity estimate that contributes to the achievement of the allowed rate of return objective.

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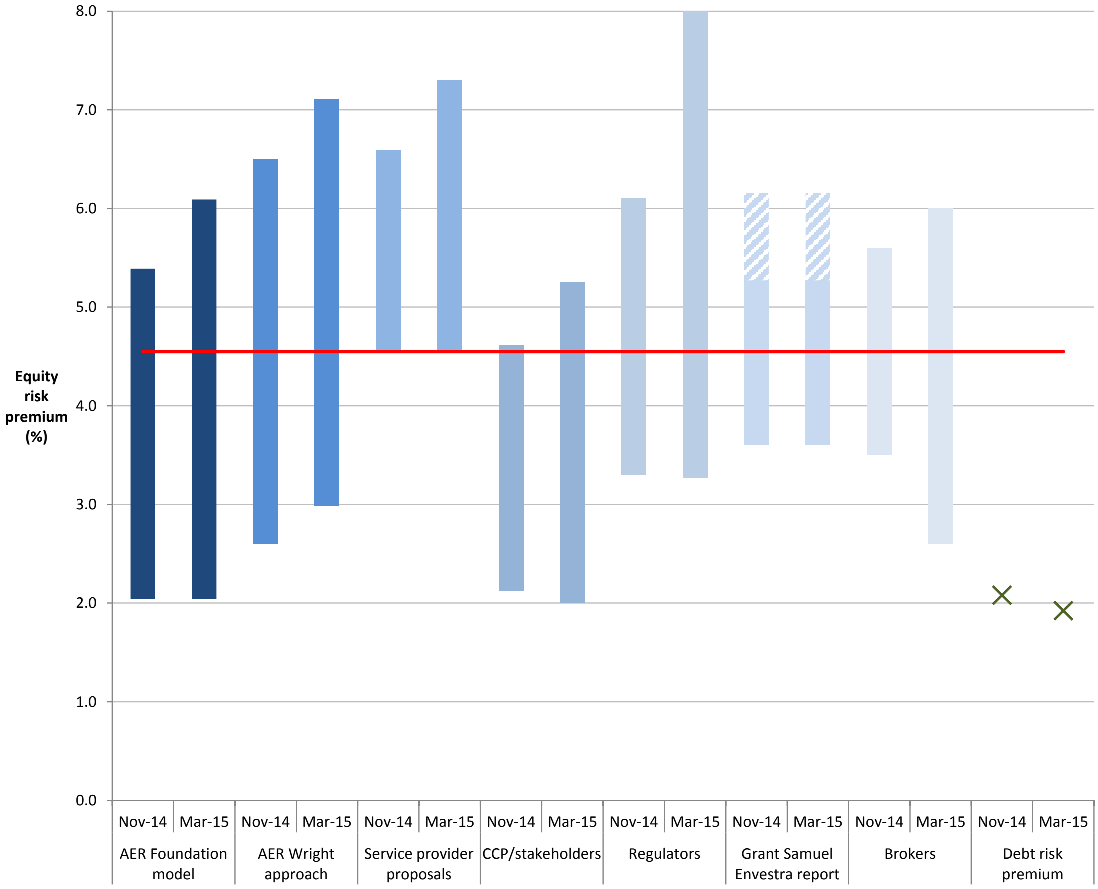
71 McKenzie & Partington, *Part A: Return on equity, Report to the AER*, October 2014, p. 13; John Handley, *Advice on return on equity, Report prepared for the AER*, October 2014, p. 3.

72 Our task is to determine the efficient financing costs commensurate with the risk of providing regulated network service by an efficient benchmark entity (allowed rate of return objective). Risks in this context are those which are compensated via the return on equity (systematic risks).

73 NGR, r. 87(5)(a).

Figure 7 Other information comparisons with the AER allowed ERP



Source: AER analysis and various submissions and reports.

Notes: The AER foundation model ERP range uses the range and point estimate for MRP and equity beta as set out in step three. The calculation of the Wright approach, debt premium, brokers, and other regulators ranges is outlined in the appendices to Attachment 3 (Appendices E.1, E.2, E.4, and E.5 respectively).

Grant Samuel's final WACC range included an uplift above an initial SLCAPM range. The lower bound of the Grant Samuel range shown above excludes the uplift while the upper bound includes the uplift and is on the basis that it is an uplift to return on equity. Grant Samuel did not make an explicit allowance for the impact of Australia's dividend imputation system. We are uncertain as to the extent of any dividend imputation adjustment that should be applied to estimates from other market practitioners. Accordingly, the upper bound of the range shown above includes an adjustment for dividend imputation, while the lower bound does not. The upper shaded portion of the range includes the entirety of the uplift on return on equity and a full dividend imputation adjustment.[74]

The service provider proposals range is based on the proposals from businesses for which we are making final or preliminary decisions in April–June 2015.[75] Equity risk premiums were calculated as the proposed return on equity less the risk free rate utilised in the service provider's proposed estimation approach.

