



DRAFT DECISION
Australian Gas Networks
Access Arrangement
2016 to 2021

Attachment 6 – Capital
expenditure

November 2015

© Commonwealth of Australia 2015

This work is copyright. In addition to any use permitted under the Copyright Act 1968, all material contained within this work is provided under a Creative Commons Attributions 3.0 Australia licence, with the exception of:

- the Commonwealth Coat of Arms
- the ACCC and AER logos
- any illustration, diagram, photograph or graphic over which the Australian Competition and Consumer Commission does not hold copyright, but which may be part of or contained within this publication. The details of the relevant licence conditions are available on the Creative Commons website, as is the full legal code for the CC BY 3.0 AU licence.

Requests and inquiries concerning reproduction and rights should be addressed to the:

Director, Corporate Communications
Australian Competition and Consumer Commission
GPO Box 4141, Canberra ACT 2601

or publishing.unit@acc.gov.au.

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

Note

This attachment forms part of the AER's draft decision on Australian Gas Networks' access arrangement for the 2016–21 access arrangement period. 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

Note	6-2
Contents	6-3
Shortened forms	6-4
6 Capital expenditure	6-6
6.1 Draft decision	6-6
6.1.1 Conforming capital expenditure for 2010–16	6-6
6.1.2 Conforming capital expenditure for the 2016–21 access arrangement period	6-7
6.2 Australian Gas Networks’ proposal	6-9
6.3 AER’s assessment approach	6-12
6.3.1 NGR requirements for conforming capital expenditure	6-13
6.3.2 Assessment of conforming capital expenditure in the previous period	6-14
6.3.3 Assessing forecast capex for the 2016–21 access arrangement period	6-16
6.3.4 Interrelationships.....	6-18
6.4 Reasons for draft decision	6-18
6.4.1 Conforming capital expenditure for 2010–15	6-18
6.4.2 Conforming capital expenditure for the 2016–21 access arrangement period	6-20
6.4.3 Labour escalation.....	6-53
6.5 Revisions	6-54
A Confidential appendix	6-55

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

6 Capital expenditure

This attachment outlines our assessment of AGN's proposed conforming capital expenditure (capex) for 2010–16 and forecast capex for the 2016–21 access arrangement period.

6.1 Draft decision

6.1.1 Conforming capital expenditure for 2010–16

We approve \$392.6 million (\$2014–15) of total net capex for AGN during the 2010–2015 period as conforming capex under rule 79(1) of the NGR.

Table 6.1 shows our approved capex for 2010–15 by category.

Table 6.1 AER approved capital expenditure by category over 2011–16 (\$million, 2014–15)

Category	2010–11	2011–12	2012–13	2013–14	2014–15	2015–16(a)
Connections (Market expansion)	22.5	20.1	19.4	25.5	17.5	18.8
Mains replacement	15.6	24.0	36.5	45.5	49.5	70.8
Meter replacement	2.7	2.2	2.4	3.6	3.8	3.6
Augmentation	1.3	6.3	15.2	5.1	5.4	15.1
Telemetry	0.2	0.2	0.2	0.3	0.3	0.5
Regulators	0.2	0.3	0.9	2.7	2.7	0.7
IT	0.3	0.1	2.4	6.8	10.6	2.2
Other distribution system	0.0	1.6	0.8	3.2	2.5	1.7
Other non–distribution system	0.8	0.0	0.7	0.6	3.1	2.3
Overheads	0.0	5.9	7.5	7.9	9.2	11.1
GROSS TOTAL CAPITAL EXPENDITURE	43.6	60.7	86.0	101.3	104.6	126.9
Contributions	0.2	0.3	1.6	0.6	0.9	0.2
NET TOTAL CAPITAL EXPENDITURE	43.4	60.4	84.4	100.7	103.7	126.6

Source: AER analysis.

Note: (a) As set out in attachment 2, we have not assessed the 2015–16 amounts as approved capex under this decision. This is because these values are estimates. We will undertake the assessment of whether the 2015–16 amounts are conforming capex as part of the next access arrangement determination.

6.1.2 Conforming capital expenditure for the 2016–21 access arrangement period

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.

Table 6.2 shows our approved capex for the 2016–21 access arrangement period by category.

Table 6.2 AER approved capital expenditure by category over the 2016–21 access arrangement period (\$million, 2014–15)

Category	2016–17	2017–18	2018–19	2019–20	2020–21	Total
Mains replacement	33.5	33.5	33.5	33.5	33.5	167.7
Meter replacement	4.2	4.0	3.7	2.9	2.3	17.1
Augmentation	0.6	0.5	1.1	1.7	0.2	4.1
Telemetry	0.3	0.2	0.2	0.2	0.1	1.1
Regulators	2.1	2.1	2.3	2.3	2.1	11.0
IT	9.1	13.3	8.0	2.6	4.8	37.9
Growth assets ^a	17.0	16.1	16.9	17.6	17.8	85.4
Other distribution system	2.2	2.0	2.0	1.9	1.9	10.0
Other non–distribution system	1.3	1.0	0.9	0.9	0.9	5.0
Escalation	0.4	0.8	1.3	1.8	2.7	7.0
Overheads	9.4	9.8	9.4	9.2	9.0	46.8
NET TOTAL CAPITAL EXPENDITURE	80.1	83.4	79.4	74.7	75.4	393.0
Contributions	0.6	0.7	0.7	0.9	0.7	3.6
GROSS TOTAL CAPITAL EXPENDITURE	80.7	84.1	80.1	75.6	76.1	396.6

Source: AER analysis.

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

Table 6.3 shows AGN's proposed capex compared with our alternative capex estimate for each category. In coming to our position, we assessed AGN's forecast capex taking into account the available evidence and submissions from stakeholders.

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

In contrast, we found that other aspects of AGN’s proposal, in particular, its proposed capex for connections, IT and mains replacement program, 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 these shortfalls.

Table 6.3 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 6.3, the main difference between AGN’s proposed capex and our alternative capex estimate for the 2016–21 access arrangement period that we consider is conforming capex that complies with rule 79 concern the following:

- Mains replacement

Our draft decision is to include \$167.7 million (\$2014–15, unescalated direct costs) of mains replacement capex in our alternative capex estimate. 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.¹ AGN has not provided evidence in the form of a rigorous (quantitative) risk assessment to demonstrate that the proposed capex is conforming capex over the 2016–21 access arrangement period that complies with rule 79.

- IT

Our draft decision is to include \$37.9 million (\$2014–15, unescalated direct costs) of IT capex in our alternative capex estimate. 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 capex for five projects is justified. The other four projects were not included because we assessed that these were not consistent with the NGR.

- Augmentation

Our draft decision is to include \$4.1 million (\$2014–15, unescalated direct costs) of augmentation capex in our alternative capex estimate. This is a reduction of 77.1 per cent from AGN's forecast expenditure of \$17.9 million (\$2014–15, 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 (SA21) and Murray Bridge (SA71).

- Other distribution system capex²

Our draft decision is to include \$10.0 million (\$2014–15, unescalated direct costs) of other distribution system capex in our alternative capex estimate. This is a reduction of 73 per cent from AGN's forecast of \$37.0 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, where we did not have a cost benefit analysis to assess prudence and efficiency of the proposed capex. We have also included alternative capex estimates for four projects that were proposed by AGN.

6.2 Australian Gas Networks' proposal

2010–15 period

AGN has proposed net capex of \$519.3 million for the 2010–16 period, where capex in 2015–16 is an estimate. Without the estimate of capex for 2015–16, AGN has

¹ AGN, *SA Access Arrangement Information*, July 2015, Attachment 8.8_SA Capex Model - Confidential Version.xls.

² This capex category includes distribution system capex that does not fall into any of the other capex categories.

proposed \$392.6 million as conforming capex. We accept \$392.6 million as conforming capex for 2010–15, and will assess whether capex incurred in 2015–16 is conforming in the next review.

For 2010–16 AGN underspent net capex by 13.2 per cent (\$79.6 million). This includes the 2015–16 estimate. Without the 2015–16 estimate, AGN underspent net capex by 20.2 per cent (\$100.2 million).³

Table 6.4 AGN's proposed capital expenditure over 2010–11 to 2015–16 (\$million, 2014–15)

Category	2010–11	2011–12	2012–13	2013–14	2014–15	2015–16
Connections (Market expansion)	22.5	20.1	19.4	25.5	17.5	18.8
Mains replacement	15.6	24.0	36.5	45.5	49.5	70.8
Meter replacement	2.7	2.2	2.4	3.6	3.8	3.6
Augmentation	1.3	6.3	15.2	5.1	5.4	15.1
Telemetry	0.2	0.2	0.2	0.3	0.3	0.5
Regulators	0.2	0.3	0.9	2.7	2.7	0.7
IT	0.3	0.1	2.4	6.8	10.6	2.2
Other distribution system	0.0	1.6	0.8	3.2	2.5	1.7
Other non–distribution system	0.8	0.0	0.7	0.6	3.1	2.3
Overheads	0.0	5.9	7.5	7.9	9.2	11.1
GROSS TOTAL CAPITAL EXPENDITURE	43.6	60.7	86.0	101.3	104.6	126.9
Contributions	0.2	0.3	1.6	0.6	0.9	0.2
NET TOTAL CAPITAL EXPENDITURE	43.4	60.4	84.4	100.7	103.7	126.6

Source: AGN, *SA Access Arrangement Information*, July 2015, Attachment 8.8_SA Capex Model – Confidential Version.xls 2016–21 access arrangement period.

AGN proposed net total capex of \$687.3 million (\$2014–15) for the 2016–21 access arrangement period. This represents a real increase of 25 per cent over the amount approved by the AER for the 2011–16 access arrangement period.

³ This includes the capital amount approved by ESCOSA for 2010–11.

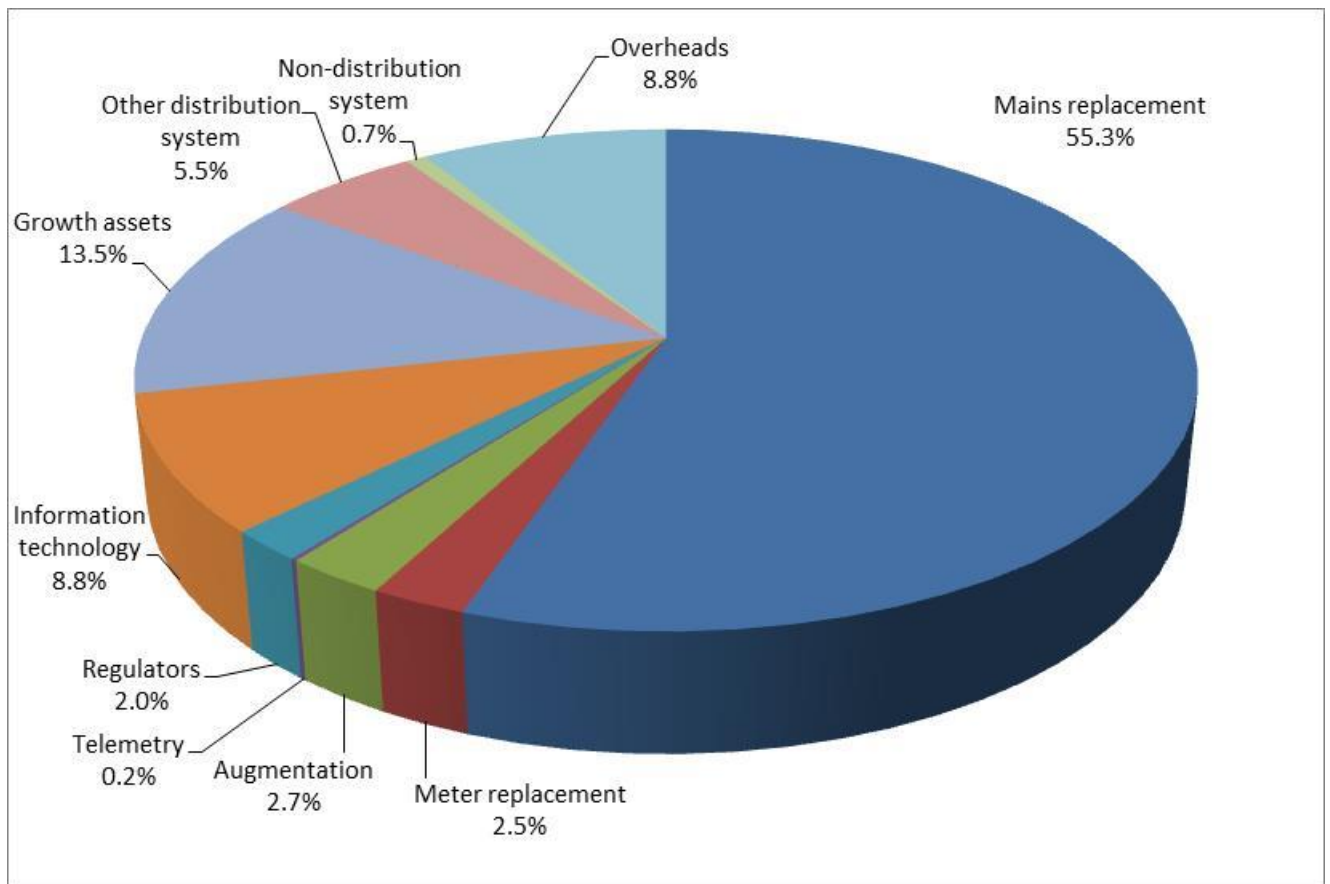
Table 6.5 AGN proposed capital expenditure by category over the 2016–21 access arrangement period (\$million, 2014–15)

Category	2016–17	2017–18	2018–19	2019–20	2020–21	Total
Mains replacement	75.2	74.1	73.6	75.8	71.3	369.9
Meter replacement	4.2	4.0	3.7	2.9	2.3	17.1
Augmentation	1.6	8.8	4.3	2.3	0.8	17.9
Telemetry	0.3	0.2	0.2	0.2	0.1	1.1
Regulators	2.6	2.6	2.8	2.8	2.7	13.6
IT	11.0	18.1	14.5	8.5	7.6	59.7
Growth assets	17.0	16.1	16.9	22.6	18.1	90.6
Other distribution system	8.9	7.5	7.3	6.8	6.4	37.0
Other non–distribution system	1.3	1.0	0.9	0.9	0.9	5.0
Escalation	0.7	1.8	2.8	4.1	5.5	14.9
Overheads	11.8	12.9	12.2	12.3	11.2	60.4
NET TOTAL CAPITAL EXPENDITURE	134.7	147.2	139.2	139.3	126.8	687.3
Contributions	0.6	0.7	0.7	0.9	0.7	3.6
GROSS TOTAL CAPITAL EXPENDITURE	135.4	147.8	139.9	140.2	127.5	690.8

Source: AGN, SA capex model updated in response to AER query AGN009, 31 July 2015.

