Attachment 7.1A

Response to Draft Decision: Business Cases for Operational Expenditure and Capital Expenditure

2016/17 to 2020/21 Access Arrangement Information Response to Draft Decision

Australian Gas Networks

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ADDENDUM TO BUSINESS CASE – SA10

PROJECT SUMMARY	
Network	AGN– SA
Project No.	SA10
Project Name	Sleeved Railway Crossings
Risk and Priority	High, Priority 2
Budget Category	Capital Expenditure (Capex)
Amendments to Original Business Case	In keeping with the Australian Energy Regulator's (AER's) Draft Decision that the number of sleeved railway crossings to be inspected and remediated in the next (2016/17 to 2020/21) Access Arrangement (AA) period should be based on the average number of sites completed in the current (2011/12 to 2015/16) AA Period, AGN has reduced the number of proposed inspections that appeared in the original business case from 11 per annum to eight per annum.
Estimated Cost	$1.587 million (real $2014/15) (reduced from $2.183 million in the original business case).
Consistency with NGR	The revised inspection and repair program complies with the new capex criteria in Rule 79 of the National Gas Rules (NGR) because it is: • necessary to maintain and improve the safety of services and maintain the integrity of services (rules 79(1)(b) and 79(2)(c)(i) and (ii)); and • such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services (Rule 79(1)(a)).
PROJECT APPROVAL	
Prepared By:	Steve Polglase, Asset Planning Engineer, APA
Reviewed By:	Robin Gray, Manager Systems Operations, APA
Approved By:	Peter Sauer, General Manager SA Networks, APA
OTHER RELEVANT DOCUMENTS	
This addendum should be read in conjunction with: • the original SA10 Business Case, which was provided to the AER on 1 July 2015 as Attachment 7.1 to the Access Arrangement Information (AAI); • AGN's response to the AER's Information Request 007, which was provided to the AER on 4 August 2015; • AGN's response to the AER's Information Request 013, which was provided to the AER on 21 August 2015; and • the 2015 South Australian Network Asset Management Plan, which was provided to the AER on 1 July 2015 as Attachment 8.1 to the AAI.	

1 Original business case

AGN's original proposal for the next AA period included a capex allowance of $2.183 million to inspect and repair 55 (11 per annum) transmission pressure (TP) sleeved railway crossings within the network.

As outlined in the original business case, work on this project commenced in 2012/13 and is required because previous installation practices and third party activities have resulted in a number of instances of compromised cathodic protection on sleeved crossings. This has created the potential for premature failure of the steel transmission mains with associated risks to the public and reliability of supply. The untreated risks associated with sleeved railway crossings has been assessed as high given the risk associated with a major gas escape resulting in an interruption to supply.

2 AER Draft Decision

In its Draft Decision, the AER accepted the basis for the inspection and remediation work and the unit costs, but reduced the level of proposed expenditure from $2.1825 million to $1 million[1] on the basis of advice it received from its engineering consultant, Sleeman Consulting (Sleeman). Sleeman's advice related to the number of inspections AGN proposed to carry out in the next AA period (i.e. 11 per annum).[2] Sleeman's view on this issue is captured in the following statement:[3]

> *"I consider completion of the inspection programme to be prudent to ensure safe and reliable operation of the transmission pressure pipeline system into the long-term. However, I note that the inspection programme to date has not identified any major corrosion problems. While it may be possible to carry out 11 sleeved railway crossing inspections per year, results to date confirm the inspection programme can be safely and prudently completed at a slower rate, and therefore at lower present value cost to consumers."*

Sleeman went on to recommend that the average annual number of inspections to be carried out in the next year be reduced to the average annual number that AGN has achieved in the current AA Period, which he estimated to be five per annum. The AER accepted this recommendation and, in doing so, noted that in its view the number of inspections carried out in the current AA period is efficient from a safety and service integrity perspective and that if there was a safety concern AGN would have carried out more inspections over this period.

AGN's response to the issues raised by Sleeman and the AER's Draft Decision is set out below.

3 AGN's Response

The only concern that Sleeman and the AER raised in respect of the original business case is that the number of sites AGN has proposed to inspect and remediate in the next AA period is higher than the average rate it has achieved in the current AA period.

AGN has therefore revisited this assumption. In short, AGN agrees with the AER and Sleeman that it is appropriate to base the inspection rate on the average number of sites it inspected and repaired in the current AA period. AGN does not, however, agree with the average rate that Sleeman has estimated, because it understates the actual rate it has achieved in the current AA period.

In the current AA period, AGN has inspected and remediated 25 sites over a three year period (2012/13 to 2014/15), which is equivalent to an average rate of 8.3 sites per annum. This is higher than the rate estimated by Sleeman, who assumed that work has been carried out over the full five year period, because:

- as noted in the original business case work on the project commenced in 2012/13, which is one year later than Sleeman assumed; and

[1] AER 2015, "*Draft Decision: Australian Gas Networks Access Arrangement 2016-2021*", November 2015, Attachment 6, pg. 6-51.

[2] Sleeman 2015, "*Review of Capex Forecasts for Selected Projects*", 18 November 2015, pg. 11.

[3] ibid.

- inspections were not able to be undertaken in 2015/16 due to the diversion of management and field resources onto the following high priority projects, which were extraordinary in their nature:
  - the work required for follow-up activities resulting from the Epic Energy pipeline rupture in 2015 which affected gas supply to Pt Pirie and Whyalla; and
  - greater than anticipated work to confirm the integrity of the Riverland Pipeline prior to its pressure upgrade as part of the Angaston compressor upgrade project.[4]

The work required on these two extraordinary projects has resulted in the number of sites that are expected to be inspected and repaired in the current AA period being lower than what was assumed in the original business case (25 compared to 26).

The inspection rate in this AA period has also been lower than what was anticipated in the business case approved for the current AA period because, as noted in the responses to AER Information Requests 007 and 013, the inspections and repairs in the earlier years were used to develop and validate the process against the scope expected during the design phase. Additionally, the earlier sites proved to be far more time and resource intensive than anticipated as a result of additional excavations and dewatering being required and thus taking significantly longer than planned, with resulting additional costs.

Based on the experience of APA Operational management the remaining sites are not expected to present these same problems, and AGN is confident that it can maintain an annual average rate of completing eight sites each year.

Accordingly, and consistent with Sleeman's advice to the AER, AGN has reduced the number of proposed inspections that appeared in the original business case from 11 sites per annum to eight sites per annum. In total, 40 sites will be inspected and repaired in the next AA period and the remaining 16 will be deferred to the next (2020/21 to 2025/26) AA period.

The associated capex for 40 sites is $1.587 million (real $2014/15), which is $595,200 lower than the original business case proposal (see Table 3.1). The revised expenditure has been calculated using the same unit cost that appeared in the original business case ($39,700 per site), which is based on the average cost of recently completed work, with the contractor rates based on the rates established through a competitive tender process.

[4] This major project is not part of the current AA capital works program, and has been undertaken in addition to this program.

Table 3.1: Revised capital expenditure ($'000 (Real 2014/15)

Item	FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21	Total
Materials	25	25	25	25	25	**124**
Labour	2923	2923	2923	2923	293	**1,463**
Total	**317**	**317**	**317**	**317**	**317**	**1,587**

Note: Totals may not sum due to rounding.

4 Summary

Consistent with the requirements of Rule 79(1)(a) of the NGR, AGN considers that the revised expenditure on the sleeved railway crossings is:

- *Prudent* – The expenditure is necessary in order to maintain the integrity of services and to reduce the risk of incidents associated with major gas escapes and is of a nature that a prudent service provider would incur, as Sleeman noted in his advice to the AER:[5]

  > *"I consider completion of the inspection programme to be prudent to ensure safe and reliable operation of the transmission pressure pipeline system into the long-term."*

- *Efficient* – The inspection and remediation program is the only practical and effective option to efficiently address the risk. Engineering assessments and design will be carried out by internal staff and field work will be carried out by external contractors based on competitively tendered rates. Bringing the number of sites to be inspected each year into line with the average rate that has been achieved in the current AA Period can, in this instance, also be considered efficient as the AER noted in its Draft Decision:[6]

  > *"We consider that the number of inspections and repair work that AGN has undertaken in the current period is efficient."*

- *Consistent with accepted and good industry practice* – Good industry practice (AS 2885) dictates that identified risks be assessed and actioned to reduce (or eliminate) those risks in a manner that balances cost and risk. This project addresses an identified risk and has been developed based on a prudent approach balancing risk, expenditure and delivery. On this basis, the expenditure is consistent with accepted and good industry practice.

- *To achieve the lowest sustainable cost of delivering pipeline services* – The proposed project is necessary to maintain the long term asset integrity, reducing the likelihood of premature failure. Failure to do so would incur additional capital and/or operating expenditure. It is therefore consistent with the objective of achieving the lowest sustainable cost of delivering services.

The revised expenditure is also consistent with 79(1)(b), because it is necessary to:

- maintain and improve the safety of services (79(2)(c)(i)); and
- maintain the integrity of services (79(2)(c)(ii)).

[5] Sleeman 2015, "*Review of Capex Forecasts for Selected Projects*", 18 November 2015, pg. 11.

[6] AER 2015, "*Draft Decision: Australian Gas Networks Access Arrangement 2016-2021*", November 2015, Attachment 6, pg. 6-51.

ADDENDUM TO BUSINESS CASE - SA21

PROJECT SUMMARY	
Network	AGN– SA
Project No.	SA21
Project Name	Replacement of TP Pipelines M21 and M53
Risk and Priority	High, Priority 2
Budget Category	Capital Expenditure (Capex)
Amendments to Original Business Case	Having regard to the Australian Energy Regulator's (AER's) Draft Decision on SA21, AGN has decided to defer the proposed replacement of TP Pipelines M21 and M53 for two years from 2016/17 and 2017/18 to 2018/19 and 2019/20. This revision has had no effect on the proposed level of capex.
Estimated Cost	$7.5 million (real $2014/15) (unchanged from the original Business Case).
Consistency with NGR	The replacement of these assets complies with the new capex criteria in Rule 79 of the National Gas Rules (NGR) because it is: • necessary to maintain and improve the safety of services and maintain the integrity of services (Rule 79(1)(b) and Rules 79(2)(c)(i) and (ii)); and • such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services (Rule 79(1)(a)).
PROJECT APPROVAL	
Prepared By:	Steve Polglase, Asset Planning Engineer, APA
Reviewed By:	Chris Liew, Integrity Manager, SA Networks, APA
Approved By:	Peter Sauer, General Manager SA Networks, APA
OTHER RELEVANT DOCUMENTS	
This addendum should be read in conjunction with: • the original SA21 Business Case, which was provided to the AER on 1 July 2015 as Attachment 7.1 to the Access Arrangement Information (AAI); • AGN's response to the AER's Information Request 007, which was provided to the AER on 4 August 2015; and • the 2015 South Australian Network Asset Management Plan, which was provided to the AER on 1 July 2015 as Attachment 8.1 to the AAI.	

1 Original Business Case

AGN's original proposal for the next (2016/17 to 2020/21) Access Arrangement (AA) period included an allowance of $7.5 million to replace the Transmission Pressure (TP) Pipelines M21 and M53. The rationale for replacing these pipelines is set out in detail in the original Business Case that was submitted to the AER on 1 July 2015 but, in summary, AGN proposes to replace the two pipelines because:

- the two pipelines are nearing the end of their useful lives with significant pitting corrosion having been identified beneath the heat shrink sleeves (HSS) at welded joints in these two pipelines, which means there is a significant risk of a major gas escape that could affect the safety and reliability of supply to 20,000 customers located in Adelaide's southern suburbs; and
- In April 2015 a section of the concrete covering pipeline M53 at Christies Creek crossing near Morrow Road was found to have been washed away, which has left this section of the pipeline exposed to a major gas escape that could adversely affect the safety and reliability of supply.