The CCP/stakeholder range is based on submissions made (not including service providers) in relation to our final or preliminary decisions in April–June 2015. The lower bound is based on the Energy Users

[74] Grant Samuel, *Envestra: Financial services guide and independent expert's report*, March 2014, Appendix 3.

[75] ActewAGL, Ausgrid, Directlink, Endeavour Energy, Energex, Ergon Energy, Essential Energy, Jemena Gas Networks, SA Power Networks, TasNetworks, and TransGrid.

Association of Australia submission on NSW distributors' revised proposals. The upper bound is based on Origin's submission on ActewAGL's proposal.[76]

3.3 Value of imputation credits (gamma)

Under the Australian imputation tax system, investors can receive an imputation credit for income tax paid at the company level.[77] These are received after company income tax is paid, but before personal income tax is paid. For eligible investors, this credit offsets their Australian income tax liabilities. If the amount of imputation credits received exceeds an investor's tax liability, that investor can receive a cash refund for the balance. Imputation credits are therefore a benefit to investors in addition to any cash dividend or capital gains they receive from owning shares.

In determining a service provider's revenue allowance, the NGR requires that the estimated cost of corporate income tax be estimated in accordance with a formula that reduces the estimated cost by the 'value of imputation credits'.[78] That is, the revenue allowance granted to a service provider to cover its expected tax liability must be reduced in a manner consistent with the value of imputation credits.

We do not accept JGN's proposed value of imputation credits of 0.25. Instead, we adopt a value of imputation credits of 0.4.

Although we have broadly maintained the approach to determining the value of imputation credits set out in the Rate of Return Guideline, we have re-examined the relevant evidence and estimates. This re-examination, and new advice and evidence considered for the first time since the Guideline, led us to depart from the value of 0.5 in the Guideline. Most notably, our updated consideration of the relevant advice and evidence led us to generally lower estimates of the 'utilisation rate' from the 0.7 estimate in the Guideline. Estimating the value of imputation credits is a complex and imprecise task. There is no consensus among experts on the appropriate value or estimation techniques to use.

Consistent with the relevant academic literature, we estimate the value of imputation credits as the product of the distribution rate and the utilisation rate. While there is a widely accepted approach to estimating the distribution rate, there is no single accepted approach to estimating the utilisation rate and there is a range of evidence relevant to the utilisation rate. This includes:

- The proportion of Australian equity held by domestic investors (the 'equity ownership approach').

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[76] Energy Users Association of Australia, *Submission to NSW DNSP Revised Revenue Proposal to AER Draft Determination (2014 to 2019)*, February 2015, pp. 15–16; Origin Energy, *Submission to ActewAGL's regulatory proposal for 2014–19*, August 2014, p. 4.

[77] *Income Tax Assessment Act 1997*, parts 3–6.

[78] NGR, rr 76(c) and 87A.

- The reported value of credits utilised by investors in Australian Taxation Office (ATO) statistics ('tax statistics').
- Implied market value studies—there is no separate market in which imputation credits are traded, and therefore there is no observable market price for imputation credits.

In estimating the utilisation rate, we place:

- significant reliance upon the equity ownership approach
- some reliance upon tax statistics, and
- less reliance upon implied market value studies.

Overall, the evidence on the distribution rate and the utilisation rate suggests that a reasonable estimate of the value of imputation credits is within the range 0.3 to 0.5. From within this range, we choose a value of 0.4. This is because:

- The equity ownership approach, on which we have placed the most reliance, suggests a value between 0.40 and 0.47 when applied to all equity and between 0.29 and 0.42 when applied to only listed equity. Therefore, the overlap of the evidence from the equity ownership approach suggests a value between 0.40 and 0.42.
- The evidence from tax statistics suggests the value could be lower than 0.4. Therefore, with regard to this evidence and the less reliance we place on it, we choose a value at the lower end of the range suggested by the overlap of evidence from the equity ownership approach (that is, 0.4).
- An estimate of 0.4 is reasonable in light of both higher and lower estimates from implied market value studies and the lesser degree of reliance we place on these studies. The service providers submitted evidence to support placing more reliance on SFG’s dividend drop off study relative to other implied market value studies. However, we consider that neither the difference from 0.4 of the estimate from this study (0.31) nor any increased reliance we might place on it relative to other implied market value studies are sufficient to warrant an estimate lower than 0.4.

3.4 Regulatory depreciation (return of capital)

We use regulatory depreciation to model the nominal asset values over the 2015–20 access arrangement period and set the depreciation building block as part of calculating the total revenue for JGN. The regulatory depreciation allowance is the net total of the real straight-line depreciation (negative) and the annual inflation indexation (positive) on the projected capital base.

We are required to make a decision on JGN's proposed:[79]

[79] NGR, rr. 59, 72, 76, 88, 89.

- depreciation on the projected capital base
- depreciation schedule, which sets out the basis on which the depreciation is calculated.

We do not approve JGN's revised proposed regulatory depreciation of $434.4 million ($nominal). Our final decision is to determine an amount of $428.9 million ($nominal) over the 2015–20 access arrangement period, as set out in Table 9. This is $5.5 million ($nominal) less than JGN's revised proposal. This is because of our final decision on forecast capex (section 3.5), which is lower than JGN's revised proposal, and affects the regulatory depreciation allowance.

