DRAFT DECISION
Australian Gas Networks Access Arrangement 2016 to 2021

Overview

November 2015

AUSTRALIAN ENERGY REGULATOR

Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 520
Melbourne Vic 3001

Tel: (03) 9290 1444
Fax: (03) 9290 1457

Email: AERInquiry@aer.gov.au

Invitation for submissions

Interested parties are invited to make submissions on our draft decision and the revised proposal AGN will submit on 6 January 2016. Submissions are due by 4 February 2016.

We will consider and respond to submissions in our final decision in late April 2016.

We prefer that all submissions are in Microsoft Word or another text readable document format. Submissions on the draft decision and revised proposal should be sent to: AGN2015GAAR@aer.gov.au.

Alternatively, submissions can be sent to:

Mr Warwick Anderson
General Manager
Australian Energy Regulator
GPO Box 3131

Canberra ACT 2601

We prefer that all submissions be publicly available to facilitate an informed and transparent consultative process. Submissions will be treated as public documents unless otherwise requested. Parties wishing to submit confidential information should:

(1) clearly identify the information that is the subject of the confidentiality claim

(2) provide a non-confidential version of the submission in a form suitable for publication.

All non-confidential submissions will be placed on our website. For further information regarding our use and disclosure of information provided to us, see the ACCC/AER Information Policy (June 2014), which is available on our website.

Note

This attachment forms part of the AER's draft decision on Australian Gas Networks' access arrangement for 2016–21. It should be read with all other parts of the draft decision.

The draft 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

Attachment 14 - Other incentive schemes

Contents

Shortened forms

Shortened form	Extended form
AA	Access Arrangement
AAI	Access Arrangement Information
AER	Australian Energy Regulator
ATO	Australian Tax Office
capex	capital expenditure
CAPM	capital asset pricing model
CCP	Consumer Challenge Panel
CESS	Capital Expenditure Sharing Scheme
CPI	consumer price index
CSIS	Customer Service Incentive Scheme
DRP	debt risk premium
EBSS	Efficiency Benefit Sharing Scheme
ERP	equity risk premium
Expenditure Guideline	Expenditure Forecast Assessment Guideline
gamma	Value of Imputation Credits
GSL	Guaranteed Service Level
MRP	market risk premium
NECF	National Energy Customer Framework
NERL	National Energy Retail Law
NERR	National Energy Retail Rules
NGL	national gas law
NGO	national gas objective
NGR	national gas rules
NIS	Network Incentive Scheme
NPV	net present value
opex	operating expenditure
PFP	partial factor productivity
PPI	partial performance indicators
PTRM	post-tax revenue model
RBA	Reserve Bank of Australia

Shortened form	Extended form
RFM	roll forward model
RIN	regulatory information notice
RoLR	retailer of last resort
RPP	revenue and pricing principles
SLCAPM	Sharpe-Lintner capital asset pricing model
STPIS	Service Target Performance Incentive Scheme
TAB	Tax asset base
UAFG	Unaccounted for gas
WACC	weighted average cost of capital
WPI	Wage Price Index

1 Introduction

We, the Australian Energy Regulator (AER), are responsible for the economic regulation of covered gas pipelines[1] in all states and territories in Australia except for Western Australia.

Australian Gas Networks' (AGN) gas network provides distribution services to customers in South Australia. As with other covered pipelines, we regulate AGN's reference tariffs, and through this, its revenue.

AGN submitted its access arrangement revision proposal on 1 July 2015, for the 2016–21 access arrangement period.

The National Gas Law (NGL) and National Gas Rules (NGR) provide the regulatory framework governing gas networks. In regulating AGN, we are guided by the National Gas Objective (NGO), as set out in the NGL. 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.[2]

We apply incentive regulation in making our decision on AGN's forecast revenue requirement.[3] Incentive regulation encourages service providers to spend efficiently and to share the benefits of efficiency gains with consumers.[4]

While we approve an overall revenue requirement for AGN, this does not bind the business to a particular operating budget. We determine an overall revenue requirement that is based on a forecast of capital and operating expenditures—such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services. The regime provides incentives for AGN to outperform those forecasts, while delivering safe, reliable and secure services to its customers.

If in assessing AGN's proposal we do not accept that its forecast revenue complies with the requirements of the NGR, we must indicate the nature of amendments required in order to make the proposal acceptable to us—including an alternative amount of revenue that we are satisfied does comply. In doing so, we must undertake this assessment and make this decision in a manner that will or is likely to contribute to

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1 Pipeline 'coverage' under the NGL determines the level of regulation that applies to a particular pipeline or network. AGN's South Australian distribution network is a covered pipeline. Under section 132 of the NGL, AGN must therefore submit for our approval an access arrangement in respect of the services it provides through the covered pipeline.

2 NGL, s. 23.

3 The revenue and pricing principles (RPPs) state a regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to reference services the service provider provides.

4 AEMC, *Consultation paper: National Electricity Amendment (Demand Management Incentive Scheme) Rule 2015*, February 2015, p. 3.

the achievement of the NGO and, where there are two or more possible decisions that will do so, make the decision that we are satisfied will contribute to the greatest degree (see section 7 of this overview).

The purpose of this draft decision is to set out our draft findings based on the information AGN has provided us, the analysis we have done and the stakeholder submissions we have received. Our final decision will be issued in April 2016 and will take into account any new information submitted by AGN in its revised proposal, additional analysis and stakeholder submissions. There are several areas in this draft decision where we have indicated that AGN needs to provide further information in support of its proposal. To the extent that new information, analysis or submissions cause us to depart from this draft decision, the final decision will deliver a different total revenue requirement, and therefore a different impact on customers.

This overview, together with its attachments, constitutes our draft decision on AGN's access arrangement for 2016–21.

1.1 Structure of overview

This overview provides a summary of our draft decision and its individual components. It is structured as follows:

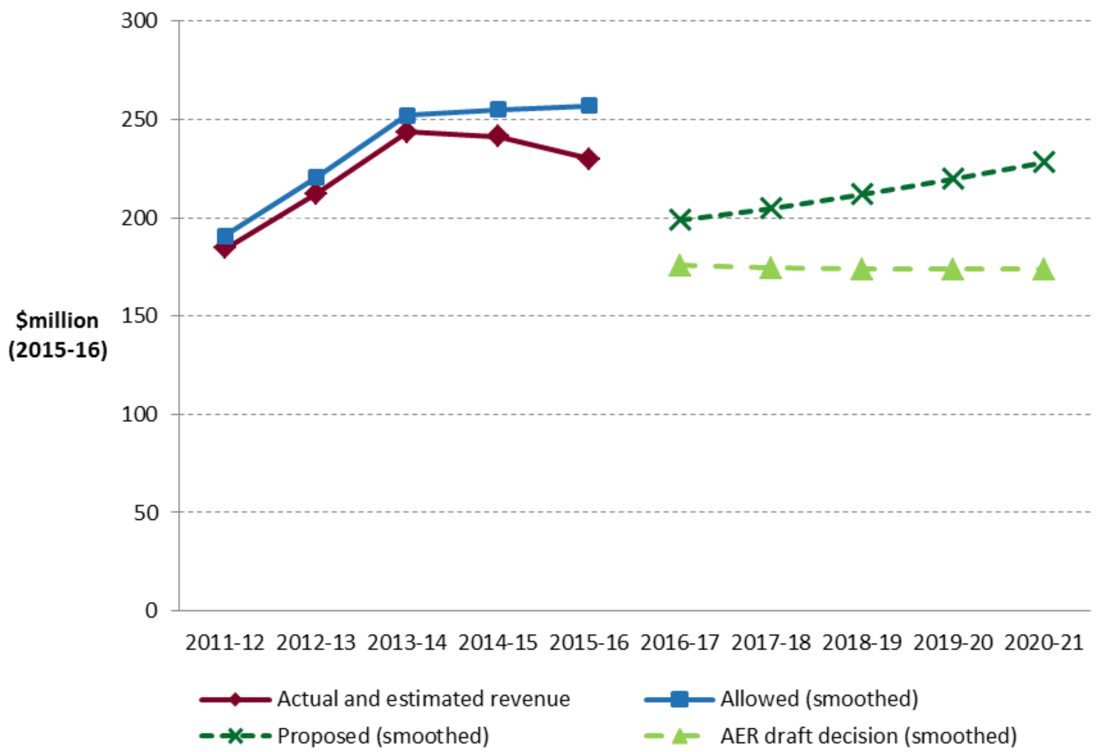
- Section 2 provides a high-level summary of our draft decision and the key issues.
- Section 3 sets out our draft decision on AGN's total revenue requirement.
- Section 4 provides a break-down of our revenue decision into its key components. We determine revenue using the building block approach and this section details the approved amount for each building block.
- Section 5 sets out our draft decision on demand, AGN's reference service, reference tariff setting and the reference tariff variation mechanism that will apply to AGN. It also sets out our draft decision on three new incentive schemes proposed by AGN.
- Section 6 sets out our draft decision on non-tariff components of AGN's access arrangement.
- Section 7 explains our views on the regulatory framework and the NGO.
- Section 8 outlines the process we undertook in reaching our draft decision.

In our attachments we set out detailed analysis of the individual components that make up AGN's proposal and our draft decision on each of them.

2 Decision

Our draft decision is to approve a forecast revenue requirement of $938.6 million[5] ($ nominal) for AGN over the 2016–21 access arrangement period, which begins on 1 July 2016, as shown in Figure 1. This is an 18.2 per cent reduction to AGN's proposed revenue of $1148.0 million ($nominal), and 16.8 per cent lower than the forecast revenue requirement used to determine reference tariffs in the current, 2011–16 access arrangement period.

Figure 1 AGN's past total revenue[a], proposed total revenue and AER's total revenue allowance ($ million, 2015–16)



Source: AER analysis.

Note: Includes ancillary reference services revenue.

(a) AGN operates under a weighted average tariff cap. This means the tariffs we determine (including the means of varying the tariffs from year to year) are the binding constraint across an access arrangement period, rather than the total revenue requirement set in our decision. Tariffs are derived from the total revenue requirement *after* consideration of demand for each tariff category. Where actual demand varies from the demand forecast in the access arrangement, AGN's actual revenue will vary from the revenue allowance determined in our decision. In general, if actual demand is above forecast demand, AGN's actual revenue will be above forecast revenue, and vice versa.

5 Includes ancillary reference services revenue.

We are satisfied that the forecast revenue requirement set in our draft decision is sufficient for AGN, acting prudently and efficiently, to recover the costs of 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.[6]

In this section, we provide a snapshot of our draft decision and highlight key issues considered as part of this review (section 2.2). Further discussion of the components that make up our draft decision follows in sections 3 to 6.

Next steps

Our draft decision sets out the nature of the amendments required to make AGN's proposal acceptable to us, and provides AGN with direction where further evidence is required in support of its proposal. AGN will respond to these in a revised proposal no later than 6 January 2016.

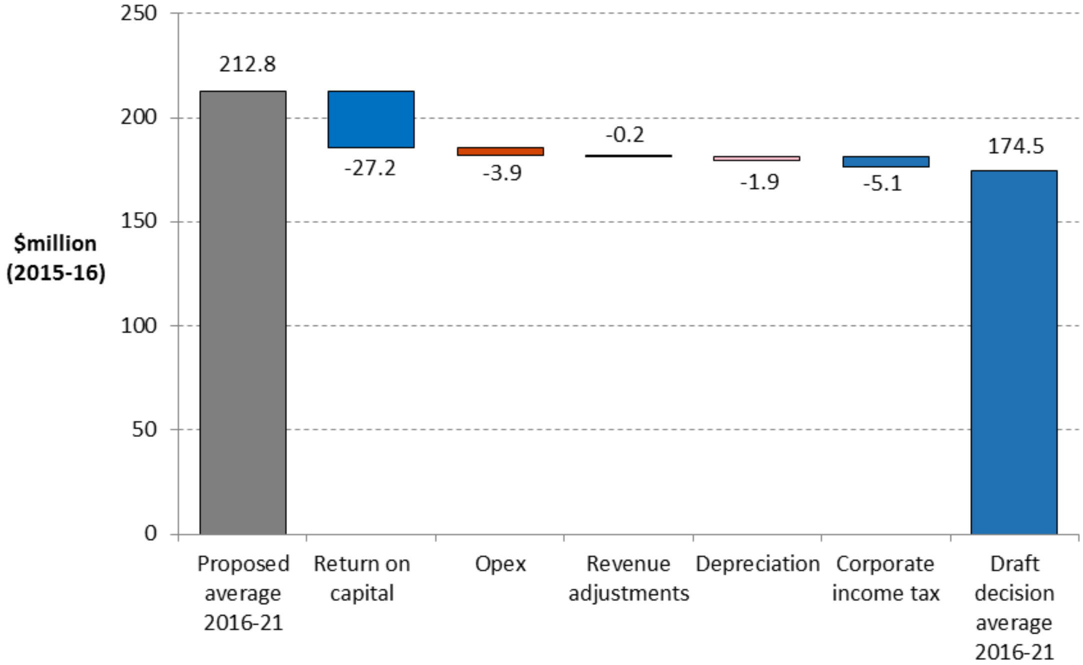
We encourage stakeholders to make submissions on this draft decision, and on AGN's revised proposal, by 4 February 2016. Details on how to make a submission are provided at the start of this overview.