The untreated risks associated with these two pipelines are rated as High.

2 AER's Draft Decision

In its Draft Decision, the AER decided not to make any provision for the proposed replacement of the M21 and M53 TP pipelines because it claimed not to be satisfied that the proposed expenditure complies with Rule 79 of the NGR.[1] The AER's decision in this case was informed by the advice it received from its engineering consultant, Sleeman Consulting (Sleeman),[2] who noted that while pitting corrosion is widespread on the M21 and M53 pipelines and "*is of concern*", the pipelines, in his view, remain fit for purpose.

Elaborating on this further, Sleeman claimed that the current level of corrosion was less than what would be required to necessitate expedited capital works and pointed to an assessment framework[3] that used to form part of AS2885.3 (Australian Standards: Pipelines – Gas and liquid Petroleum; Part 3: Operations and Maintenance) in support of this claim. Sleeman went on to add that AGN should carry out further analysis to identify the probable range of pitting corrosion depths and implement a monitoring regime as part of Business Case SA21a to determine when replacement is justified.

The AER agreed with the advice that Sleeman provided and, on this basis, concluded that the project was not required in the next AA period.

3 AGN's Response

The greatest concern that Sleeman and the AER appear to have with the proposed replacement of the M21 and M53 TP pipelines is the timing of the proposed replacement[4]. AGN has therefore revisited this aspect of the original Business Case. In doing so, AGN has carried out a more detailed analysis of the level of corrosion on these two pipelines and the extent to which the replacement could be deferred. AGN has also considered whether there would be any value in implementing a monitoring programme that would allow it to better predict when the replacement should occur.

In short, the results of this analysis indicate that the replacement of the M21 and M53 TP pipelines should still occur in the next AA period to mitigate the risks associated with the corrosion that is present on these pipelines, but the timing of the replacement can be deferred by two years to 2018/19 and 2019/20.

Further detail on the analysis that AGN has carried out on the level of corrosion in the pipeline and the relative merits of replacing the two pipelines in the next AA Period versus implementing a monitoring program and deferring the replacement until the subsequent (2021/22 to 2025/26) AA Period is provided below.

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1 AER 2015, *"Attachment 6: Capital expenditure | Draft Decision: Australian Gas Networks Access Arrangement 2016-2021",* November 2015, pg. 6-26-6-27.

2 Sleeman 2015, "*Review of Capex Forecasts for Selected Projects",* 18 November 2015, pg. 5-6.

3 Sleeman has used the assessment framework that was included in of AS2885.3 -2001(Australian Standards: Pipelines – Gas and liquid Petroleum; Part 3: Operations and Maintenance), but this part of the standard is not contained in the current version, AS2885.3 2012. AGN uses an assessment framework conforming to the current version.

4 AER 2015, *"Attachment 6: Capital expenditure | Draft Decision: Australian Gas Networks Access Arrangement 2016-2021",* November 2015, pg. 6-26

3.1 Analysis of corrosion levels

Sleeman has contended in his advice to the AER that the critical length for the worst pitting corrosion found on the pipelines is in excess of 40 mm. Although not specifically stated in Sleeman's advice, AGN has interpreted this comment of critical length to be "critical defect length", which relates to pipeline rupture. Pipeline rupture is where the pipe bursts open, such that the cylinder has opened to a size equivalent to its diameter (AS2885.1, 2012). This is opposed to a leak, where a section of the pipe wall fails resulting in a gas escape, but the pipe does not burst open.

Like Sleeman, AGN is of the view that the risk of a burst rupture is highly unlikely. AGN is, however, concerned with the risk of a major gas leak arising from corrosion in the two pipelines than a rupture. The analysis below therefore focuses on the potential for a major gas leak to occur from the observed corrosion, with the high potential for it to catch fire. Either circumstance would require the pipeline to be shut down for repairs, resulting in loss of gas supply to over 20,000 consumers.

AGN has focused on determining the depth of the corrosion, remaining pipe wall thickness left to contain pipeline pressure the estimated growth rate of corrosion and thus the reduction in wall thickness over time. Using this information, it is possible to estimate the time within which the pipe wall thickness would reduce to being equal to, or less than, that which (when assessed in accordance with industry standards), has a high risk of a leak.[5]

AGN has performed this analysis on the corrosion defects observed on the M21 (six in total) and M53 (16 in total) pipelines to determine the likely deepest pit (95% confidence level) on each pipeline, and thus the worst case remaining wall thickness. Applying an industry standard corrosion rate[6] for loss of the remaining wall thickness over time, results in an approximate remaining life for the pipelines of approximately six and a half years for M53 and eight years for M21 as at June 2015, which is when the latest corrosion data was obtained. Because the M53 pipeline contains the majority of the length of the combined section proposed for replacement (4.06 km of 5.16 km total), it would be both prudent and efficient to replace the two pipelines within the six and a half year remaining life window that applies to the M53 pipeline.

3.2 Replacement and monitoring options

While the analysis in the preceding section suggests that the replacement of the M53 and M21 pipelines could be deferred until 2021/22, it is important to recognise that the corrosion rate is dependent on a number of factors and typically subject to a range of uncertainties. Trying to predict the progression of corrosion to a high degree of accuracy over time is therefore extremely difficult.

Given the approximations involved and the risks associated with the corrosion, one option that AGN has considered is to defer the Front End Engineering and Design (FEED) study and replacement until 2018/19 and 2019/20. This is two years later than what was assumed in the original Business Case

[5] American Society of Mechanical Engineers, ASME B31.8 Gas Transmission and Distribution Piping Systems, Appendix L (Determination of Remaining Strength of Corroded Pipe).

[6] American National Standards Institute and NACE Intl., Standard Practice Pipeline External Corrosion Direct Assessment Methodology (SP0502), clause C3.2. This clause suggests a corrosion rate of 0.4 mm per year.

and will result in a lower present value cost to consumers. Deferring the replacement by this period will result in the pipelines being replaced two to three years earlier than the estimated end of their useful lives, but in AGN's view this is prudent given the risks and uncertainties associated with corrosion, and represents the least present cost (see Table 3.3). The cost of implementing this option, which is based on the costs set out in the original Business Case, is set out in the table below.[7]

Table 3.1: Option 1: Replacement of M21 and M53 pipelines in 2018/19 and 2019/20 ($'000 Real 2014/15)

	FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21	Total
Replacement capex	0	0	350	7,118	0	**7,468**

The second option that AGN has considered is to try and defer the replacement until the end of the useful lives of the two pipelines (i.e. until 2021/22) by implementing a monitoring programme that will enable AGN to more closely monitor the corrosion activity and have greater confidence in any decision to defer the replacement. It is worth noting in this context that implementing a monitoring programme provides no guarantee that the replacement will be able to be deferred until 2021/22, because the replacement decision will depend on the state of the pipelines. The value of the monitoring programme in this case is that if it is actually technically feasible to defer the replacement to the subsequent AA period, then AGN will have more confidence to make this deferral decision because it is more informed about the state of the assets. AGN is of the view that it would not be prudent or efficient to delay the replacement of the pipelines to the subsequent AA period and **not** implement a monitoring programme.

In his advice to the AER, Sleeman suggested[8] that a monitoring program could be incorporated into the exploratory excavation programme proposed in Business Case 21a. That Business Case proposes 52 excavations per year (i.e. two excavations per kilometre across the 130 km length of the metropolitan Adelaide transmission pressure system) [redacted], with a total overall cost of $3.3 million.

Given how widespread the corrosion is on the M21 and M53 pipelines (22 sites over a length of 5.2 km), any corrosion monitoring programme on these two pipelines would need to occur at a rate of 20 excavations per year, or approximately four per km, which is double the rate for the rest of the transmission system. Based on the cost of excavations estimated for Business Case SA21a,[9] this equates to a monitoring cost of [redacted] per year, or [redacted] over the next AA period. This cost represents an additional 38% of the proposed SA21a cost, and additionally, AGN would be required to incur additional opex in order to undertake the programme.

The cost of implementing this option is set out in Table 3.2. Before examining this table it is worth noting that even if a monitoring programme is put in place, the section of pipeline across Christies

7 AGN, Business Case 21, which was provided to the AER on 1 July 2015, Attachment B.

8 Sleeman 2015, *"Review of Capex Forecasts for Selected Projects"*, 18 November 2015, pg. 4.

9 AGN, Business Case 21a, which was provided to the AER on 1 July 2015, pg. 6.

Creek will still require replacement in the next AA Period. As noted in the original Business Case[10], a section of the concrete covering pipeline M53 at Christies Creek crossing near Morrow Road has recently been washed away[11], which has left this section of the pipeline exposed to an increased risk of a larger failure or washaway at this location, resulting in a major gas escape that could adversely affect the safety and reliability of supply to over 20,000 consumers. In the absence of replacing the pipelines in the next AA Period, deferring the replacement of this section of the pipeline to 2021/22 is not therefore an option. The replacement of this part of the pipeline is therefore assumed to occur in 2016/17[12] and, consistent with the original Business Case, is expected to cost [redacted][13]

Table 3.2: Option 2: Monitoring programme with replacement in 2021/22 -2022/23 ($'000 Real 2014/15)

Item	Next AA period					Subsequent AA period		Total
	FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21	FY 21/22	FY 22/23	
Christies Creek replacement - capex	[redacted]							[redacted]
Corrosion monitoring excavations - opex	255	255	255	255				[redacted]
Replacement of M21-M53 (ex. Christies Creek) - capex						350	[redacted]	[redacted]
Total	**705**	[redacted]	[redacted]	[redacted]	[redacted]	**350**	[redacted]	**8,488**

Table 3.3 compares the present value of the costs of the two options outlined above, i.e.:

- Option 1: Replace the M21 and M53 pipelines in 2018/19 and 2019/20; and
- Option 2: Institute a monitoring programme in the next AA Period and defer the replacement until 2021/22 (with the FEED occurring in 20/21).

Table 3.3: Comparison of the two options ($'000 Real 2014/15)

Item	Present value (PV) 2014/15	Next AA period					Subsequent AA period	Total
		FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21	FY 21/22	
Option 1	**$5,503**	0	0	350	7,118	0	0	7,468
Option 2	**$5,794**	705	[redacted]	[redacted]	[redacted]	350	[redacted]	8,488
Discount Rate (nominal pre-tax WACC)*	**6.36%**							

* The nominal pre-tax Weighted Average Cost of Capital used in this analysis is consistent with the AER's Draft Decision.

[10] AGN, Business Case 21, which was provided to the AER on 1 July 2015, pg. 3.

[11] This was washed away in 2009 and subsequently repaired. In April 2015 it was found to have been washed away for a second time.

[12] Note that the timing of this replacement does not affect choice between Option 1 and 2 in the NPV analysis in Table 3.3.

[13] AGN, Business Case 21, which was provided to the AER on 1 July 2015, pg. 11

As this table shows, Option 1 is more cost effective than Option 2 and it also provides significantly better risk reduction in the next AA Period. While not shown in this table, AGN has also considered whether this finding would change if Option 2 allowed for the replacement to be deferred by a further two years to 2022/23 and 2023/24, but found that Option 1 would still be less cost in this case.

Given the results of this analysis, AGN has decided to implement Option 1 (the replacement of M21 and M53 in 2018/19 and 2019/20) at an estimated cost of $7.5 million (capex real $2014/15) rather than Option 2.

4 Summary

For the reasons set out above, AGN remains of the view that the M21 and M53 pipelines should be replaced in the next AA Period, but has decided that the replacement should occur two years later than what was contemplated in the original Business Case (i.e. 2018/19 and 2019/20 rather than 2016/17 and 2017/18). The cost of replacing the two pipelines on this delayed schedule is unchanged from the original Business Case (i.e. $7.5 million in capex).