Table 9 AER's final decision on JGN's regulatory depreciation allowance for the 2015–20 access arrangement period ($million, nominal)

	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Straight-line depreciation	145.4	161.5	178.2	191.8	179.0	855.9
Less: indexation on opening capital base and capex at the first half of the regulatory year	78.8	82.5	85.9	88.9	91.0	427.0
Regulatory depreciation	**66.6**	**79.0**	**92.2**	**103.0**	**88.1**	**428.9**

Source: AER analysis.

The detailed reasons for our final decision on JGN's annual regulatory depreciation allowance and depreciation schedule (including the calculation of standard asset lives and remaining asset lives) are set out in attachment 5.

3.5 Capital expenditure (capex)

Capex refers to the capital expenses incurred in the provision of pipeline services. The return on and of forecast capex are two of the building blocks we use to determine a service provider's total revenue requirement.

Our final decision allows forecast net capex of $957.2 million ($2014–15). This is 14.4 per cent less than JGN's forecast net capex of $1,118.3 million ($2014–15), set out in Table 10.

Table 10 AER's final decision on total net capex for 2015-20 ($ million 2014-15)

	2015-16	2016-17	2017-18	2018-19	2019-20	Total
JGN revised proposal	243.8	230.2	237.5	219.0	187.9	1,118.3
AER final decision	216.6	200.8	204.2	180.1	155.4	957.2
Difference	-27.2	-29.4	-33.3	-38.9	-32.5	-161.1
% difference	-11.2%	-10.5%	-12.8%	-17.82%	-17.3%	-14.45%

Source: AER analysis

We tested JGN's proposed forecast capex taking into account the best available evidence. We have accepted the majority of expenditure proposed but consider that JGN has overstated the replacement requirements for some projects and we have adjusted the expenditure for these in order to reflect efficient costs to achieve the lowest sustainable cost of providing the service.

The outcomes of our assessment revealed that some aspects of JGN's proposal such as expenditure for mains and service renewal, mine subsidence and SCADA, were consistent with the NGR requirements in that the proposed expenditure is justified and 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.

We found that other aspects of JGN's proposal, in particular the level of overheads, connections and some projects and programs associated with facilities renewal and upgrade respectively, did not meet the NGR requirements because they were not based on the best estimate in the circumstances and/or revealed inefficiency inconsistent with the NGR requirements. The key differences between our final decision and JGN's revised proposal are summarised below:

- We have included \$285.6 million (\$2015, unescalated direct costs, excluding overheads) for Connections/Market expansion in our alternative capex estimate, compared to JGN's proposed \$368.0 million. This is a 22.4 per cent reduction in JGN's proposed amount.
- We have included \$115.2 million (\$2015, unescalated direct costs, excluding overheads) in our alternative capex estimate for overheads. JGN proposed \$125.7 million. This is a 8.3 per cent reduction.
- We have included \$95.2 million (\$2015, unescalated direct costs, excluding overheads) in our alternative capex estimate for facilities renewal and upgrade. JGN proposed \$106.6 million (\$2015, unescalated direct costs, excluding overheads). This is a 10.7 per cent reduction.
- We have substituted our estimate of the labour and material escalation in place of that proposed by JGN.

The detailed reasons for our final decision on JGN's proposed capex are set out in attachment 6.

3.6 Operating expenditure (opex)

Forecast opex is the forecast operating, maintenance and other non-capital costs incurred in the provision of distribution network services. It includes labour costs and other non-capital costs that a prudent service provider is likely to require during the 2015–20 access arrangement period for the efficient operation of its network.

We are not satisfied that the forecast of total opex that JGN proposed complies with the applicable requirements of, and is consistent with the applicable criteria in, the NGL and NGR.[80] We therefore do not approve the forecast opex JGN included in its revised building block proposal.

Our alternative estimate of opex (excluding debt raising costs) is $8.2 million lower than JGN's forecast over the 2015–20 access arrangement period. This is due the following factors:

- we have forecast lower input price growth than JGN over the 2015–20 access arrangement period
- we have not included a step change in opex for JGN's proposed asbestos meter cover removal program. We consider that this program can be funded without a step change.

Our final decision on JGN's forecast opex is set out in Table 11.

Table 11 AER's final decision on total opex—JGN ($ million, 2014–15)

	2015–16	2016–17	2017–18	2018–19	2019–20	Total
JGN's initial proposal	156.7	156.8	158.2	163.0	162.7	797.5
AER draft decision	154.4	153.8	154.6	159.0	157.8	779.7
Update to JGN's revised proposal[81]	158.0	159.9	160.4	165.3	164.8	808.2
AER final decision	157.1	158.0	158.9	163.5	162.7	800.0

Source: AER analysis.