The major components of the forecast gross total expenditure over the 2016–21 access arrangement period are mains replacement (55.3 per cent), growth assets (13.5 per cent), overheads (8.8 per cent) and IT (8.8 per cent). This is set out in Figure 6.1.

Figure 6.1 Composition of AGN's total capex for 2016–21



Source: AER analysis.

6.3 AER's assessment approach

Under the NGR, we are required to 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, with approved capex added to the starting capital base.⁴ Where capex meets these criteria, it is referred to as "conforming".⁵ Secondly, we are required to assess AGN's proposed forecast of required capex for the 2016–21 access arrangement period to determine whether it is 'conforming.' The following sections set out our approach and the tools and techniques we employ in forming a view on these two decisions. We also need to take into account timing issues associated with the lag between actual capex data being available and the need to forecast an opening capital base. This is explained in the next section.

⁴ NGR, r. 77(2)(b).

⁵ NGR, r. 79.

6.3.1 NGR requirements for conforming capital expenditure

Capex is defined as costs and expenditure of a capital nature incurred to provide, or in providing, pipeline services.⁶ It is based on a forecast or estimate which must be supported by a statement of the basis of the forecast or estimate.⁷ Any forecast or estimate submitted must:

- be arrived at on a reasonable basis; and
- represent the best forecast or estimate possible in the circumstances.⁸

Capex is conforming capital expenditure if it conforms with the criteria in rule 79 of the NGR. There are two essential criteria that must both be met under this rule:

- The expenditure must be such as would be incurred by a prudent service provider acting efficiently, in accordance with good industry practice, to achieve the lowest sustainable cost of providing services; and
- The expenditure must be justifiable on one of four grounds set out in rule 79(2) of the NGR.

The four grounds set out in rule 79(2) of the NGR can be summarised as follows. The capex must either:

- have an overall economic value that is positive
- demonstrate an expected present value of the incremental revenue that exceeds the present value of the capex
- be necessary to maintain and improve the safety of services, or maintain the integrity of services, or comply with a regulatory obligation or requirement, or maintain capacity to meet levels of demand existing at the time the capex is incurred, or
- be justifiable as a combination of the preceding two dot points.

Rule 79(3) of the NGR provides:

In deciding whether the overall economic value of capital expenditure is positive, consideration is to be given only to economic value directly accruing to the service provider, gas providers, users and end users.

We have limited discretion when making decisions under rule 79 of the NGR.⁹ This means that we must approve a particular element of the access arrangement proposal if we are satisfied that the element complies with the applicable requirements of the NGR and NGL and is consistent with any criteria set out in the NGR or NGL.¹⁰

⁶ NGR, r. 69.

⁷ NGR, r. 74(1).

⁸ NGR, r. 74(2).

⁹ NGR, r. 79(6).

¹⁰ NGR, r. 40(2).

6.3.2 Assessment of conforming capital expenditure in the previous period

In assessing AGN's proposed capex in the earlier access arrangement period, we reviewed AGN's supporting material. This included information on AGN's reasoning and, where relevant, business cases, audited regulatory accounts, and other relevant information. This information helped us identify whether capex over the earlier access arrangement period was conforming capex and, in turn, whether that capex should be included in the opening capital base in accordance with rule 77(2)(b) of the NGR.

We do not approve certain information and forecasts provided by AGN if the information does not meet the requirements set out in the NGR.¹¹ We must exercise our economic regulatory functions in a manner that will or is likely to contribute to the achievement of the NGO.¹² For instance, having regard to the NGO, we take the view that a prudent service provider will seek cost efficiencies through continuous improvements, and that customers ultimately share in these benefits. This also provides the service provider with a reasonable opportunity to recover at least its efficient costs in accordance with the revenue and pricing principles.

Although the capital base roll forward relates to the 2011–16 access arrangement period, we are also required to adjust for the difference between actual and forecast capex in the capital base.¹³ Generally, the final year of the previous access arrangement period is based on forecast capex (in this case, 2010–11). Therefore, our assessment of conforming capex includes the regulatory years for 2010–15. This is because:

- 2010–11 capex—when conducting the previous access arrangement review, we did not yet have actual capex for 2010–11. We therefore included in the capital base benchmark AGN's estimate of capex for 2010–11. Since actual capex is now available for 2010–11, we have assessed whether AGN's actual capex for 2010–11 is conforming capex under the NGR.¹⁴ This conforming capex is now included in the capital base roll forward.¹⁵
- 2011–15 capex—for this access arrangement review, we have the actual capex for 2011–15. We have assessed whether AGN's actual capex for 2011–15 is conforming under the NGR for inclusion in the capital base roll forward.¹⁶
- 2015–16 capex—for this access arrangement review, we do not yet have actual capex for 2015–16. We have therefore included in the capital base roll forward AGN's estimate of capex for 2015–16. At the next access arrangement review, we

¹¹ For instance, r. 74 of the NGR requires estimates and forecasts to be made on a reasonable basis, amongst other things.

¹² NGL, s. 28(1).

¹³ NGR, r. 77(2)(a).

¹⁴ NGR, r. 79.

¹⁵ NGR, r. 77(2)(b).

¹⁶ NGR, r. 77(2)(b), 79r.

will assess whether AGN's actual capex for 2015–16 is conforming capex under the NGR.¹⁷

We assessed the key drivers for the capex to assess whether AGN's proposed capex in the projected capital base complies with the capex criteria in rule 79(1) of the NGR. In doing so, we relied on the following information:

- The access arrangement information (AAI) – this document outlines AGN's program of capital expenditure and describes the main drivers of increased capital expenditure¹⁸
- The Asset Management Plan, Mains Replacement Plan, Capacity Management Plan, Information Technology Plan, and other attachments which provided specific expenditure detail¹⁹
- AGN's RIN template²⁰
- Business cases which detail expenditure requirements of specific projects²¹
- AGN's tender and contract documentation²²
- AGN's capex model.²³

We assessed the prudence and efficiency of the proposed capex, to determine whether the capex is 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.²⁴ We also assessed whether the proposed capex is justified on one of the four grounds under NGR rule 79(2).

For analysis purposes the capex was broken into categories depending on whether the expenditure is driven by:

- Growth in demand – extensions, connections, augmentation
- Replacement on the basis of asset life, obsolescence, safety or regulatory obligations – mains, services, meters, regulators, city gates, IT, SCADA, or
- Other – new regulatory or safety obligations, opex or reliability improvements.

For each category of expenditure the scope, timing and cost of the proposed expenditure was considered in order to form a view on the prudence and efficiency of the expenditure. Our assessment also considered whether cost forecasts have been

¹⁷ NGR, r. 79.

¹⁸ AGN, *SA Access Arrangement Information*, July 2015.

¹⁹ AGN, *SA Access Arrangement Information*, July 2015, Attachments 8.1, 8.2, 8.3, 8.4, 8.5, 8.6, 8.7.

²⁰ AGN, *SA Access Arrangement Information*, July 2015, MASTER Final RIN - AGN SA - Regulatory templates (Revised CC) – CONFIDENTIAL.xls.

²¹ AGN, *SA Access Arrangement Information*, July 2015, Attachment 7.1_Business Cases.pdf.

²² AGN, *SA Access Arrangement Information*, July 2015, Attachment 8.6, Appendices 1a, 1b, 2a, 2b, 3a–3e, 5a, 6a.

²³ AGN, *SA Access Arrangement Information*, July 2015, Attachment 8.8_SA Capex Model - Confidential Version.xls.

²⁴ NGR, r. 79(1)(a).

arrived at on a reasonable basis and represent the best forecast possible in the circumstances.

6.3.3 Assessing forecast capex for the 2016–21 access arrangement period

The following sections set out our approach to assessing AGN's forecast capex for the 2016–21 access arrangement period. Our tools and techniques cover:

- assessing whether any outsourcing to third-parties reflect genuine arm's length arrangements
- assessing historical expenditure under the revealed cost approach
- how we compare costs against previous decisions we have made (benchmarking)
- consideration of technical engineering advice
- determining the appropriate estimate for equity raising costs.

Assessing competitive tender processes for outsourced activities

Outsourcing to specialist providers of a particular service is a common means by which businesses in the economy are able to gain access to economies of scale and scope and other efficiencies.

Where AGN has used tendered rates as the basis of proposed unit costs, we relied on our approach to assessing outsourcing arrangements.²⁵ The first stage of the conceptual framework is a 'presumption threshold' designed to be an initial filter to determine which contracts can be presumed to reflect efficient costs that would be incurred by a prudent operator.²⁶

In undertaking this 'presumption threshold' assessment, we consider:

- Did the service provider have an incentive to agree to non-arm's length terms at the time the contract was negotiated (or at its most recent re-negotiation)?
- If yes, was a competitive open tender process conducted in a competitive market?

In the absence of an incentive to agree to non-arm's length terms, we consider it reasonable to presume a contract price reflects efficient costs. We also consider this presumption to be reasonable where an incentive to agree to non-arm's length terms exists but the contract was the outcome of a competitive open tender process in a competitive market.²⁷

²⁵ AER, *Better Regulation: Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, pp. 9–10.

²⁶ NGR, r. 71(1).

²⁷ NGR, r. 71(1).

Where an arrangement 'passes' the presumption threshold, we consider the starting point for setting future expenditure should be the contract price itself, with limited further examination. This further examination involves checking whether the contract wholly relates to the relevant services and whether the contract price already compensates for risks or costs provided for elsewhere in the building blocks.

Revealed cost approach

The revealed cost approach considers information revealed by the past performance of a gas business. Under the ex-ante regime, gas businesses are rewarded for spending less capex than allowed by the regulator. This incentive enables us to place some reliance on the historical costs of a gas business when reviewing its forecast capex. We used historical costs and volumes as an indicator of efficient costs and volumes for certain categories of capex in this draft decision. In particular, we used historical total costs, unit costs and volumes in assessing connections, mains and services replacements, meter replacements, SCADA and IT.

The revealed cost approach is an accepted industry practice. Many gas businesses, including AGN, have used this approach as a basis to forecast expenditure proposals. We have also used this approach previously in our assessment of access arrangement proposals for the Victorian gas businesses.

Benchmarking against the other businesses' proposed unit costs and volumes

We also conducted comparative analysis of unit costs AGN has used to develop its capex forecast. Comparing the costs incurred by one regulated entity against the costs incurred by other regulated entities in similar circumstances, and using the comparison to assess the efficiency and prudence of those costs, is known as 'benchmarking'. We consider that the use of benchmarking to assess whether capex is conforming is consistent with the requirements of the NGR.

We undertook high level benchmarking of a selection of AGN's unit costs against similar unit costs of the Victorian gas businesses. Where required some adjustment for compositional difference was made. This comparison was used for assessing connections, mains and services replacements, meter renewals and upgrade and SCADA.

Where this benchmarking indicated that AGN's capex may not be efficient, we undertook a detailed review of AGN's proposal. Our detailed review involved consideration of relevant documentation and the impact of factors expected to differ from the past and/or from the Victorian gas businesses.

We recognise that forecast efficient costs may legitimately depart from those revealed through past performance, and compared with other gas businesses. For example, gas businesses may discover more efficient processes over time. The gas businesses may propose that they can best achieve their safety, reliability or regulatory obligations by incurring expenditure to implement new, more efficient processes, and include such expenditure in their proposed forecast capex. We consider it likely that a prudent

service provider, acting efficiently, would only change operating processes (from revealed, or otherwise efficient processes) if they are likely to result in efficiency gains (in the absence of any information to suggest other reasons for the change). Where we consider that future cost savings should result from capex investments, we have taken this into consideration in determining our alternative opex estimate.

Specialist technical advice

We drew on engineering and other technical expertise within the AER to assist with our review on the prudence and efficiency of AGN's proposed mains replacement program.

We also engaged an engineering consultant, Sleeman Consulting, to provide us with specialist technical advice on the prudence and efficiency of AGN's proposed augmentation, regulators and valves, and other distribution system capex.²⁸

Cash flow analysis for equity raising costs

To determine the amount of equity raising costs, we have undertaken an assessment of benchmark cash flows calculated in the PTRM. Under this method, a prudent service provider, acting efficiently, would first exhaust the cheapest sources of funding, such as internal cash flows, before using more expensive external sources of funding, such as equity financing. The cash flow modelling approach used by the AER incorporates this assumption to determine if any external equity financing would be required based on the AER's capex forecast for AGN. For further discussion see attachment 3, section 3.4.1.

6.3.4 Interrelationships

In assessing AGN's total forecast capex we took into account other components of its proposal, including:

- the trade-off between potential capex and opex solutions in our assessment of AGN's proposed capex.
- any change in the capitalisation policy applied between the current access arrangement and the 2016–21 access arrangement period.

6.4 Reasons for draft decision

6.4.1 Conforming capital expenditure for 2010–15

AGN has proposed net capex of \$519.3 million for the 2010–16 period, where capex in 2015–16 is an estimate. Without the estimate of capex for 2015–16, AGN has proposed \$392.6 million as conforming capex. We accept \$392.6 million as conforming

²⁸ Sleeman Consulting, *Australian Gas Networks access arrangement 2016/17 to 2020/21: Review of capex forecasts for selected projects*, 18 November 2015.

capex for 2010–15, and will assess whether capex incurred in 2015–16 is conforming in the next review.

In reaching this view we have considered the following factors:

- AGN's network capex was \$7.4 million (14.4 per cent) under the ESCOSA approved amount of \$51 million (\$2014–15) for 2010–11.²⁹
- AGN's network capex was \$93 million (20 per cent) under the AER approved amount of \$445.4 million for 2011–15.³⁰
- AGN spent less than our forecast on its network in six out of nine categories during the 2010–15 access arrangement period. In five categories, the underspend was greater than 20 per cent below forecast (see).
- The largest underspends in the 2010–15 access arrangement period³¹ occurred in the connections/growth assets, other distribution, and meter replacement categories:³²
 - In the connections/growth assets category, AGN spent \$57.7 million less forecast due to a smaller volume of new connections occurring than was approved
 - In the other distribution category, AGN spent \$34 million less than forecast due a change in the costs captured in this category. Formerly this category captured the costs of complying with new requirements for road works and reinstatement. These costs were instead allocated directly to the augmentation, growth and mains replacement categories.
 - In the meter replacement category, AGN spent \$4.0 million less than the AER's estimate due to lower volumes of domestic meters being replaced than forecast, which AGN submitted reflected an updated view of the required replacement program for various meter family types.
- The largest overspends in the 2010–15 access arrangement period occurred in information technology (IT), augmentation, and regulators categories:³³
 - In the IT category, AGN exceeded the forecast by \$10.1 million due to the development and implementation of AGN's Enterprise Asset Management (EAM) system, the requirements/complexity of which was not forecast at the time the benchmarks were set.

²⁹ Envestra, *South Australia Access Arrangement Information*, 1 October 2010, Table 3.6, p. 36; AGN, *SA Access Arrangement Information*, July 2015, MASTER Final RIN - AGN SA - Regulatory templates (Revised CC) – CONFIDENTIAL.xls.