Consistent with the requirements of Rule 79(1)(a) of the NGR, AGN considers the forecast capex for this project to be:

- *Prudent* – The expenditure is necessary to ensure that the ongoing integrity of the TP mains is maintained and there are no major gas escapes that could impact public safety and reliability of supply. The expenditure is also of a nature that a prudent service provider would incur.
- *Efficient* – The replacement of the TP mains is more cost effective over the long term than a programme of monitoring and remediating the corrosion, relaying the pipeline at Christies Creek and deferring the replacement of the two pipelines until the subsequent AA period. The proposed expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur. The manner in which AGN intends the replacement to be carried out (i.e., FEED study to be carried out internally and field work carried out by external contractors that will be selected through a competitive tender) can also be considered efficient.[14] AGN also notes that neither Sleeman nor the AER has raised any concerns about the costs that were proposed in the original Business Case, which AGN has also adopted in this Addendum.
- *Consistent with accepted and good industry practice* – The identification and rectification of pipeline integrity issues as outlined above and the reduction of risk to as low as reasonably practicable in a manner that balances cost and risk is consistent with Australian Standard AS2885 and therefore in keeping with accepted and good industry practice.
- *To achieve the lowest sustainable cost of delivering pipeline services* – The forecast expenditure is the most cost effective long-term option as demonstrated in Section 6 of the original Business Case and more cost effective than the monitoring option as shown in Section 3.3 above.

The capex can therefore be viewed as being consistent with Rule 79(1)(a) of the NGR. The proposed capex is also consistent with Rule 79(1)(b), because it is necessary to:

[14] More detail on the costs of this project is provided in AGN, Business Case 21, which was provided to the AER on 1 July 2015, pg. 6-7.

- maintain and improve the safety of services (79(2)(c)(i)); and
- maintain the integrity of services (79(2)(c)(ii)).

ADDENDUM TO BUSINESS CASE – SA24

PROJECT SUMMARY	
Network	AGN– SA
Project No.	SA24
Project Name	Two Wells high pressure mains extension
Risk Rating	Low
Budget Category	Capital Expenditure (capex)
Amendments to Original Business Case	The original Business Case has been amended in the following ways: • the demand per connection rates for residential and small commercial customers have been brought into line with the Australian Energy Regulator's (AER's) Draft Decision (i.e. 13 GJ and 273 GJ, respectively); • the number of small commercial connections has been increased to reflect a more realistic (albeit conservative) assumption about the number of small businesses that are likely to set up in Two Wells given the growth in residential customers in the area; • the tariffs used in the calculation of the revenue per connection assumptions (Tariff R (excluding Tanunda) and Tariff C (excluding Tanunda) are based on the AER's Draft Decision; and • the discount rate used in the cost-benefit analysis is based on the AER's Draft Decision on the weighted average cost of capital (WACC).
Estimated Cost	Total capex for the next (2015/16 to 2020/21) Access Arrangement (AA) period: $5.2 million (real $2014/15) (Extension cost: $5 million; Reticulation, meters and services costs for the AA period: $0.2 million) For the purposes of assessing the viability of this project, the total capex has been used, but in the AA proposal, the costs have been divided between the Two Wells project (extension cost) and Growth Capex (reticulation, meters and services costs).
Consistency with NGR	The proposed expenditure on the Two Wells project is justifiable under Rule 79(2)(b) of the National Gas Rules (NGR) because the present value of the expected incremental revenue to be generated from the project exceeds the present value of the capex. The proposed expenditure is also such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services, as required by Rule 79(1)(a).
PROJECT APPROVAL	
Prepared By:	Ed Macolino, Manager Strategic Development, APA
Reviewed By:	Peter Gayen, Networks Commercial Manager, APA
Approved By:	John Ferguson, Group Executive Networks, APA

OTHER RELEVANT DOCUMENTS

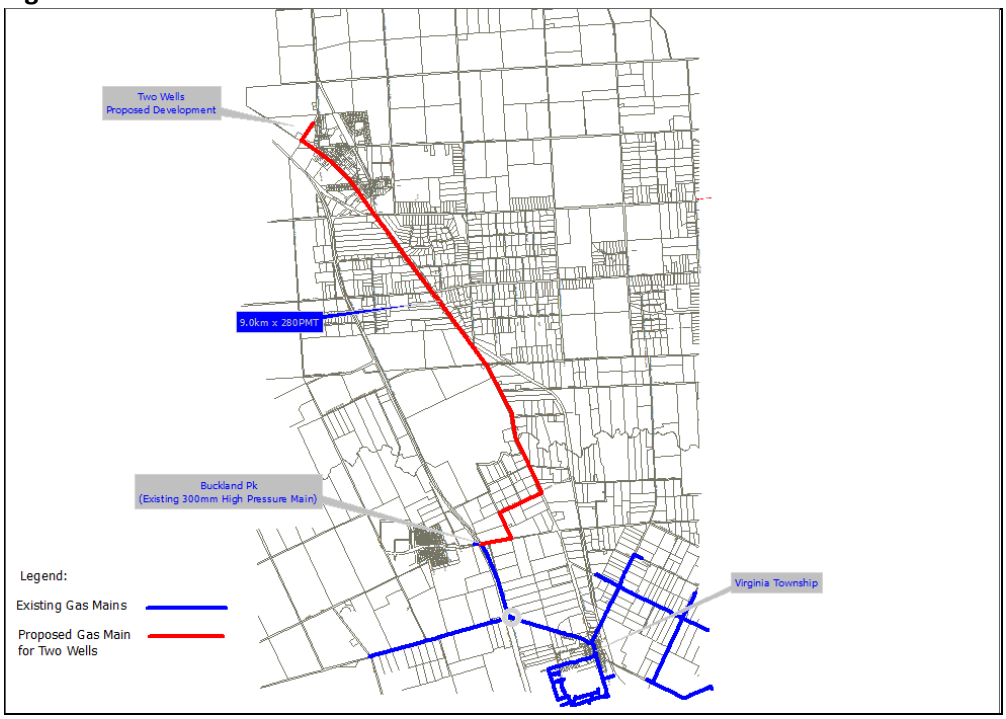
This addendum should be read in conjunction with:

- the original SA24 Business Case, which was provided to the AER on 1 July 2015 as Attachment 7.1 to the Access Arrangement Information (AAI);
- Supporting Information 1-3 of this Business Case addendum, as outlined below:
  - Supporting Information 1: Connor Holmes report;
  - Supporting Information 2: Development plans for Two Wells (Eden and Liberty plans); and
  - Supporting Information 3: Cash flow model [confidential]
- AGN's response to Information Request 002, which was provided to the AER on 23 July 2015 and included the Connor Holmes report.

1 Original Business Case

AGN's original proposal for the next AA period included a capex allowance of $5.0 million to extend the high pressure network by 9 kilometres to the Two Wells township north of Adelaide (see Figure 1.1).

Figure 1.1: Two Wells Mains Extension



As outlined in the original Business Case, AGN has worked closely with the District Council of Mallala and the developer, the Hickinbotham Group, on this proposed extension, which is expected to result in an additional 3,260 domestic and 30 small commercial customers by 2042 and yield a positive net present value (NPV) as required by Rule 79(2)(b) of the NGR. The project is also expected to lower the costs to existing customers in the network by spreading the largely fixed costs of operating the network across a larger customer base. Further detail on the background to the Two Wells project is provided in Box 1.1, while the developer's plans can be found in Supporting Information 2.

Box 1.1: Background to the Two Wells project

In 2010 the Hickinbotham Group and the District Council of Mallala entered into detailed discussions on the approach to infrastructure provision for Two Wells. These discussions canvassed options for the provision of infrastructure to serve both the existing established township and the proposed future urban growth area north of the town. It was agreed that the Hickinbotham Group would take responsibility for internal infrastructure including the provision of services such as natural gas.

As a result of this process, the District Council implemented the rezoning of land immediately to the north of the existing township. The District Council and the Hickinbotham Group worked together to prepare a Residential Development Plan Amendment (DPA) for the Two Wells development. On 30 August 2013, the Minister for Planning announced the approval of the Two Wells Residential Development Plan Amendment (DPA), a major milestone for this significant urban development.

The project includes plans for around 3,500 new homes, small commercial facilities, a private school and community sporting facilities. The 300 hectare site is about 800 metres north of the existing town centre. Housing will be split into two "villages" - one featuring large blocks between 1,200 square metres to 1 hectare and the other with blocks that will likely be as small as 350 square metres up to 1,000 square metres - that will be sold in stages.

AGN has been working closely with the District Council of Mallala and the Hickinbotham Group for the last two years on the proposed installation of gas infrastructure in the Two Wells development.

2 AER Draft Decision

In the Draft Decision, the AER decided not to make any provision for the Two Wells project because it stated that it was not satisfied that the proposed expenditure was justified under Rule 79(2)(b).[1]

Elaborating further on this decision, the AER stated that it had identified a number of inconsistencies between the assumptions that AGN made in its Two Wells analysis about the demand per connection, domestic penetration rate and revenue assumptions per connection and those used in other areas of AGN's proposal relating to new estates. The AER added that if these assumptions were brought into line with the assumptions used for new estates then the Two Wells project would yield a negative NPV over a 20 year period.[2]

The AER also raised concerns about the standard life that AGN assumed for industrial and commercial connections and noted that a 10 year life was "*a more reasonable assumption taking into account the standard connection life for these customers.*"[3]

AGN's response to the issues raised in the AER's Draft Decision is set out in the following section.

3 AGN's Response

Before addressing the concerns that the AER has raised about the assumptions AGN made when carrying out the Two Wells project NPV analysis, it is worth noting that unlike other broad acre residential developments, the Two Wells project is being developed by a single developer/builder the Hickinbotham Group. AGN has therefore had greater involvement in the proposed development and

1 AER 2015, *" Attachment 6: Capital Expenditure | Draft Decision: Australian Gas Networks Access Arrangement 2016-2021",* November 2015, pg. 6-24.

2 Ibid.

3 Ibid.

been provided with more detailed information about the scope and timing of the development than it would usually be provided because the Hickinbotham Group has not had to worry about competition from other developers and so has been less concerned about keeping its plans confidential.

For example, AGN has been provided with precinct structure plans developed by Connor Holmes, on behalf of the Hickinbotham Group, which contains information on the forecast number of housing plots under a low and high scenario, the timing of the development of the plots, the average household size and plans for a commercial hub.[4] AGN has also been provided with progressive updates on the development by the Hickinbotham Group,[5] which has included information on things like indicative build out rates and the types of houses that will be developed. More recently, the Hickinbotham Group has provided AGN with a copy of the Stage 1 plans for its review. Updated staging plans will be provided to AGN throughout the project.

Having access to this level of detail about the project has meant that AGN has been in a better position to forecast demand and revenue for the Two Wells project than it usually is when preparing forecasts for other greenfield developments. In keeping with Rule 74 of the NGR, which requires forecasts to be arrived at on a reasonable basis and to represent the best forecast possible in the circumstances, AGN has had recourse to this information when preparing the Business Case for this project rather than the standard assumptions that it usually applies where there is less certainty about the scope and timing of the greenfield development.

The remainder of this section addresses the specific concerns that the AER has raised about the demand and revenue related assumptions that AGN made when assessing the Two Wells project and sets out the revisions that have been made to the NPV analysis to reflect the AER's Draft Decision on the rate of return and reference tariffs for the next AA period.

3.1 Demand assumptions

Table 3.1 sets out the assumptions that AGN has made when developing the domestic and small commercial customer demand forecasts for the Two Wells project and the basis for these assumptions.