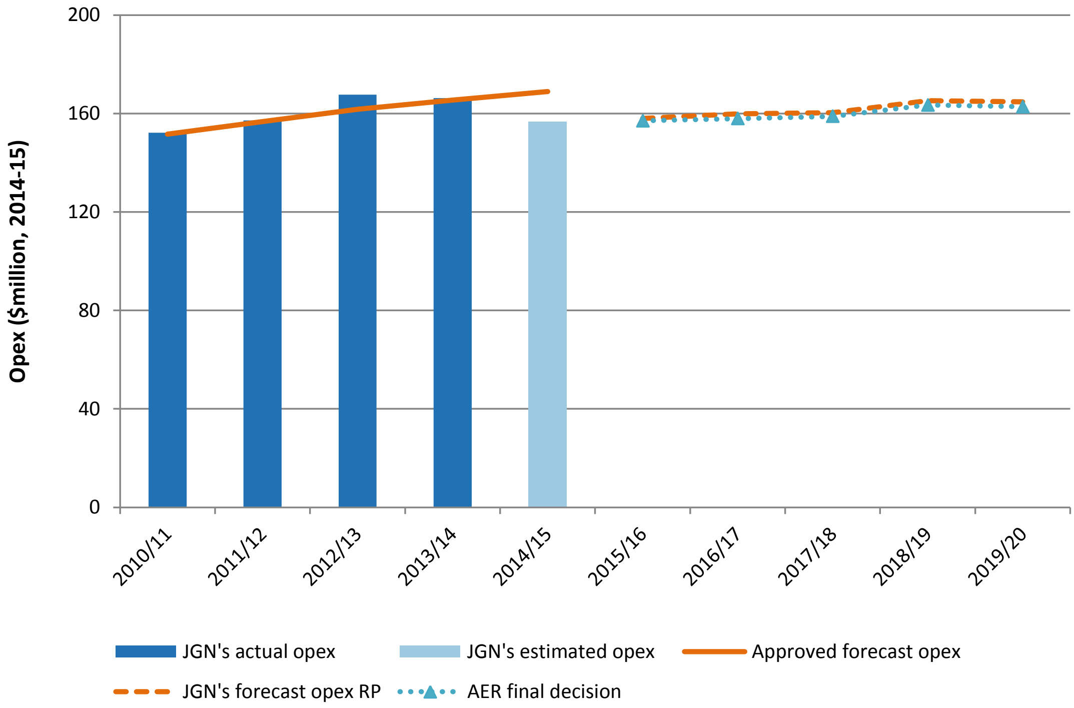
Note: Excludes debt raising costs.

Figure 8 shows our final decision compared to JGN's proposal, its past allowances and past actual expenditure.

[80] NGR, rr. 40(2), 91.

[81] In its revised proposal, JGN proposed total opex of $805.0 million ($2014-15). After submitting its revised proposal it updated its estimate to $808.2 million.

Figure 8 Our final decision compared to Jemena Gas Networks' past and proposed opex ($ million, 2014–15)



Source: AER analysis.

Our final decision on JGN's operating expenditure is set out in attachment 7.

3.7 Corporate income tax

When determining the total revenue for JGN, we must estimate JGN’s cost of corporate income tax.[82] JGN has adopted the post-tax framework to derive its revenue requirement for the 2015–20 access arrangement period.[83] Under the post-tax framework, a separate corporate income tax allowance is calculated as part of the building blocks assessment.

We do not approve JGN’s revised proposed corporate income tax allowance of $105.9 million ($nominal). Our final decision is to determine an amount of $42.4 million ($nominal) as shown in Table 12, which is $63.5 million ($nominal) less than JGN's revised proposal.[84] This is mainly a consequence of our adjustments to JGN's proposed value of imputation credits—gamma—(section 3.3) and other building block

[82] NGR, r. 76(c).

[83] JGN, *Revised access arrangement proposal, Appendix 10.1 - Revenue model - updated*, February 2015.

[84] JGN updated its proposed cost of corporate income tax after the submission of its revised proposal. JGN, *Submissions on draft decision, Attachment N - updated appendix 10.1 - JGN revenue forecast model*, 27 March 2015.

costs that affect revenues, such as the rate of return on capital (section 3.2), forecast capex (section 3.5) and forecast opex (section 3.6). All these components affect the calculation of the corporate income tax allowance.

Table 12 AER's final decision on JGN's corporate income tax allowance for the 2015–20 access arrangement period ($million, nominal)

	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Tax payable	9.7	11.6	15.2	19.0	15.2	70.6
Less: value of imputation credits	3.9	4.6	6.1	7.6	6.1	28.2
Net corporate income tax allowance	5.8	6.9	9.1	11.4	9.1	42.4

Source: AER analysis.

Attachment 8 sets out the detailed reasons for our final decision on JGN's estimated cost of corporate income tax.