³⁰ AER, *Access arrangement final decision – Envestra (SA)*, June 2011, Table 3.11, p. 30.

³¹ Only the 2011–15 period comparison by category has been presented as the ESCOSA decision was not made on the same category basis and was not in the same level of detail as the AER 2011–16 Access Arrangement Decision.

³² AGN, *SA Access Arrangement Information*, July 2015, p. 78.

³³ AGN, *SA Access Arrangement Information*, July 2015, p. 78.

- In the augmentation category, AGN exceeded the forecast by \$5.8 million due to the completion of additional augmentation projects than were forecast, including projects in Tapley's Hill Road, Gawler, and Salisbury.
- In the regulators category, AGN exceeded the forecast by \$3.6 million due to a new national design standard requiring more expensive components and installation costs, increased decommissioning costs of existing regulators and valves due to greater traffic management requirements and higher than expected instances of asbestos.

6.4.2 Conforming capital expenditure for the 2016–21 access arrangement period

The rest of this attachment sets out our analysis of the capex drivers in coming to our position to 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.

Growth Assets (new connections capex)

Distribution businesses have a regulatory obligation to make a connection offer to residential and commercial/industrial customers making application to connect to its distribution network.³⁴

The capex associated with these connections, which includes the cost of new mains, gas service pipe from the main to the meter and the meter, generally differs depending on whether the connection is for a Tariff V customer or a Tariff D customer. Tariff V customers are categorised into existing homes, new estates, multi-users and commercial/industrial customers who consume less than 10 TJ/year. Tariff D customers are major industrial customers who consume more than 10 TJ/year.

We have included \$85.4 million (\$2015, unescalated direct costs) of connections net capex in our alternative capex estimate. We consider that this amount is conforming capex that complies with rule 79(1) of the NGR. This is lower than AGN's forecast net capex of \$90.6 million (\$2015, unescalated direct costs).³⁵ Our reduction of 5.8 per cent is largely driven by our position that capital expenditure for AGN's proposed Two Wells extension has not been justified.

We have considered confidential material in coming to our position. The confidential material is contained in Appendix A.

³⁴ NGR, r. 119S, for basic and standard connections and NGR, r. 119V, for negotiated connections.

³⁵ AGN, *SA Access Arrangement Information*, July 2015, Attachment 8.8_SA Capex Model - Confidential Version.xls.

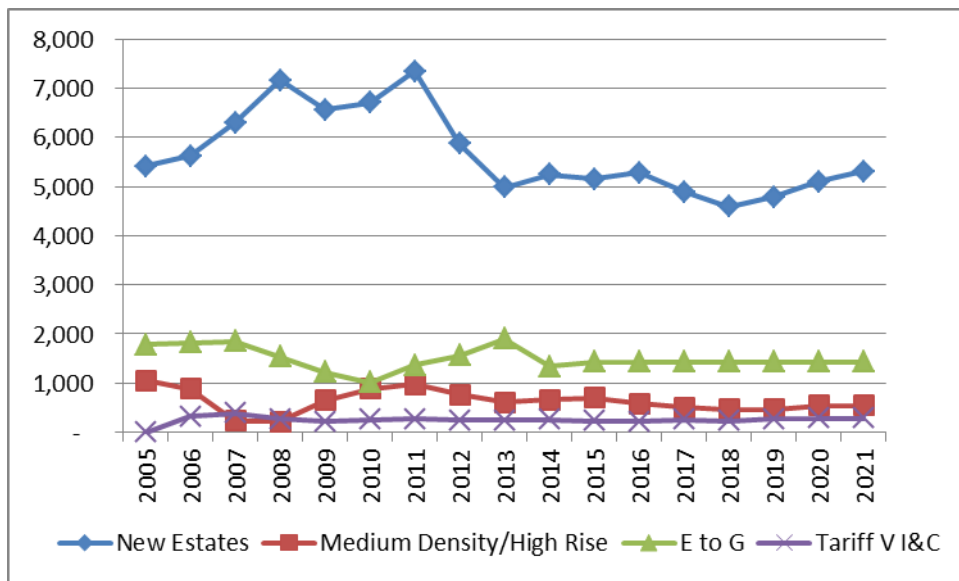
Volumes

Upon reviewing AGN's forecast for new connections, our consultant, ACIL Allen advised us that it was satisfied that these forecasts are reasonable.³⁶ We have taken into account ACIL Allen's advice, which we were persuaded by. In particular, we are satisfied that ACIL Allen's comparative analysis of AGN's forecasts with ABS data indicates that AGN's new connections forecasts are not unreasonable.³⁷ We have therefore arrived at the conclusion that AGN's forecast new connection volumes are consistent with rule 74 (2) of the NGR.

Core Energy which produced AGN's new connection volume forecasts, predict an increase in total new connection of 0.15 per cent, a fall of -0.70 per cent in new medium density/high rise connection, and an increase of 0.26 per cent in new estate (single detached) connections.³⁸

Figure 6.2 shows the historical trend in AGN's new connections as well as its projections for the forecast period. As the figure shows, new estate connections make up a significant proportion of total new connections, and show the most variability. There appears to be little change in the growth of new connections for all other individual connection types.

Figure 6.2 AGN's historical and forecast connection volumes



Source: AGN, *SA Access Arrangement Information*, Attachment 14, July 2015, p. 226.

Note: The new estates connection forecast includes the proposed Two Wells extension connections.

³⁶ ACIL Allen, *Review of demand forecasts for the AGN SA Gas Network*, 5 November 2015.

³⁷ ACIL Allen, *Review of demand forecasts for the AGN SA Gas Network*, 5 November 2015, pp. 33–4.

³⁸ AGN, *SA Access Arrangement Information 2016–21*, Attachment 14, July 2015, p. 241.

In deriving its forecast for new connections, Core Energy applies a gas connection rate in new dwellings which falls from 75 per cent in 2015 (down from 73 per cent the previous year) to 65 per cent by 2021.³⁹ This corresponds to a decrease in total new connection numbers from about 6400 to 5700 dwellings per year.⁴⁰ The apportionment of new estates versus MD/HR connections (88 per cent new estates and 12 per cent MD/HR) was determined based on the average split between the historical numbers of new estate and MD/HR connections between 2011 and 2014.⁴¹

Unit rates

AGN forecast connection unit rates for mains, services and meters for each connection category. As Table 6.6 shows, for existing homes, multi-user and industrial and commercial connections, AGN uses a 3-year historical average to forecast the unit rate for some connection costs. We have assessed AGN's proposed historical average calculations and agree applying it will result in the best forecast in the circumstances.

Table 6.6 AGN forecasting method for each Tariff V connection type

	Mains	Services (Inlets)	Meters
New estates	2015 contract unit rates	2015 contract unit rates	2015 contract unit rates ^(a)
Existing homes	3 year weighted average (FY13–FY15)	3 year weighted average (FY13–FY15)	2015 contract unit rates ^(a)
Industrial and commercial	3 year weighted average (FY13–FY15)	3 year weighted average (FY13–FY15)	3 year weighted average (FY13–FY15)
Multi user	N/A	3 year weighted average (FY13–FY15)	2015 contract unit rates ^(a)

Source: AGN, *SA Access Arrangement Information*, July 2015, Attachment 8.6 SA Unit Rates 300615, pp. 4.

Note: N/A means not applicable.

(a) AGN forecast meter unit rates for residential meters as a single unit rate – meter connection domestic

New estate connections

AGN's forecast method for new estate connections is based on contract unit rates.

We are satisfied with some aspects of the forecast approach, namely the competitively tendered processes that have resulted in the unit rates for mains, services and meters. However, we do not consider that applying construction and labour escalation to the contractor labour component of these unit rates would result in estimates that are arrived at on a reasonable basis. We note that the underlying contracts do not provide for any real construction, labour or material escalation.

³⁹ Core Energy, *Gas Demand Forecasts*, p. 99.

⁴⁰ Core Energy, *Gas Demand Forecasts*, p. 99.

⁴¹ Core Energy, *Gas Demand Forecasts*, p. 99.

Competitive tendered contracts and meter contract unit rates build up

AGN indicated that contractor rates for mains and services changed due to:⁴²

- higher civil construction costs associated with increased scope and increased width of common service trenches (i.e. contractors are now required to work in wider trenches, because common trench standards have changed in order to accommodate additional telecommunication services)
- changes to the way in which the DPTI standard trenching specifications are applied, with some councils now requiring full spoil removal and replacement for any trenching works in council roads
- the trend towards a higher proportion of new homes being built in urban infill areas, driven by the South Australian Government Strategic Plan. Under this plan, the ratio of urban infill to Greenfield development is expected to increase from historical levels below 50:50 to the plan target of 70:30. Contractor, traffic control and reinstatement costs associated with work completed in established areas are higher than greenfield new estates; and
- expected increases in administrative and safety standards (in particular specialist traffic control).

We requested that AGN provide the build up from the contract unit rates to the aggregated unit rates submitted.⁴³ We are satisfied with the prudence of the unit rates and how these costs were aggregated, upon verifying the numbers provided by AGN.⁴⁴

Construction and labour escalation

AGN's application of construction and labour escalation to its new estate mains, services and meters unit rate forecasts is not consistent with AGN's contracts for these elements.

In some instances businesses rely on historical costs. In these instances, it may be reasonable to expect that real construction and labour escalation may apply to forecasts. This is because these contracts are based on past costs which do not have a real cost escalation applied. However, where contracts are based on forecast project costs, the real construction and labour escalation set out in the contracts should apply. The basis of the forecast is a known amount of escalation.

Given the contracts stipulate a known amount of escalation, we have adjusted AGN's proposed real construction and labour escalation to the contractor labour component of the units costs. To apply AGN's proposed escalation would be inefficient and over-estimate the forecast project costs, given that the contracts only provide for certain

⁴² AGN, *SA Access Arrangement Information*, July 2015, Attachment 8.6 SA Unit Rates 300615, pp. 6 and 12.

⁴³ AER, *Information request AER Australian Gas Networks 006 – Connections*, sent 23 July 2015, questions 1 and 3.

⁴⁴ AGN, *Response to Information request AER Australian Gas Networks 006 – Connections*, received 29 July 2015, Question 1 & 3_CONFIDENTIAL.xls.

known amount of escalation. It would also not represent the best possible forecast in the circumstances.

Two Wells high pressure mains extension

AGN proposed a 9 km high pressure extension of its network to Two Wells, costing \$5.0 million (\$2016, unescalated direct costs, excluding overheads) in 2019–20.⁴⁵ We have not included this amount in our capex forecast as we consider that this new extensions capex is not justified under rule 79(2) of the NGR.

We requested AGN to provide the cost build up for the mains, the NPV analysis to establish whether the proposed extension would be at least revenue neutral, and independent evidence regarding the expected the forecast number of housing and commercial plots, the percentage of plots taking-up gas, and the timing of the development of the housing and commercial plots.⁴⁶

AGN provided a 2011 Connor Holmes report as independent evidence of the forecast number of housing and commercial plots and the timing of the development of the housing and commercial plots. The report indicates that there could be between 2,440 (low scenario) and 3,260 (high scenario) dwellings.⁴⁷

We reviewed the cost build up and NPV analysis provided by AGN.⁴⁸ Some of the assumptions were inconsistent with other aspects of AGN's proposal, including:

- the demand per connection (AGN assumed 12.5 GJ pa for domestic and 263 GJ pa in the Two Wells analysis but forecast 8.27 GJ pa and 194.7 GJ pa in its demand forecasts for new estates)
- the revenue assumptions per connection
- the domestic penetration rate (AGN assumed 95 per cent in the Two Wells analysis but forecast a much lower penetration rate for new connections forecast for new estates).

We note that correcting these inconsistent assumptions results in a negative NPV outcome over a 20 year period. Furthermore, we consider that a 10 year period, at a maximum, should be applied for revenue to be recovered from industrial and commercial connections. In our view, this is a more reasonable assumption taking into account the standard connection life for these customers. We have therefore concluded that the proposed capex for the high pressure extension is not conforming capex because it is not justified under rule 79(2)(b) of the NGR.

⁴⁵ AGN, *SA Access Arrangement Information 2016–21*, Attachment 8, p. 142.

⁴⁶ AER, *Information request AER Australian Gas Networks 002 – Two Wells*, sent 17 July 2015.

⁴⁷ AGN, *Response to Information request AER Australian Gas Networks 002 – Two Wells*, received 23 July 2015, Attachment 2 - Connor Holmes SIPC_Attachment_B_Report_11_6_2_-_Two_Wells_Residential_Development_Plan1.pdf, p. 30.

⁴⁸ AGN, *Response to Information request AER Australian Gas Networks 002 – Two Wells*, received 23 July 2015, Attachment 1c - Cashflow model and assumptions CONFIDENTIAL.xls.

Capital contributions

Where a connection is not a standard connection, as specified in the NGR and/or AGN's access arrangement, AGN can seek a contribution from the customer.

AGN has proposed contributions expenditure of \$3.6 million. AGN forecast its capital contributions by applying the five year average (2009–14) of the historically observed ratio of contributions to connection capex, to forecast connections capex.⁴⁹

Based on the information before us, we are satisfied that this amount is the best estimate in the circumstances.

Augmentation

Network augmentation capex is directed at increasing the capacity of the existing network to meet the demand of existing and future customers. Augmentation capex is required to maintain gas pressure and minimise the risk of gas outages. AGN stated its augmentation capex is necessary under the NGR.⁵⁰

We have included \$4.1 million (\$2014–15, unescalated direct costs) of augmentation capex in our capex forecast in this draft decision compared to AGN's proposed amount of \$17.9 million (\$2014–15, unescalated direct costs). We consider this capex complies with rule 79(1) of the NGR for the following reasons:

- we consider that the proposed capex for four smaller scale augmentation projects totalling \$4.1 million (\$2014–15, unescalated direct costs) are justified and necessary under the NGR.⁵¹
- we do not consider that the proposed capex for two significant project—Southern Transmission Pipeline (SA21) and Murray Bridge (SA71) totalling \$10.5 million (\$2014–15, unescalated direct costs) — are conforming capex because they are not justified in the 2016–21 access arrangement period. This results in a reduction to AGN's capex forecast.
- we consider that the capex for the project, 'Pitting issues under sleeves' (SA21a) totalling \$3.3 million (\$2014–15, unescalated direct costs) is an opex item. We have therefore included this project in our assessment of AGN's opex forecast (see attachment 7). This results in a reduction to AGN's capex forecast.

We assessed AGN's augmentation projects by considering the timing of the proposed works, the capacity benefit resulting from the augmentation solution and whether the input cost of each project is that which a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable

⁴⁹ AGN, *Email to the AER re customer contributions*, 15 July 2015.

⁵⁰ NGR, r. 79(2)(c).

⁵¹ NGR, r. 79(2)(c).

cost of providing services would incur.⁵² In undertaking this assessment we sought advice from Sleeman Consulting, who examined the business cases submitted by AGN and requested further information from AGN.