Table 3.1: Demand assumptions – domestic and small commercial connections

Parameter	Assumption	Basis for Assumption
Domestic connections		
Total number of *potential* domestic connections	50 in the first year rising to 3,432 over a 21 year period	This assumption is based on the high "targeted dwelling occupation" scenario set out on page 31 of the Connor Holmes report (Supporting Information 1), which has also been confirmed by the Hickinbotham Group. This forecast has also been benchmarked against other projects with which AGN has had experience.
Domestic penetration rate	95% (when applied to the number of potential domestic connections this results in 48	The typical penetration rate for master built developments is close to 100% because gas is fully reticulated into every street and passes every house. While there may be a case for assuming a 100% penetration rate for the Two Wells project, AGN has decided to

[4] See Supporting Information 1: Connor Holmes, *"Two Wells Township Expansion"*, December 2011.

[5] AGN has also received a direct email from the Hickinbotham Group confirming the forecasts in the Connor Holmes report, which it can provide to the AER upon request.

Parameter	Assumption	Basis for Assumption
	domestic connections in the first year and 3,260 in year 21)	adopt a more conservative assumption and assume a penetration rate of 95%. The application of this penetration rate to the total number of potential domestic connections results in an estimate of 48 domestic connections in the first year and 3,260 in year 21
Connection timing	Connections commence in 2020/21 and reach their peak in 2040/41	This assumption reflects the indicative build out rates that appeared in the Connor Holmes report, which has been confirmed by the Hickinbotham Group. The timing of the first set of connections, however, is assumed to be six years later than originally assumed in the Connor Holmes report (Supporting Information 1) (i.e. 2020 rather than 2014) because work on the development has taken longer to commence than was originally anticipated.
Demand per connection	13 GJ per annum in 2020/21	AER Draft Decision.
Small commercial connections		
Number of small commercial customers	Five in the first year rising to 30 by the year 11 and remaining at this level for the remainder of the period.	The number of small commercial connections has been revised up from the 14 that appeared in the original Business Case, because the ratio of small commercial connections to residential customers implied by the original assumption was found to be too low and unlikely to satisfy Rule 74. The revised number of small commercial connections has been informed by: • communications with the Hickinbotham Group and existing small commercial customers in the Two Wells township; and • information on the ratio of small commercial connections to residential customers from other parts of AGN's network. In Adelaide the ratio of small commercial customers to domestic customers is around 1:50 while the state wide average is approximately 1:40. For Two Wells AGN has assumed a ratio of 1:230, which results in a forecast of 30 small commercial customers. This assumption results in a much lower number of small commercial customers than would arise if the Adelaide or state wide averages were used (65-80) and can therefore be considered conservative.
Connection timing	Connections commence in 2020/21	Aligned with commencement of domestic connections.
Demand per connection	273 GJ per annum in 2020/21	AER Draft Decision

Of the assumptions set out in this table, the AER has raised concerns about:

- the penetration rate assumed for domestic customers, which it noted was less than the penetration rate that AGN had assumed for other new estates; and
- the demand per connection assumed for both domestic and small commercial customers, which it noted was higher than the volumes that AGN has assumed for other new estates and new connections.

AGN's response to these two concerns is set out below.

3.1.1 Domestic penetration rate

As outlined in Table 3.1, AGN has assumed a penetration rate of 95% for domestic customers, which is higher than the South Australian market average penetration rate of 63% as modelled by Core Energy Group in the development of demand forecasts for the next AA period.[6]

AGN has adopted a higher penetration rate for the Two Wells project because the typical penetration rate for new broad-acre estate master built developments is closer to 100% than the South Australian market average of 63%. As outlined in the Core Energy Group report[7], the 63% reflects the total proportion of new dwellings that connect to gas in total South Australia, it does not specifically identify any differences between a singular new dwelling and a new broad-acre estate such as Two Wells. The penetration rate in new broad-acre estates tends to be much higher than the market average because when these estates are developed gas is usually fully reticulated into every street and passes every house in the development. Gas is therefore far more accessible in these estates than it is in the broader network, which is why AGN has adopted a 95% penetration rate.

Further support for AGN's assumption of a 95% penetration rate can be found in Table 3.2, which sets out the actual penetration rate that has been achieved on two recent master-built developments in the Sunday Estate. While these developments are still in their initial stages, the achieved penetration rates are already averaging over 95%

Table 3.2: Actual penetration rates - Sunday Estate master built development

Development	Actual Penetration Rate
Aldinga Beach Stage 4	96%
Aldinga Beach Stage 5	100%

3.1.2 Demand per connection

In the original Business Case the demand per connection rates were based on a conservative estimate of the volume of gas that domestic customers would consume given the types of dwellings that Hickinbotham proposed to develop (for example largely four bedroom family homes), the target market (for example young families) and the types of small commercial customers that were likely to set up in the area (for example coffee shops, restaurants etc.). This resulted in an estimate of 12.5 GJ per annum for domestic customers and 263 GJ per annum for small commercial customers.

AGN understands that the AER has some concerns with the fact that these rates were higher than Core Energy Group's forecasts for new estates and new commercial connections. The concerns that the AER has expressed in this context are, however, directly at odds with its decision to reject these aspects of Core Energy Group's forecasts and to assume a higher level of consumption than that which AGN assumed in the original Business Case (i.e. residential: 13 GJ and small commercial: 273 GJ).[8]

[6] Core Energy Group 2015, "*Attachment 14.1: Core Energy Group Gas Forecasting Report, Access Arrangement Information for Australian Gas Networks' South Australian Natural Gas Distribution Network*", 1 July 2015.

[7] Ibid.

[8] AER 2015, "*Attachment 13: Demand forecasts | Draft decision: Australian Gas Networks Access Arrangement 2016-2021*", November 2015, pg. 13-7.

For the purposes of assessing the viability of the Two Wells project the demand forecasts should be based on the AER's Draft Decision these being 13 GJ for residential customers and 273 GJ for small commercial customers.

3.2 Revenue assumptions

Table 3.3 sets out the assumptions that AGN has made when estimating the revenue that will be earned from domestic and small commercial customers that connect in the next AA period and the basis for these assumptions.

Table 3.3: Revenue assumptions – domestic and small commercial connections

Parameter	Assumption	Basis for Assumption
Tariffs	Domestic customers: Tariff R (excluding Tanunda)	AER Draft Decision.
	Small commercial customers: Tariff C	AER Draft Decision.
Revenue per connection (per annum)	Domestic:$385	The revenue per connection charge has been calculated by multiplying the demand per connection for domestic and small commercial customers by the volumetric tariffs the relevant tariff class and then adding the supply charge. For new domestic connections, because they will be spread evenly across all months of the year, we have assumed that we get, on average, 6 months of revenue in year 1 of connection. For small commercials, because there are fewer we assume they are connected on day 1 and hence get a full 12 months of revenue in first year of connection.
	Small commercial: $3,503	
Period of revenue recovery	Domestic customers: Weighed average 18 years	A 20 year build-out term has been modelled with revenue assessed over 30 years. Revenue has been assessed over 30 years because truncating revenue at year 20 would adversely impact the economics of the domestic connections that are expected to occur in years 15-20. The modelling window has therefore been extended to 30 years to capture a fair value for the tail-end connections (i.e. a connection that is installed in year 20 is assumed to generate revenue for 10 years). While a 30 year window is used, the weighted average connection term for domestic customers is around 18 years (i.e. because some connections are in place for up to 30 years while others are only in place for 10 years).
	Small commercial customers: 30 years	Small commercial connections are assumed to remain connected for the full term of the analysis and to generate revenue over this entire period, noting that the overall small commercial connection market is very conservative.
Consumer Price Index (CPI)	2.5%	AER Draft Decision.

Of the assumptions set out in this table, the AER only raised concerns about:

- the revenue per connection assumptions, which it claimed were inconsistent with other aspects of AGN's proposal; and

- the period over which revenue is assumed to be recovered from I&C customers, which it claimed should at most be 10 years given the standard connection life for these customers.

On the first of these issues, AGN notes that the tariffs used in the calculation of the revenue per connection estimates in the original Business Case were based on preliminary estimates of the volumetric and supply charges that would apply to Tariff R and Tariff C customers in 2020/21 rather than the tariffs that appeared in the AA proposal. AGN has since corrected this issue and the revenue per connection assumptions are now based on the AER's Draft Decision on the Tariff R and Tariff C volumetric and supply charges in 2020/21.

As to the period over which revenue is assumed to be recovered from the 30 commercial customers, it would appear from the AER's Draft Decision that there may be some confusion about the type of customers that AGN has assumed will connect. Although these customers were described as I&C customers in the original Business Case, the 30 connections are in fact assumed to be small commercial customers that will service the local community (for example, coffee shops, restaurants, supermarkets, butchers, fruit shops, hairdresser etc.) and not industrial or large commercial customers.

There also appears to be some confusion about what the 30 year assumption implies in this case. To be clear, it does not imply that the small commercial customer that connects on day one will remain connected for the 30 year period. Rather, it implies that the connection will continue to generate revenue over the 30 year period, irrespective of who the small commercial customer is. That is, even if the small commercial customer that originally connects closes down, another small commercial customer can be assumed to take over the site and continue to use gas because it is already connected at the site. In AGN's view, this is a reasonable assumption to make, particularly given it has been relatively conservative in its estimate of the number of small commercial customers that will connect over the 30 year period. AGN disagrees therefore with the AER's suggestion that the period should be reduced to ten years and has retained its original assumption.

3.3 Cost assumptions

Table 3.4 sets out the capex and incremental operating expenditure (opex) that AGN expects to incur in extending the high pressure network to Two Wells and installing the reticulation, meter's and services that are required for connections that are to occur in the next AA period. Further detail on the scope of the work and unit rates that underpin the capex forecast is provided in Table 3.5. The unit rates appearing in this table are based on the rates that appeared in AGN's 2016/17 – 2020/21 Unit Rates Forecast report, which the AER approved in the Draft Decision.[9] The unit rates have not changed since the original Business Case was submitted.

It is worth noting in this context that for the purposes of determining whether the project should proceed, AGN has included all of the costs set out in Table 3.4 in the cost-benefit analysis. However, in the AA Proposal the capex has been divided between:

- the Two Wells project - $5 million has been allocated to this project in the AA Proposal, which represents the cost of installing the supply mains and the planning, design and commissioning costs; and

[9] AER 2015, "*Attachment 6: Capital Expenditure | Draft Decision: Australian Gas Networks Access Arrangement 2016-2021",* November 2015, pg. 6-22.

- Growth Capex - $0.2 million has been allocated to growth capex, which represents the costs of installing the reticulation, meters and services.

To be clear, this is just a cost allocation issue and does **not** affect the assessment of the viability of the Two Wells project.

In relation to opex, the incremental costs of $1,100k are assumed to be recovered through the trend component of AGN's opex forecast.