2.1 Snapshot of draft decision

Figure 2 and Figure 3 compare our draft decision to AGN's proposal, broken down by the building block components that make up the forecast revenue requirement. These figures highlight that the allowed rate of return—which feeds into the return on capital—is the key difference between our draft decision and AGN's proposal.

[6] NGL, s. 23.

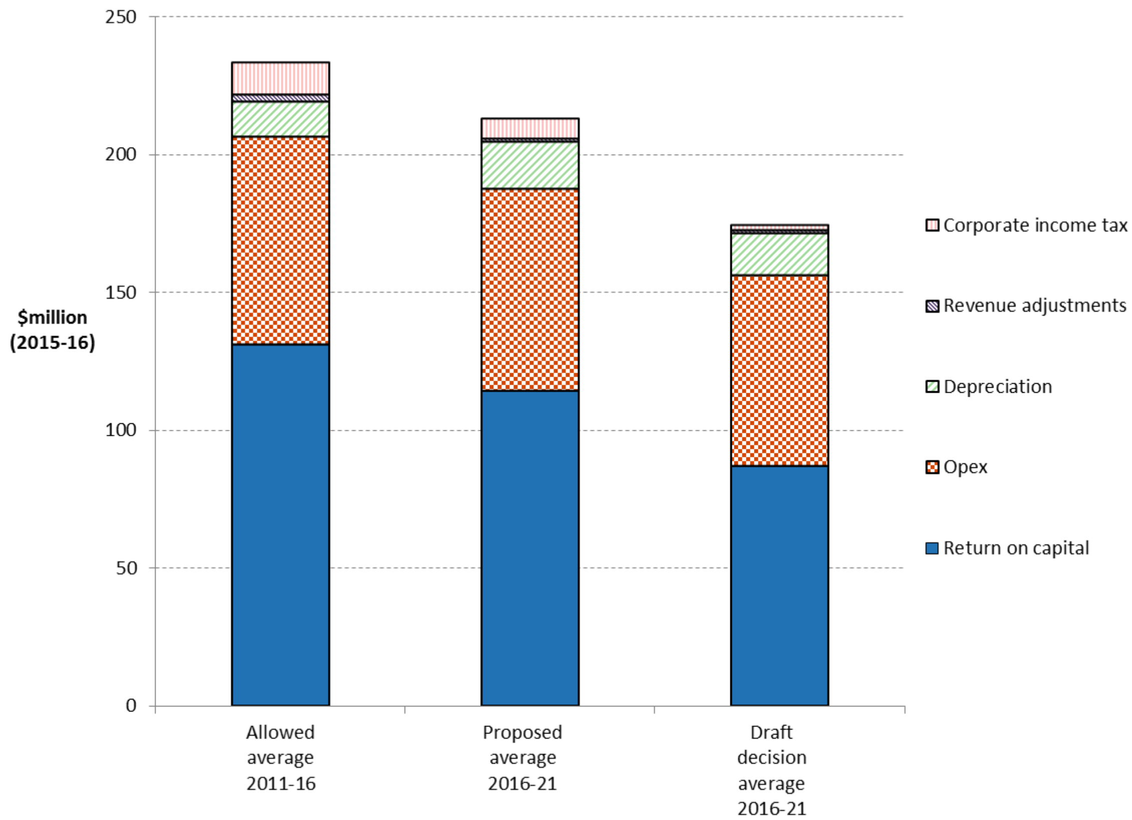
Figure 2 AER's draft decision and AGN's proposed annual building block costs ($ million, 2015–16)



Source: AER analysis.

Note: Includes ancillary reference services revenue.

Figure 3 AER's draft decision average annual revenue (unsmoothed) compared with AGN's proposed average annual revenue and approved average annual revenue for 2011–16 ($ million, 2015–16)



Source: AER analysis.

Note: Includes ancillary reference services revenue.

2.2 Key aspects of our draft decision

The total revenue requirement in our draft decision reflects a number of factors:

- the investment environment has improved compared to the previous access arrangement period, which translates to lower financing costs necessary to attract efficient investment (section 2.2.1).
- demand is trending downwards, as growth in gas connections and usage gradually falls. This reduces pressure on AGN to expand the capacity of its network, putting downward pressure on capex and opex (section 2.2.2).
- operating efficiencies have been passed on to consumers, but increases in the wholesale price of gas continue to impact operating costs (section 2.2.3).
- significant mains replacement programs have been completed over the last two access arrangement periods, and ongoing capital expenditure is expected to stabilise (section 2.2.4).

- the current regulatory framework has delivered incentives for AGN to seek efficiencies in operation of its network, while delivering high levels of performance (section 2.2.5).

2.2.1 Network funding costs are lower

The rate of return provides AGN with revenue to service the interest on its loans and to give a return on equity to shareholders. The allowed rate of return is a key determinant of the total revenue requirement. The differences between the rate of return we determine and that proposed by AGN may appear small—a percentage point or two. However, even a small difference can have a big impact on revenues. This is because AGN has raised large amounts of funds from lenders and other investors in the past, which is to be expected given the capital intensive nature of the sector. These fund raisings have to continue to be financed, as well as financing of any new capital spending.

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

Prevailing market conditions for debt and equity heavily influence the rate of return. Financial conditions have changed since our last decision for AGN in July 2011, which covered the 2011–16 access arrangement period. This is reflected in a lower rate of return in this draft decision. Interest rates are lower and financial market conditions are more stable. This means that the cost of debt and the returns required to attract equity are lower. These factors are reflected in the rate of return.

Our draft decision is for a rate of return of 6.02 per cent (for 2016–17)[7]—compared to 10.28 per cent we set for the 2011–16 access arrangement period.

We set out our approach to determining the rate of return in the Rate of Return Guideline (Guideline) we published in December 2013.[8] We undertook extensive consultation in developing the Guideline. Although it is not binding, a service provider must provide reasons to justify any departure from the Guideline.

AGN proposed a rate of return of 7.23 per cent. It proposed that we depart from the Guideline. We received several submissions regarding AGN's proposed rate of return. Other network businesses generally supported AGN's approach. However, other stakeholder submissions either urged us to maintain the approach set out in the Guideline or argued that even the Guideline yielded a rate of return that is too high.[9]

7 For the remaining years of the access arrangement period, we will update the rate of return annually.

8 AER, *Rate of Return Guideline*, December 2013: http://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rate-of-return-guideline.

9 A full list of submissions is provided in Appendix A to this overview. These submissions are discussed further in Attachments 3 (Rate of Return) and 4 (Value of Imputation Credits) to this draft decision.

We have considered AGN's arguments and those raised in submissions, and do not consider that there are reasons for us to depart from the Guideline.

This draft decision on rate of return is consistent with our mid-2015 final decisions for the New South Wales and ACT electricity distribution and transmission, and New South Wales gas distribution, network businesses. Some of these network businesses have appealed many aspects of our rate of return decisions to the Australian Competition Tribunal. The Tribunal’s process had not been finalised at the time of this draft decision.

Relationship between return on and return of capital

The depreciation (or return of capital) allowance in our decision on AGN's revenue determines how quickly the capital base is being recovered. Higher (or quicker) depreciation leads to higher revenues over the access arrangement period. AGN proposed a depreciation allowance that aligned with our standard approach. However, AGN also included an alternative proposal for higher depreciation, contingent on an assessment of its financeability. AGN submitted that it must be allowed sufficient cash flow to maintain the benchmark BBB+ credit rating that is assumed by the AER when setting the rate of return.[10] Its proposal focused on the rate of return as the catalyst for its concerns over its credit rating, and suggested that a different approach to depreciation should apply if particular credit metrics were not met.

We do not accept the contingent nature of AGN’s proposal. Its alternative proposal is incomplete and undeveloped. As a result, we are not able to accept it. Further, it is difficult for other stakeholders to provide comments on a proposal that is only referred to in incomplete and general terms.

In making our draft decision we have considered the manner in which the constituent components of our decision relate to each other. We have also considered the manner in which those interrelationships should be taken into account in our overall decision. AGN (and its consultant, Incenta) submitted that there is a specific interrelationship between depreciation and rate of return, and that one or the other should be set to achieve particular credit metrics. However, for the reasons set out in attachments 3 and 5, we consider that this suggested interrelationship is overstated. Neither AGN nor Incenta has engaged with the potential long-term consequences of the approach, or demonstrated why accelerated depreciation would achieve the depreciation criteria in the rules.[11]

Further, we are not persuaded by AGN or Incenta’s analysis regarding credit metrics (as discussed in attachment 3). For this reason, we are not satisfied that there is evidence that a benchmark business in the circumstances of AGN faces a credit rating downgrade or a financeability problem more generally. Overall, we are satisfied that AGN’s proposed regulatory depreciation approach, as opposed to its alternative

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10 AGN, *Access arrangement information*, July 2015, pp. 162–165.

11 NGR, r. 89.

contingent proposal, allows for AGN's reasonable needs for cash flow to meet financing, non-capital and other costs.[12]

2.2.2 Forecast demand

Past trends in gas connections and usage suggest that demand on AGN's network continues to decline, as reflected in the demand forecasts that have informed our draft decision. While these suggest a more gradual decline in consumption in some sectors than AGN put to us in its proposal, they still point to a reduction in the revenue AGN will require to operate its network and provide safe, reliable services going forward. This is because AGN will be under less pressure to expand the capacity of its network.

Our draft decision not to accept AGN's demand forecasts is reflected in the approved opex in our draft decision, which assumes a lower output change than AGN has proposed. For example, opex includes maintenance expenditure which will vary depending on the size of the network, and expenditure due to gas leakage, which will vary depending on throughput. We have taken the impact of changes in customer numbers and gas throughput into account in deriving our output rate of change.

The impact of our decision on forecast demand can also be seen in our draft decision on forecast capex for new connections and augmentation.

2.2.3 Approved operating expenditure

Our draft decision approves total forecast opex of $342 million ($2015–16) for the 2016–21 access arrangement period. Our assessment of efficient opex takes into account a number of countervailing factors. The wholesale gas prices AGN will need to pay for UAFG are increasing. However, AGN's efficiency gains in the current access arrangement period bring the base year expenditure that informs our opex forecast down. The total opex we have approved is four per cent lower than AGN proposed, and broadly in line with current levels of expenditure.

UAFG is the difference between the volume of gas that enters a distribution pipeline and the volume of gas billed to customers. AGN must meet the cost of that difference, by purchasing gas from the wholesale market. AGN's forecast UAFG costs, which we have included in our approved opex forecast, make up around 16 per cent of total opex. This is the main driver for the increase in AGN's opex from the current period.

UAFG levels have fallen over the current period, and with the benefit of forecast capex for AGN's ongoing mains replacement program (discussed below), we expect will continue to do so. This reduction in UAFG volumes is offset, however, by forecast increases in wholesale gas prices.

Within the 2016–21 access arrangement period, two things will impact how this forecast increase to AGN's UAFG costs will flow through to customers.

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[12] NGR, r. 89(1)(e).

AGN is currently participating in AEMO's review of the arrangements for the treatment of UAFG, which is considering a proposal to transfer the responsibility for supplying UAFG from AGN to retailers and self–contracting users.[13] If the proposal is implemented, one potential outcome is that AGN would not incur any UAFG costs. If this occurred, this reduction in costs would then be passed through to customers through the cost pass through mechanism, in the form of lower reference tariffs.[14]

For the purposes of this draft decision we cannot pre-empt the outcomes of AEMO's review and must assess AGN's forecast of UAFG costs as though this change will not occur. Our draft decision introduces a new mechanism to reduce the exposure of AGN and its customers from windfall gains or losses arising from significant variations in gas prices. Reference tariffs will now be adjusted annually to reflect movements in wholesale gas prices relative to the forecasts included in our decision. The mechanism set out in this draft decision specifically targets changes in wholesale gas prices, rather than UAFG volumes. This means AGN has an ongoing incentive to manage UAFG levels on its network, including through its capex program which we discuss further below.

2.2.4 Approved capital expenditure

Our draft decision includes forecast capex of $393.0 million ($2014–15). This is a reduction of 44 per cent from what AGN proposed. We are satisfied, however, that this forecast will enable AGN to maintain the safety of its network, maintain system integrity and continue to provide a safe and reliable service to its customers. This is because the forecast we have set makes provision for projects that are justified on grounds set out in the NGR[15], and capex such as would be incurred by a prudent operator acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services.[16]

The key driver of difference between our draft decision on forecast capex and that proposed by AGN is its mains replacement program. Over the last two access arrangement periods AGN has progressed a significant mains replacement program. From 2006 to 2016, it estimates that it will have replaced over 1600 kilometres of mains. AGN's forecast capex for 2016–21 targets a further 1273 kilometres, at a forecast cost of $369.9 million ($2014-15) over the 2016–21 access arrangement period.

We have included $167.7 million ($2015, unescalated direct costs) of mains replacement capex in our alternative estimate in this draft decision. This is 54.7 per

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13 AGN, *Access Arrangement Information for AGN's South Australian Natural Gas Distribution Network* (July 2015), p. 116.

14 Our draft decision approves a 'regulatory change' pass through event. Where there are substantial changes to AGN's obligations which materially impact the cost of providing reference services, those changes are passed through to customers in the form of lower (or higher) distribution charges.

15 NGR, r. 79(2).

16 NGR, r. 79(1)(a).

cent less than AGN's proposed forecast expenditure for its mains replacement program.