4 Other components of this decision

4.1 Demand

We do not approve the proposed demand forecasts set out in JGN's revised proposal as we are not satisfied that they comply with rule 74(2) of the NGR. JGN relied upon forecasts prepared by Core Energy. JGN also engaged HoustonKemp and Frontier Economics to review Deloitte Access Economics' (DAE) (our consultant's) methodology and forecasts for tariff V customers.[85]

Based on information provided in JGN's revised proposal and advice from DAE, we now accept some assumptions used by Core Energy (submitted in JGN's initial proposal and submitted again in its revised proposal) to estimate JGN's demand forecasts for the 2015−20 period. In particular, we have accepted, in forecasting consumption per customer, the application of a time series (or linear trend) approach as a starting point to estimate consumption per customer. In our draft decision, we considered that a structural approach (or an econometrics approach) would result in a better estimate of forecast demand.[86] In light of this, the remaining issue we have with JGN's forecast demand relates to an adjustment to the linear trend to take account of exogenous factors (post-model adjustment).

As we do not agree with all of the post-model adjustments made by JGN, we do not consider that JGN's forecasts of consumption per customer are the best estimates possible in the circumstances. Our post-model adjustment results in increases to annual consumption per customer, from JGN's revised proposal of:

- up to 2.6 per cent for residential customers
- up to 3.7 per cent for small business customers
- up to 2.2 per cent for tariff V industrial and commercial (I&C) customers.

We also do not agree with JGN's forecast small business connections as we agree with DAE that JGN's forecast is high when compared to their historical levels. We also consider that Core Energy's assumption that over the access arrangement period, 48.8 per cent of new dwellings will be new estate connections and 51.2 per cent will be medium/high density connections was not arrived at on a reasonable basis. We agree with DAE that a 45 and 55 per cent allocation respectively for new estate and medium/high density connections respectively produces a better estimate in the circumstances. [87]

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[85] HoustonKemp, *Review of Gas Consumption Forecasting Methodology*, February 2015; Frontier Economics, *Gas Consumption forecasts for JGN's Tariff V customers*, February 2015.

[86] AER, Draft Decision, Jemena Gas Networks (NSW) Ltd, Access arrangement 2015-2020, Attachment 13 - Demand, p. 13-12 – 13-13.

[87] Deloitte Access Economics, Gas demand forecast for Jemena Gas Network NSW, 15 May 2015, p25-6.

As in our draft decision, we accept JGN's Tariff D connections forecast. [88]

The reasons for our final decision are set out in attachment 13.

4.2 Efficiency carryover mechanism

Incentive schemes are a component of incentive-based regulation and complement our approach to assessing efficient costs.

Our final decision is to approve the application of an efficiency carryover mechanism to JGN in the 2015–20 access arrangement period. The mechanism we will apply is consistent with the Efficiency Benefit Sharing Scheme (EBSS) we apply to electricity service providers.

In applying the efficiency carryover mechanism to JGN in the 2015–20 access arrangement period we will:

- exclude unaccounted for gas (UAG) costs, licence fee costs, carbon costs, the cost of any relevant tax change and debt raising costs. Consistent with the electricity network EBSS we will also maintain discretion to exclude cost categories that are not forecast using a single year revealed cost approach in the access arrangement period commencing in 2020.[89]
- adjust JGN's opex forecast to account for determined pass through amounts, and
- adjust JGN's opex forecast to account for any capitalisation policy changes.

The reasons for our final decision are set out in attachment 9.

4.3 Services covered by the access arrangement

Our draft decision approved JGN's proposed Haulage Reference Service. JGN accepted our draft decision on the services to be covered by this access arrangement and did not propose any further amendments, so we approve JGN's services covered by the access arrangement as presented in its revised proposal.

The reasons for our final decision are set out in attachment 1.

4.4 Reference tariff setting

We accept the proposed structure of JGN's reference tariffs as set out in its revised proposals, but consider that the 2015–20 access arrangement should be amended in order to comply with the NSW Retail Market Procedures.[90]

The reasons for our final decision are set out in attachment 10.

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88 AER, D*raft Decision, Jemena Gas Networks (NSW) Ltd, Access arrangement 2015-2020, Attachment 13 - Demand*, p. 13-17-8.

89 AER, *Efficiency benefit sharing scheme for electricity network service providers*, November 2013, p. 7.

90 NGR, rr. 93 and 94.

4.5 Reference tariff variation mechanism

We have approved most of JGN's proposed reference tariff variation mechanism, except for:

- JGN's proposed initial reference tariffs and X factors, which must be revised to reflect the changes to the forecast total revenue requirement identified in section 2 of this overview.
- JGN's proposed cost pass through events. We have substituted our preferred definitions of the following events for those proposed by JGN:
    - Service standard event
    - Regulatory change event
    - Terrorism event
    - Natural disaster event
    - Insurance cap event
    - Insurer's credit risk event
    - Network user failure event
- We have rejected JGN's proposed gas supply shortfall event and its proposed materiality threshold.

The reasons for our final decision are set out in attachment 11.

4.6 Non-tariff components

JGN’s Reference Service Agreement (RSA) forms part of its 2015–20 access arrangement proposal. The RSA sets out terms and conditions upon which JGN offers to supply the Haulage Reference Service. These are not directly related to the nature or level of tariffs that users pay. JGN's access arrangement also contains additional terms and conditions governing the relationship between JGN and users. Together we refer to these as the non-tariff components of the access arrangement.