Table 3.4: Two Wells Capital Expenditure (by Activity) and Operating Expenditure

($'000 Real 2014/15)	2016 -17	2017 -18	2018 -19	2019 -20	2020 -21	Total
Capital Expenditure						
Supply Mains	0	0	0	4,780.6		**4,780.6**
Reticulation	0	0	0	40.5	39.7	**80.2**
Meters – Domestic	0	0	0		14.2	**14.2**
Meters - I&C	0	0	0		19.1	**19.1**
Meters – D	0	0	0		0.0	**0.0**
Services – Domestic	0	0	0		57.5	**57.5**
Services - I&C	0	0	0		21.6	**21.6**
Services – D	0	0	0		0.0	**0.0**
Planning, design and commissioning	0	0	0	219.1	6.2	**226.0**
Total Capex	0	0	0	**5,040.2**	**158.2**	**5,199.1**
Operating Expenditure						
Total Opex	**0**	**0**	**0**	**0.0**	**1.1**	**1.1**

Table 3.5: Two Wells Reticulation Scope of Work and Unit Costs

Asset Category	Scope of Work			Unit Costs ($ Real $2014/15 excl. overheads)	
	2019 -20	2020 -21	Total	2019 -20	2020 -21
Supply Mains					
Reticulation					
Meters – Domestic					
Meters - I&C					
Meters – D					
Services – Domestic					
Services - I&C					
Services – D					
Incremental operating costs					

3.4 Cost benefit analysis

In keeping with Rule 79(2)(b) of the NGR, AGN has assessed whether the present value of the expected incremental revenue to be generated from the Two Wells project exceeds the present value of the capex. The results of this assessment are set out in Table 3.6. As the bottom of this table shows, the present value of the incremental revenue is expected to exceed the present value of the costs by $390,050 (the NPV). The project is therefore justifiable under Rule 79(2)(b).

The calculations underpinning this analysis can be found in Supporting Information 4: Two Wells Cash flow model and assumptions Confidential.xls.

Table 3.6: Two Wells NPV Analysis ($'000 Nominal)

	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2034/35	2039/40	2044/45	2049/50
	0	1	2	3	4	5	6	7	8	9	10	15	20	25	30
Total Revenue	$0	$31	$74	$120	$171	$230	$298	$382	$476	$581	$697	$1,488	$2,408	$2,820	$3,191
Operating Expenditure	$0	$1	$2	$4	$7	$9	$13	$17	$21	$27	$32	$73	$118	$137	$155
Incremental Revenue	**$0**	**$29**	**$71**	**$115**	**$164**	**$221**	**$285**	**$365**	**$455**	**$554**	**$665**	**$1,415**	**$2,290**	**$2,684**	**$3,036**
Capital Expenditure	**$6,178**	**$199**	**$229**	**$300**	**$334**	**$372**	**$464**	**$529**	**$571**	**$644**	**$694**	**$1,025**	**$439**	**$0**	**$0**
Net Cash flow (pre-tax)	**-$6,178**	**-$169**	**-$158**	**-$185**	**-$171**	**-$151**	**-$179**	**-$164**	**-$117**	**-$90**	**-$29**	**$390**	**$1,851**	**$2,684**	**$3,036**
Discount Rate (pre-tax nominal WACC)*	6.36%														
NPV	$390.05														
Internal Rate of Return	6.64%														

* The discount rate (pre-tax WACC) used in this calculation is consistent with the rate of return parameters that were adopted in the AER's Draft Decision.

4 Summary

For the reasons set out above, AGN remains of the view that the proposal to extend the South Australian Network to Two Wells is justified under Rule 79(2)(b) of the NGR and, as required by Rule 79(1)(a), is also:

- *Prudent* – The expenditure will expand gas supply services to the Two Wells township and, in so doing, provide additional demand growth, which will lower the cost of service delivery. The project is also based on a conservative approach to forecasting customer connections, which has been deliberately taken to ensure the financial viability of the proposed extension. The proposed expenditure is therefore of a nature that would be incurred by a prudent service provider.
- *Efficient* – The forecast expenditure is based on unit rates that have been established through recent competitive tenders and were accepted by the AER in the Draft Decision. The supply main has also been designed to minimise length and the reticulation mains have been designed to maximise customer numbers during the development phase. The proposed expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur.
- *Consistent with accepted and good industry practice* – The proposed project involves expanding the network to meet potential demand growth, where the capital investment has been justified on the basis of a positive NPV. In addition, the demand forecasts underpinning the economic analysis are considered to be conservative. A higher number of customer connections than that forecast in this Business Case may be achieved, and ultimately provide greater benefits to customers (in the form of lower tariffs) than have been assumed in the Business Case.
- *To achieve the lowest sustainable cost of delivering pipeline services* - The project will lower the cost of delivering pipeline services over the life of the project because it will enable the largely fixed costs of operating the gas network to be spread over a larger customer base.

BUSINESS CASE – SA25

PROJECT SUMMARY	
Network	AGN– SA
Project No.	SA25
Project Name	Mount Barker high pressure mains extension
Risk Rating	Low
Budget Category	Capital expenditure (capex)
Estimated Cost	Total capex for the next Access Arrangement (AA) period: $23.5 million (real $2014/15) (extension cost: $23.1 million; reticulation, meters and services costs for the next AA period: $0.4 million).
Consistency with NGR	The proposed expenditure on the Mount Barker project is justifiable under Rule 79(2)(b) of the National Gas Rules (NGR) because the present value of the expected incremental revenue to be generated from the project exceeds the present value of the capex. The proposed expenditure is also such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services, as required by Rule 79(1)(a).
PROJECT APPROVAL	
Prepared By:	Ed Macolino, Manager Strategic Development, APA
Reviewed By:	Peter Gayen, Networks Commercial Manager, APA
Approved By:	Andrew Staniford, Chief Operating Officer, AGN
OTHER RELEVANT DOCUMENTS	
This Business Case should be read in conjunction with: • AGN's Access Arrangement Information (AAI), which was provided to the Australian Energy Regulator on 1 July 2015. • Supporting Information 1: Natural Gas to Mt Barker Concept Route Options Study • Supporting Information 2: Mount Barker Cash Flow Model and Assumptions (Confidential).	

1 Introduction

In AGN's original proposal for the next AA period, AGN noted that while it had commenced investigations into the feasibility of reticulating gas in the Mount Barker region, the investigations were not sufficiently progressed to submit a capex proposal under Rule 79 of the NGR by 1 July 2015. AGN therefore proposed to proceed with the extension through a 'Significant Extension' cost-pass through event, which would be triggered if AGN's Board approved the decision to reticulate gas to the area and the extension was deemed to satisfy the relevant requirements of the NGR. [1]

This proposal was rejected by the Australian Energy Regulator (AER) in its Draft Decision because in its view the "*limited assessment of an application under the cost pass through mechanism should not be considered an alternative avenue for approval of expenditure*".[2]

Since submitting the original AA proposal, AGN has undertaken further work to assess the technical and financial feasibility of the Mount Barker extension and to determine whether it would satisfy Rule 79 of the NGR. The results of this assessment are set out in the remainder of this Business Case, which

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1 AGN, *"SA Access Arrangement Information",* July 2015, pg. 266-267.

2 AER 2015, "*Attachment 11: Tariff Variation Mechanisms | Draft decision: Australian Gas Networks Access Arrangement 2016-2021*", November 2015, pg. 11-36.

commences with an overview of the proposed extension and then sets out the results of the economic analysis that AGN has carried out.

AGN is aware that the South Australian Minister for Mineral Resources and Energy has written to the AER about the proposed extension of the network to Mount Barker and, as highlighted in the following statement taken from this letter, indicated its broad support for the proposed development:[3]

> *"The Government of South Australia has considered this proposal and considers that there are many benefits of extending the gas network into Mount Barker. Access to natural gas will allow Mount Barker residents to take advantage of an alternative low emission energy source for various applications including cooking, water heating and space and central heating. Natural gas can also be used for a wide range of commercial and industrial applications. Provision of natural gas in Mount Barker will offer residents and businesses greater choice and improve energy security."*

As this statement highlights, the proposed extension of the network to Mount Barker is an important development for the region that needs to be duly considered by the AER as part of this AA review.

2 Project overview

The Mount Barker district is located approximately 36 km to the south-east of Adelaide and includes the townships of Mount Barker, Littlehampton and Nairne. This district is separated from Adelaide's eastern fringe by the Adelaide Hills and is subject to colder climatic conditions than Adelaide.

In early 2010 the South Australian Government released its 30-Year Plan for Greater Adelaide (the Plan), which, amongst other things, identified land in the Mount Barker district as part of Adelaide's urban land supply.[4] In keeping with this Plan, land in the Mount Barker district was rezoned for urban development by the State Government in late 2010 through the Mount Barker Urban Growth Development Plan Amendment.[5]

In 2013, the District Council of Mount Barker (Council) retained "id consulting" to prepare a population forecast for the region.[6] This forecast suggests that the district's population will increase from 31,325 in 2013 to 38,000 in 2023 and 48,000 in 2033. Approximately 75% of this growth is expected to occur through the rezoning of land in the Mount Barker district. The Council is also expecting that, when fully developed, the population of greater Mount Barker will be around 53,000 while the district population will be around 65,000.[7] The average household size is also expected to be higher in the

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[3] Hon. Tom Koutsantonis, Letter to Warwick Anderson (AER), 20 November 2015, http://www.aer.gov.au/system/files/Government%20of%20South%20Australia%20-%20Additional%20submission%20on%20Australian%20Gas%20Networks%20proposed%20Access%20Arrangement%20for%202016-2021%20-%2020%20November%202015.PDF.

[4] http://www.dpti.sa.gov.au/planning/30_year_plan/30_year_plan_2010

[5] Department of Planning and Local Government, Mount Barker Development Plan Mount Barker Urban Growth, 16 December 2010.

https://www.sa.gov.au/__data/assets/pdf_file/0008/9917/Ministerial_Mt_Barker_Urban_Growth_DPA_The_Amendment_and_Rpt_Approved_16_Dec_2010.pdf

[6] District Council of Mount Barker, 2013-14 Annual Report, http://www.mountbarker.sa.gov.au/webdata/resources/files/Final%20Annual%20Report%202013-14%20Amended%2016th%20Dec-1.pdf,.

[7] District Council of Mount Barker, *"Land on the Table: 2013 to 2014 Annual Report",* 10 February 2015, pg. 3.

Mount Barker district (2.8 – 3.0 persons per household[8]) than it is in Adelaide, which when coupled with the colder climatic conditions, suggests higher than average gas use in this district.

AGN's SA Network does not currently extend as far as Mount Barker, so with the support of the South Australian State Government, Council and developers, AGN has been examining the technical and financial viability of extending the Network to this region. This examination has involved:

- conducting a detailed desktop analysis of a number of alternative routes[9];
- selecting a preferred route to use in a high level screening economic analysis; and
- preparing a capital cost estimate for each route.

The alternative routes that were identified through this process included but were not limited to:

- a 30 km extension that would run from Adelaide to Mount Barker via the Princes Hwy through the Adelaide Hills (Route A);
- a 34 km extension that would run from Adelaide to Mount Barker along Greenhill Rd, via Crafers and the Princes Hwy through the Adelaide Hills (Route B);
- a 34 km extension from Pallamana (north of Murray Bridge) to Mt Barker via public roads and private land (Route C); and
- a 36 km extension from Murray Bridge to Mt Barker via the Old Princes Hwy and Back Callington Rd (Route D).

Of the routes listed above, Routes A and B would commence in the Adelaide metropolitan transmission network while Routes C and D would commence from new connection points on the SEA Gas Pipeline. Each of these routes has been subject to a detailed desktop analysis using available software tools, which analyse a range of factors including the length of the extension, the terrain (i.e. the amount of rock, river, rail and road crossings), construction and operational difficulties.