In assessing the prudence and efficiency of the proposed projects, we and Sleeman Consulting considered:⁵³

- the capacity shortfall and/or projected growth demonstrating the requirement for the augmentation
- whether AGN considered alternative options to address the issue
- the prudence of the timing of the proposed augmentation
- the prudence and efficiency of the scale of the proposed augmentation
- the efficiency of the proposed project costs.

Three projects make up \$13.8 million (or 77 per cent) of AGN's augmentation capex forecast of \$17.9 million (\$2014–15, unescalated direct costs). Our assessment focused largely on these three projects, which we set out below.

Southern Transmission Pipeline (SA21)

We are not satisfied that the proposed capex for the Southern Transmission Pipeline augmentation (SA21) is conforming capex that complies with rule 79. In coming to this view we took into account the advice we received from Sleeman Consulting which we found to be persuasive.⁵⁴

AGN proposed to replace this 5.2km pipeline because it detected corrosion at 20 joints it recently excavated. AGN stated the level of corrosion varied in depth up to 2.4mm.⁵⁵

Based on the available evidence, Sleeman Consulting considered the levels of corrosion AGN found in its survey are considerably below threshold levels that would necessitate capital works. This means the pipeline will remain fit for purpose, and that a burst failure is unlikely.⁵⁶ AGN itself considered a burst rupture of the pipeline is 'highly unlikely'.⁵⁷ Hence, we agree with Sleeman Consulting that this project is not required in the 2016–21 access arrangement period.

⁵² NGR, r. 79(1)(a).

⁵³ Sleeman Consulting, *Australian Gas Networks access arrangement 2016/17 to 2020/21: Review of capex forecasts for selected projects*, 18 November 2015.

⁵⁴ NGR, r. 79(2)(c)(i) and (ii). AGN, *Access arrangement information: Attachment 7.1: Business cases: Business case – SA21*, July 2015, p. 7.

⁵⁵ AGN, *Access arrangement information: Attachment 7.1: Business cases: Business case – SA21*, July 2015, p. 2.

⁵⁶ Sleeman Consulting, *Australian Gas Networks access arrangement 2016/17 to 2020/21: Review of capex forecasts for selected projects*, 18 November 2015, section 2.2.

⁵⁷ AGN, *Access arrangement information: Attachment 7.1: Business cases: Business case – SA21*, July 2015, pp. 2–3.

Sleeman Consulting also recommended the ongoing monitoring of this pipeline, which AGN can incorporate into its SA21a project (see below).⁵⁸ This would enable AGN to determine a more optimal time to replace (or perform other work on) the pipeline.

Murray Bridge augmentation (SA71)

We are not satisfied that the proposed capex for the Murray Bridge augmentation (SA71) is conforming capex that complies with rule 79. In coming to this view we took into account the advice we received from Sleeman Consulting which we found to be persuasive.⁵⁹

AGN proposed to construct a 2km pipeline to complement an existing pipeline. AGN stated the existing pipeline is operating close to full capacity and, with organic growth within Murray Bridge, will require an augmentation to the network.⁶⁰

AGN expects 250–300 new connections per year due to new developments in the Murray Bridge township. This would increase the peak hour growth within the township from 50 m³/hr per year to about 100m³/hr per year.⁶¹ We agree with Sleeman Consulting that AGN's growth assumptions are excessive given there are only about 400 residential customers within the Murray Bridge township. Importantly, the township has grown by 33 new connections per year, on average, between 2005 and 2014, with 52 being the largest number of new connections in any one year.⁶² These are well below the annual forecasts AGN used to justify the project. In addition, the growth in gas connections would be lower as not all potential customers will connect to gas.⁶³

Based on the available information, we agree with Sleeman Consulting's position that the pipeline can operate at considerably higher pressure than its current pressure of 1.65MPa, such that construction of the new pipeline will not be necessary in the 2016–21 access arrangement period.⁶⁴

Pitting issues under sleeves (SA21a)

We consider that the proposed capex for the project, 'Pitting issues under sleeves' (SA21a), is an opex item. We have assessed this project as part of our assessment of

⁵⁸ Sleeman Consulting, *Australian Gas Networks access arrangement 2016/17 to 2020/21: Review of capex forecasts for selected projects*, 18 November 2015, section 2.2.

⁵⁹ NGR, rr. 79(2)(c)(i), 79(2)(c)(ii); AGN, *Access arrangement information: Attachment 7.1: Business cases: Business case – SA71*, July 2015, p. 5.

⁶⁰ AGN, *Access arrangement information: Attachment 7.1: Business cases: Business case – SA71*, July 2015, pp. 1–2.

⁶¹ AGN, *Access arrangement information: Attachment 7.1: Business cases: Business case – SA71*, July 2015, pp. 1–2.

⁶² AGN, *Access arrangement information: Attachment 8.1: AMP*, July 2015, p. 62.

⁶³ Sleeman Consulting, *Australian Gas Networks access arrangement 2016/17 to 2020/21: Review of capex forecasts for selected projects*, 18 November 2015, section 2.4.

⁶⁴ Sleeman Consulting, *Australian Gas Networks access arrangement 2016/17 to 2020/21: Review of capex forecasts for selected projects*, 18 November 2015, section 2.4.

AGN's opex forecast where we adjusted our base year opex to account for the reclassification of this project (see attachment 7).

Following from the SA21 project (see above), AGN proposed to undertake exploratory excavations to check for corrosion on field-welded joints on transmission pipelines in its network.⁶⁵ Its expenditure forecast includes provision for repair of 10 per cent of excavated joints.⁶⁶

The CCP asked whether this project is a maintenance activity (opex).⁶⁷ We consider this item should be assessed as opex given that the majority of this expenditure relates to inspection-type work. Where AGN needs to repair joints, we agree with Sleeman Consulting that the work AGN would perform does not materially alter the productive capacity of the pipeline and is, therefore, an operating and maintenance activity.⁶⁸

Mains replacement

Distribution mains are the pipes which convey gas to service pipes at each end user point. AGN's distribution mains replacement program consists of proactive and reactive replacement programs. It involves the replacement of aging cast iron (CI) and unprotected steel pipe (UPS) mains as well as newer high density polyethylene (HDPE) mains.

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 cent less than AGN's proposed forecast expenditure of \$369.9 million (\$2015, unescalated direct costs) for its mains replacement program.⁶⁹

We have undertaken a technical review of the mains replacement program, which has drawn on internal engineering and technical expertise. Our technical analysis is set out in the confidential appendix (Appendix A).

For the reasons below, 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 proposal is prudent or efficient. In particular, AGN did not provide a rigorous

⁶⁵ AGN, *Access arrangement information: Attachment 7.1: Business cases: Business case – SA21a*, July 2015, pp. 1–3.

⁶⁶ AGN, *Access arrangement information: Attachment 7.1: Business cases: Business case – SA21a*, July 2015, p. 5.

⁶⁷ CCP, *Advice to AER from Consumer Challenge Panel sub-panel 8 regarding Australian Gas Networks' (SA) Access arrangement 2016–2021 proposal*, 25 August 2015, p. 14.

⁶⁸ Sleeman Consulting, *Australian Gas Networks access arrangement 2016/17 to 2020/21: Review of capex forecasts for selected projects*, 18 November 2015, section 2.3; AGN, *Response to AER Australian Gas Networks 007 – Augmentation, Regulators & Other*, 4 August 2015, p. 3.

⁶⁹ AGN, *Access Arrangement Information, Attachment 8.2, Mains Replacement Plan, 2016/17 to 2020/21*, July 2015, p. 38.

(quantitative) risk assessment to establish that its proposed rate of mains replacement over the 2016–21 period is prudent and efficient. Rather, its 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. 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.

We note, however, that there are some remaining concerns that we have with AGN’s proposed unit rates. These are set out in the confidential appendix (Appendix A). We invite AGN to address these concerns as part of its revised proposal.

We discuss below our assessment of AGN’s proposal and the other material submitted by AGN and how we determined our alternative estimate.

AGN’s proposal

AGN proposed forecast mains replacement expenditure of \$369.9 million (\$2015, unescalated, excluding overheads). As Table 6.7 shows, this expenditure includes:⁷⁰

- Proactive ‘block’ replacement⁷¹ of aging cast iron and unprotected steel (CI and UPS)
- Proactive replacement of high density polyethylene (HDPE) (class 250 and class 575)
- Proactive replacement of CI and UPS for services post 2004–12

⁷⁰ AGN, *Access Arrangement Information, Attachment 8.2, Mains Replacement Plan, 2016/17 to 2020/21*, July 2015, pp. 38–9.

⁷¹ Block replacement is a planned program where, to achieve least cost, tenders are let for parcels of work.

- Proactive replacement of medium pressure (MP) CI and UPS trunk mains
- Reactive piece meal replacement of CI and UPS mains and services.

Table 6.7 AGN proposed mains replacement programs (\$2015, unescalated direct costs, excluding overheads)

	2016–17	2017–18	2018–19	2019–20	2020–21	Total km	Total
CI/UPS block replacement	37.7	38.8	36.4	36.0	31.5	796.5	180.4
Services replacement post 2004–12 CI/UPS block replacement	2.9	2.9	2.9	2.9	2.9	n/a	14.4
HDPE mains replacement	23.2	23.2	25.3	28.1	28.1	401	127.9
MP trunk mains replacement	10.0	8.1	8.1	8.1	8.1	62	42.5
Piece meal mains and services replacement	1.4	1.1	0.9	0.7	0.7	13.5	4.8
Total	75.2	74.1	73.6	75.8	71.3	1273km	369.9

Source: AGN, *Access Arrangement Information, Attachment 8.2, Mains Replacement Plan, 2016/17 to 2020/21*, July 2015, pp. 38–9

- This block replacement relates to service replacements in multi-user sites not undertaken in 2004–12. These were deferred because of their complexity, and time required to replace them such that these sites could be replaced as a contract package on a stand-alone basis (AGN, *Access Arrangement Information, Attachment 8.2, Mains Replacement Plan, 2016/17 to 2020/21*, July 2015, p. 18).

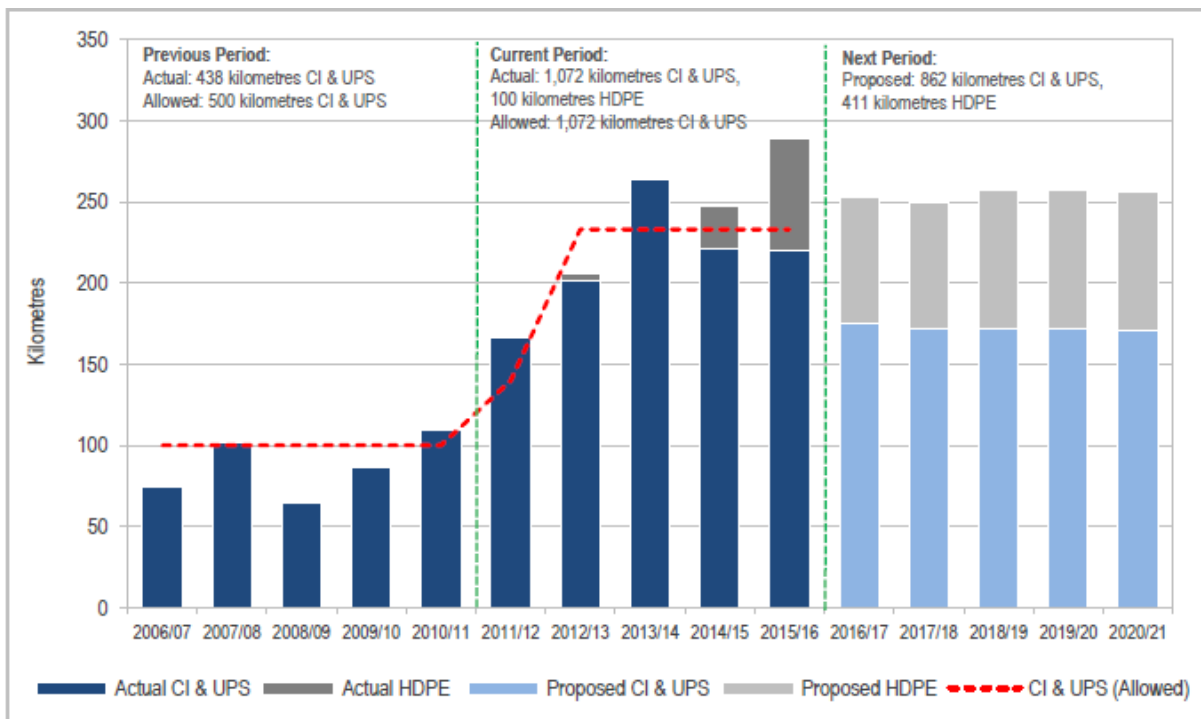
The proposed capex amount of \$369.9 million involves replacing 1273 km of mains. The proposed kilometres of mains to be replaced compared to the current and previous periods are set out in Figure 6.3.

Over the 2016–21 access arrangement period, AGN proposed to replace the remaining 862 km⁷² of CI and UPS mains in the network, and to commence a new HDPE program replacing 411 km of mains.⁷³ The proposed kilometres of mains replacement is about 8 per cent higher than the 1,172 km of mains that AGN expected to replace in the 2010–15 access arrangement period. While most of the replacement relates to CI and UPS mains, approximately 100 km of HDPE mains was also replaced in the latter half of the 2010–15 access arrangement period. This is illustrated in Figure 6.3.

⁷² Block replacement (796.5km)+ MP trunk main (62km) +ad hoc (3.5km) = 862km.

⁷³ This involves replacing all MP class 250 HDPE mains by 2020/21 (260km) and HP class 575 HDPE mains (141km) in a number of locations, and ad hoc replacement (10km).

Figure 6.3 AGN proposed CI/UPS and HDPE mains replacement volumes



Source: AGN, *SA Access Arrangement Information*, July 2015, p. 134.

AGN’s proposed replacement of remaining CI and UPS mains continues its replacement program from the last two access arrangement periods. AGN has indicated that it is committed to replacing all CI and UPS mains by 2020/21, and that its proposed volume (kilometres) reflects this target.

The HDPE mains replacement is a new program that we have not considered in previous access arrangement reviews. HDPE was used for gas reticulation within South Australia (and elsewhere in Australia and around the world) between the early 1970s until the late 1990s. During that time, the type of HDPE was known as class 250 and class 575. A newer generation of medium density polyethylene (MDPE) was used from the late 1990s and is still in use. MDPE improved pipe properties when compared to the earlier high density materials, and were used in pipes due to its improved flexibility, ductility, slow crack growth resistance and crack propagation resistance.⁷⁴

AGN submitted that there was concern around the integrity of the HDPE mains, with increasing evidence that these mains are susceptible to sudden brittle crack failures under certain conditions.