We have undertaken a technical review of the mains replacement program, which has drawn on internal engineering and technical expertise. Based on the information before us, we are not satisfied that AGN’s proposed forecast capex of $369.9 million for its mains replacement program, and the associated target of 1273 kilometres of main pipes to be replaced, is conforming capex that complies with rule 79.

The information that AGN has provided us does not support or demonstrate that its proposed forecast is prudent or efficient. In particular, AGN did not provide a rigorous (quantitative) risk assessment to establish that its proposed rate of mains replacement over the 2016–21 period is prudent and efficient. Rather, AGN’s assessment identifies what it terms ‘hazards’ and proceeds on the basis that they will occur and have significant impacts. We consider a rigorous risk assessment that measures the likelihood and impact of a hazard occurring is necessary in determining whether proposed investment is prudent and efficient. This is especially the case where, as here, there are no regulatory or legislative obligations that require AGN to replace mains at the rate it has proposed over the 2016–21 period.

We have not adopted AGN’s proposed mains replacement expenditure and have therefore determined an alternative estimate for the purposes of our total forecast capex. Our alternative estimate does not identify the specific allocation of capex across the three types of mains pipe replaced (CI, UPS or HDPE). Since we have not been provided with a rigorous risk assessment, we have used the limited information and data before us to derive an alternative estimate of the kilometre of main pipes we consider would be more efficient than what AGN has proposed to replace during the 2016–21 access arrangement period.

Since we do not have the information to undertake a rigorous risk assessment, we have based our alternative estimate on the kilometre of main pipes we consider would be efficient to replace during the 2016–21 access arrangement period. To derive our alternative capex estimate, we have reduced AGN’s proposed capex for mains replacement by our percentage reduction in total kilometres. This approach means we have applied AGN’s unit rates across all categories of mains replacement and our reduction reflects our view regarding prudent and efficient volumes of mains replacement.

Our assessment of AGN's forecast of mains replacement capex is set out in attachment 6 to this draft decision. We invite AGN to address the issues we have identified in its revised proposal, and to include the necessary material—particularly a rigorous risk assessment—to demonstrate and justify the extent to which its proposed capex for mains replacement is conforming capex that complies with rule 79.

2.2.5 Incentives

As noted in section 1, we apply incentive regulation in making our decision on AGN's forecast revenue requirement, to encourage AGN to spend efficiently and to share the benefits of efficiency gains with its customers.[17] AGN retains the benefits of efficiencies (cost savings) during an access arrangement period. These are passed on to consumers as these efficiencies are reflected in lower costs—and therefore lower capex and opex—in future periods. The information before us suggests to us that the current incentive framework is working well, and delivering positive outcomes for AGN and its customers.

To supplement these incentives, AGN's proposal included suggested changes to its current opex efficiency carryover mechanism, and the introduction of three new incentive schemes in its 2016–21 access arrangement period: a capital expenditure sharing scheme (CESS); a customer service incentive scheme (CSIS); and a network innovation scheme (NIS).

We applied a CESS for the first time in the electricity distribution and transmission determinations we made in April 2015 (for New South Wales and ACT distribution networks and New South Wales and Tasmanian transmission networks). However, to date we have not considered development or application of a CESS for gas service providers under the NGR. AGN's proposed CSIS and NIS are new schemes that we have not applied before in electricity or gas decisions.

Where we have developed and introduced new incentive schemes under the NER—including the CESS— we have done this in conjunction with consideration of related forecasting methodologies and complementary schemes, and as part of extended consultation with stakeholders, including other service providers. It is unusual for us to consider introduction of a new incentive scheme in the context of an individual access arrangement or service provider.

In this context we note that there are conflicting views on the benefits of these schemes in gas, which require further exploration through an appropriate consultation process. For example, while AGN has proposed a CESS, other gas service providers who submitted their proposals at the same time as AGN have said that they do not support introduction of a CESS in their own access arrangements.[18] While supportive of a CESS in principle where an opex efficiency scheme is also applied, the CCP does not support the CESS that AGN has proposed. Other stakeholders have also questioned the need for new incentive schemes in AGN's access arrangement, and the design of the schemes that AGN has proposed. These issues are discussed further in section 5.5, and attachment 14 to this draft decision.

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[17] The revenue and pricing principles (RPPs) state a regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to reference services the service provider provides.

[18] ActewAGL, *Access arrangement information for the 2016–21 access arrangement, Attachment 10*, June 2015, p. 13; APTNT, *Amadeus gas pipeline, Access arrangement revision proposal, Submission*, August 2015, p. 169.

Our draft decision does not accept the introduction of these new schemes in AGN's access arrangement at this time. We consider it preferable that the development and implementation of any new incentive schemes under the NGR be subject to a consultative, informed and industry-wide process such as that undertaken as part of our 2013 Better regulation program.

3 Total revenue requirement

The total revenue requirement is a forecast of the efficient cost of providing gas distribution services over the access arrangement period. The total revenue requirement set out in this draft decision has been determined by assessing each building block cost of AGN's access arrangement proposal. We have assessed whether these building block costs are consistent with the costs that would be incurred by an efficient provider of gas distribution services.

Tariffs are derived from the total revenue requirement *after* consideration of demand for each tariff category. AGN operates under a weighted average tariff cap. This means the tariffs we determine (including the means of varying the tariffs from year to year) are the binding constraint across the 2016–21 access arrangement period, rather than the total revenue requirement set in our decision.[19]

3.1.1 The building block approach

We have employed the building block approach to determine AGN's total revenue requirement—that is, we based the total revenue requirement on our estimate of the efficient costs that AGN is likely to incur in providing gas distribution network services. The building block costs, as shown in Figure 4, include:[20]

- return on the projected capital base (return on capital)
- depreciation of the projected capital base (return of capital)
- the estimated cost of corporate income tax
- revenue increments or decrements resulting from incentive schemes such as the efficiency carryover mechanism
- 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 depreciation building blocks.

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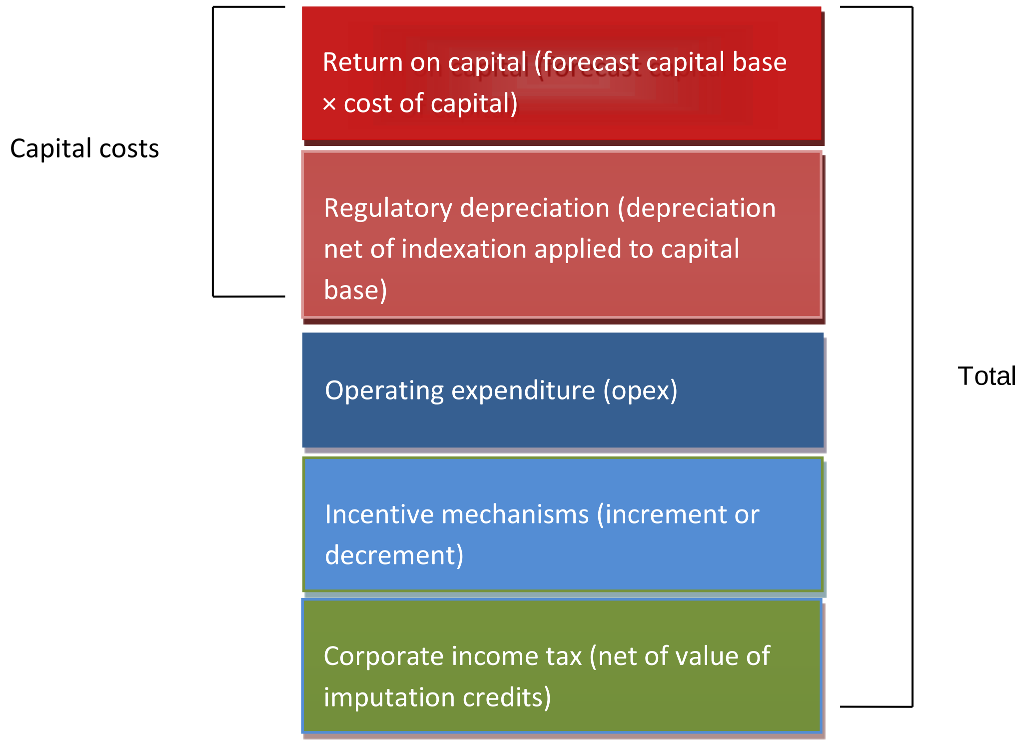
19 Where actual demand across the 2016–21 access arrangement period varies from the demand forecast in the access arrangement, AGN's actual revenue will vary from the revenue allowance determined in our decision. In general, if actual demand is above forecast demand, AGN's actual revenue will be above forecast revenue, and vice versa.

20 NGR, r. 76.

Figure 4 The building block approach for determining total revenue



3.1.2 Draft decision

We accept that some aspects of AGN's proposal are consistent with the requirements of the NGR. However, we have not approved all elements, and as such, have not approved AGN's access arrangement proposal as a whole.[21]

We do not approve AGN's proposed total revenue requirement (smoothed) of $1148.0 million ($nominal) for reference services over the 2016–21 access arrangement period.[22] Based on our assessment of the building block costs, we determine a total revenue requirement (smoothed) of $938.6 million ($nominal) for AGN over the 2016–21 access arrangement period.[23] Our draft decision on the total revenue requirement has been determined using the building block approach set out in rule 76 of the NGR. This total smoothed revenue requirement is $209.4 million (or 18.2 per cent) lower than AGN's proposal.

We do not approve AGN's proposed 2016–17 tariffs, which imply a weighted average decrease in real tariffs of 11.38 per cent. We also do not approve AGN's proposed 2017–21 tariff path, which implied a weighted average increase in real tariffs of 5.0 per

[21] NGR, r. 41(2).

[22] This amount includes revenues for ancillary reference services. See AGN, *Access arrangement information,* July 2015, p. 214.

[23] This is calculated by smoothing the unsmoothed building block revenue for the 2016–21 access arrangement period as set in this draft decision.

cent per year.[24] As a result of our lower total revenue requirement and higher demand forecast, our draft decision is for a real decrease in weighted average tariffs of 22.80 per cent in 2016–17, and then real increases of 0.77 per cent for each subsequent year of the 2016–21 access arrangement period.

Table 1 sets out our draft decision on AGN's revenue requirement, by building block, for each year of the 2016–21 access arrangement period, the total revenue after equalisation (smoothing) and the X factors for use in the tariff variation mechanism.

Table 1 AER's draft decision on AGN's smoothed total revenue and X factors for the 2016–21 access arrangement period ($million, nominal)

Building block	2016–17	2017–18	2018–19	2019–20	2020–21	Total
Return on capital	85.1	89.6	94.2	98.4	102.2	469.5
Regulatory depreciation	9.9	13.3	17.9	21.6	19.9	82.7
Operating expenditure	70.1	72.8	75.0	76.6	78.5	373.1
Revenue adjustments	6.9	–1.4	–2.3	1.7	0.0	4.9
Corporate income tax	2.2	2.0	2.0	2.8	1.7	10.8
Building block revenue – unsmoothed (incl. ARS)	**174.2**	**176.3**	**186.8**	**201.1**	**202.4**	**940.9**
Less: ancillary reference services revenue (ARS)	2.2	2.3	2.4	2.5	2.6	12.1
Building block revenue – unsmoothed (excl. ARS)	172.0	174.0	184.4	198.6	199.8	928.8
Building block revenue – smoothed (excl. ARS)	177.9	180.8	184.8	189.1	193.8	926.4
Building block revenue – smoothed (incl. ARS)	**180.1**	**183.1**	**187.3**	**191.7**	**196.4**	**938.6**
X factor[a]	**22.80%**	**–0.77%**	**–0.77%**	**–0.77%**	**–0.77%**	n/a
Inflation forecast	2.50%	2.50%	2.50%	2.50%	2.50%	n/a
Nominal price change	–20.87%	3.29%	3.29%	3.29%	3.29%	n/a

Source: AER analysis.

n/a: not applicable.