JGN's revised proposal accepted many of the revisions to non-tariff components set out in our draft decision. Where it did not do so, it proposed alternative revisions to address our concerns. Our final decision adopts most of JGN’s revised proposal. However, we have made revisions to clarify mechanisms for the user and JGN to raise revisions to the RSA during the access arrangement period, for example in response to changes in JGN’s regulatory obligations. We have also made a small number of revisions to improve the clarity of the terms and conditions on which the reference service will be provided.

The reasons for our final decision are set out in attachment 12.

5 Regulatory framework

The NGL and the NGR provide the regulatory framework under which we operate. These set out how we must assess proposed access arrangement revisions and make our decision. In this section we set out some key aspects of this framework.

The NGO is the central feature of the regulatory framework. The NGO is to promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas. [91]

The NGL also includes the revenue and pricing principles (RPP), which support the NGO.[92] As the NGL requires,[93] we have taken the RPPs into account throughout our analysis. The RPPs are:

> A service provider should be provided with a reasonable opportunity to recover at least the efficient costs the service provider incurs in—
>
> - providing reference services; and
> - complying with a regulatory obligation or requirement or making a regulatory payment.
>
> A service provider should be provided with effective incentives in order to promote economic efficiency with respect to reference services the service provider provides. The economic efficiency that should be promoted includes—
>
> - efficient investment in, or in connection with, a pipeline with which the service provider provides reference services; and
> - the efficient provision of pipeline services; and
> - the efficient use of the pipeline.
>
> Regard should be had to the capital base with respect to a pipeline adopted—
>
> - in any previous—
>   - full access arrangement; or
>   - decision of a relevant regulator under section 2 of the Gas Code; or
> - in the Rules.

91 NGL, s. 23.

92 NGL, s. 24.

93 NGL, s. 28(2).

> A reference tariff should allow for a return commensurate with the regulatory and commercial risks involved in providing the reference service to which that tariff relates.
>
> Regard should be had to the economic costs and risks of the potential for under and over investment by a service provider in a pipeline with which the service provider provides pipeline services.
>
> Regard should be had to the economic costs and risks of the potential for under and over utilisation of a pipeline with which a service provider provides pipeline services.

Consistent with Energy Ministers' views, we set the amount of revenue that service providers can recover from customers to balance all of the elements of the NGO, and consider each of the RPPs are equally vital.[94]

Part 9 of the NGR provides specifically for the economic regulation of covered pipelines. It includes detailed rules about the individual components of our decisions. These are intended to contribute to the achievement of the NGO. The AEMC has made clear that, in relation to key aspects of revenue, the rules guide the AER. These rules do not dictate any specific regulatory outcome.[95] For example, the AEMC has said:

> Some stakeholders appear to have understood the objectives as imposing on the regulator a requirement and that failure to comply with this would mean the regulator is in breach of the rules. This is not the case. Although the language of an obligation is used in some objectives, it is not necessarily expected that the substance of the objective will always be fully achieved, but rather the regulator should be striving to achieve the objective as fully as possible.

Given this framework, we consider the NGO and how to achieve it throughout our decision making processes.

5.1 Understanding the NGO

Energy Ministers have provided us with a substantial body of explanatory material that guides our understanding of the NGO.[96] The long term interests of consumers are not

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[94] Hansard, SA House of Assembly, 27 September 2007 pp. 965, Hansard, SA House of Assembly, 9 April 2008 p. 2886, Hansard, SA House of Assembly, 26 September 2013, p. 7173.

[95] AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18,* pp. 33–34
AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012,* pp. 35–36.

[96] Hansard, SA House of Assembly, 9 February 2005 pp. 1451–1460.
Hansard, SA House of Assembly, 27 September 2007 pp. 963–972.
Hansard, SA House of Assembly, 9 April 2008 pp. 2884-2916
Hansard, SA House of Assembly, 26 September 2013 pp. 7171–7176.

delivered by any one of the NGO's factors in isolation, but rather by balancing them in reaching a regulatory decision.[97]

In general, we consider that we will achieve this balance and, therefore, contribute to the achievement of the NGO, where consumers are provided a reasonable level of safe and reliable service that they value, at least cost in the long run.[98] In most industries, competition creates this outcome. Competition drives suppliers to develop their offerings to attract customers. Where a supplier's offering is not attractive it risks being displaced by other suppliers.

However, in the energy networks industry the usual competitive disciplines do not apply. While often referred to as 'a fuel of choice', gas distributors are largely natural monopolies. In addition, many of the products they offer support essential services for customers connected to the gas network. PIAC in its submission on our draft decision for JGN comments that many low income and vulnerable consumers have no choice about whether to use gas.[99] Consequently, in an uncompetitive environment, those customers have little choice but to accept the quality, reliability and price the service providers offer.

The NGL and NGR aim to remedy the absence of competition by providing that we, as regulator, make decisions that are in the long term interests of consumers. In particular, we might need to require the service providers to offer their services at a different price than they would choose themselves. By its nature, this process will involve exercising regulatory judgement to balance the NGO's various factors.