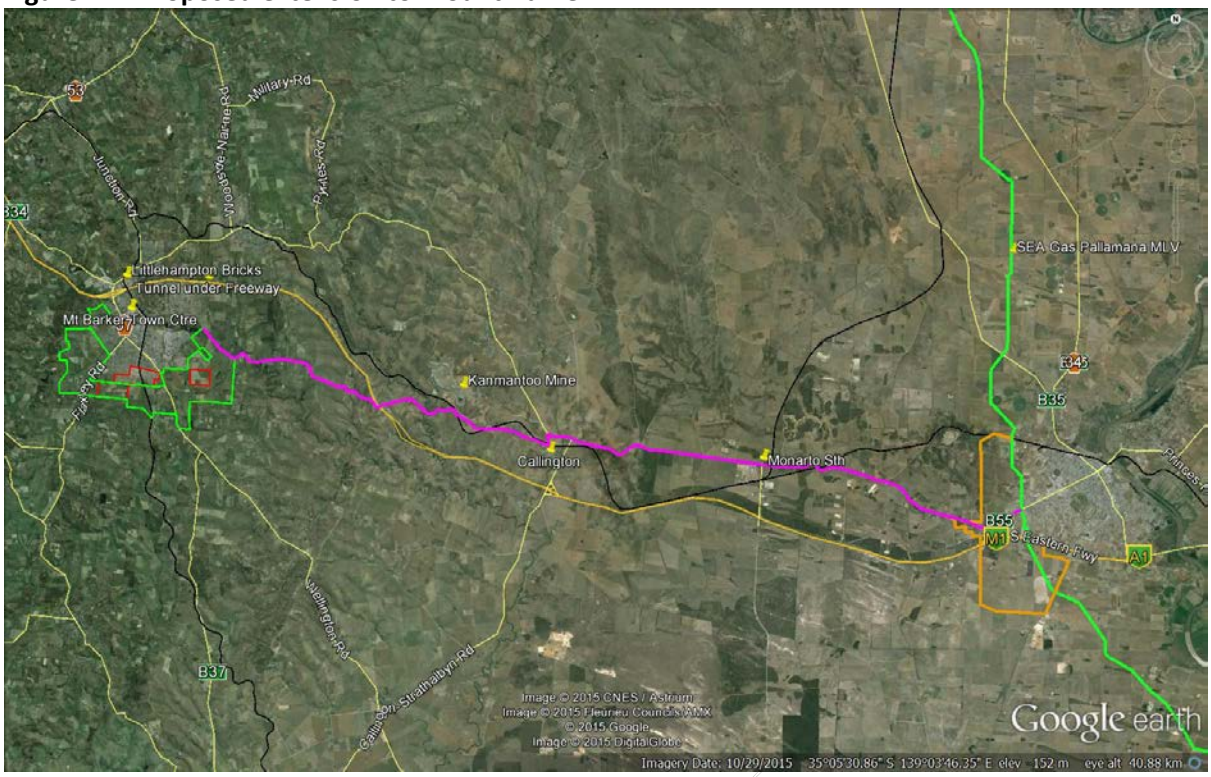
AGN's analysis of these options has been provided in Supporting Information 1: Natural Gas to Mt Barker Concept Route Options Study.

Based on this analysis, AGN has dismissed Routes A and B because they both require the extension to pass through very difficult terrain in the Adelaide Hills. Of the remaining routes, Route D provides significantly greater opportunities to connect existing customers on line of main than Route C while also providing further potential upside through this new growth corridor. Route D has therefore been selected, noting that Route C is likely to be cheaper to construct. The location of this route is illustrated in Figure 2.1 below.

[8] .id Consulting. "District Council of Mt Barket polulation forecasts", http://forecast.id.com.au/mount-barker

[9] The Natural Gas to Mt Barker Concept Route Options Study as attached.

Figure 2.1: Proposed extension to Mount Barker



The key features of Route D are set out in the table below.

Table 2.1: Key features of the proposed extension

Parameter	Description
Length	36 km
Pressure	Nominally Class 300, with a preliminary MAOP of 5 MPa
Pipe	DN150 (6”), steel, FBE coated. Nominally X60 strength rating
Offtakes	Monarto and Callington

3 Economic analysis of the extension (Rule 79(2)(b) of the NGR)

The proposed extension of the SA Network to the Mount Barker region is a growth related capex project and has therefore been considered under Rule 79(2)(b) of the NGR. In keeping with this rule, AGN has assessed whether the present value of the expected incremental revenue to be generated from the Mount Barker extension is likely to exceed the present value of the capex. The cost, demand and revenue related assumptions that AGN has made when carrying out this assessment are set out in Sections 3.1 to 3.3 while Section 3.4 sets out the results of the assessment.

3.1 Capital costs

Table 3.1 sets out the capex and incremental operating expenditure (opex) that AGN expects to incur in extending the high pressure network to Mount Barker and installing the reticulation, meters and services that will be required for the connections that are expected to occur in the next AA period. Further detail on the scope of the work and unit rates that underpin the capex forecast is provided in

Table 3.2. The unit rates appearing in this table are based on the rates that appeared in AGN's 2016/17 – 2020/21 Unit Rates Forecast report, which the AER approved in the Draft Decision.[10]

Table 3.1: Mount Barker Capital Expenditure (by Activity) and Operating Expenditure

($'000 Real 2014/15)	2016 -17	2017 -18	2018 -19	2019 -20	2020 -21	Total
Capital Expenditure						
Headworks	0	0	0	[redacted]		4,200
Supply Mains	0	0	0	[redacted]		15,712.6
Reticulation				[redacted]	73.5	145
Meters – Domestic	0	0	0		40.7	40.7
Meters - I&C	0	0	0		42.0	42.0
Meters – D	0	0	0		0.0	0.0
Services – Domestic	0	0	0		165.2	165.2
Services - I&C	0	0	0		47.5	47.5
Services – D	0	0	0		0.0	0
Planning, design and commissioning	0	0	0	[redacted]	18.2	3,160
Total Capex	**0**	**0**	**0**	[redacted]	**387.1**	**23,513**
Operating Expenditure						
Total incremental Opex	**0**	**0**	**0**	**0.0**	**3.0**	**3.0**

Table 3.2: Mount Barker Extension Scope of Work and Unit Costs

Asset Category	Scope of Work			Unit Costs ($ Real $2014/15 excl. overheads)	
	2019 -20	2020 -21	Total	2019 -20	2020 -21
Headworks	1	0	**1**	n.a.	**n.a.**
Supply Mains	36,000m	0	**36,000m**	$436	**0**
Reticulation	1,743m	1,794m	**3,537m**	$41	**$41**
Meters – Domestic	n.a.	138 units	**138 units**	0	**$295**
Meters - I&C	n.a.	11 units	**11 units**	0	**$3,819**
Meters – D	n.a.	0	**0**	0	**0**
Services – Domestic	n.a.	138 units	**138 units**	0	**$1,197**
Services - I&C	n.a.	11 units	**11 units**	0	**$4,318**
Services – D	n.a.	0	**0**	0	**0**
Incremental operating costs per connection		n.a.	**n.a.**	0	**$20**

For the purposes of determining whether the project should proceed, AGN has included all of the costs set out in Table 3.1 in the cost-benefit analysis. The capex component of these costs has been included in AGN's Growth Capex forecast, while the opex component has been assumed to be recovered through the trend component of AGN's opex forecast.

AGN is planning to undertake the following steps prior to the commencement of construction: (i) pre-FEED analysis primarily focussing on engagement with existing customers; (ii) a formal FEED study to firm up the cost estimate and schedule; (iii) commercial negotiations with SEAGas for the construction of a new gate station; (iv) land acquisition; (v) formal tender processes for construction activities; and (vi) internal capital approvals. The proposed project timing is determined by these activities, particularly land acquisition.

[10] AER 2015, "*Attachment 6: Capital Expenditure | Draft decision: Australian Gas Networks Access Arrangement 2016-2021*", November 2015, pg. 6-22.

3.2 Demand assumptions

Over a 20 year period, the Mount Barker extension is expected to result in the connection of at least 6,950 domestic customers, 48 small commercial customers (for example, coffee shops, restaurants, supermarkets, butchers, fruit shops, hairdressers etc.) and three Demand customers. Table 3.3 contains more detail on how these connection forecasts have been developed.

Table 3.3: Domestic, small commercial and Demand connections

Parameter	Assumption	Basis for Assumption
Domestic connections		
Total number of *potential* domestic connections	145 in the first year rising to 7,315 over a 20 year period	This assumption is based on forecasts provided to the Council by the Council's demographic and spatial analysts "***.id consulting"***[11], which were last updated in March 2015. AGN has also confirmed the forecasts directly with the Council and tested the forecasts against other projects with which AGN has had experience. This can be viewed as conservative as AGN has not included any existing dwellings in its connection number forecast, though a number of these could be reasonably expected to connect over the next 20 years.
Domestic penetration rate	95% (when applied to the number of potential domestic connections this penetration rate results in 138 domestic connections in the first year rising to 6,950 in year 21)	The typical penetration rate for new broad-acre master built developments is closer to 100% than the South Australian market average of 63%[12] because gas is fully reticulated into every street and passes every house. Gas is therefore far more accessible in these estates than it is in South Australia more generally, which is why higher penetration rates can be achieved in these areas. Further support for this view can be found in the actual penetration rates that have been achieved in two recent stages of the Sunday Estate at Aldinga Beach in South Australia. Stages 4 and 5 whilst recent are reasonably mature and achieved penetration rates averaging over 95%, with Stage 4 exhibiting a 96% penetration rate and Stage 5 exhibiting a 100% penetration rate.[13] While there may be a case for assuming a 100% penetration rate for the Mount Barker region, AGN has decided to adopt a more conservative assumption and assume a penetration rate of 95%. The application of this penetration rate to the total number of potential domestic connections results in an estimate of 138 domestic connections in the first year and 6,950 by year 20.
Connection timing	Connections commence in 2020/21 and reach their peak in 2040/41	The first connections in the Mount Barker region are forecast to occur in 2020/21. This timing assumption is based on advice from the Council and AGN's own experience with the time these developments typically take to progress.

[11] Id consulting, "*District Council of Mount Barker population forecasts*", http://forecast.id.com.au/mount-barker.

[12] Core Energy Group 2015, "*Attachment 14.1: Core Energy Group Gas Forecasting Report, Access Arrangement Information for Australian Gas Networks' South Australian Natural Gas Distribution Network*", 1 July 2015.

[13] AGN periodically surveys the penetration of natural gas in new home estates. The most effective means of conducting these surveys is by driving through a sample of new home estates. The penetration rates have been calculated by dividing the total number of houses connected to gas in each development by the total number of new houses built in each development. Aldinga Beach Stages 4 and 5 are sufficiently recent that they have only just been built out, and thus provide current data on penetration in greenfields estates.

Parameter	Assumption	Basis for Assumption
Small commercial connections		
Number of small commercial customers	11 in the first year, rising to 48 connections by the sixth year and remaining at this level for the remainder of the period.	The number of small commercial customers that have been assumed to connect has been estimated having regard to information provided by the Council about its plan for commercial hubs and retail/employment precincts taken together with identifying existing businesses likely to connect. This information has then been tested using information from other parts of AGN's network. In Adelaide the ratio of small commercial customers to domestic customers is around 1:50 while the state wide average is approximately 1:40. For Mount Barker AGN has applied a forecast of 48 small commercial customers (developed as described above) equivalent to a ratio of approximately 1:145. This bottom up forecast results in a much lower number of small commercial customers than would arise if the Adelaide or state wide averages were used (174) and can therefore be viewed as conservative.
Connection timing	Connections commence in 2020/21	Aligned with commencement of domestic connections.
Demand connections		
Number of Demand customers	One in the sixth year rising to three connections by the 11th year and remaining at this level for the remainder of the period.	The number of Demand customers that have been assumed to connect includes two large customers that are already in the area that could convert from other fuels to gas [redacted] The tariff D demand forecast is realistic as two of the three demand customers already exist. Further in South Australia AGN typically connects two demand customers for every 4500 domestic connections, suggesting that three can be expected for the forecast 6950 domestic connections.