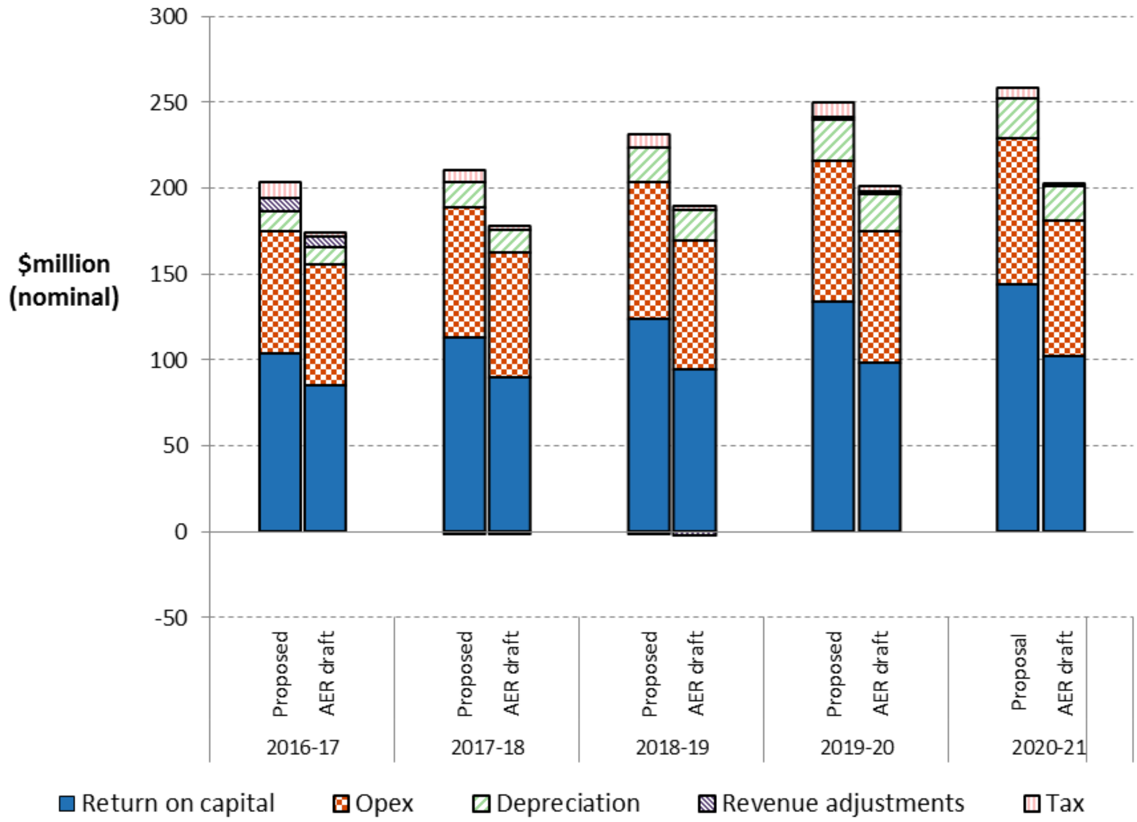
(a) Under the CPI–X form of control, a positive X factor is a decrease in price (and therefore in revenue). The X factors are for haulage reference services. The X factor for 2016–17 is indicative only. The draft decision establishes 2016–17 tariffs directly, rather than referencing a change from 2015–16 tariffs.

[24] AGN, *Access arrangement information,* July 2015, p. 214.

3.1.3 Total revenue

Figure 5 shows the effect of our draft decision adjustments on AGN's proposed building blocks for the 2016–21 access arrangement period. It shows the reductions to AGN's proposed return on capital, opex, depreciation and tax building blocks.

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



Source: AER analysis.

3.1.4 Revenue equalisation (smoothing) and tariffs

After our assessment of AGN's total building block revenue (unsmoothed revenue), we need to determine the smoothed revenue profile across the 2016–21 access arrangement period. AGN operates under a weighted average tariff cap as its tariff variation mechanism. This means we determine the weighted average tariff change each year such that the net present value (NPV) of unsmoothed and smoothed revenue is equal across the entire period. This weighted average tariff change is labelled the 'X factor'. The mechanics of the tariff variation mechanism are addressed in attachment 11.

Table 2 presents our draft decision X factors, and compares them to AGN's proposal.

Table 2 Weighted average tariff change across the access arrangement period (X factors) — comparison of AGN's proposal and AER's draft decision (per cent)

	2016–17	2017–18	2018–19	2019–20	2020–21
AER draft decision					
X factor[a]	22.80%	–0.77%	–0.77%	–0.77%	–0.77%
Nominal price change	–20.87%	3.29%	3.29%	3.29%	3.29%
AGN proposal					
X factor[a]	11.38%	–5.00%	–5.00%	–5.00%	–5.00%
Nominal price change	–9.16%	7.62%	7.62%	7.62%	7.62%

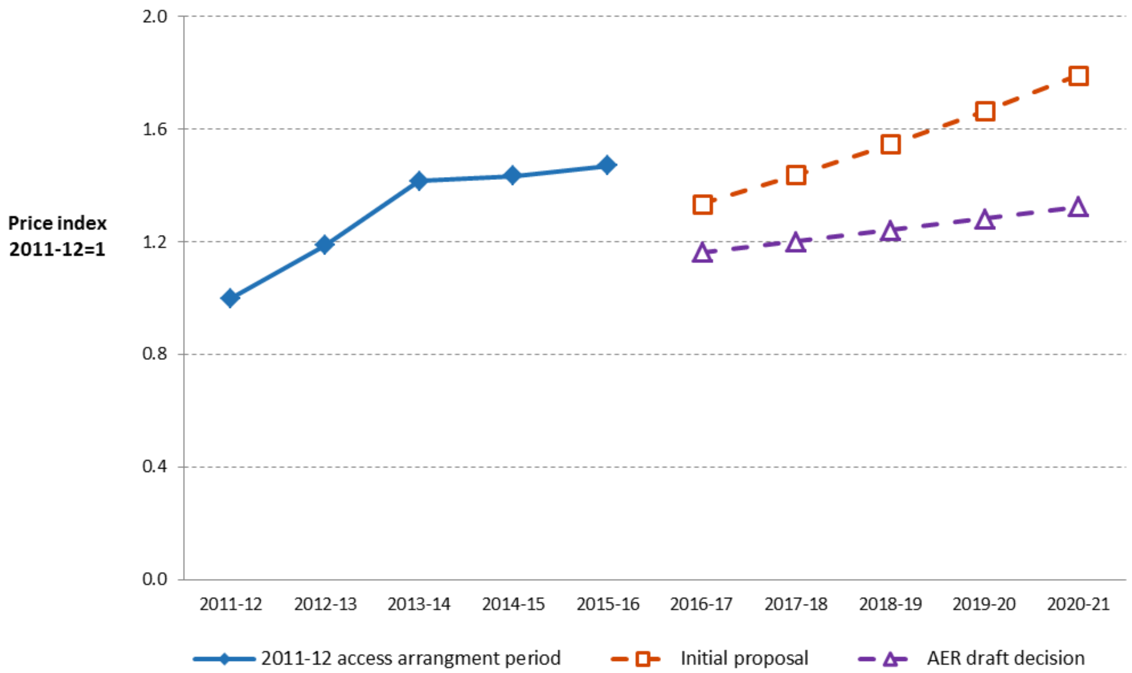
Source: AGN, *Access arrangement information*, July 2015, p. 214; AER analysis.

(a) Under the CPI–X form of control, a positive X factor is a decrease in price (and therefore in revenue). For example, an X factor of –5.00 per cent in 2017–18 means a real price increase of 5.00 per cent that year. After consideration of inflation (assumed at 2.50 per cent) this becomes a nominal price increase of 7.62 per cent.

Figure 6 shows indicative tariff paths for AGN's reference services across the 2011–21 period. It compares AGN's proposed tariff path with that approved in the 2011–16 access arrangement, and with this draft decision.[25] This provides a broad overall indication of the average movement across this period.

[25] The tariff path for 2011–21 uses actual inflation outcomes for the 2011–15 period, and estimated inflation for 2015–21.

Figure 6 Indicative reference tariff paths for AGN's reference services from 2011 to 2021 (nominal index)



Source: AER analysis; AGN, *Access arrangement information*, July 2015, p. 214.

AGN's proposed tariff path reflected a decrease of 9.16 per cent (in nominal terms) in 2016–17, followed by tariffs that increase at 7.62 per cent for each subsequent year of the 2016–21 access arrangement period. Our draft decision provides for lower total smoothed revenue than AGN's proposal, in line with our reductions to total unsmoothed revenue. As such, a decrease to the tariff path is required over the 2016–21 access arrangement period to reflect the lower smoothed revenue than provided for in the 2011–16 access arrangement period. Our draft decision tariff path shows a decrease of 20.87 per cent in tariffs (in nominal terms) in 2016–17, followed by an increase of 3.29 per cent for each subsequent year of the 2016–21 access arrangement period.

In choosing the smoothing profile for this draft decision we have balanced a number of competing objectives:

- Equalising (in NPV terms) unsmoothed and smoothed revenue
- Providing price signals that reflect the underlying efficient costs
- Minimising variability in tariffs in 2015–16 and within the 2016–21 access arrangement period
- Minimising the likelihood of variability in tariffs at the start of the 2021–26 access arrangement period.

Each of these points is discussed in turn.

First, we are satisfied that our draft decision tariff path for AGN's 2016–21 access arrangement period achieves revenue equalisation as required by rule 92(2) of the NGR.[26] As set out above, we have made substantial reductions to the unsmoothed revenue proposed by AGN. Accordingly, we set the tariff path so that it adjusts the smoothed revenue downward to better reflect the unsmoothed building block costs.

Second, but closely related to the first point, our smoothing allows closer alignment of tariffs and costs. This 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.[27] Our draft decision tariff path shows a large decrease in the first year of the 2016–21 access arrangement period reflecting the lower unsmoothed building block costs.

Third, in setting the tariff path, we aim to minimise tariff volatility in 2015–16 and within the 2016–21 access arrangement period. Our chosen tariff path reflects this objective, but also reflects the consideration we must give to other competing objectives. For instance, setting a flat tariff path from 2015–16 would better minimise within-period volatility, but would not achieve revenue equalisation.

Fourth, in setting the tariff path, we also aim to minimise the likelihood of tariff volatility between this access arrangement period and the next. We do not know with certainty what AGN's efficient costs will be in 2021–22, or across the 2021–26 access arrangement period more generally. The unsmoothed building block costs for 2020–21 (the last year of the 2061–21 access arrangement period) are the best available proxy. Hence, this objective requires minimising the divergence between the smoothed and unsmoothed revenues for the last year of the access arrangement period—for AGN, this is 2020–21. If there were no significant changes in forecast costs from 2020–21 to 2021–22, this final year divergence gives us an estimate of the size of the tariff change at the start of the 2021–26 access arrangement period. For this draft decision, this final year divergence is 3 per cent, which is consistent with our usual target. We note that if there are significant changes in costs at the start of the 2021–26 access arrangement period, this might increase or decrease the required tariff change at that time.

We are satisfied that our draft decision tariff path reflects our balanced consideration of these competing objectives. We will review this smoothing profile for the final decision if necessary.

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26 The revenue equalisation occurs in NPV terms, discounting the yearly cash flows at the rate of return to reflect the time value of money.

27 NGL, ss. 23, 24.

4 Key elements of decision on AGN's revenue

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

In setting our overall total revenue requirement of $940.9 million ($nominal, unsmoothed) for the 2016–21 access arrangement period, we:

- apply relevant tests under the NGR, the assessment methods and tools developed as part of our Better Regulation guidelines[28].
- consider information provided by AGN, the Consumer Challenge Panel (CCP), consultants and stakeholder submissions.
- consider our overall revenue decision against section 23 of the NGL, including the components of our decision and the interrelationships we discuss in sections 7.1.1 and 4.

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

4.1 Capital base

We are required to make a decision on AGN's opening capital base as at 1 July 2016 for the 2016–21 access arrangement period. We are also required to make a decision on AGN's projected capital base for the 2016–21 access arrangement period.

The capital base roll forward accounts for the value of AGN's regulated assets over the access arrangement period. The level of the capital base substantially impacts the service provider's revenue and the price consumers ultimately pay. It is an input into the determination of the return on capital and depreciation (return of capital) allowances.[29] Other things being equal, a higher capital base increases both the return on capital and depreciation allowances. In turn, it increases the service provider's revenue, and prices for services.

We do not approve AGN’s proposed opening capital base of $1428.8 million ($nominal) as at 1 July 2016. This is because we made several amendments to AGN’s proposed roll forward model (RFM) to correct some inputs and modelling errors. With these corrections, we determine an opening capital base of $1414.3 million ($nominal) as at 1 July 2016. This is $14.6 million (or 1.0 per cent) less than that proposed by AGN.

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

29 The size of the capital base also impacts the benchmark debt raising cost allowance. However, this amount is usually relatively small and therefore not a significant determinant of revenues overall.

Table 3 summarises our draft decision on the roll forward of AGN's capital base during the 2011–16 access arrangement period.

Table 3 AER's draft decision on AGN's capital base roll forward for the 2011–16 access arrangement period ($million, nominal)

	2011–12	2012–13	2013–14	2014–15	2015–16
Opening capital base	1023.9	1070.7	1140.0	1230.9	1305.6
Net capex	58.0	83.9	102.9	108.2	134.7
Indexation of capital base	16.2	26.8	33.4	16.3	32.6
Depreciation	–27.5	–41.4	–45.4	–49.9	–51.9
Closing capital base	1070.7	1140.0	1230.9	1305.6	1421.0
Adjustment for difference between estimated and actual capital expenditure in 2010–11					–6.7
Opening capital base at 1 July 2016					**1414.3**

Source: AER analysis.

We also do not approve AGN's proposed projected capital base of $2116.0 million ($nominal) as at 30 June 2021. We instead determine a closing capital base of $1767.5 million ($nominal) as at 30 June 2021, a reduction of $348.4 million or 16.5 per cent from the proposed value. The main reasons for the reduction are our adjustments—also reductions—to AGN's opening capital base as at 1 July 2016 (discussed above), forecast net capex (see section 4.5) and depreciation (see section 4.4).

Table 4 sets out the projected roll forward of the capital base during the 2016–21 access arrangement period.

Table 4 AER's draft decision on projected capital base roll forward for the 2016–21 access arrangement period ($million, nominal)

	2016–17	2017–18	2018–19	2019–20	2020–21
Opening capital base	1414.3	1489.0	1566.0	1636.2	1699.6
Net capex	84.6	90.3	88.1	85.0	87.9
Indexation of capital base	35.4	37.2	39.1	40.9	42.5
Depreciation	–45.3	–50.5	–57.0	–62.5	–62.4
Closing capital base	1489.0	1566.0	1636.2	1699.6	1767.5

Source: AER analysis.