AGN submitted that the older HDPE mains (class 250), installed from the early 1970s, have become brittle to the extent that fractures occur in service or when undertaking

⁷⁴ Vinidex, Polyethylene properties, <http://www.vinidex.com.au/technical/material-properties/polyethylene-properties/>, accessed 7 August 2015.

repairs. Class 575 was installed from the early 1980s and is also becoming brittle over time, But, AGN submitted that its younger age means that the concern with class 575 is more related to the combination of brittleness and any defects that may have affected the pipe during the installation of service.⁷⁵

From its analysis, AGN has concluded that all class 250 HDPE mains should be replaced by 2020/21, while some class 575 mains should be replaced.⁷⁶

Our assessment

In support of its proposed mains replacement program, AGN provided:

- a Mains Replacement Plan;
- an Asset Management Plan;
- a business case 'SA 54 Risk Management of HDPE';
- a HDPE risk model; and
- in response to information requests, historical leakage data, and data on its installed mains and data relating to any costs that have been realised due to mains failure.

Our assessment of this material is provided below.

Historical trend of leakage from main pipes

Leakage surveys are the key proactive maintenance strategy to manage leakage and determine the condition and reliability of the gas distribution network. 'High consequence' locations are surveyed more frequently. APA Group, which manages the network for AGN, reports the results of the leakage survey to the Office of the Technical Regulator (OTR) annually as part of its Key Performance Indicators (KPIs).⁷⁷

The leakage historical data⁷⁸ provided by AGN indicates that over 2005 to 2007 there was an increase in leakage rates, which may have been due an accelerated decline in main pipes. This may be a reason for AGN's major CI and UPS mains replacement in the 2010–15 access arrangement period.⁷⁹ There is also a significant ongoing decline in the annual leakage rate from 2009 to 2014, especially since 2010. Across this same period the leakages per kilometre of pipe have been declining at a rate of about 200 leaks per year. Part of this decline may be attributed to AGN's increased frequency of leakage surveys (resulting in increased leak identification and repair), and to the CI and UPS mains replacement undertaken in the 2010–15 access arrangement period.

⁷⁵ AGN, *Access Arrangement Information, Attachment 8.2, Mains Replacement Plan, 2016/17 to 2020/21*, July 2015, p. 24.

⁷⁶ AGN, *Access Arrangement Information, Attachment 8.2, Mains Replacement Plan, 2016/17 to 2020/21*, July 2015, p. 24.

⁷⁷ Government of South Australia, *Annual Report of the Technical Regulator, Gas 2013–14*, p. 15.

⁷⁸ AGN (maximo4-southaustralia_envestra June 2015 AER 0.1.xls).

⁷⁹ Filenote of conversation between AER and OTR staff, 13 October 2015; Minister for Mineral Resources and Energy, *Submission on AGN SA Access Arrangement Proposal 2016–2021*, p. 2.

AGN also provided information that it submits shows the leakage rate of HDPE pipes is likely to increase. This may be due to brittle cracking at stress points such as where the pipe has been squeezed-off during laying and has been subject to subsequent repair works. AGN submits that there is independent evidence of similar brittle cracking failures occurring in other overseas networks.⁸⁰

In support of its submission that HDPE leakage events are likely to increase over the next 5 to 10 years, AGN also provided information in its Mains Replacement Plan, including graphs that indicate the expected impact on HDPE pipe failure.⁸¹ We recognise the issue of cracking at stress points in certain types of HDPE. However, the information provided by AGN does not establish the actual impact on its network or the extent to which its HDPE mains pipe would be subject to failure.⁸² The series of graphs provided by AGN have no scale information. They appear to be indicative rather than representing a known numerical relationship. Consequently, the graphs provided by AGN have not satisfied us of the veracity of its submissions.

In summary, we acknowledge that leaks in AGN's mains pipes may need to be addressed for CI, UPS and HDPE main pipes. We have examined the information before us to assess whether the rate of replacement during the 2016–21 access arrangement period is conforming capex that complies with rule 79.

Assessment of the prudence and efficiency of the investment

As we noted above, AGN's proposal is based on its target to replace all CI and UPS mains by 2020/21. This is different to the situation relating to other recent AER decisions on mains replacement. For example, CI and UPS mains replacement in our 2012 Victorian Gas Reviews were associated with discharging regulatory obligations imposed by the Energy Safe Victoria. However, there is no legislative or regulatory obligation on AGN to replace these mains by 2020/21. At the same time, we note that AGN also submitted that its mains replacement program is on track to reduce public risk (leaks) and unaccounted for gas (UAFG) and improve system capacity. In particular, AGN submitted:⁸³

- while the current CI and UPS program has been effective to date, the leak rate per kilometre of mains is about three times that of the remaining polyethylene network. Therefore, AGN submits that continuing the replacement program to reduce the leak rate to that of the remaining network is prudent

⁸⁰ AGN, *Access Arrangement Information, Attachment 8.2, Mains Replacement Plan, 2016/17 to 2020/21*, July 2015, p. 24.

⁸¹ AGN, *Access Arrangement Information, Attachment 8.2, Mains Replacement Plan, 2016/17 to 2020/21*, July 2015, pp. 44–45.

⁸² AGN, *Access Arrangement Information, Attachment 8.2, Mains Replacement Plan, 2016/17 to 2020/21*, July 2015, p47; and *Asset Data and HDPE Risk Model*, 19 August 2015, p. 15.

⁸³ AGN, *Access Arrangement Information, Attachment 8.2, Mains Replacement Plan, 2016/17 to 2020/21*, July 2015, p. 25.

- while there has been a significant reduction in UAFG, completion of the CI and UPS replacement program is expected to reduce UAFG levels even further
- the CI and UPS are considered at the end of their useful lives with escalating leaks and UAFG if the program is curtailed.

We recognise the benefits of the mains replacement program in the 2010–15 access arrangement period. However, AGN did not provide a risk based assessment of its proposed replacement of the remaining CI and UPS during the 2016–21 access arrangement period. A rigorous risk assessment is necessary to determining whether the level of expenditure associated with its mains replacement program is prudent and efficient and, in turn, satisfying us that it is conforming capex that complies with rule 79.

The CI and UPS mains replacement program in the 2010–15 access arrangement period was justified on evidence supporting an accelerated decay in these pipes. However, that evidence does not indicate whether it is prudent and efficient to replace the remaining 862 km of CI and UPS main pipes by 2020/21. In particular, we note APA Group’s comments that ‘this plan [its Mains Replacement Program] prioritises replacement of mains that are assessed as posing the highest risk’.⁸⁴ As CI and UPS have been replaced based on risk, the highest risks pipes should have already been replaced. In turn, the remaining CI and UPS should be of relatively lower risk and the efficient and prudent rate of replacement should decline. Business SA and the CCP made similar observations in their submissions.⁸⁵

In support of its proposed HDPE mains replacement program, AGN provided preliminary risk modelling,⁸⁶ and submitted that ‘further significant development of the risk model, will inform annual asset management strategies’⁸⁷. AGN noted that the model ‘takes into account a number of factors in order to determine those parts of the HDPE network that should be replaced.’⁸⁸

Our review of the current HDPE model below demonstrates that it does not adequately identify or assess the relevant risks. In particular, the model does not demonstrate that the rate at which AGN is proposing to replace its HDPE mains over the access arrangement period is a prudent and efficient investment. We note several

⁸⁴ AGN, *Access Arrangement Information, Attachment 8.2, Mains Replacement Plan, 2016/17 to 2020/21*, July 2015, p. 11.

⁸⁵ Business SA, *Submission to the Australian Energy Regulator on Australian Gas Networks Access Arrangement (2016–21)*, August 2015, p. 6, Consumer Challenge Panel, *Advice to AER from Consumer Challenge Panel sub-panel 8 regarding Australian Gas Networks (SA) Access Arrangement 2016–2021 Proposal*, pp. 13–4.

⁸⁶ AGN, *Access Arrangement Information, Attachment 8.2, Mains Replacement Plan, 2016/17 to 2020/21*, July 2015, p. 24.

⁸⁷ AGN, *Access Arrangement Information, Attachment 8.2, Mains Replacement Plan, 2016/17 to 2020/21*, July 2015, p. 24.

⁸⁸ AGN, *Access Arrangement Information, Attachment 8.2, Mains Replacement Plan, 2016/17 to 2020/21*, July 2015, p. 24.

stakeholders expressed concern about consumers paying more than necessary to fund the HDPE and CI and UPS main pipes over the access arrangement period.⁸⁹

AGN's HDPE model ranks those suburbs with a history of squeeze off failures (130 suburbs) based on a number of factors (i.e. squeeze-offs, pressure, soil type, housing construction). For instance, suburbs with cottages with a footing construction close to the front of the property boundary were assessed as having the highest factor.⁹⁰ The factors in the model describe a 'hazard' (something that could cause harm). These factors do not describe a risk. This distinction is important. We consider a risk assessment should analyse the probability, high or low, that any hazard will cause somebody harm. A rigorous risk assessment would generally therefore take account of the 'probability' (usually measured as frequency of events) and the impact (in monetary terms) of that harm occurring. In contrast, the HDPE model assumes that all 'hazards' identified will be realised (as no analysis of the likely frequency of events is provided), and essentially prioritises areas of the network for replacement. As such, the model as currently specified does not provide sufficient evidence for us to accept AGN's forecast of its HDPE mains replacement.

The absence of a rigorous risk assessment ultimately also means that AGN's HDPE model potentially overestimates the prudent and efficient amount of kilometres of mains to be replaced. In its business case for HDPE, AGN proposed the option of implementing an integrity management program for HDPE pipes combined with a replacement program.⁹¹ However, this is not a substitute for a rigorous risk assessment.

For these reasons, we are not satisfied that AGN's proposed expenditure is conforming capex that satisfies rule 79. Therefore, as we discuss below, we have determined an alternative estimate using what information is before us. .

Basis of our alternative estimate

Our alternative estimate for mains replacement capex over the 2016–21 access arrangement period is \$167.7 million. This represents the replacement of 577 kilometres of main pipes over the 2016–21 access arrangement period. We have determined our alternative estimate based on the information and data before us. To derive our alternative capex estimate, we 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

⁸⁹ Consumer Challenge Panel, *Advice to AER from Consumer Challenge Panel sub-panel 8 regarding Australian Gas Networks (SA) Access Arrangement 2016–2021 Proposal*, pp. 12–3; Energy Consumers Coalition of SA, *AER Review of AGN proposal 2015, August 2015*, p. 25–7; SACOSS, *Submission on AGN's regulatory proposal for the 2016–2021 Access Arrangement period*, 8 August 2015, p. 5.; Business SA, *Submission to AER on proposed Australian Gas Networks Access Arrangement (2016–21)*, 10 August 2015, p. 6.

⁹⁰ AGN, *Access Arrangement Information, Attachment 8.2, Mains Replacement Plan, 2016/17 to 2020/21*, July 2015, p. 47.

⁹¹ AGN, *Access Arrangement Information, Attachment 7.1, Business Cases, SA 54 Risk Management of HDPE*, p. 1.

reduction reflects our view regarding prudent and efficient volumes of mains replacement.

Our approved capex amount does not distinguish between the pipe type (CI, UPS or HDPE class 250 or 575) to be replaced. We consider that a prudent operator acting efficiently would prioritise replacement of mains based on a risk assessment across all pipe types. We recognise that the level of risk can vary across the different pipe types depending on several factors such as pressure of the pipes, and location of the pipes which has nothing to do with the pipe type. For instance, we recognise that:

- The higher pressure on HDPE mains means that, while they have better leakage rates than CI and UPS, they carry more risk
- CI and UPS mains for block replacement are mostly low pressure and carry less risk, especially of a major consequence. This is because the manner of the leak is likely to result in a slow release of gas
- CI and UPS mains located in the CBD are likely to be deemed high risk given the high population density that exists there. However, the leakage rates in these areas are low, as the CI is of a high grade, with most leaks coming from the joints.

We consider that AGN is best placed to undertake a risk assessment which draws on all the information it has on mains pipes to determine what pipes should be replaced first. In this regard, we consider that within the overall approved efficient capex for mains replacement, it is up to AGN to allocate its capex where necessary.

In coming to our alternative estimate, we had regard to the expectation that a prudent business seeking to allocate investment to maximise hazard reduction would replace the pipes with the highest rate of leakage first. With this in mind, we have reviewed the data available to us to calculate the rate of leaks per kilometre of main by suburb over the period from 2005 to 2014. Our review reveals that AGN's proposed 1273 kilometres of mains replacement assumes a certain percentage reduction in leaks⁹² over the 2016–21 access arrangement period. The information before us does not support or justify AGN's assumed percentage reduction in leaks over the 2016–21 access arrangement period. In particular, as noted above, there is no regulatory or legislative obligation that requires AGN to commit to its proposed kilometres of mains replacement (or assumed leakage rate reduction) over the 2016–21 access arrangement period. Further, the AGN's assumed percentage reduction in leaks far exceeds the historical average reduction in leakage incident rate from 2007 to 2014.⁹³

Using AGN's leakage data, AGN's assumed leakage reduction rate comes to an estimate of 1273 kilometre of mains replacement, at a cost of \$369.9 million. Applying an assumed 25 per cent reduction in leaks translates to 577 kilometres of mains replacement. Reducing AGN's capex by the percentage reduction in total kilometres of mains replacement results in our alternative capex estimate of \$167.7 million.

⁹² See the confidential appendix (Appendix A) for the assumed percentage reduction value.

⁹³ See the confidential appendix (Appendix A) for the historical average reduction in leaks.

In coming to our position, ideally, we would derive an alternative estimate based on a cost benefit analysis. This information is not available to us, and we accept that this kind of analysis may be difficult to undertake. Given the limited information available to us, we have drawn on historical leakage reduction rates.

In this regard, we note that AGN significantly stepped up investment in pipeline replacement after 2010–11 to historically high levels. Even with the high levels of investment leakage rates only fell by a certain level from 2007 to 2014.⁹⁴

One option for us would be to adopt investment levels consistent with achieving the historical reduction in leakage. On balance, we consider there is case to adopt a more cautious approach and accommodate a higher level of mains replacement. There are two reasons for this.

Firstly, leakage associated with HDPE pipes is emerging as a new issue. HDPE pipes typically run at higher pressure than CI and UPS pipes and are more prone to sudden failure. This combination increases the probability that leakage events will cause harm compared to CI and UPS main pipes.

Secondly, the main pipes will continue to deteriorate over the period as they age. There is some uncertainty about the rate of deterioration going forward. The pipes could deteriorate faster than historically with corresponding increases in leakage rates. In this scenario, additional investment would be required to achieve a given reduction in leakage rates.

Our approach in deriving our alternative estimate is to adopt a point that takes account of the historical average leakage reduction and AGN's proposal. On the basis of the information available to us, we consider that a capex amount of \$167.7 million is conforming capex that complies with rule 79. In particular, we consider that this amount would be incurred by a prudent service provider, acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services.

We invite AGN in its revised proposal to address the issues raised above 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.