As to the average demand per connection, AGN has assumed that:

- domestic customers consume 21 GJ per annum, which for the reasons set out below is higher than the average adopted by the AER in the Draft Decision; [14] and
- small commercial customers consume 273 GJ per annum, which is consistent with the average adopted by the AER in the Draft Decision. [15]

AGN's forecast for Demand customers, on the other hand, is based on business specific estimates and requests that AGN has received over the last 10 years to connect to gas. For the two existing customers, [redacted]

[14] AER 2015, *"Attachment 13: Demand | Draft decision: Australian Gas Networks Access Arrangement 2016-2021",* November 2015, pg. 13-7.

[15] Ibid.

In relation to domestic consumers, AGN has adopted what it considers to be a conservative assumption (21 GJ per annum), given the following characteristics of the development and the region:

- *Dwelling type:* Based on discussion with developers and the Council, AGN expects that dwellings in the Mount Barker region will typically be four bedroom family homes and is consistent with .id consulting's forecast of a higher than average household size (2.8-3.0 persons per household) in Mount Barker. This is larger than the average Adelaide existing residential home connected to natural gas and, in conjunction with the factors below, is expected to drive a higher than average gas consumption level in the region.
- *Household type*: Based on the work that .id consulting has carried out for the Council,[16] the target market for the new developments is expected to be young families upgrading to larger homes to raise families. These households typically consume greater volumes of gas for cooking, hot water and heating as they family grow in size, and as young children grow to be teenagers.
- *Penetration of gas appliances:* When AGN has engaged with developers and builders, and implemented development specific marketing campaigns, the penetration of gas appliances has been higher than the market average, which has, in turn, resulted in higher than average levels of demand. The same outcome is expected to occur in the Mount Barker region, where AGN has been actively involved with the Council and a number of developers.
- *Climatic conditions:* The minimum and maximum temperatures in the Mount Barker region are 2-4 degrees colder than they are in Adelaide, with the difference being particularly obvious in winter when temperatures typically range from 4.5-14 degrees in Mount Barker, while in Adelaide they range from 7.5 to 16.6 degrees. Given the cooler conditions in this region, gas heating is expected to be more prevalent in this area, which will drive higher than average levels of demand.

As the preceding discussion highlights, the demand per domestic connection in the Mount Barker region is expected to be substantially higher than the average observed across the SA Network. Further support for this view can be found in the analysis that AGN has carried out on both:

- the gas that residential customers in Mount Barker are likely to require for cooking, hot water and heating - using a simple bottom up approach and the characteristics outlined above, AGN has estimated that domestic connections in Mount Barker are likely to consume 26 GJ per annum for cooking, hot water and heating (i.e. 2 GJ for cooking, 9 GJ for hot water and 15 GJ for heating); and
- the average demand for gas by residential customers in comparable new estates – information on the demand for gas by domestic connections in comparable new estates in Nuriootpa and Mt Gambier reveals that residential customers consume, on average, 21 GJ per annum in Nuriootpa and 33 GJ per annum in Mt Gambier, with the difference between the two reflecting the colder climatic conditions in Mt Gambier[17]. These two areas were chosen for having reasonably similar inland/hills climatic conditions.

It follows from this analysis that AGN's assumption that domestic connections in Mount Barker will consume 21 GJ per annum is conservative, particularly given the colder climatic conditions in this region.

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[16] .id consulting, 2014, "*Mount Barker, Littlehampton and Nairne Strategic Infrastructure Plan",* September 2014.

[17] The average consumption levels have been calculated over the period 2008-2015 using information on the volume of gas consumed by each of the domestic customers (by MIRN) in the Nuriootpa and Mt Gambier estates in each of these years.

3.3 Revenue assumptions

Table 3.4 sets out the assumptions that AGN has made when estimating the revenue that will be earned from domestic, small commercial and Demand customers and the basis for these assumptions.

Table 3.4: Revenue assumptions – domestic and small commercial connections

Parameter	Assumption	Basis for Assumption
Tariffs	Domestic customers: Tariff R Tanunda	The tariffs for domestic and small commercial customers are based on the AER's Draft Decision on the Tariff R Tanunda and Tariff C Tanunda tariffs for 2020/21, which is when the first connection is due to occur.[18] The Tanunda tariffs have been used in this case because the Mount Barker extension exhibits similar characteristics to the Tanunda extension which was approved by the AER and has been constructed.
	Small commercial customers: Tariff C Tanunda	
	Demand customers: Tariff D Riverland	Because there is no Demand tariff for Tanunda, the Demand tariff will be based on the Riverland Demand tariff as set out in the AER's Draft Decision.[19] The Riverland tariff is geographically relevant because of its proximity to Murray Bridge.
Revenue per connection (p.a.)	Domestic average:$559	The revenue per connection charge has been calculated by applying the demand per connection for domestic, small commercial and Demand customers to the volumetric charges for the relevant tariff class and then adding the supply charge. For the Demand customers the revenue has been calculated by multiplying the MDQ by the Riverland Demand tariffs.
	Small commercial average: $4,485	
	Demand [redacted]	
Period of revenue recovery	Domestic customers: Weighted average 18 years	A 20 year build-out term has been modelled with revenue assessed over 30 years. Revenue has been assessed over 30 years because truncating revenue at year 20 would adversely impact the economics of the domestic connections that are expected to occur in years 15-20. The modelling window has therefore been extended to 30 years to capture a fair value for the tail-end connections (i.e. a connection that is installed in year 20 is assumed to generate revenue for 10 years). While a 30 year window is used, the weighted average connection term for domestic customers is around 18 years (i.e. because some connections are in place for up to 30 years while others are only in place for 10 years). AGN notes the mains have a useful life of 60 years.
	Small commercial customers: 30 years	Small commercial connections are assumed to generate revenue over the entire period. It is worth noting that this assumption does not imply that the same small commercial customer will remain connected for 30 years. It just means that the connection will continue to generate revenue over the period, irrespective of who the small commercial customer is. That is, even if the small commercial customer that originally connects closes down, another small commercial customer will take over the site and continue to use gas because it is already connected at the site. In AGN's view, this is a reasonable assumption to make, particularly given it has been relatively conservative in its estimate of the number of small commercial customers that will connect over the 30 year period.
	Demand customers: 10 years	Standard life for large industrial and commercial connections.
CPI	2.5%	AER Draft Decision.

3.4 Cost benefit analysis

Drawing on the assumptions set out above, AGN has estimated:

[18] AER, *"Draft Decision: AGN AA – Post tax revenue model - November 2015.xlsm"*, November 2015, Reference tariffs tab.

[19] Ibid.

- the incremental revenue (revenue less incremental opex) that is expected to be generated from the Mount Barker project over the period 2019/20 - 2049/50; and
- the capex that is expected to be incurred over the period 2019/20 - 2049/50.

These estimates are set out in Table 3.5. As the bottom of this table shows, the present value of the incremental revenue is expected to exceed the present value of the capex by $0.219M ($2014/15) (the net present value (NPV)). The project is therefore justifiable under Rule 79(2)(b).

The calculations underpinning this analysis can be found in Supplementary Information 2: Mount Barker Cash flow model and assumptions Confidential.xls.

As a sensitivity analysis, the number of small commercial customers connecting over the next 20 years has been doubled. At this level the number is still conservative relative to the ratio observed to have connected in Adelaide over time. This demonstrates a significantly higher NPV of $2.9M ($14/15), demonstrating that the project is economically robust.

A further sensitivity analysis was undertaken where the number of small commercial customers was increased to 174 to achieve the same ratio to domestic customers observed across South Australia (ie: 1:40), and the average domestic consumption was reduced to 13 GJ which is consistent with the average adopted by the AER in the Draft Decision. This demonstrates an NPV of $0.196M, again demonstrating that the project is economically robust.

These sensitivity tests indicate the robustness of the NPV outcomes generated using AGN's preferred assumptions.

Table 3.5: Mount Barker NPV Analysis ($'000 Nominal)

	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2034/35	2039/40	2044/45	2049/50
	0	1	2	3	4	5	6	7	8	9	10	15	20	25	30
Total Revenue	$0	$95	$241	$400	$580	$902	$1,082	$1,319	$1,602	$1,911	$2,314	$4,389	$7,288	$8,451	$9,562
Opex	$0	$3	$7	$11	$16	$22	$29	$38	$48	$59	$72	$151	$257	$291	$329
Incremental Revenue	**$0**	**$91**	**$234**	**$388**	**$564**	**$880**	**$1,053**	**$1,281**	**$1,554**	**$1,852**	**$2,242**	**$4,238**	**$7,031**	**$8,161**	**$9,233**
Capital Expenditure	**$28,349**	**$486**	**$515**	**$573**	**$659**	**$872**	**$796**	**$1,003**	**$1,066**	**$1,192**	**$1,591**	**$1,972**	**$1,515**	**$0**	**$0**
Net Cashflow (pre-tax)	**-$28,349**	**-$395**	**-$281**	**-$185**	**-$95**	**$9**	**$258**	**$279**	**$488**	**$660**	**$651**	**$2,266**	**$5,515**	**$8,161**	**$9,233**
Discount Rate (nominal pre-tax WACC)	6.36%														
NPV ($2014/15)	$219.17														
IRR	6.40%														

* The discount rate (pre-tax WACC) used in this calculation is consistent with the rate of return parameters that were adopted in the AER's Draft Decision.

4 Summary

For the reasons set out above, AGN is of the view that the proposal to extend the SA Network to Mount Barker is justified under Rule 79(2)(b) of the NGR and, as required by Rule 79(1)(a), is also:

- *Prudent* – The expenditure will expand gas supply services to the Mount Barker region and, in so doing, provide additional demand growth, which will lower the cost of service delivery to other areas of the SA Network. The South Australian government is supportive of the project, including for reasons of providing increased security of energy supply to the Mount Barker district. The project is also based on a conservative approach to forecasting customer connections, which has been deliberately taken to ensure the financial viability of the proposed extension. The proposed expenditure can therefore be seen to be of a nature that would be incurred by a prudent service provider.
- *Efficient* – The forecast expenditure is based on unit rates that have been established through recent competitive tenders, which were accepted by the AER in the Draft Decision. The supply and reticulation mains have been designed to maximise customer numbers during the development phase. The proposed expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur.
- *Consistent with accepted and good industry practice* – The proposed project involves expanding the SA Network to meet potential demand growth, where the capital investment has been justified on the basis of a positive NPV. In addition, the demand forecasts underpinning the economic analysis are considered to be conservative. A higher number of customer connections than that forecast in this Business Case may be achieved, and ultimately provide greater benefits to customers (in the form of lower tariffs) than have been assumed in the Business Case.
- *To achieve the lowest sustainable cost of delivering pipeline services* - The project will lower the cost of delivering pipeline services over the life of the project because it will enable the largely fixed costs of operating the gas Network to be spread over a larger customer base.

ADDENDUM TO BUSINESS CASE – SA31

PROJECT SUMMARY	
Network	AGN– SA
Project No.	SA31
Project Name	Fire safety valves (FSVs)
Risk and Priority	Moderate, Priority 3
Budget Category	Capital Expenditure (Capex)
Amendments to Original Business Case	Having regard to the Australian Energy Regulator's (AER's) Draft Decision on SA31, AGN has revised the number and timing of the installation of FSVs as follows: • The number of FSVs to be installed in high bushfire risk areas over the next (2016/17 to 2020/21) Access Arrangement (AA) period has increased (10,920 versus 9,900) reflecting updated data and the installation is now planned to occur at an even rate across the next AA period. • The installation of FSVs at brush fence locations is now planned to occur at an even rate over the next AA period. • Provision is no longer being made for FSVs to be installed at new and existing domestic consumer premises.
Estimated Cost	$1.2 million (real $2014/15) (reduced from $10.5 million in the original Business Case)
Consistency with NGR	The installation of the FSVs in high bushfire risk areas and near brush fences complies with the new capex criteria in Rule 79 of the National Gas Rules (NGR) because it is: • necessary to maintain and improve the safety of services and maintain the integrity of services (Rule 79(1)(b) and Rules 79(2)(c)(i) and (ii)); and • such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services (Rule 79(1)(a)).
PROJECT APPROVAL	
Prepared By:	Spiro Ellul, Manager Field Operations, APA
Reviewed By:	Dominic Zappia, Manager Planning and Engineering, APA
Approved By:	Peter Sauer, General Manager SA Networks, APA
OTHER RELEVANT DOCUMENTS	
This addendum should be read in conjunction with: • the original SA31 Business Case, which was provided to the AER on 1 July 2015 as Attachment 7.1 to the Access Arrangement Information (AAI); • AGN's response to the AER's Information Request 007, which was provided to the AER on 4 August 2015; • AGN's response to the AER's Information Request 011, which was provided to the AER on 11 August 2015; and • the 2015 South Australian Network Asset Management Plan, which was provided to the AER on 1 July 2015 as Attachment 8.1 to the AAI.	