The capital base at the commencement of the 2021–26 access arrangement period will be subject to adjustments consistent with the NGR.[30] These adjustments include (but are not limited to) the difference between estimated and actual capex for 2015–16 (the final year of the 2011–16 access arrangement period), actual inflation and approved depreciation over the 2016–21 access arrangement period. We accept AGN's proposal to use forecast depreciation for the 2016–21 access arrangement period to establish AGN's opening capital base as at 1 July 2021.

4.2 Rate of return (return on capital)

The return on capital provides AGN with revenue to service the interest on its loans 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.[31]

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 distributor in respect of the provision of distribution services. The NGR refer to this requirement as the 'allowed rate of return objective'.[32]

We have determined an allowed rate of return of 6.02 per cent (for 2016–17, nominal vanilla[33]). We have not accepted AGN's proposed 7.23 per cent rate of return. In accordance with our Rate of Return Guideline, we will update the rate of return annually.[34] Table 5 sets out the parameters we have used to determine the rate of return.

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30 NGR, r. 77(2).

31 NGR, r. 87(1).

32 NGR, r. 87(3).

33 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.

34 NGR, r. 87(9)(b); AER, *Rate of Return Guideline*, December 2013.

Table 5 AER's draft decision on AGN's rate of return (nominal)

	AER previous decision (2011–16)	AGN proposal (2016–17)(a)	AER draft decision (2016–17)	Return over 2016–21 access arrangement period
Return on equity (nominal post–tax)	10.36%	9.91%	7.3%	Remains constant (7.3%)
Return on debt (nominal pre–tax)	10.23%	5.44%	5.16%	Updated annually
Gearing	60%	60%	60%	Remains constant (60%)(b)
Nominal vanilla WACC	10.28%	7.23%	6.02%	Updated annually as return on debt is updated
Forecast inflation	2.55%	2.50%	2.50%	Remains constant (2.50%)

Source: AER analysis; Australian Gas Networks, 2016/17 to 2020/21 Access Arrangement Information: Attachment 10.1 - Rate of Return, July 2015, p. 59; AER, Final decision: Envestra Ltd Access Arrangement Proposal for the SA Gas network 1 July 2011 – 30 June 16, June 2011, p. 59.

(a) Australian Gas Networks' revised proposal uses values derived from the placeholder averaging periods for risk free rate and rate on debt.

(b) This rate will be updated in the final decision because our draft decision rate is based on a placeholder averaging period. However, after the rate is updated for the final decision it will then 'remain constant' for the access arrangement period and will not be updated each regulatory year.

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.[35] The NGR recognise that there may be several plausible answers that could achieve the allowed rate of return objective. We agree with stakeholders that predictability and consistency in our approach to rate of return issues, consistent with prevailing market conditions, materially benefits the long term interests of consumers and also benefits investors.[36]

We developed our approach prior to the submission of AGN's proposal. As required by the rate of return framework, in December 2013 we published the Guideline.[37] The Guideline was developed through extensive consultation and involved effective and inclusive stakeholder participation.[38]

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35 NGR, r. 87(2).

36 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.

37 NGR, r. 87(13).

38 See AER: http://www.aer.gov.au/node/18859.

Return on debt

Previously, we used an on-the-day approach to determine the return on debt.[39] This is the approach that several Australian regulators continue to use. We have determined a return on debt estimate that gradually transitions from an on-the-day approach to a trailing average approach.[40] This is consistent with the approach most stakeholders supported during the Guideline development process.

In its proposal, AGN proposed a hybrid transition from the on–the–day to trailing average approach. We have not accepted AGN's proposal, because we consider it is backward looking and produces a biased estimate of the return on debt. We discuss this more extensively in attachment 3 — rate of return.

Return on equity

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 Rate of Return Guideline (foundation model approach). This includes detailed consideration of a number of financial models for determining the return on equity.[41] Considering all of this material helps inform a return on equity estimate that contributes to the achievement of the allowed rate of return objective.

Notwithstanding the approach set out in the Guideline, AGN proposed a multi-model approach to calculating the 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. We are persuaded by the evidence before us that 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.[42]

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.[43] 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

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39 This involved determining the return on debt by reference to the return on BBB+ rated bonds over a 10-40 business day averaging period that occurred as close as practicable to the start of the access arrangement period.

40 In broad terms, this means that the return on debt for any year will represent the average return on debt over the previous ten years.

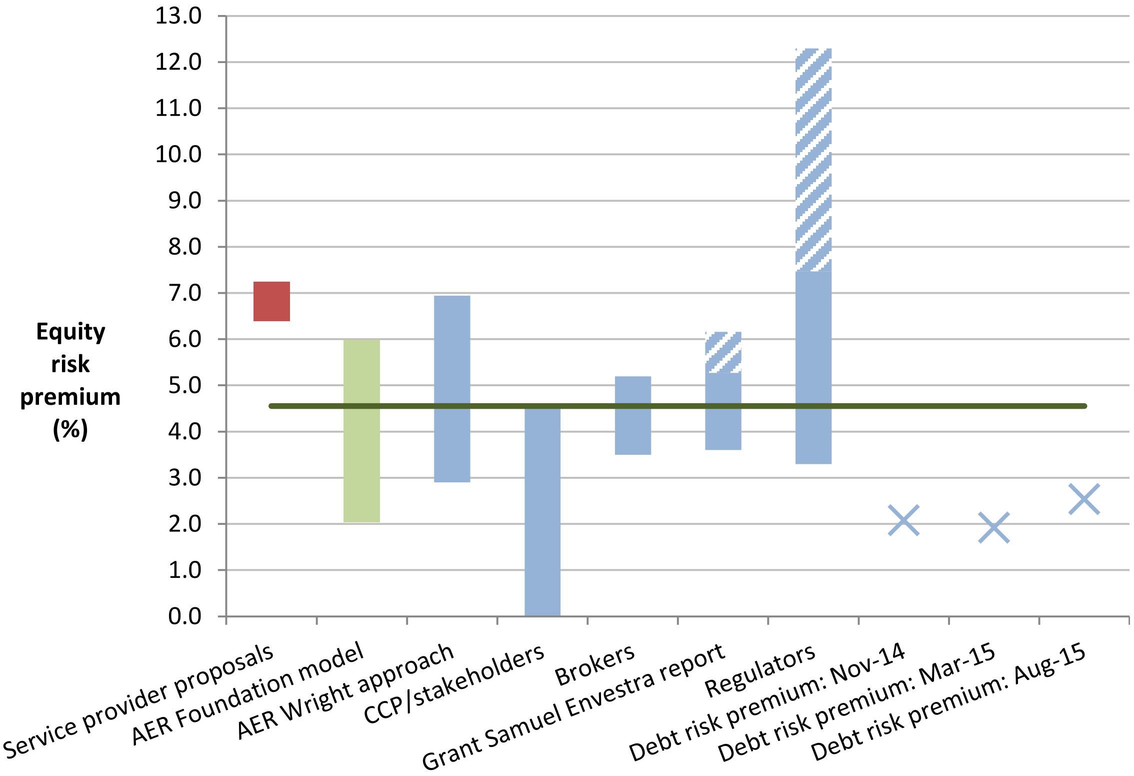
41 NGR, r. 87(5)(a).

42 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.

43 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).

Figure 7). A detailed explanation of our findings on return on equity and this figure can be found attachment 3 — rate of return.

Figure 7 Other information comparisons with the AER allowed equity risk premium



Source: AER analysis and various submissions and reports.

Notes: The AER foundation model equity risk premium (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 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 made no 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.[44]

The service provider proposals range is based on the proposals from businesses for which we are making final or preliminary/draft decisions in October-November 2015.[45] Equity risk premiums were calculated as the

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

[45] ActewAGL, Ausgrid, Directlink, Endeavour Energy, Energex, Ergon Energy, Essential Energy, Jemena Gas Networks, SA Power Networks, TasNetworks, and TransGrid. Jemena Gas Networks' revised proposals contained an indicative return on equity based on an indicative risk free rate averaging period. On 27 March 2015 JGN

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/draft decisions in October-November 2015. The lower bound is based on the Alliance of Electricity Consumers submission on Energex and Ergon Energy revised proposals. The upper bound is based on Origin Energy's submission on the preliminary decision for SA Power Networks.[46]

4.3 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.[47] 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 total revenue, the NGR require 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'.[48] That is, the revenue a service provider recovers from customers in respect of its expected tax liability must be reduced in a manner consistent with the value of imputation credits.

Our draft decision is to adopt a value of imputation credits of 0.4. This differs from AGN's proposed value of imputation credits of 0.25.

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 since publishing our Guideline. This re-examination, and new evidence and advice considered since the Guideline was published, 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 somewhat 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

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provided submissions that updated its approach using values derived from its proposed averaging periods. We have shown the 27 March 2015 updates.

46 Alliance of Electricity Consumers, *Submission to the Australian Energy Regulator's Preliminary Decision (Queensland)*, July 2015, p. 29; Origin Energy, *Submission to AER Preliminary Decision SA Power Networks*, July 2015, p. 9.

47 *Income Tax Assessment Act 1997*, parts 3–6.

48 NGR, rr. 76(c) and 87A.

widely accepted approach to estimating the distribution rate, there is no single accepted approach to estimating the utilisation rate. There is a range of evidence relevant to the utilisation rate:

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

4.4 Regulatory depreciation (return of capital)

Regulatory depreciation is a building block component of the annual revenue requirement.[49] When determining the total revenue for AGN, we must decide on the depreciation for the projected capital base (otherwise referred to as 'return of capital').[50] Regulatory depreciation is used to model the nominal asset values over the 2016–21 access arrangement period and the depreciation forecast in the total revenue requirement.

Ultimately, however, a service provider can only recover the capex it has incurred on assets once. The depreciation forecast reflects how quickly the capital base is being recovered and is based on the remaining and standard asset lives used in the depreciation calculation. Higher (or quicker) depreciation leads to higher revenues over the access arrangement period. It also causes the capital base to reduce more quickly (assuming no further capex). This reduces the return on capital building block, although this impact is usually less than that of the increased depreciation forecast.

In making a decision on the proposed depreciation schedule, we assess the compliance of the proposed depreciation schedule with the depreciation criteria set out in the NGR.[51] We must also take into account the NGO and the revenue and pricing principles.[52] If a proposed depreciation schedule complies with the NGR, we must approve it.

We approve AGN's proposal to use the real straight-line method to calculate the regulatory depreciation allowance. However, we do not approve AGN's proposed regulatory depreciation forecast of $93.0 million ($nominal) for the 2016–21 access arrangement period.[53] Our draft decision on AGN's regulatory depreciation forecast is $82.7 million ($nominal) over the 2016–21 access arrangement period, a reduction of $10.3 million ($nominal) or 11.1 per cent compared to the proposed amount. This is set out in Table 6.

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49 Under our standard approach, the distinction is made between straight-line depreciation and regulatory depreciation. The difference being that regulatory depreciation is the straight-line depreciation minus the indexation adjustment.

50 NGR, r. 76(b).

51 NGR, r. 89.

52 NGL, s. 28; NGR, r. 100(1). The NGO is set out in NGL, s. 23. The revenue and pricing principles are set out in NGL, s. 24.

53 Regulatory depreciation allowance is the net total of the straight-line depreciation (negative) and the annual inflation indexation (positive) on the projected capital base.

Table 6 AER's draft decision on AGN's regulatory depreciation for the 2016–21 access arrangement period ($million, nominal)

	2016–17	2017–18	2018–19	2019–20	2020–21	Total
Straight-line depreciation	45.3	50.5	57.0	62.5	62.4	277.8
Less: indexation on capital base	35.4	37.2	39.1	40.9	42.5	195.1
Regulatory depreciation	**9.9**	**13.3**	**17.9**	**21.6**	**19.9**	**82.7**

Source: AER analysis.

This reduction to AGN’s proposal is required because of:

- our required updates to the proposed remaining asset lives as at 1 July 2016
- our draft decision on other components of AGN’s proposal, which also affect the calculation of forecast regulatory depreciation. These include reductions to AGN’s opening capital base and forecast net capex (see sections 4.1 and 4.5, respectively).

Contingent proposal—relationship between return on and return of capital

AGN submitted that its proposed approach to depreciation was contingent on meeting certain credit metric thresholds, which it considered to be necessary in order to achieve a BBB+ credit rating.[54] The specific credit metrics were two financial ratios used by credit rating agencies, *Funds From Operations (FFO) to debt* and *FFO to interest*. AGN also commissioned a review of its assessed credit metrics by Incenta Economic Consulting (Incenta).[55] AGN submitted that it must be allowed sufficient cash flow to maintain the benchmark BBB+ credit rating that is assumed by the AER when setting the rate of return.[56] AGN submitted that if those credit metrics thresholds for a BBB+ credit rating were not met due to a lower rate of return, a different depreciation approach should apply.[57] This alternative approach would produce higher depreciation by adjusting the indexation component of the regulatory depreciation allowance. Hence, the key outcome of AGN’s contingent proposal is that if we reduce the return *on* capital building block, we should make an offsetting increase to the return *of* capital building block.

We do not accept AGN’s contingent proposal to adjust the indexation component of the regulatory depreciation building block for the following reasons:

[54] AGN, *Access arrangement information*, July 2015, p. 163; see also Incenta, *Using the profile of prices during an access arrangement period and return of capital to improve financial metrics*, 17 June 2015, pp. 14–16.