Proposed capex for camera inspections in HDPE main pipes

AGN also proposed \$11.3 million for an in-line camera for HDPE main pipe inspections, to provide a means to detect squeeze off sites and mitigate brittle cracking

⁹⁴ See the confidential appendix (Appendix A) for the historical average reduction in leaks.

in HDPE main pipes.⁹⁵ The defeats are then excavated and reinforced with stainless steel clips (which are clamped around the pipe).⁹⁶

We asked AGN to provide a business case for the HDPE camera. AGN did not provide a business case, but it did comment on how the HDPE camera forms part of its prudent risk management strategy.⁹⁷ Whilst we recognise that the HDPE camera could assist in deferring mains replacement at a relatively low cost, we cannot be satisfied AGN's proposed cost estimate of \$11.3 million for this equipment in the absence of a business case or a cost–benefit analysis. We have therefore not included this amount in our alternative capex estimate as we are not satisfied it is conforming capex that satisfies rule 79.

Meter replacement

Meter renewal is an ongoing activity which is necessary to ensure that gas meters in the field are replaced when they fail to accurately read data. AGN stated it requires capex on its meter replacement program to meet obligations under the Gas Measurement Management Plan and the Gas Metering Code (NGR, rule 79(2)(c)(iii)).⁹⁸

We are satisfied AGN's capex forecast for meter replacement is conforming capex that complies with rule 79.⁹⁹ We have included \$17.1 million (\$2014–15, unescalated direct costs) of meter replacement expenditure in our alternative capex forecast.

AGN calculated meter replacement expenditure for two general classes of meters: domestic meters, and industrial and commercial meters. It derived expenditure using forecast unit rates and volumes.

We consider that:

- AGN's unit rates for domestic meters¹⁰⁰ compares favourably against the unit rates for domestic meter replacement in NSW, Victoria and the ACT¹⁰¹
- AGN's unit rate forecasts for industrial and commercial meter replacement are reasonable
- the large volume increase in domestic meter replacements in the first three years of the 2016–21 access arrangement period, as well as in the last two years of the

⁹⁵ AGN, *Access Arrangement Information, Attachment 7.1, Business Cases*, SA 52: HDPE camera investigation and repair, p. 9.

⁹⁶ AGN, *Access Arrangement Information, Attachment 8.2, Mains Replacement Plan, 2016/17 to 2020/21*, July 2015, p. 37.

⁹⁷ AER, *Info request to AGN from the AER no. 23*, 18 September 2015.

⁹⁸ AGN, *Access arrangement information for Australian Gas Networks' South Australian Natural Gas distribution network*, July 2015, p. 143.

⁹⁹ Specifically, NGR, r. 79(2)(c)(iii).

¹⁰⁰ AGN, *Access arrangement information: Attachment 8.6: Unit rates*, July 2015, p. 20.

¹⁰¹ These unit rates are confidential, so we do not reproduce it here.

2011–16 period is justified as the end of meter lives align with installation date.¹⁰² AGN notes its volume forecasts had regard to state-based standards for meter replacements, and that the rise was due to the coincident increase in the number of meter types coming up for changeover in these years.¹⁰³ We also agree with AGN that a degree of oversight is provided by the OTR in relation to its meter replacement activities¹⁰⁴

For these reasons, we consider AGN's forecast capex for meter replacement is conforming capex that complies with rule 79.

Telemetry (SCADA)

AGN stated it relies on telemetry systems to monitor network conditions in real time and, in some cases, for the remote control of gas flows and pressures to optimise system performance and maximise safety. These works will reduce the risk of major supply interruption (NGR, rule 79(2)(c)(i)) and provide more accurate, reliable and timely pressure data to better inform network capacity models (NGR, rule 79(2)(c)(ii)).¹⁰⁵

We are satisfied AGN's capex forecast for telemetry is required conforming capex that complies with rule 79.¹⁰⁶ We have included \$1.1 million (\$2014–15, unescalated direct costs) of telemetry expenditure in our alternative capex forecast.

Information technology

AGN proposed \$66.7 million (\$2014–15, including cost escalation and overheads) for IT capex.¹⁰⁷ This is an increase of \$42.7 million or 178 per cent from the 2010–16 period. It is also 5.5 times our approved forecast for the 2010–16.¹⁰⁸ AGN's unescalated, direct capex forecast for IT is \$59.7 million (\$2014–15).

Our decision is to approve \$37.9 million (\$2014–15, unescalated direct costs) of AGN's proposed IT capex of \$59.7 million (\$2014–15, unescalated direct costs) for the 2016–21 access arrangement period. We have included this amount for non-network IT

¹⁰² AER, *Information request – AER Australian Gas Networks 022 – Meters and regulators*, 8 September 2015. AGN, *Access arrangement information: Attachment 8.1: Asset management plan*, July 2015, p. 93. In those years, volumes are over 30,000 units compared to an average of about 22,000 units for the other years in the two access arrangement periods.

¹⁰³ AGN, *Response to AER Australian Gas Networks 022 – Meters and Regulators*, 18 September 2015, p. 3.

¹⁰⁴ AGN, *Access arrangement information for Australian Gas Networks' South Australian Natural Gas distribution network*, July 2015, pp. 142–143.

¹⁰⁵ AGN, *Access arrangement information for Australian Gas Networks' South Australian Natural Gas distribution network*, July 2015, p. 143.

¹⁰⁶ NGR, r. 79(2)(c)(i), 79(2)(c)(ii).

¹⁰⁷ AGN, *Access Arrangement Information for Australian Gas Networks' South Australian Gas Distribution Network*, July 2015, p. 151.

¹⁰⁸ AGN, *Access Arrangement Information for Australian Gas Networks' South Australian Gas Distribution Network*, July 2015, p. 77.

capex in our estimate of total capex, which we consider is conforming capex that complies with rule 79.

AGN had proposed a capex program of nine projects. AGN stated that these projects are to complete the nationalisation of IT systems that AGN commenced in the current period, to mitigate the risks associated with core business systems, enable the effective and efficient delivery of Reference Services, and ensure compliance with regulatory obligations.¹⁰⁹

AGN's proposed large increase in expenditure is driven by the stage of the IT lifecycle that it is in. We have conducted individual project reviews to examine the drivers of this change and to determine whether the proposed expenditure is conforming capex that complies with rule 79.

The Consumer Challenge Panel (CCP) submitted that it has concerns regarding the deliverability of the IT program given that it is more than twice the expenditure in the 2010–16 period. The CCP also questioned the need for such a large program, given the pressure on gas prices for consumers as a result of the proposed mains replacement program and also given that much of the IT expenditure appears discretionary.¹¹⁰ BusinessSA expressed concerns about the large increase in IT spending compared to the current period. It did not support the increase in expenditure when there is declining consumption and slowing connection rates, unless there is clear evidence that consumers will get tangible savings as a result.¹¹¹ The Energy Consumers Coalition of South Australia (ECCSA) submitted that AGN has not shown how its IT program will benefit consumers. It noted that consumers are relatively content with the quality of current services. ECCSA argued that projects should only be approved if they result in a net benefit from opex reduction in less than four years.¹¹²

As to deliverability, we note that the program is part of a national IT program across AGN's networks that should benefit from economies of scale and scope. In assessing whether the proposed IT capex is conforming capex that complies with rule 79, we have examined the economic value of the proposed expenditure. The expenditure we have included in our alternative capex estimate is:

- is justified under rule 79(2), because the economic value is positive or it is necessary to maintain or improve the safety of services, maintain the integrity of services, or comply with regulatory obligations;

¹⁰⁹ AGN, *Access Arrangement Information for Australian Gas Networks' South Australian Gas Distribution Network*, July 2015, p. 137.

¹¹⁰ Consumer Challenge Panel, *Advice to AER from Consumer Challenge Panel sub-panel 8 regarding Australian Gas Networks' (SA) Access Arrangement 2016–2021 Proposal*, 25 August 2015, p. 13.

¹¹¹ Business SA, *Submission to AER on proposed Australian Gas Networks Access Arrangement (2016–21)*, 10 August 2015, p. 6.

¹¹² ECCSA, *Australian Energy Regulator SA Gas Distribution Revenue Reset AGN Application response*, 16 August 2015, pp. 27–28

¹¹³ Origin, *Submission on AGN 2016–21 Access Arrangement Proposal for its SA Gas Distribution Network*, 10 August 2015, p. 4.

- would be incurred by a prudent service provider acting efficiently, in accordance with good industry practice, to achieve the lowest sustainable cost of providing services.

Origin submitted that we should ensure that the costs of this upgrade are allocated on a per user basis across all of AGN's networks, regulated and unregulated.¹¹³ In our assessment, where projects are part of a national program, we examined whether the allocation to AGN's South Australia network was made on the appropriate basis (customer number, network size, or another metric).

Individual project reviews

We reviewed AGN's nine proposed IT projects to assess whether the proposed capex is conforming capex that complies with rule 79. We reviewed AGN's documentation on IT expenditure, including its Information Technology Plan, businesses cases and responses to our information requests. Of the nine proposed projects, we consider that the capex associated with the following projects is conforming capex that complies with rule 79: Applications renewal, Geospatial information system, SCADA IT, Development of digital capabilities and Infrastructure upgrades.

Applications renewal project

AGN has proposed \$17.7 million (\$2014–15) of capex for its Applications renewal project. This project provides for upgrade of key applications across the access arrangement period.¹¹⁴ AGN submitted that these upgrades will “ensure that AGN can maintain reliable, compliant and efficient business processes and systems and preserve the on-going integrity of services”.¹¹⁵

We are satisfied that this capex is justified as necessary under rule 79(2)(c). AGN has estimated the costs of this project using historic actual costs for similar projects. We are satisfied that this capex would be incurred by a prudent service provider acting efficiently and that it is conforming capex that complies with rule 79.¹¹⁶ We have included this amount in our alternative capex estimate.

Geospatial information system project

AGN has proposed \$15.0 million (\$2014–15) of capex for its Geospatial information system project. It has also proposed opex for this project which is discussed in Attachment 7. This project provides for the upgrade of AGN's geospatial information system (GIS) which has been out of vendor support since 2010.¹¹⁷ Based on AGN's supplied documentation it is necessary to upgrade the GIS because it is no longer vendor supported and increasingly requires manual workarounds to maintain

¹¹³ Origin, *Submission on AGN 2016–21 Access Arrangement Proposal for its SA Gas Distribution Network*, 10 August 2015, p. 4.

¹¹⁴ AGN, *Attachment 7.1_Business Cases.pdf*, July 2015, pp. 247–264.

¹¹⁵ AGN, *Attachment 7.1_Business Cases.pdf*, July 2015, p. 248.

¹¹⁶ NGR, r. 79(1)(a).

¹¹⁷ AGN, *Attachment 7.1_Business Cases.pdf*, July 2015, pp. 265–276.

functionality.¹¹⁸ AGN's GIS upgrade is part of a national upgrade. The costs apportioned to South Australia are 40 per cent for procurement, development and planning, and 100 per cent for the South Australian deliver and close portion.¹¹⁹ This apportionment of costs is based on South Australia accounting for 40% of customers for this project. We are satisfied that this is an appropriate division of costs and that AGN's proposed capex is conforming capex that complies with rule 79 of the NGR.¹²⁰ We have included this amount in our alternative capex estimate.

SCADA IT

AGN has proposed \$3.3 million (\$2014–15) for SCADA IT. This project is an upgrade of the SCADA system to AGN's national standard and replacement of the South Australian Historian system with an SA specific module on the Networks Interval Metering Data System application. Based on AGN's supplied documentation, these upgrades are necessary due to the Historian system reaching a capacity constraint in 2017 and the non-standard SA specific SCADA implementation.¹²¹ We are satisfied that its proposed capex is conforming capex that complies with rule 79 of the NGR.¹²² We have therefore included AGN's proposal for SCADA IT in our alternative capex estimate for this project.

Development of digital capabilities project

AGN has proposed \$0.9 million (\$2015–15) for its Development of digital capabilities project. It has also proposed opex for this project which is discussed in Attachment 7. This project is to establish a digital platform for AGN to deliver online digital services and communications for customers and stakeholders.¹²³ AGN, through its customer engagement program, found that stakeholders were not satisfied with its digital presence. AGN engaged consultants to develop a strategic plan for its online presence, which AGN is implementing with this project.¹²⁴ AGN submitted that this capex is necessary to maintain the integrity of its services. This project is for all of AGN's businesses nationally. The costs proposed by AGN represent 36 per cent of the national costs.¹²⁵ AGN's South Australian network has approximately 36 per cent of AGN's customers. We are satisfied that its proposed capex is conforming capex that complies with rule 79 of the NGR.¹²⁶ We have therefore included AGN's proposal for its Development of digital capabilities project in our alternative capex estimate.

¹¹⁸ AGN, *Attachment 7.1_Business Cases.pdf*, July 2015, p. 268.

¹¹⁹ AGN, *Response to AER Information Request 017*, 4 September 2015, p. 15.

¹²⁰ NGR, rr. 79(1) (a), 79(2)(ii).

¹²¹ AGN, *Attachment 7.1_Business Cases.pdf*, July 2015, pp. 305–314.

¹²² NGR, rr. 79(1) (a), 79(2)(ii).

¹²³ AGN, *Attachment 7.1_Business Cases.pdf*, July 2015, pp. 421–431.

¹²⁴ AGN, *Attachment 7.1_Business Cases.pdf*, July 2015, p. 421.

¹²⁵ AGN, *Attachment 7.1_Business Cases.pdf*, July 2015, p. 429.

¹²⁶ NGR, rr. 79(1) (a), 79(2)(ii).

Infrastructure upgrades

AGN has proposed \$1.0 million (\$2014–15) for infrastructure upgrades. This project involves upgrading desktop computers and telephony infrastructure.¹²⁷ The existing desktop operating platform is six years old and is typically refreshed on a 3–7 year cycle. The existing telephony system is over ten years old and AGN submitted that it is increasingly difficult to source spare parts for the system.¹²⁸ Based on AGN's submitted documentation, we are satisfied that its proposed capex is conforming capex that complies with rule 79 of the NGR.¹²⁹ We have therefore included AGN's proposal for its infrastructure upgrades in our alternative capex estimate.

Mobility IT

AGN has proposed \$9.0 million (\$2014–15) for its Mobility IT project. It has also proposed opex for this project which is discussed in Attachment 7. This project involves automating current paper-based and manual processes and integrating mobile devices into the field work force. We are not satisfied that the proposed capex for this project is necessary to maintain and improve safety of services, to maintain the integrity of services or to comply with regulatory obligations.

Based on AGN's documentation, this project appears discretionary because while it does provide improvements over the current paper based system, there are not significant problems with the current system to justify a step increase in costs.¹³⁰ AGN has rated the risk from not doing this project as a priority 3 (on a scale of 1 to 4, with 1 being greatest risk). The risk after completing this project is priority 4.¹³¹ This project generates some ongoing cost savings for AGN, but it does not have a net positive economic value. We are not satisfied that this capex is conforming capex because it is not justified under rule 79(2) of the NGR. We have therefore not included AGN's proposal for its mobility IT project in our alternative capex estimate.