It is important to recognise that there are a number of plausible outcomes that may contribute to the achievement of the NGO. The nature of decisions under the NGR is such that there may be a range of economically efficient decisions, with different implications for the long term interests of consumers.[100] At the same time, however, there are a range of outcomes that are unlikely to advance the NGO to a satisfactory extent. For example, we do not consider that the NGO would be advanced if allowed revenues encourage overinvestment and result in prices so high that consumers are unwilling or unable to efficiently use the network.[101] This could have significant longer term pricing implications for those consumers who continue to use network services. Equally, we do not consider the NGO would be advanced if allowed revenues result in prices so low that investors are unwilling to invest as required to adequately maintain the appropriate quality and level of service, and where customers are making more use

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[97] Hansard, SA House of Assembly, 26 September 2013 p. 7173.

[98] Hansard, SA House of Assembly, 9 February 2005 p. 1452, Hansard, SA House of Assembly, 9 April 2008 p. 2884.

[99] PIAC, *This is how we do this now: PIAC submission to the AER's draft determination for Jemena Gas Network*, 27 March 2015.

[100] *Re Michael: Ex parte Epic Energy* [2002] WASCA 231 at [143].
Energy Ministers also accept this view – see Hansard, SA House of Assembly, 26 September 2013 p. 7172.
AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18,* p. 50.

[101] NGL, s. 24(7).

of the network than is sustainable. This could create longer term problems in the network[102] and could have adverse consequences for safety, security and reliability of the network.

5.2 The 2012 framework changes

This is the first Access Arrangement we have made following changes to the NGL and NGR in 2012 and 2013. The NGL and NGR were amended, in areas such as rate of return, to provide greater emphasis on the NGO and greater discretion to us.[103] The NGR allow, and the AEMC has encouraged, us to approach decision making more holistically to meet overall objectives consistent with the NGO and RPPs.[104] Also, one of the purposes of these changes was to give consumers a clearer and more prominent role in the decision making process.[105]

In 2013, the NGL was changed with similar aims in mind. The long term interests of consumers are a key focus of the changes.[106] The changes also support analysing the decision *as a whole* in light of the NGO.[107] The NGL now requires us to specify how the constituent components of our decision relate to each other and how we have taken those interrelationships into account in making our decision.[108] It also anticipates the possibility of two or more decisions that will or are likely to contribute to the achievement of the NGO. It requires that, in those cases, we must make the decision we are satisfied will or is likely to contribute to the achievement of the NGO to the greatest degree.[109] The NGR requires that we provide reasons for our decisions.[110]

The NGL does not prescribe how we are to apply these overarching requirements and so in applying them, we have exercised our regulatory judgement.

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[102] NGL, s. 24(6).

[103] NGL, ss. 28(1)(b)(iii), 259(4a)(c).
AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012,* pp. i, iii, iv, vi, vii, 8, 24 32, 36, 38, 45, 49, 67, 68, 90, 96 106, 112 and 113.
Hansard, SA House of Assembly, 26 September 2013 p. 7172.

[104] AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012,* pp. xi, 10, 19, 32 and 35.

[105] AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012,* esp. pp. 166–170.

[106] Hansard, SA House of Assembly, 26 September 2013 p. 7171.

[107] NGL, ss. 28, 244, 259 which focus the AER's decision making and merits review at the overall decision, rather than its constituent components.
Hansard, SA House of Assembly, 26 September 2013 pp. 7171 and 7173; See also NEL, ss. 2, 16 and 71A which focus the AER's decision making and merits review at the overall decision, rather than its constituent components.
SCER, *Regulation Impact Statement – Limited Merits Review of Decision-Making in the Electricity and Gas Regulatory Frameworks'* 6 June 2013 pp. i, ii, 6–7, 10, 36, 41 and 76.

[108] NGL, s. 28(1)(b)(ii).

[109] NGL, s. 28(1)(b)(iii).

[110] NGR, r. 62(4).

We have done so by determining revenue in accordance with the detailed provisions in the NGR. This assessment is in each of our Attachments. As part of that assessment, and in accordance with the NGL requirements, we identify and assess the interrelationships between the constituent components of our final decision. In the following sections, we explain our approach to evaluating these interrelationships and then set out how we assessed what will contribute to the achievement of the NGO to the greatest degree. Section 1 of this overview demonstrates how we have applied these approaches for this decision.