[55] Incenta Economic Consulting, *Using the profile of prices during an access arrangement period and return of capital to improve financial metrics*, 17 June 2015 (attachment 5.1 to the AAI).

[56] AGN, *Access arrangement information*, July 2015, pp. 95–97, 162–165.

[57] AGN, *Access arrangement information*, July 2015, pp. 164–165.

- AGN's contingent proposal appears to be incomplete and not fully specified. Therefore, we consider AGN's proposal is incapable of being accepted even if we were persuaded that some adjustment to indexation was necessary (which we do not). It is not possible for us and other stakeholders to undertake a full assessment of this incomplete contingent proposal. We note that a number of stakeholders do not agree in principle with AGN's proposal to increase its depreciation and change the indexation on the capital base if we determine a lower rate of return.[58]
- We are not persuaded by either AGN's or Incenta's analysis of credit metrics for the reasons set out in attachment 3. Therefore, we are not satisfied that there is evidence that a benchmark business in the circumstances of AGN faces a credit rating downgrade or a financeability problem more generally. Overall, we consider that the approach to evaluating credit metrics, as documented in AGN's proposal and Incenta's report, gives undue weight to the metrics as an indicator of creditworthiness, and is based on assumptions which are not satisfactorily tested or substantiated.
- Even if we accepted that there was evidence of a financeability problem, neither AGN nor Incenta has demonstrated why its accelerated depreciation would achieve the depreciation criteria in the rules and be in the long term interests of consumers. Therefore, we are not persuaded that an adjustment to indexation would be an effective response to evidence of a financeability problem.

4.5 Capital expenditure

Capital expenditure (capex) refers to the capital expenses incurred in the provision of network services. The return on and of forecast capex for reference services are two of the building blocks we use to determine a service provider's total revenue requirement.

We must make two decisions regarding AGN's capex. First, we are required to assess past capex and determine whether it meets the criteria set out in the NGR to be added to the starting capital base.[59] Where capex meets these criteria, it is referred to as "conforming capex".[60] Secondly, we are required to assess AGN's forecast of required capex for the 2016–21 access arrangement period to determine whether it is conforming capex.

We consider that the $392.6 million ($2014-15) net capex incurred by AGN for 2010–15[61] is conforming capex that complies with rule 79(1) of the NGR. This amount will be rolled into AGN's opening capital base.

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[58] Alternative Technology Association, *Australian Gas Network (SA) access arrangement proposal*, August 2015, pp. 10–11; Energy Consumers Coalition of SA, *AER review of AGN proposal 2015*, August 2015, p. 32; Origin Energy LPG, *Australian Gas Networks 2016–21 access arrangement proposal for its south Australian gas distribution network*, August 2015, pp. 4–5.

[59] NGR, r. 77(2)(b).

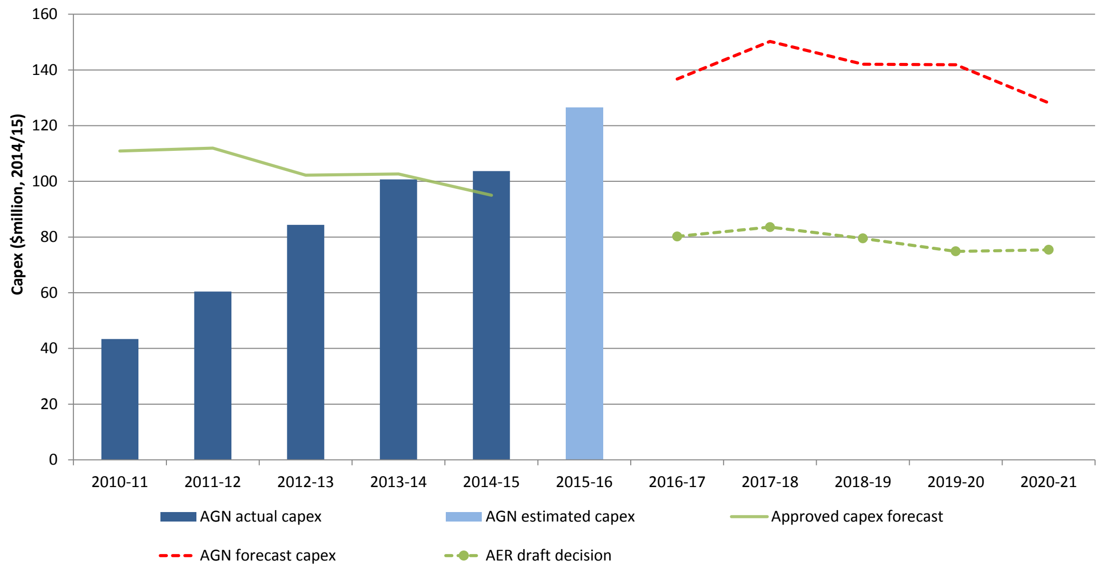
[60] NGR, r. 79.

[61] Capex for 2015–16 will be assessed as part of our next review, when actual data for that year will be available.

We approve $393.0 million ($2014–15) of AGN's proposed $687.3 million ($2014–15) total net capex for the 2016–21 access arrangement period as conforming capex under rule 79(1) of the NGR. This is 43.8 per cent less than AGN's proposed capex. Much of this reduction is because we did not have sufficient information to find the proposed expenditures to be prudent or efficient. We have identified where further information needs to be provided by AGN in order for us to be satisfied that the proposed expenditures meets the NGR. In attachment 6—which sets out our draft decision on capex—we have identified where further information needs to be provided by AGN in order for us to be satisfied that its proposed forecast expenditure meets the criteria set out in the NGR.

Figure 8 shows the difference between AGN's past and proposed forecast capex, and the forecasts we have approved in our previous decision for 2011–16 and this draft decision for 2016–21.

Figure 8 AER draft decision compared to AGN's past and proposed capex ($million, $2014-15)



Source: AER analysis.

Table 7 shows AGN's proposed capex forecast compared with our approved forecast for each category.

The outcomes of our assessment revealed that some aspects of AGN's forecast, such as capex for meter replacement and telemetry, were consistent with the NGR requirements. That is, the forecast expenditures are justified, and are such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services.[62]

We found that other aspects of AGN's forecast, in particular, its forecast capex for connections, IT and mains replacement, did not meet the NGR requirements. As such we have not approved them in this draft decision. It is open to AGN to provide further information in its revised proposed access arrangement to address our concerns.

Table 7 Comparison of AER approved and AGN's proposed capital expenditure over the 2016–21 access arrangement period ($million, 2014–15)

Category	Proposed	Approved	Difference ($millions)
Mains replacement	369.9	167.7	-202.2
Meter replacement	17.1	17.1	0.0
Augmentation	17.9	4.1	-13.8
Telemetry	1.1	1.1	0.0
Regulators	13.6	11.0	-2.7
IT	59.7	37.9	-21.8
Growth assets[a]	90.6	85.4	-5.2
Other distribution system	37.0	10.0	-26.9
Other non-distribution system	5.0	5.0	0.0
Escalation	14.9	7.0	-7.9
Overheads	60.4	46.8	-13.7
NET TOTAL CAPITAL EXPENDITURE	687.3	393.0	-294.3
Contributions	3.6	3.6	0.0
GROSS TOTAL CAPITAL EXPENDITURE	690.8	396.6	-294.3

Source: AER analysis.

Notes: (a) AGN proposed growth assets capex as net capex.

As can be seen in Table 7, the main differences between AGN's proposed capex forecast and our draft decision on total forecast capex for the 2016–21 access arrangement period concern the following:

62 NGR, r. 79(1)(a).

- Mains replacement—we have included $167.7 million ($2014–15, unescalated direct costs) of mains replacement capex in our alternative capex forecast. This is a reduction of 54.6 per cent from AGN's forecast expenditure of $369.9 million ($2015, unescalated direct costs) for its mains replacement program. AGN has not provided evidence in the form of a rigorous (quantitative) risk assessment to demonstrate that its forecast mains replacement capex is conforming capex over the 2016–21 access arrangement period that complies with rule 79.
- IT—we have included $37.9 million ($2014–15, unescalated direct costs) of IT capex in our alternative capex forecast. This is a reduction of 36.5 per cent from AGN’s forecast expenditure of $59.7 million ($2015) for its IT program. We reviewed AGN’s nine proposed individual IT projects against rule 79 of the NGR. Of the nine proposed projects, we consider that forecast capex for five projects is justified. Capex in respect of the other four projects was not included in our forecast because we considered that capex for these was not consistent with the conforming capex criteria in the NGR.
- Augmentation—we have included $4.1 million ($2014–15, unescalated direct costs) of augmentation capex in our alternative capex forecast. This is a reduction of 77.1 per cent from AGN’s forecast expenditure of $17.9 million ($2015, unescalated direct costs) for augmentation. This adjustment is largely driven by a reduction in AGN’s forecast expenditure for two projects - the Southern Transmission Pipeline and Murray Bridge.
- Other distribution system capex[63]—we have included $10.0 million ($2014–15, unescalated direct costs) of other distribution system capex in our alternative capex forecast. This is a reduction of 73 per cent from AGN’s forecast of $37 million for other distribution system capex. The adjustment is driven by not including a capex amount for the proposed in line camera to inspect HDPE mains, for which we did not have a cost benefit analysis to assess prudency and efficiency of the proposed capex. We have also included alternative capex estimates for four projects that were proposed by AGN.

We set out our reasons for our draft decision on AGN's conforming capex for both the current (2011–16) access arrangement period and the forecast (2016–21) period in attachment 6. Our draft decision also provides AGN with direction where we need more compelling evidence if its proposal is to be accepted. AGN may respond to these in its revised proposal.

4.6 Operating expenditure

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

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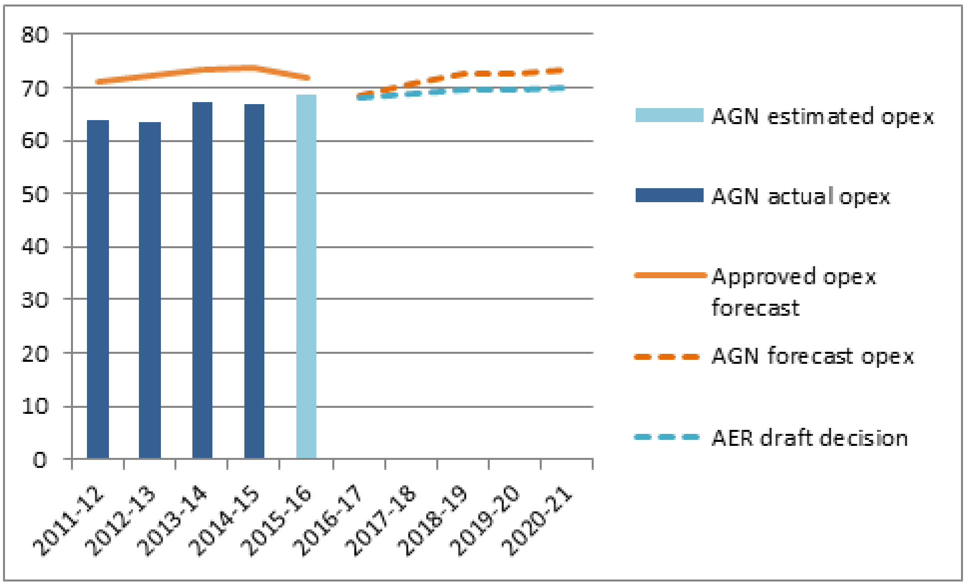
[63] This capex category includes distribution system capex that does not fall into any of the other capex categories.

AGN proposed total forecast opex of $357 million ($2015–16) over the next (2016–21) period, equivalent to an average annual opex of $71 million ($2015–16). We are not satisfied that the forecast of total opex AGN proposed reflects the opex criteria and the criteria for forecasts and estimates under the NGR.[64] Our approved opex forecast—which we consider is such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services[65]— is $ 342 million, a four per cent reduction from AGN's proposal. This is illustrated in Figure 9.

Figure 9 AER draft decision compared to AGN's past and proposed opex ($million, $2015-16)



Source: AGN opex model and RIN; and AER analysis.

Table 8 shows the difference between AGN's proposed forecast opex and the forecast in our draft decision.

64 NGR, r. 91, r. 74.

65 NGR, r. 91.

Table 8 Draft decision on total opex—AGN ($million, 2015–16)

	2016-17	2017-18	2018-19	2019-20	2020-21	Total
AGN's proposal	68.38	70.58	72.44	72.64	73.39	357.43
AER draft decision	67.66	68.55	68.90	68.61	68.62	342.35
Difference	–0.73	–2.03	–3.54	–4.03	–4.77	–15.09

Source: AER analysis.

Note: Excludes debt raising costs.

The key areas of difference between our opex forecast and AGN's forecast are:

- Category specific forecasts – we do not agree that the category specific forecasts developed by AGN for ancillary reference services, network management fee and insurance result in a total opex forecast that meets the opex criteria. We have, however, included AGN's category specific forecast for unaccounted for gas (UAFG) in our opex forecast. This is discussed further below.
- Rate of change – We consider AGN's forecast of price changes is not the best estimate of a rate of change in the circumstances. As such we consider that including it in our forecast of total opex would not lead to a forecast of opex that complies with the opex criteria. We have applied a rate of change that takes into account more recent labour cost forecasts, the impact of output growth and productivity changes.
- Step changes – We have not included forecast increases in opex related to step changes. We consider the new opex requirements identified by AGN do not relate to new obligations facing AGN or other changes in AGN's circumstances requiring a material increase in opex for the 2016–21 access arrangement period.