Business Intelligence project

AGN has proposed \$8.6 million (\$2014–15) for its Business intelligence project. This project involves increasing data analysis and improved reporting through integration of various data sources within the AGN IT suite. We are not satisfied that the proposed capex for this project is necessary to maintain and improve safety of services, to maintain the integrity of services and to comply with regulatory obligations.

Based on AGN's documentation, our draft decision is that this project is discretionary in nature because while it does provide improvements in data analysis and usage, AGN has not identified deficiencies in these areas that require addressing.¹³² AGN has rated

¹²⁷ AGN, *Attachment 7.1_Business Cases.pdf*, July 2015, pp. 393–401.

¹²⁸ AGN, *Attachment 7.1_Business Cases.pdf*, July 2015, p. 394.

¹²⁹ NGR, rr. 79(1) (a), 79(2)(ii).

¹³⁰ AGN, *Attachment 7.1_Business Cases.pdf*, July 2015, pp. 277–290.

¹³¹ AGN, *Attachment 7.1_Business Cases.pdf*, July 2015, p. 290.

¹³² AGN, *Attachment 7.1_Business Cases.pdf*, July 2015, pp. 291–304.

the risk from not doing this project as a priority 3 (on a scale of 1 to 4, with 1 being greatest risk). The risk after completing the project is unchanged at priority 3.¹³³ This project does generate some ongoing cost savings for AGN, but it does not have a net positive economic value so is not justified under rule 79(2)(a). As we are not satisfied that this capex is conforming capex because it is not justified under rule 79, we have therefore not included AGN's proposal for its business intelligence project in our alternative capex estimate.

Remote meter reading trial

AGN has proposed \$2.5 million (\$2014–15) for its Remote meter reading trial. It has also proposed opex for this project which is discussed in Attachment 7. This project involves trialling automated meter reading for sites that have historically had poor access (mainly due to customer security and privacy concerns) and in a new subdivision in the early stages of development.¹³⁴ AGN submitted that this project is justified because it is necessary to comply with the regulatory obligation that an actual meter read must be carried out each year.¹³⁵

We are not satisfied that this proposed capex is justified. While AGN must carry out an actual meter read annually, under the National Energy Customer Framework, customers must provide AGN with safe and unhindered access to allow AGN to read their meters. The Government of South Australia submitted that it was concerned that this project would lead to gas consumers across the network funding meter changes to address site-specific problems, and therefore did not support this project.¹³⁶ We agree with this submission that where there are site-specific problems, the associated costs should be borne by the specific customers.

AGN also submitted that this project was consistent the insights from its stakeholder engagement.¹³⁷ However, AGN's willingness to pay survey found that only 44% of customers were willing to pay \$3 per year for remote meter reading.¹³⁸ On this basis, AGN scaled down its planned roll out of remote meter reading devices to the trial that is proposal in their Access Arrangement Information. Nevertheless, as we are not satisfied that this project is justified under rule 79(2), we have not included it in our alternative capex estimate.

Industry change projects

AGN has proposed \$1.8 million (\$2014–15) for Industry change projects. This project is for the costs associated with potential, but not yet determined, AEMO changes to the Retail Market Procedures. AGN stated that the costs are expected to fall below the

¹³³ AGN, *Attachment 7.1_Business Cases.pdf*, July 2015, p. 304.

¹³⁴ AGN, *Attachment 7.1_Business Cases.pdf*, July 2015, pp. 319–320.

¹³⁵ AGN, *Attachment 7.1_Business Cases.pdf*, July 2015, p. 324.

¹³⁶ Government of South Australia, *Submission on AGN SA Access Arrangement Proposal 2016–2021*, p. 5.

¹³⁷ AGN, *Attachment 7.1_Business Cases.pdf*, July 2015, p. 320.

¹³⁸ AGN, *Access Arrangement Information for Australian Gas Networks' South Australian Gas Distribution Network*, July 2015, p. 63.

threshold for a pass through and therefore AGN needs an allowance to cover these costs.¹³⁹ AGN submitted that this project is justified because it is necessary to maintain the integrity of services in the changing IT environment and to comply with a regulatory obligation.¹⁴⁰ As there is no specific regulatory requirement made at this time, we are not satisfied that this capex is necessary. Therefore, we have not included an allowance for this project in our total alternative capex estimate. If, when the changes to the Retail Market Procedures are announced, AGN finds that their costs to comply will be material, they may be able to recover these costs through a pass through for a regulatory change event.

In summary, we do not accept AGN's IT capex forecast. Instead we have included an amount of \$37.85 million in our alternative capex estimate that we consider is conforming capex that complies with rule 79.

Regulators and valves

AGN stated regulator stations and valves play a critical role in regulating gas pressures and flows.¹⁴¹ AGN stated its forecast expenditure of \$13.6 million (\$2014–15, unescalated direct costs) for this category is necessary to maintain and improve the safety of services and to maintain the integrity of services.¹⁴²

We have included the proposed capex of \$11.0 million (\$2014–15, unescalated direct costs) for regulators and valves capex in our capex forecast. We consider this capex complies with rule 79(1) of the NGR for the following reasons:

- we consider regulators and valves projects totalling \$11.0 million (\$2014–15, unescalated direct costs) are justifiable and necessary under the NGR.¹⁴³
- we consider the proposed project, 'Relocation of meters' (SA75) should not be included in the calculation of Reference Tariffs. This results in a \$2.3 million (\$2014–15, unescalated direct costs) reduction to AGN's capex forecast.
- we consider the proposed project, 'Valve corrosion protection' (SA09), is an opex item. We have therefore included this project in our assessment of AGN's opex forecast (see attachment 7). This results in a \$0.3 million (\$2014–15, unescalated direct costs) reduction to AGN's capex forecast.

In undertaking our assessment of other distribution system capex, we sought advice from Sleeman Consulting who examined the business cases and requested further information from AGN. We discuss the reasons for adjusting certain projects within this capex category below.

¹³⁹ AGN, *Attachment 7.1_Business Cases.pdf*, July 2015, p. 336.

¹⁴⁰ AGN, *Attachment 7.1_Business Cases.pdf*, July 2015, p. 342.

¹⁴¹ AGN, *Access arrangement information for Australian Gas Networks' South Australian Natural Gas distribution network*, July 2015, p. 145.

¹⁴² AGN, *Access arrangement information for Australian Gas Networks' South Australian Natural Gas distribution network*, July 2015, p. 146.

¹⁴³ NGR, rr. 79(2)(c)(i), 79(2)(c) (ii).

Below ground regulators (SA22)

We are satisfied AGN's forecast expenditure of \$5.0 million (\$2014–15, unescalated direct costs) for the SA22 project is conforming capex that complies with rule 79.¹⁴⁴

We were persuaded by Sleeman Consulting's advice that the volumes and expenditures associated with this project are reasonable.¹⁴⁵ We agree with Sleeman Consulting's advice.

AGN proposed to replace 15 below ground regulators which are near the end of their working lives. This is the continuation of a program the AER approved in the previous review.¹⁴⁶ We assess that it is prudent to replace 15 below ground regulators over the 2016–21 access arrangement period due to asset deterioration. We note AGN proposed to replace 26 below ground regulators, which we accepted, in the previous review.¹⁴⁷ AGN stated it expects to have finished replacing 21 below ground regulators in the 2011–16 period.¹⁴⁸ This is 80 per cent of the volume it forecast, which we consider is a reasonable variance. We consider AGN provided reasonable explanations for the variance. AGN stated it was not able to complete the program in the 2011–16 period because the work was more complex than it originally anticipated. For example, the unexpected presence of asbestos coated pipe increased construction time in some sites. There was also difficulty in site selection and associated lengthy third-party negotiations.¹⁴⁹

Relocation of meters (SA75)

We consider the proposed capex for the project, 'Relocation of meters' (SA75) should not be included in the calculation of Reference Tariffs.

In the 2011–16 period, requesting customers paid for meter relocation services. However, some customers elected to not proceed to avoid the cost of the relocation. In some cases, this left the meters in a potentially vulnerable location. AGN therefore proposed to include customer-requested meter relocations in Reference Tariffs.¹⁵⁰

¹⁴⁴ NGR, rr. 79(2)(c)(i), 79(2)(c) (ii).

¹⁴⁵ Sleeman Consulting, *Australian Gas Networks access arrangement 2016/17 to 2020/21: Review of capex forecasts for selected projects*, 18 November 2015, section 3.2.

¹⁴⁶ AGN, *Access arrangement information: Attachment 7.1: Business cases: Business case – SA22*, July 2015, pp. 2–3.

¹⁴⁷ AER, *Draft decision: Envestra Ltd Access arrangement proposal for the SA gas network 1 July 2011 – 30 June 2016*, February 2011, p. 37; Envestra, *South Australian access arrangement information: Public version*, 1 October 2010, p. 105; AER, *Final decision: Envestra Ltd access arrangement proposal for the SA gas network 1 July 2011 – 30 June 2016*, June 2011, p. 30; Envestra, *South Australian access arrangement information: Public version*, 23 March 2011, p. 108.

¹⁴⁸ AGN, *Access arrangement information: Attachment 7.1: Business cases: Business case – SA22*, July 2015, pp. 2–3.

¹⁴⁹ AGN, *Response: AER Australian Gas Networks 022 – Meters and regulators*, 18 September 2015, pp. 1–2.

¹⁵⁰ AGN, *Access arrangement information: Attachment 7.1: Business cases: Business case – SA75*, July 2015, p. 2.

We consider customers requesting this service should bear the cost, consistent with the approach in the 2010–16 period. We therefore do not consider it appropriate to include this in the calculation of Reference Tariffs.

The CCP and Alternative Technology Association submitted that this project did not receive overwhelming support in AGN's WTP study.¹⁵¹ The CCP also suggested AGN may have under-represented the unit cost of this project in its WTP study (or over-estimated it in their business case).¹⁵² The SA Government stated that it does not object to this project being in Reference Tariffs as long as it is a once-off project to resolve legacy issues. However, the SA Government also stated that it was reasonable that the cost of this program was not recovered from Reference Tariffs.¹⁵³

I&C meter sets (SA33)

We are satisfied AGN's forecast expenditure of \$2.0 million (\$2014–15, unescalated direct costs) for the SA33 project is conforming capex that complies with rule 79.¹⁵⁴

AGN proposed to upgrade the metering sites for 24 demand customers (>10TJ) because of non-compliance with current safety requirements.¹⁵⁵ We agree with Sleeman Consulting that this project is reasonable and prudent. This project will ensure AGN complies with current standards, avoid the reuse of degraded equipment, and would ensure safety at customer sites.¹⁵⁶ Taking into account Sleeman Consulting's advice, we agree that this project is reasonable and prudent.

Valve corrosion protection (SA09)

We consider the proposed capex for the project, 'Pitting issues under sleeves' (SA21a), is an opex item. We have therefore included this project in our assessment of AGN's opex forecast where we are not satisfied AGN requires additional funding for this work (see attachment 7).

This project involves blasting valves with significant corrosion and coating them to protect from further corrosion.¹⁵⁷ This is a continuation of a program that AGN proposed in the current access arrangement period, which we accepted. In our draft

¹⁵¹ CCP, *Advice to AER from Consumer Challenge Panel sub-panel 8 regarding Australian Gas Networks' (SA) Access arrangement 2016–2021 proposal*, 25 August 2015, p. 14; Alternative Technology Association, *Submission on Australian Gas Networks (South Australia) access arrangement proposal 2016–21*, 10 August 2015, p. 10.

¹⁵² CCP, *Advice to AER from Consumer Challenge Panel sub-panel 8 regarding Australian Gas Networks' (SA) Access arrangement 2016–2021 proposal*, 25 August 2015, p. 14.

¹⁵³ SA Government, *Submission on Australian Gas Networks SA access arrangement proposal 2016–21*, 21 August 2015, p. 4.

¹⁵⁴ NGR, r. 79(2)(c)(i).

¹⁵⁵ AGN, *Access arrangement information: Attachment 7.1: Business cases: Business case – SA33*, July 2015, pp. 1–2.

¹⁵⁶ Sleeman Consulting, *Australian Gas Networks access arrangement 2016/17 to 2020/21: Review of capex forecasts for selected projects*, 18 November 2015, section 3.4.

¹⁵⁷ AGN, *Access arrangement information: Attachment 7.1: Business cases: Business case – SA09*, July 2015, pp. 2–4.

and final decision for the previous access arrangement review, we included this project in our alternative opex estimate.¹⁵⁸ AGN, then Envestra, agreed with this classification in its revised proposal.¹⁵⁹ The CCP also asked whether this project is a maintenance activity (opex).¹⁶⁰ We therefore consider we should assess this project as opex.

Other distribution system

This category captures distribution system capex that do not fall into the categories we discussed above. AGN provided the justification of its proposed \$37 million for other distribution system capex, including the assessment against NGR requirements and its stakeholder program, in the business case for each project.¹⁶¹

We have included \$10.0 million (\$2014–15, unescalated direct costs) of other distribution system capex in our alternative capex estimate. We consider this capex is conforming capex that complies with rule 79(1) of the NGR for the following reasons:

- we consider the proposed capex for the 5 smaller scale augmentation projects totalling \$4.1 million (\$2014–15, unescalated direct costs) is conforming capex that complies with rule 79 because it is justified¹⁶²
- we do not consider the proposed capex for several proposed projects totalling \$25.5 million (\$2014–15, unescalated direct costs) is conforming capex (which we discuss in more detail below).
- we consider the proposed capex for the project, 'Non-compliant meter installations' (SA32), totalling \$1.4 million (\$2014–15, unescalated direct costs) is an opex item. We have therefore included this project in our assessment of AGN's opex forecast (see attachment 7).

In undertaking our assessment of other distribution system capex, we sought advice from Sleeman Consulting, who examined the business cases submitted by AGN and requested further information from AGN. We discuss the reasons for adjusting certain projects within this capex category below.

We note the Energy Consumers Coalition of SA also questioned the need for the projects in 'Other distribution system' given AGN already received funding for many of them in the current access arrangement period.¹⁶³

¹⁵⁸ AER, *Draft decision: Envestra Ltd Access arrangement proposal for the SA gas network 1 July 2011 – 30 June 2016*, February 2011, p. 37; Envestra, *South Australian access arrangement information: Public version*, 1 October 2010, p. 105; AER, *Final decision: Envestra Ltd access arrangement proposal for the SA gas network 1 July 2011 – 30 June 2016*, June 2011, p. 19.

¹⁵⁹ Envestra, *South Australian access arrangement information: Attachment 7–7: Public version*, 23 March 2011, p. 1.

¹⁶⁰ CCP, *Advice to AER from Consumer Challenge Panel sub-panel 8 regarding Australian Gas Networks' (SA) Access arrangement 2016–2021 proposal*, 25 August 2015, p. 14.

¹⁶¹ AGN, *Access arrangement information for Australian Gas Networks' South Australian Natural Gas distribution network*, July 2015, p. 147.