5.2.1 Interrelationships

An access arrangement decision is complex and must be considered as such. Considering individual components in isolation ignores the importance of interrelationships between the components and would not contribute to the achievement of the NGO. As outlined by Energy Ministers, considering the elements in isolation has resulted in regulatory failures in the past.[111] Interrelationships can take various forms, including:

- underlying drivers and context which are likely to affect many constituent components of our decision. For example, forecast demand affects the efficient levels of capex and opex in the access arrangement period and it also affects how overall revenue is translated into individual prices (see attachment 6, 7 and 13).
- direct mathematical links between different components of a decision. For example, the value of imputation credits (gamma) has an impact on the appropriate tax allowance; the benchmark efficient entity's debt to equity ratio has a direct effect on the cost of equity, the cost of debt, and the overall vanilla rate of return (see attachments 3, 4 and 8).
- trade-offs between different components of revenue. For example, undertaking a particular capex project may affect the need for opex and vice versa (see attachments 6 and 7).
- trade-offs between forecast and actual regulatory measures. The reasons for one part of a proposal may have impacts on other parts of a proposal. For example, an increase in augmentation to the network means the service provider has more assets to maintain leading to higher opex requirements (see attachments 6 and 7).
- the service provider's approach to managing its network. The service provider's governance arrangements and its approach to risk management will influence most aspects of the proposal, including capex/opex trade-offs (see attachments 6 and 7).

111 SCER, *Regulation Impact Statement: Limited Merits Review of Decision-Making in the Electricity and Gas Regulatory Frameworks – Decision Paper*, 6 June 2013 p. 6.

We have considered these types of interrelationships in our analysis of the constituent components of our decision. These considerations are explored in the relevant attachments.

6 Process

The NGL requires us to inform stakeholders of the material issues we are considering and to give them a reasonable opportunity to make submissions in respect of this decision.[112]

Below we set out the process we have followed leading up to the submission of JGN's proposal, to ensure that we have fully taken into account all views.

6.1 Better Regulation program

Following the 2012 changes to the NER and NGR, we spent much of 2013 consulting on and refining our assessment methods and approaches to decision making. We referred to this as our Better Regulation program. The objective of this program was to refine our approaches, with a greater emphasis on incentive regulation.[113] The Better Regulation program was designed to be an inclusive process that provided an opportunity for all stakeholders to be engaged and provide their input.[114]

The resulting guidelines support our decision making framework as set out in section 28 of the NGL. Our consultation and engagement gives us confidence the approaches set out in the Guidelines, which we have applied in this decision, will result in decisions that will or are likely to contribute to the achievement of the NGO. Our Better Regulation Guidelines are available on our website and include:[115]

- Expenditure Forecast Assessment Guideline
- Expenditure Incentives Guideline
- Rate of Return Guideline
- Consumer Engagement Guideline for Network Service Providers
- Shared Assets Guideline
- Confidentiality Guideline.

We acknowledge that the changes to the NGR were more limited than those to the National Electricity Rules. However, many of the concepts and analytical tools are the same and we involved gas service providers in consultation on all aspects of the Better Regulation program.

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112 NGL, s. 28(1)(b)(j)

113 AER, *Overview of the Better Regulation reform package*, April 2014, pp. 4 and 7–13.

114 AER, *Overview of the Better Regulation reform package*, April 2014, pp. 4 and 7–13.

115 http://www.aer.gov.au/Better-regulation-reform-program

6.2 Our engagement during the decision making process

Effective consultation with stakeholders is essential to the performance of our regulatory functions. In summary, throughout the review process, we engaged with stakeholders by:

- considering stakeholder submissions on JGN's initial access arrangements
- having JGN present its access arrangement to the AER Board in August 2014, so questions could be raised and key issues explained
- having the CCP present its advice in response to JGN's access arrangement to the AER Board in August 2014
- publishing our draft decision for consultation on 27 November 2014, and hosting a public forum in Sydney on 8 December 2014 so stakeholders could question the AER and JGN on our draft decision
- considering JGN's revised access arrangement and stakeholder submissions on the draft decision and revised proposal. A list of stakeholder submissions is provided in appendix A.
- having JGN present its revised access arrangement to the AER Board in March 2015, so questions could be raised and key issues explained.

AER staff, including our technical advisors and consultants, directly engaged with staff at JGN throughout the review process, and tested material and information underpinning its proposal. During this process, we requested and considered additional information from JGN to help us understand its proposals.

A List of submissions

We invited submissions on our draft decision by 27 March 2015. The following stakeholders made written submissions on our draft decision for JGN:

Submission	Date
CitiPower and Powercor	6 February 2015
SA Power Networks	6 February 2015
United Energy	6 February 2015 13 February 2015 27 March 2015
Australian Gas Networks	13 February 2015
Ergon Energy	13 February 2015 27 March 2015
Public Interest Advocacy Centre	23 March 2015
Ethnic Communities of NSW	26 March 2015
JGN	27 March 2015 16 April 2015* 13 May 2015* 18 May 2015*
AusNet Services	27 March 2015
Origin Energy	27 March 2015
AGL	30 March 2015
Energy Markets Reform Forum	30 March 2015

* Section 65 of the NGL provides that the AER may, but is not required to, consider any late submission. JGN's submission of 16 April was provided a considerable time after submissions on our draft decision and JGN's revised proposal closed. As we were in the final stages of our review of JGN's revised proposal at that time, there was not sufficient time for the AER, consumers or regulated businesses to comment upon or respond to this submission in a meaningful way. We therefore exercised our discretion under section 65 not to consider this late submission for the purposes of this final decision. This did not affect our consideration of JGN's submission of 27 March 2015.