Unaccounted for gas

UAFG is the difference between the volume of gas that enters a distribution pipeline and the volume of gas billed to customers.[66] UAFG costs are determined by AGN as the product of forecast UAFG volumes and the price of gas AGN must purchase to supply UAFG. AGN forecast UAFG costs of $56 million ($2015–16) in the 2016–21 period, around 16 per cent of its total opex forecast.

AGN is currently participating in AEMO's review of the arrangements for the treatment of UAFG, which is considering transferring the responsibility for supplying UAFG from AGN to retailers and self–contracting users.[67] If the proposal is implemented, one

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[66] ESCV, *Gas distribution system code, Review of UAFG benchmarks*, draft decision, March 2013, p. 8.

[67] AGN, *Access Arrangement Information for AGN's South Australian Natural Gas Distribution Network* (July 2015), p. 116.

potential outcome is that AGN would not incur any UAFG costs. If this occurred, this reduction in costs will be passed through to customers through the cost pass through mechanism.

For the purposes of this draft decision we cannot pre-empt the outcomes of AEMO's review and must assess AGN's forecast of UAFG costs as though this change will not occur. There is considerable uncertainty around AGN's UAFG expenditure forecast, arising from possible forecasting error impacting UAFG volumes and gas prices. In other jurisdictions we have dealt with the uncertainty around UAFG forecasting through the application of a tariff variation mechanism. We consider there is considerable merit in applying a similar approach to AGN's UAFG expenditure forecast to reduce the exposure of AGN and its customers from windfall gains or losses arising from significant variations in gas prices. By specifically targeting changes in price, rather than changes in volume, this mechanism will still maintain incentives on AGN to reduce the UAFG volume.

This approach requires us to maintain a category specific forecast for UAFG expenditure within the total opex forecast. As a consequence, AGN's expenditure on UAFG will no longer be subject to the efficiency carryover mechanism applying to AGN.

4.7 Efficiency carryover mechanism

An efficiency carryover mechanism provides an additional incentive for service providers to pursue efficiency improvements in opex.

An efficiency carryover mechanism applied to AGN during the 2011–16 access arrangement period. Table 9 shows our draft decision on the carryover amounts from that period that will be added to the revenue building blocks for the 2016–21 access arrangement period.[68]

Table 9 AER's draft decision on AGN's carryover amounts ($million, $2015–16)

	2016-17	2017-18	2018-19	2019-20	2020-21	Total
AER draft decision on carryover amounts	6.7	(1.3)	(2.1)	1.5	0.0	4.8

Source: AER analysis.

AGN proposed a different efficiency carryover mechanism for the 2016–21 access arrangement period. We agree that AGN should continue to be subject to an efficiency carryover mechanism. However, we are concerned that AGN's proposed scheme does

68 This number differs from the $5.7 million initially provided in AGN's access arrangement RIN and which was outlined in its proposed access arrangement. The explanation for the difference is that AGN subsequently provided updated insurance amounts, which are an excluded cost category in its existing efficiency carryover mechanism. We accept that the updated amounts should be applied in calculating AGN's carryover amounts.

not adequately address the main functions of an efficiency carryover mechanism, and therefore do not accept the changes it has proposed.

The key change that AGN proposed was to allow it to retain an increased (50 per cent) share of efficiency gains, which would decrease the share allocated to consumers.[69] We do not accept AGN's argument that businesses require an increased share of efficiency gains as time passes to ensure they continue to seek efficiency gains. Actual business behaviour, including that of AGN, has been to continue to seek efficiencies under the existing incentive scheme. Further, our review of AGN's proposed scheme shows that:

- AGN would achieve an even greater share of efficiency gains (closer to 75 per cent) using its proposed equations, compared to maintaining the approach in the current efficiency carryover mechanism.
- AGN's proposed equations also provided an incentive for AGN to increase expenditure in the base year, rewarding it for efficiency losses.
- AGN's proposed mechanism provided a reward for non-recurrent efficiency gains made in the final year that is greater than the value of the efficiency gain, making network customers worse off.

Our draft decision instead requires AGN to amend its access arrangement to include a mechanism consistent with the Efficient Benefit Sharing Scheme (EBSS) for Electricity Network Service Providers which we released in November 2013.[70] This will retain the current 30:70 sharing ratio, and will streamline and reduce the costs excluded from the operation of the mechanism. It will also align the equations in AGN's access arrangement to give effect to the carryover mechanism with those used in electricity determinations, which we consider better support a revealed opex forecasting approach.

4.8 Corporate income tax

When determining the total revenue for AGN, we must estimate AGN's cost of corporate income tax.[71] AGN has adopted the post-tax framework to derive its total revenue requirement for the 2016–21 access arrangement period.[72] Under the post-tax framework, a separate corporate income tax building block is calculated, based on the estimated cost of corporate income tax less the value of imputation credits. The corporate income tax building block feeds directly into the annual revenue requirement.

Our draft decision on AGN's corporate income tax building block over the 2016–21 access arrangement period is $10.8 million ($nominal), as set out in Table 10. This

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69 An outcome of the efficiency carryover mechanism that applied to AGN in the 2011–16 access arrangement is that increases or decreases in opex relative to the allowance are shared approximately 30:70 between network service providers and consumers.

70 AER, *Efficient Benefit Sharing Scheme for Electricity Network Service Providers*, November 2013.

71 NGR, r. 76(c).

72 AGN, *Access arrangement information*, July 2015, p. 179.

represents a reduction of $27.3 million ($nominal) or 71.7 per cent of AGN's proposed corporate income tax building block.

Table 10 AER's draft decision on the corporate income tax building block for AGN for the 2016–21 access arrangement period ($million, nominal)

	2016–17	2017–18	2018–19	2019–20	2020–21	Total
Tax payable	3.7	3.4	3.3	4.7	2.9	18.0
Less: value of imputation credits	1.5	1.4	1.3	1.9	1.1	7.2
Net corporate income tax building block	2.2	2.0	2.0	2.8	1.7	10.8

Source: AER analysis.

We accept AGN's proposed approach to calculating the corporate income tax building block. The difference between our draft decision and AGN's proposal is mainly a consequence of our adjustments to:

- the opening tax asset base as at 1 July 2016, from AGN's proposed $615.6 million ($nominal) as at 1 July 2016 to $619.7 million ($nominal)
- remaining tax asset lives as at 1 July 2016
- AGN's proposed tax treatment of revenue adjustments associated with the efficiency carryover mechanism
- the value of gamma, from 0.25 to 0.40 (see section 4.3)
- other building block components, including reductions made in this draft decision to the rate of return, forecast capex and forecast opex (see sections 4.2, 4.5 and 4.6, respectively).[73]

[73] NGR, r. 87A.

5 Demand, reference tariffs and incentive schemes

5.1 Demand

Demand is an important input to the derivation of AGN's reference tariffs. Tariff prices depend on estimates of total demand (GJ/day). Changes in these forecasts will translate into changed tariff prices. In simple terms, tariff prices are determined by cost divided by total demand (GJ/day), such that an increase in forecast demand has the effect of reducing the tariff price and vice versa. Demand forecasts also affect capex and opex linked to increased network capacity.

Our review of the forecasts AGN proposed has identified concerns with the forecasting method that Core Energy has used to forecast consumption per connection for residential and commercial (or 'volume') customers. We are not satisfied that these forecasts comply with the NGR. They have not been arrived at on a reasonable basis and are not the best estimates in the circumstances.[74]

We have developed alternative demand forecasts that we consider address these concerns and comply with the NGR. We have used these alternative demand forecasts in this draft decision. These forecasts are set out in attachment 13 to this draft decision. In particular, they result in an annual average decline in forecast consumption per connection over the 2016–21 access arrangement period of:

- -3.53 per cent for all residential customers, compared to AGN's estimate of -3.96 per cent;
- -1.44 per cent for all commercial customers, compared to AGN's estimate of -1.9 per cent.

Demand forecast are a critical input into the calculation of reference tariffs and approved capex and opex. In particular, demand forecasts will impact our decision on:

- forecast connections capex - the number of new connections forecast has informed our decision on the approved connections capex allowance.
- forecast opex - forecast total connections numbers and total consumption (output growth) has been used in derive the additional opex required to service the larger network.
- tariff prices - tariff prices depend on forecast consumption per connection. Changes in these forecasts have been translated into changed tariff prices. In simple terms, tariff prices are determined by cost divided by quantity (where quantity is measured by consumption per connection). This means that the increase in forecast

[74] NGR, r. 74(2).

consumption in this draft decision relative to AGN's proposal has the effect of reducing the tariff price.

5.2 Services covered by the access arrangement

Our draft decision accepts the reference services AGN proposes to offer on its network over the 2016–21 access arrangement period. We consider that the reference services proposed by AGN are likely to be sought by a significant part of the market. This means they must be covered by the access arrangement.

The proposed haulage reference services—domestic, demand and commercial—are consistent with the haulage reference services offered by AGN during the 2011–16 access arrangement period.

AGN proposed six ancillary reference services. Three of these services—disconnection, reconnection and special meter read—are consistent with the ancillary reference services offered by AGN over the 2011–16 access arrangement period. AGN also proposed three additional ancillary reference services for meter gas installation tests, meter removal and meter reinstallation after being requested to do so from its engagement with the retailer reference group.[75]

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

5.3 Reference tariff setting

Our draft decision accepts AGN's proposed structure of reference tariffs for the 2016–21 access arrangement period. We are satisfied the proposed structure of the reference tariffs complies with the requirements of the NGR.[76] The tariff structure is consistent with that applied in the current access arrangement.[77] However, we consider the quantum of the proposed reference tariffs must be amended to reflect the revised revenue allowance based on this draft decision.

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

5.4 Reference tariff variation mechanism

The reference tariff variation mechanism:

- permits building block revenues to be recovered smoothly over the access arrangement period, subject to any differences between forecast and actual demand

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75 AGN, *Access arrangement information*, July 2015, p. 104; Origin Energy, *Response to Australian Gas Networks' proposal for the 2016–2021 regulatory control period for its South Australia gas distribution network*, August 2015, p. 6.

76 NGR, rr. 93, 94.

77 Origin Energy, *Submission on Australian Gas Networks (South Australia) Access Arrangement Proposal 2016–21*, 10 August 2015, p. 6.

- accounts for actual inflation
- accommodates other reference tariff variation adjustments that may be required, such as approved cost pass through events, and
- sets administrative procedures for the approval of any proposed changes to reference tariffs.

Our draft decision does not approve the reference tariff variation mechanism as proposed by AGN. In particular:

- the proposed initial reference tariffs and X factors must be revised to reflect the changes to the forecast total revenue identified in the overview attachment of this draft decision
- we do not accept definitions for certain parameters within the control and rebalancing mechanisms
- we do not accept AGN's reference tariff variation process
- we do not approve the cost pass through events proposed by AGN. We require amendments to the definitions of AGN’s proposed regulatory change event, service standard event, terrorism event, network user failure event, insurer credit risk event, insurance cap event and tax change event. We do not approve AGN’s proposed significant safety event, security of supply event and significant extension event.
- our draft decision also requires amendments to AGN’s access arrangement so that it more clearly includes the efficiency of AGN's actions in relation to the risk of a pass through event occurring and the magnitude of costs incurred as a result of the event as a matter that will be relevant to our assessment of a cost pass through application.

We have also included in AGN's reference tariff variation mechanism adjustment factors to accommodate additional variations to reference tariffs with respect to:

- an approved cost pass through event
- price variations for gas required to meet UAFG obligations).

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

5.5 Incentive schemes

We aim to incentivise service providers such as AGN to make efficient decisions on when and what type of expenditure to incur, and to balance expenditure efficiencies with service quality. There are a number of incentives that already exist in the framework that applies to AGN's access arrangement. For example, the NGR allow AGN to retain the full value of its approve capex forecast, including any amount it saves through more efficient delivery of its capex program, until the end of the access arrangement period. In addition, we review the capex it actually spends at the end of the period so that only conforming capex is rolled into its capital base. AGN has also described gas as a 'fuel of choice'—as an alternative energy source, it must compete with electricity—creating further incentives to remain cost efficient, and competitive in price and the quality of service.

In addition to these inherent incentives, the NGR also allow the inclusion of one or more targeted incentive schemes in an access arrangement, to supplement the incentives under the regulatory regime and encourage efficiency in the provision of services.

In addition to its proposed changes to the efficiency carryover mechanism, discussed in section 4.7, AGN proposed the introduction of three new incentive schemes in its 2016–21 access arrangement:

- a capital expenditure sharing scheme (CESS)
- a customer service incentive scheme (CSIS), and
- a network innovation scheme (NIS).

As part of our Better regulation program in 2013, we consulted on and developed a CESS to apply to electricity network service providers under the NER. The electricity CESS will apply for the first time in the electricity distribution and transmission determinations we made in April 2015 (for New South Wales and ACT distribution networks and New South Wales and Tasmanian transmission networks). However, to date we have not considered development or application of a CESS for gas service providers. AGN's proposed CSIS and NIS are new schemes that we have not applied before in electricity or gas decisions.

Where we have developed and introduced new incentive schemes under the NER—including the CESS—we have done this in conjunction with consideration of related forecasting methodologies and complementary schemes, and as part of extended consultation with stakeholders, including other service providers. It is unusual for us to consider introduction of a new incentive scheme in the context of an individual access arrangement or service provider.