¹⁶² NGR, rr. 79(2)(c)(i), 79(2)(c) (ii).

¹⁶³ Energy Consumers Coalition of SA, *Submission: SA gas distribution revenue reset*, August 2015, p. 29.

HDPE live camera inspection and repairs (SA52)

We are not satisfied the AGN's forecast expenditure of \$11.3 million (\$2014–15, unescalated direct costs) for the SA52 project is conforming capex that complies with rule 79. The discussion on AGN's mains replacement program contains our assessment of this project.

Fire safety valves (SA31)

We are not satisfied AGN's forecast expenditure of \$10.5 million (\$2014–15 unescalated direct costs) for the fire safety valves project (SA31) is conforming capex that complies with rule 79. Based on advice from Sleeman Consulting, we consider that \$520 000 (\$2014–15 unescalated direct costs) is conforming capex for this project.¹⁶⁴ Our draft decision is to include \$520 000 (\$2014–15 unescalated direct costs) as conforming capex.

The capex proposed involves continuing the current program of installing fire safety valves in bushfire risk areas. AGN also proposed to expand the program to install the valves in other areas (non-bush fire prone areas). We discuss these components below.

In the previous review, AGN proposed to install fire safety valves in approximately 14,000 connections in bushfire risk areas, which we accepted.¹⁶⁵ AGN submitted that it expects to have installed 4,800 units in the 2010–16 period, and proposed to complete the remaining 9,900 units in the 2016–17 year.¹⁶⁶

Sleeman Consulting recommended reducing the volumes forecast for these installations to 1,000 installations per annum, reflecting the annual rate AGN achieved in recent years.¹⁶⁷ We consider that the number of actual installations AGN has undertaken in the current period is efficient. We also expect that AGN would have undertaken more installations if there was a safety concern. In this regard, we consider that the actual number of installations it undertook over the current period reveals, from a risk basis, the efficient number of installations to be undertaken from a safety and service integrity perspective. AGN also did not provide convincing evidence that an increase in the installation rate from the current period is warranted. We therefore agree with Sleeman Consulting that an amount of \$520 000 is reasonable for the

¹⁶⁴ NGR, rr. 79(2)(c)(i), 79(2)(c) (ii).

¹⁶⁵ AER, *Draft decision: Envestra Ltd Access arrangement proposal for the SA gas network 1 July 2011 – 30 June 2016*, February 2011, p. 39; Envestra, *South Australian access arrangement information: Public version*, 1 October 2010, p. 108; Envestra, *South Australian access arrangement information: Business case S43*, 1 October 2010 (Confidential); AER, *Final decision: Envestra Ltd access arrangement proposal for the SA gas network 1 July 2011 – 30 June 2016*, June 2011, p. 30; Envestra, *South Australian access arrangement information: Public version*, 23 March 2011, p. 111.

¹⁶⁶ AGN, *Access arrangement information: Attachment 7.1: Business cases: Business case – SA31*, July 2015, p. 3.

¹⁶⁷ Sleeman Consulting, *Australian Gas Networks access arrangement 2016/17 to 2020/21: Review of capex forecasts for selected projects*, 18 November 2015, section 4.2.

continued installation of fire safety valves in bushfire prone areas for the 2016–21 access arrangement period.

We do not accept that capex is required for the expanded program to install the valves in other areas (non–bush fire prone areas).¹⁶⁸ More specifically, the expanded program involves installing valves to 1) approximately 800 domestic properties where gas meters are in proximity to brush fences, and 2) all new (8,500 per annum) and changeover (16,000 to 37,000 per annum) domestic meter installations.

These additions to the rollout of fire safety valves are not conforming capex under the NGR.¹⁶⁹ Sleeman Consulting considers the risk of damage from a brush fence fire to be very low, and street access remains available for isolation of the domestic service.¹⁷⁰ Regarding domestic meter installations, Sleeman Consulting advised that internal fires pose the greater risk, whereas fire safety valves protect from external fires (where the risk of a fire in a non–bush fire prone area is low).¹⁷¹ The SA Government also questioned the need to expand the roll–out to meters near brush fences and the meter changeovers. The SA Government noted the risk of not carrying out this work is ‘moderate’¹⁷²

Replacement of exposed PE service pipe (SA28)

We are not satisfied AGN’s forecast expenditure of \$7.1 million (\$2014–15 unescalated direct costs) for the SA21 project is conforming capex. Based on advice from Sleeman Consulting, we consider \$4.3 million (\$2014–15 unescalated direct costs) is conforming capex for this project.¹⁷³

AGN proposed to continue a program, commenced in 2013, to replace above–ground polyethylene pipe in the lead up to domestic meters. AGN proposed to replace 3,000 units per annum in the 2016–21 access arrangement period.¹⁷⁴ Sleeman Consulting considered the program is justified, but recommended reducing the replacement rate to 2,000 units per annum based on the historical replacement rate of approximately 1,700 units per annum.¹⁷⁵ We consider the replacement rate of 2,000 units per annum is justified under NGR rules 79(2)(c)(i) and (ii) given it is slightly above historical rates of approximately 1,700 units per annum. Similar to the SA31 project we discussed above,

¹⁶⁸ AGN, *Access arrangement information: Attachment 7.1: Business cases: Business case – SA31*, July 2015, pp. 3, 8.

¹⁶⁹ NGR, rr. 79(2)(c)(i), 79(2)(c)(ii).

¹⁷⁰ Sleeman Consulting, *Australian Gas Networks access arrangement 2016/17 to 2020/21: Review of capex forecasts for selected projects*, 18 November 2015, section 4.2.

¹⁷¹ Sleeman Consulting, *Australian Gas Networks access arrangement 2016/17 to 2020/21: Review of capex forecasts for selected projects*, 18 November 2015, section 4.2.

¹⁷² SA Government, *Submission on Australian Gas Networks SA access arrangement proposal 2016–21*, 21 August 2015, p. 4.

¹⁷³ NGR, rr. 79(2)(c)(i), 79(2)(c)(ii).

¹⁷⁴ AGN, *Access arrangement information: Attachment 7.1: Business cases: Business case – SA28*, July 2015, pp. 2 and 6.

¹⁷⁵ Sleeman Consulting, *Australian Gas Networks access arrangement 2016/17 to 2020/21: Review of capex forecasts for selected projects*, 18 November 2015, section 4.3.

we consider that the actual number of replacements it undertook over the current period reveals, from a risk basis, the efficient number to be undertaken from a safety and service integrity perspective. AGN also did not provide convincing evidence that an increase in the replacement rate from the current period is warranted.

Sleeman Consulting considered AGN's unit cost forecast were reasonable, although it should exclude the cost of fire safety valves (see also assessment of project SA31). This reduces the unit cost of each job.¹⁷⁶ We agree with Sleeman Consulting's recommendation as it reflects efficient costs.¹⁷⁷

Sleeved railway crossings (SA10)

We are not satisfied AGN's forecast expenditure of \$2.2 million (\$2014–15 unescalated direct costs) for the SA10 project is conforming capex. Based on advice from Sleeman Consulting, we consider that the proposed capex of \$1.0 million (\$2014–15 unescalated direct costs) is conforming capex that complies with rule 79.¹⁷⁸

In the previous review, AGN proposed to inspect and repair 81 sleeved railway crossings, which we accepted.¹⁷⁹ AGN stated it expects to have finished replacing 26 sleeved railway crossings in the 2011–16 period. AGN proposed to complete the remaining 55 units in the 2016–21 access arrangement period at a rate of 11 units per annum. AGN states that the inspection and repair work is required to maintain the safety and integrity of the network.¹⁸⁰

Sleeman Consulting recommended reducing the volumes forecast for these inspections and repair to five per annum, reflecting the annual rate AGN achieved in recent years.¹⁸¹ We consider that the number of inspections and repair work AGN has undertaken in the current period is efficient. We also expect that AGN would have undertaken more work if there was a safety concern. In this regard, we consider that the actual number of inspections and repair it undertook over the current period reveals, from a risk basis, the efficient number of installations to be undertaken from a safety and service integrity perspective.

¹⁷⁶ Sleeman Consulting, *Australian Gas Networks access arrangement 2016/17 to 2020/21: Review of capex forecasts for selected projects*, 18 November 2015, section 4.3.

¹⁷⁷ NGR, r. 79(1)(a).

¹⁷⁸ NGR, rr. 79(2)(c)(i), 79(2)(c)(ii).

¹⁷⁹ AER, *Draft decision: Envestra Ltd Access arrangement proposal for the SA gas network 1 July 2011 – 30 June 2016*, February 2011, p. 39; Envestra, *South Australian access arrangement information: Public version*, 1 October 2010, p. 108; AER, *Final decision: Envestra Ltd access arrangement proposal for the SA gas network 1 July 2011 – 30 June 2016*, June 2011, p. 30; Envestra, *South Australian access arrangement information: Public version*, 23 March 2011, p. 111.

¹⁸⁰ AGN, *Access arrangement information: Attachment 7.1: Business cases: Business case – SA10*, July 2015, pp. 2–6.

¹⁸¹ Sleeman Consulting, *Australian Gas Networks access arrangement 2016/17 to 2020/21: Review of capex forecasts for selected projects*, 18 November 2015, section 4.4.

We therefore consider that this expenditure is justified under NGR rules 79(2)(c)(i) and (ii) given it is consistent with historical rates. Sleeman Consulting also noted AGN's inspection program to date has not identified any major corrosion problems.¹⁸²

Therefore, we consider \$1.0 million (based on 5 units per year) is the best estimate for this work in the next period.

Non-compliant meter installations (SA32)

We consider that the proposed capex for the project, 'Non-compliant meter installations' (SA32), is an opex item. We have therefore included this project in our assessment of AGN's opex where we adjusted our base year opex to account for the reclassification of this project forecast (see attachment 7).

AGN proposed to relocate 726 meters located inside buildings. The installation of these meters is a legacy of past practices and is now non-compliant with Australian Gas Distribution Code AS4645.1:2008.¹⁸³

The CCP asked whether this project is a maintenance activity (opex).¹⁸⁴ We consider these works do not materially alter the productive capacity of the assets. We therefore consider we should assess this project as opex.

Other non-distribution system

AGN stated this category covers capex that does not relate directly to the distribution system infrastructure. AGN provided justification in the business case for each project.¹⁸⁵

We are satisfied AGN's capex forecast for other non-distribution system capex is conforming capex that complies with rule 79.¹⁸⁶ We have included \$5.0 million (\$2014–15, unescalated direct costs) of expenditure in our alternative capex forecast.

Overheads

We have not included AGN's proposed overheads expenditure of \$60.4 million (\$2014–15) in our alternative capex estimate. This is because we consider that it is not conforming capex that complies with rule 79.¹⁸⁷ Instead we have included \$46.8 million

¹⁸² Sleeman Consulting, *Australian Gas Networks access arrangement 2016/17 to 2020/21: Review of capex forecasts for selected projects*, 18 November 2015, section 4.4.

¹⁸³ AGN, *Access arrangement information: Attachment 7.1: Business cases: Business case – SA32*, July 2015, pp. 1–2.

¹⁸⁴ CCP, *Advice to AER from Consumer Challenge Panel sub-panel 8 regarding Australian Gas Networks' (SA) Access arrangement 2016–2021 proposal*, 25 August 2015, p. 14.

¹⁸⁵ AGN, *Access arrangement information for Australian Gas Networks' South Australian Natural Gas distribution network*, July 2015, p. 148.

¹⁸⁶ NGR, rr. 79(1)(a), 79(2)(c)(i), 79(2)(c)(ii).

¹⁸⁷ NGR, rr. 74(2), 79(1)(a).

(\$2014–15) for overheads in our alternative capex estimate for the 2016–21 access arrangement period.

Overheads are costs that are not directly attributable to the output of distribution businesses but are necessary to support their operations. Examples of overhead costs include network planning, procurement and human resources.

AGN's capitalised overhead forecast is based on applying an average overhead rate of 9.6 per cent¹⁸⁸ to the total forecast direct escalated capex. While the proposed average overhead rate of 9.6 per cent is broadly in line with other gas businesses, we consider that a better forecast of overheads would take account of the fixed and variable proportion of overheads.

We consider that overhead costs are not likely to increase (or decrease) in direct proportion to AGN's capex. Instead overhead costs would only partly relate to the level of capex as these costs contain certain fixed costs which are incurred regardless of the level of capex spend. In response to an information request, AGN provided an analysis of the historical fixed and variable proportions of each of its overhead costs in the 2013–14 year.¹⁸⁹ We reviewed AGN's split of fixed and variable capitalised overhead components for 2013–14, which indicates an overhead split consisting of approximately 80 per cent fixed costs and 20 per cent variable costs.

Using this information, we applied a modified base–step–trend approach, similar to what was applied in the NSW and Victorian access arrangement review decisions.¹⁹⁰ This approach takes an average of the past four years of actual overhead data (2011–15) to derive a 'base' year. For each forecast year of the access arrangement period, we scaled the variable components of these overheads by the size of the capex program and then applied a real cost escalation to the total overhead amount.¹⁹¹

6.4.3 Labour escalation

AGN applied real labour cost escalators to its capex forecasts. To develop its labour cost escalators AGN used an average of the BIS Shrapnel forecasts in Electricity, Gas, Water and Waste Services industry in South Australia and forecasts prepared by

¹⁸⁸ AGN estimated the average proportion of actual overhead costs incurred over 2011–12, 2012–13, and 2013–14.

¹⁸⁹ AGN, *Response to Information request AER Australian Gas Networks 012 – Capitalised overheads*, received 19 August 2015, p. 2.

¹⁹⁰ AER, *Final decision, Jemena Gas Networks (NSW) access arrangement 2015–20, Attachment 6 – Capital expenditure*, June 2015, p. 6–44; AER, *Access arrangement final decision, SPI Networks (Gas) Pty Ltd 2013–17, Part 4: Confidential appendix*, March 2013; AER, *Access arrangement final decision, Envestra (Gas) Networks 2013–17, Confidential appendix*, March 2013.

¹⁹¹ With capex expansion calculated as the difference between our direct capex estimate compared to the 4 year average historical direct capex estimate.

Deloitte Access Economics as part of the AER's Preliminary decision for SA Power Networks.¹⁹²

We do not consider that AGN's proposed labour cost escalation is the best estimate in the circumstances. We have substituted our estimate of the labour escalation in place of that proposed by AGN. Our reason for this is detailed in Attachment 7.

6.5 Revisions

We require the following revisions to make the access arrangement proposal acceptable:

Revision 6.1: Make all amendments necessary to reflect our draft decision on conforming capex for 2016–21, as set out in Table 6.2.

¹⁹² AGN state this averaging approach was adopted by them based upon the AER's Preliminary Decision for SA Power Networks. See Australian Gas Networks, *Access Arrangement Information for Australian Gas Networks South Australian Natural Gas Distribution Network*, July 2015, pp. 121–122.

A Confidential appendix