We consider it preferable that the development and implementation of any new incentive schemes under the NGR be subject to a similar consultative, informed and industry-wide process. Our draft decision does not accept the introduction of these new schemes in AGN's access arrangement at this time.

In this context we note that there are conflicting views on the benefits of these schemes in gas, which require further exploration through an appropriate consultation process.

For example, while AGN has proposed a CESS, other gas service providers who submitted their proposals at the same time as AGN have said that they do not support introduction of a CESS in their own access arrangements.[78] The CCP indicated

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[78] ActewAGL, *Access arrangement information for the 2016–21 access arrangement, Attachment 10*, June 2015, p. 13; APTNT, *Amadeus gas pipeline, Access arrangement revision proposal, Submission*, August 2015, p. 169.

support for a CESS that was aligned with an opex efficiency carryover mechanism to balance incentives across opex and capex, but it did not support the scheme that AGN proposed. In their submissions on AGN's proposal Origin Energy and AGL cautioned against the introduction of a CESS that was not carefully calibrated with the regulatory framework, and may not be sufficiently transparent, enforceable or equitable. SACOSS suggested that introduction of a CESS in 2016–21 was unnecessary given existing incentives to seek capex efficiencies, and unadvisable given difficulties forecasting efficient capex for that period.

Stakeholder submissions on AGN's proposed NIS also suggest that further consideration is required. The Alternative Technology Association considered innovation incentives inappropriate given gas is a competing fuel. While the CCP and the Government of South Australia saw potential benefit in the kind of projects a NIS would support, both pointed to the need for clearer criteria and boundaries were such a scheme to be introduced.

We also have concerns about AGN's proposed introduction of a CSIS, when this scheme has yet to be developed. The Essential Services Commission of South Australia (ESCOSA), in its recent decision on the service standards that will apply to AGN in the 2016–21 access arrangement period, noted that:[79]

> This review has determined that AGN's current service levels are appropriate and should be maintained for the 2016-2021 regulatory period.
>
> Participants in AGN's stakeholder engagement program were generally satisfied with AGN's gas distribution services and reluctant to pay for improvements to current service levels.

Stakeholder submissions on the proposal for a CSIS questioned the need to incentivise what was a fundamental business imperative, and based on the ESCOSA report did not support the introduction of a CSIS. It is difficult to assess the extent to which AGN's proposed CSIS would address these concerns when the scheme itself has yet to be developed.

The reasons for our draft decision on AGN's proposed CESS, CSIS and NIS are set out in Attachment 14.

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79 ESCOSA, *Australian Gas Networks Jurisdictional Service Standards for the 2016-2021 Regulatory Period, Final Decision*, June 2015, p. 21. AGN provided this decision as Attachment 3.10 to its Access Arrangement Information.

6 Non-tariff components

AGN’s proposed 2016–21 access arrangement sets out terms and conditions on which AGN offers to supply services. These describe the relationship between AGN and users, including setting out, amongst other things, their obligations and liabilities under the agreement.

We are satisfied that most of the proposed terms and conditions are consistent with the NGO, NGR and applicable market procedures. However, our draft decision requires AGN to make a number of revisions to its terms and conditions to improve clarity and certainty for users.

AGN’s access arrangement also includes specific provisions around:

- review submission date and revision commencement date
- extension and expansion requirements
- capacity trading requirements
- provisions for changing receipt and delivery points

We have approved AGN's proposed extension and expansion requirements, but our draft decision requires amendments to clarify the capacity trading requirements and provisions for changing receipt and delivery points. We have not accepted AGN's proposed review submission and revision commencement dates for our next review. These set out the date by which AGN must submit its proposal for the next access arrangement period, and the date on which approved revisions under that proposal are intended to commence. The NGR require AGN to specify single dates for each of these, and not alternative dates as AGN has proposed. Our draft decision nominates a review submission date of 1 July 2020 and a revision commencement date of 1 July 2021.

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

7 Understanding the NGO

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. [80]

Energy Ministers have provided us with a substantial body of explanatory material that guides our understanding of the NGO.[81] The long term interests of consumers are not delivered by any one of the NGO's factors in isolation, but rather by balancing them in reaching a regulatory decision.[82]

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.[83] We have also considered the quality and reliability of services provided to consumers. For example, the opex allowance and pass through mechanism approved in this draft decision has been set so that AGN can meet existing and new regulatory requirements. Our approved capex forecast includes expenditure to replace assets that are aged or in unacceptable condition. It also allows for augmentation and connections capex catering for expected areas of growth, and for upgrades to IT systems to maintain current service levels.

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.[84] At the same time, however, there are a range of outcomes that are unlikely to advance the NGO, or advance the NGO to the degree that others would.

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.[85] 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

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80 NGL, s. 23.

81 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*, 26 September 2013, pp. 7171–7176.

82 Hansard, *SA House of Assembly*, 26 September 2013, p. 7173.

83 Hansard, *SA House of Assembly*, 9 February 2005, p. 1452.

84 *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.

85 NGL, s. 24(7).

the appropriate quality and level of service, and where customers are making more use of the network than is sustainable. This could create longer term problems in the network[86] and could have adverse consequences for safety, security and reliability of the network.

The NGL also includes the revenue and pricing principles (RPPs), which support the NGO.[87] As the NGL requires,[88] 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.
>
> 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.

86 NGL, s. 24(6).

87 NGL, s. 24.

88 NGL, s. 28(2).

> 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.[89] For example:

- In determining forecast opex and capex that reasonably reflects the opex and capex criteria, we take into account the revenue and pricing principle that we should provide AGN with a reasonable opportunity to recover at least efficient costs. (Refer to capex attachment 6 and opex attachment 7).
- We take into account the economic costs and risks of the potential for under and over investment by a service provider in our assessment AGN's forecast capex and opex proposals. (Refer to capex attachment 6 and opex attachment 7).
- We consider the economic costs and risks of the potential for under and over utilisation of AGN's distribution system in our decisions on demand forecasting and forecast augmentation capex (Refer to capex attachment 6 and demand attachment 13).
- Our application of the efficiency carryover mechanism in this decision provides AGN with effective incentives which we consider will promote economic efficiency with respect to the reference service that AGN provides throughout the access arrangement period. (Refer to attachments 9 and 14).
- We have determined AGN's opening capital base taking into account the capital adopted in the previous access arrangement. (Refer to attachment 2, capital base).
- The allowed rate of return objective reflects the revenue and pricing principle in section 24(5). We have determined a rate of return that we consider will provide AGN with a return commensurate with the regulatory and commercial risks involved in providing pipeline services. (Refer to attachment 3, rate of return).
- Our financing determinations provide AGN with a reasonable opportunity to recover at least the efficient costs of accessing debt and capital. (Refer to attachment 3, rate of return).

In some cases, our approach to a particular component (or part thereof) results in an outcome towards the end of the range of options that may be favourable to the businesses, for example, our choice of equity beta. Some of these decisions include:

- selecting at 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+

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89 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.

- the cash flow timing assumptions in the post-tax revenue model.

We take into account the RPPs when exercising discretion about an appropriate estimate. This requires a recognition that for the long term interests of consumers, the risk of under compensation for, or underinvestment by, a service provider may be less desirable than the risk of overcompensation or overinvestment. However, we are also conscious of the risk of introducing an inherent bias towards higher amounts where estimates throughout the different components of the forecast revenue requirement are each set too conservatively.[90] The legislative framework recognises the complexity of this task by providing us with significant discretion in many aspects of the decision-making process to make judgements on these matters.

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.

7.1 Achieving the NGO to the greatest degree

An access arrangement decision is complex and must be considered as such. In most instances, the provisions of the NGR do not point to a single answer, either for our decision as a whole or in respect of particular components. They require us to exercise our regulatory judgment. For example, Part 9 of the NGR requires us to prepare forecasts, which are predictions about unknown future circumstances. As a result, there will likely always be more than one plausible forecast. There is substantial debate amongst stakeholders about the costs we must forecast, with both sides often supported by expert opinion. As a result, for certain components of our decision there may be several plausible answers or several plausible point estimates.

When the components of our decision are considered together, this means there will almost always be several potential, overall decisions. More than one of these may contribute to the achievement of the NGO. Where this is the case, our role is to make an overall decision that we are satisfied contributes to the achievement of the NGO to the *greatest* degree.[91]

We approach this from a practical perspective, accepting that it is not possible to consider every permutation specifically. Where there are choices to be made among several plausible alternatives each of which would result in an overall decision that contributes to the achievement of the NGO, we have selected what we are satisfied would result in an overall decision that contributes to the achievement of the NGO to the greatest degree.

Also, in coming to this draft decision we have considered AGN's proposal. We have examined each of the building block components of the forecast revenue requirement,

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90 AEMC, Rule Determination, National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18, 16 November 2016, p. 52.

91 NGL, s. 28(1)(b)(iii).

and the incentive mechanisms that should apply across the next access arrangement period. We have considered submissions we received in regard to AGN's proposal. We have conducted our own analysis and engaged expert consultants to help us better understand if and how AGN's proposal contributes to the achievement of the NGO. We have also considered how the individual components of our decision relate to each other, the impact that particular components of our decision have on others, and have described these interrelationships in this draft decision. We have had regard to and weighed up all of the information assembled before us in making this draft decision, and have made as much of this information publicly available as practicable for the purposes of consultation.

Therefore, we are satisfied that among the options before us, our draft decision on AGN's access arrangement for the 2016–21 access arrangement period contributes to achieving the NGO to the greatest degree.

7.1.1 Interrelationships between individual components

Considering individual components in isolation ignores the importance of interrelationships between components of the overall decision, 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.[92] 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 forecasts of the efficient levels of capex and opex in the access arrangement period (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, completion of forecast augmentation (capex) to the network will mean the service provider has more assets to maintain, leading to higher opex requirements (see attachments 6 and 7).

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

- 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).

We have considered interrelationships, including those above, in our analysis of the individual components of our decision. These considerations are explored in the relevant attachments.

8 Consultation

Stakeholder participation is important to informed decision making under the NGL and NGR. It allows us to take a range of views into account when considering how a proposal or decision contributes to the NGO. Effective consultation and engagement provide confidence in our processes and are good regulatory practice. This is reflected in the consultation process set out in the NGR.

We published AGN's access arrangement revision proposal and supporting material on our website in July 2015, and invited written submissions on the access arrangement proposals.[93] We also sought advice on AGN's access arrangement proposal from the AER's Consumer Challenge Panel (CCP). During this consultation period, AER staff and members of the CCP met with a number of key stakeholders in Adelaide. In developing this draft decision we have considered views presented to us by all stakeholders.[94] We received 15 written submissions from stakeholders. This includes written advice from the CCP, which was presented to the AER Board in August 2015. A list of stakeholder submissions is provided in appendix A to this Overview. All submissions are available on our website.

This process builds on consultation undertaken by the AER as part of the Better Regulation program. Following the 2012 changes to the National Electricity Rules (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 Better Regulation program was designed to be an inclusive process that provided an opportunity for all stakeholders to be engaged and provide their input.[95]

This 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 to the greatest degree. Our Better Regulation guidelines are available on our website and include:[96]

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

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93 NGR, r. 58(1).

94 NGR, r. 59(1).

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

96 See AER, http://www.aer.gov.au/networks-pipelines/better-regulation.

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.

AGN presented its access arrangement revision proposal to the AER Board in August 2015. AER staff, including our technical advisors, directly engaged with AGN staff throughout the review process, and tested material and information underpinning its access arrangement revision proposal. During this process, we requested and considered additional information from AGN to help us understand its proposal.

AGN also undertook its own stakeholder engagement in the development of its proposal. Submissions received by us from Business SA, [97] the South Australian Council on Social Service (SACOSS) [98] and the Energy Consumers Council of SA (ECCSA), [99] and advice from the Consumer Challenge Panel recognise that AGN has taken important steps to involving consumers in the regulatory process.[100] We support this view. Submissions also indicate there are further opportunities for AGN (and us) to improve our engagement. We will consider this in developing our consumer engagement programs going forward, and encourage AGN to do the same.

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[97] Business SA, *Submission to AER on proposed Australian Gas Networks Access Arrangement (2016-21),* 10 August 2015, p. 4.

[98] SACOSS, *Submission on AGN's regulatory proposal for the 2016-2021 Access Arrangement (AA) period*, 8 August 2015.

[99] ECCSA, *Australian Energy Regulator SA Gas Distribution Revenue Reset AGN Application response*, 16 August 2015.

[100] CCP8, *Advice to AER from Consumer Challenge Panel sub-panel 8 regarding Australian Gas Networks' (SA) Access Arrangement 2016-2021 Proposal,* 25 August 2015.

A List of submissions

Submission from	Date received
AGL Energy Ltd	11 August 2015
Alternative Technology Association	10 August 2015
Business SA	10 August 2015
Consumer Challenge Panel	25 August 2015
CitiPower and Powercor	24 July 2015
Energy Consumers Coalition of South Australia	16 August 2015
Energy Networks Association	2 September 2015
Jemena Electricity Networks	24 July 2015
Multinet Gas	24 July 2015
Nyrstar Port Pirie Pty Ltd	10 August 2015
Origin Energy LPG	10 August 2015
Government of South Australia	21 August 2015
South Australian Council of Social Service	8 August 2015
South Australian Wine Industry Association Inc.	10 August 2015
United Energy	24 July 2015