1 Original Business Case

AGN's original proposal for the next AA period included an allowance of $10.5 million to maintain and improve the safety of services and maintain the integrity of services by installing FSVs in the following locations in AGN's network:

- high bushfire risk areas[1] ($1.0 million);[2]
- brush fence sites where the gas meter is located near the fence ($0.1 million); and
- new domestic sites and existing sites when the meter is due to be changed ($9.3 million).

As noted in the original Business Case, the primary driver for this project is the risk that AGN's network contributes to property damage and/or personal injury in the event of a fire (bushfire or house fire) if the emergency shut-off of gas supply cannot occur. The untreated risk has been assessed as Moderate (Priority 3).

Work on reducing this risk commenced in the current AA period with 3,747 FSVs installed in high bushfire risk areas in 2013/14 and 2014/15 as noted in AGN's response to the AER's Information Request 011.[3]

2 AER Draft Decision

In its Draft Decision, the AER:

- reduced the installation rate for FSVs in high bushfire risk areas from 9,900 installations in 2016/17 to 5,000 over the next AA period (i.e. 1,000 installations per annum);[4]
- did not accept AGN's proposal to install FSVs at brush fence sites; and
- did not accept AGN's proposal to install FSVs at new and existing domestic sites.

The AER's decision in this case was made on the basis of the following advice that it received from its engineering consultant, Sleeman Consulting (Sleeman):[5]

1. Sleeman noted that the continuation of the program to install FSVs in high bushfire risk areas and the proposed unit costs were prudent but claimed that the proposal to complete the program in one year (2016/17) through the installation of 9,900 meters was not realistic based on the experience in the current AA period. Sleeman went on to add that a "*realistic, achievable and manageable programme be based on the installation of 1,000 FSVs per annum*", which he claimed reflected the annual installation rate most recently achieved by AGN.
2. Sleeman claimed that the proposed installation of 800 FSVs at brush fence sites was not justified because, in his opinion, the risk of damage to a gas meter as a result of a brush fence fire is "*very*

[1] Minister's Code, February 2009 (as amended October 2012), Undertaking development in Bushfire Protection Areas, Section 1.2

[2] The program to install FSVs in high bushfire risk areas commenced in the current AA period.

[3] AGN Response to the AER's Information Request 011, 11 August 2015.

[4] AER 2015, "*Attachment 6 – Capital Expenditure |Draft Decision: Australian Gas Networks Access Arrangement 2016-21*", November 2015, pg. 6-49-50.

[5] Sleeman2015, "*Review of Capex Forecasts for Selected Projects*", 18 November 2015, pg. 9-10.

low" and if there was such a fire, street access will remain available for isolation of the domestic service.

3. Sleeman also claimed that the proposed installation of FSVs at domestic sites was not justified because the greatest risk for domestic sites is an internal fire, which Sleeman claimed FSVs provide little protection against.

On the basis of this advice, the AER excluded the proposed expenditure on brush fences and new domestic sites and reduced the proposed expenditure on high bushfire risk areas from $1.04 million to $0.52 million.

3 AGN's Response

In response to the Draft Decision, AGN has revised assumptions relating to the rate and timing of FSV installation. More specifically this Addendum outlines that AGN has:

- retained the high bushfire risk areas aspect of the project but assumed that the installation of FSVs occurs evenly over the upcoming AA period, rather than in a single year;
- increased the number of FSV installations to occur in high bushfire risk areas to reflect updated data;
- retained the brush fence sites aspect of the project but assumed that the installation of FSVs occurs evenly over the upcoming AA period rather than in a single year; and
- accepted the AER's decision not to install FSVs at domestic sites.

Further detail follows in Sections 3.1 through 3.4.

3.1 High bushfire risk areas

The only concern that the AER and Sleeman have raised about this aspect of the original Business Case is the installation rate that AGN assumed, with the original Business Case assuming that the full program (9,900 meters) would be installed in 2016/17 as opposed to the installation occurring progressively across the next AA period. AGN has therefore revisited this assumption.

In short, AGN accepts the AER's position that the installation of FSVs occur evenly over the AA period rather than in a single year. We do not however agree with the installation rate (1,000 per annum) that Sleeman has recommended, for the following reasons:

1. An annual installation rate of 1,000 FSVs understates the actual installation rate that AGN has achieved in the current AA period. As AGN noted in its response to the AER's Information Request 007, the installation of FSVs in high bushfire risk areas commenced in 2013/14 and in the last two years 3,747 FSVs have been installed. This equates to an average installation rate of approximately 1,900 per annum, which is substantially higher than Sleeman's estimate.
2. An annual installation rate of 1,000 FSVs will also result in the deferral of the installation of FSVs at a large number of sites in high bushfire risk areas to the 2021/22-2025/26 AA period and, in so

doing, leave the public exposed to the risk of property damage and/or personal injury in these areas for a longer period of time.

The risks that AGN's network can pose in high bushfire risk areas cannot be understated, which is why AGN is proposing to complete the installation program in the next AA period.

Since submitting the original Business Case, AGN has recalculated the number of sites that will need to be retrofitted with FSVs in the next AA period to be approximately 10,920, which is 1,020 more sites than were identified in the original Business Case but consistent with the information that was provided to the AER in AGN's response to the AER's Information Request 011.[6]

If FSVs at the 10,920 sites are installed evenly over the next AA period, then this equates to an average installation rate of approximately 2,185 sites per annum. While this is slightly higher than the *average* installation rate (1,900) that AGN achieved in 2013/14 and 2014/15, it is **below** the rate that AGN actually achieved in 2013/14 (2,294)[7] and, in AGN's view, is readily achievable. AGN has therefore decided to amend the original Business Case by assuming that FSVs will be installed at 2,185 sites per annum over the next AA period.

3.2 Brush fence locations

As outlined in Section 2, AGN's proposal to install 800 FSVs at sites where the gas meter is in close proximity to a brush fence was rejected by the AER because it was advised by Sleeman that:

- the risk of damage to the gas meter as a result of a brush fence fire is "*very low*"; and
- street access would remain available for isolation of the domestic service in the event of a fire.

Contrary to the advice provided by Sleeman, the risk of damage to a gas meter as a result of a brush fence fire is **not** very low. Domestic gas meters are made from light aluminium alloy, with polyethylene internal components and connections to the inlet and outlet piping. The radiant heat from a brush fence fire can be very high, and can easily damage the meter and melt its connection fittings, particularly if the fire impinges directly on the meter.

It is not, however, the risk of damage to the gas meter that the installation of FSVs is intended to address, rather the risk it is intended to address is that the fire will escalate if the gas meter or connection fittings fail as a result of the brush fence fire. If this was to occur, then the escaping gas would ignite and feed the fire in the time period between the incident and emergency services arrival. During this undetermined time period, the escaping, ignited gas would be contributing to the fire and consequent damage. The extent of this contribution increases with the operating pressure of the site in question (i.e. sites operating on a high pressure network would have a greater contribution to the

[6] AGN, Response to the AER's Information Request 011, 11 August 2015.

[7] AGN, Response to the AER's Information Request 007, 4 August 2015.

incident than sites on a low pressure network). To this extent, it is noteworthy that as a result of the ongoing mains replacement program, low pressure networks will gradually disappear from the network, which will further increase the risk within the network overall.

While Sleeman has claimed that street access would remain available for isolation of the domestic service in the event of such a fire, there is no isolation valve between the gas main in the street and the gas meter at the house or property boundary. Isolating the service therefore requires excavating where the service takes off from the main, which could take up to an hour or more, with personnel working in hazardous conditions adjacent to the fire site.

It is for these reasons that AGN remains of the view that the installation of FSVs at brush fence sites is necessary to improve safety and maintain the integrity of services and is therefore justified under Rules 79(2)(c)(i) and (ii) of the NGR.

With respect to the rate at which FSVs should be installed at these sites, the original Business Case assumed that all of the installations would occur in 2016/17. Having considered the AER's Draft Decision on FSV installation in high bushfire risk areas, AGN has decided to amend this aspect of the original Business Case and assume that the installation of the 800 FSVs will occur evenly over the next AA period. This equates to 160 installations per annum.

When combined with the installation rate for FSVs in high bushfire risk areas, the total FSV annual installation rate is 2,345 per annum, which is only slightly above the rate that AGN actually achieved in 2013/14 (2,294). In the current South Australian business environment, resources to support this additional effort are readily available and AGN expects that they will be able to sustain the increased annual rate. AGN is therefore confident that it can maintain this rate over the next AA period.

3.3 New and existing domestic sites

Like brush fence sites, the AER has rejected AGN's proposal to install FSVs at new domestic sites and existing sites when the meter is due to be changed.

AGN's decision to include this initiative in the original Business Case was made in response to the feedback consumers provided through AGN's stakeholder engagement process, which was that 89% of consumers were prepared to pay for the roll-out of these valves to domestic sites.[8]

While the results of this feedback clearly indicate customer support for the installation of FSVs at domestic sites, AGN has decided to accept the AER's Draft Decision on this aspect of the program. AGN has therefore excluded the provision that was originally made for installing FSVs at domestic sites from the revised capex estimate (see Section 3.4).

[8] AGN 2015, *"Access Arrangement Information for Australian Gas Networks' South Australian Natural Gas Distribution Network",* 1 July 2015, pg. 62

3.4 Revised installation rate and cost estimates

Table 3.1 sets out the revised number of FSV installations that AGN proposes to carry out in high bushfire risk areas (2,185 per annum) and brush fence locations (160 per annum) in the next AA period and the associated capex. The proposed expenditure has been calculated using the same unit cost presented in the original Business Case [redacted] which is based on the cost of recently completed work that was subject to a competitive tender process and was accepted by Sleeman.[9]

Table 3.1: Revised installation numbers and capex for FSVs

	FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21	Total Amended Business Case	Original Business Case	Difference
Installation Numbers								
High Bushfire Risk Areas	2,185	2,185	2,185	2,185	2,185	**10,925**	**9,900**	**1,025**
Brush Fence	160	160	160	160	160	**800**	**800**	**0**
New domestic and PMC sites	0	0	0	0	0	**0**	**186,745**	**-186,745**
Total installations	**2,345**	**2,345**	**2,345**	**2,345**	**2,345**	**11,725**	**197,445**	**-185,720**
Capital expenditure (excluding overheads (real $2014/15)								
High Bushfire Risk Areas	**$229,425**	**$229,425**	**$229,425**	**$229,425**	**$229,425**	**$1,147,125**	**$1,039,500**	**$107,625**
Brush Fence	**$16,800**	**$16,800**	**$16,800**	**$16,800**	**$16,800**	**$84,000**	**$84,000**	**$0**
New domestic and PMC sites	0	0	0	0	0	**$0**	**$9,337,250**	**-$9,337,250**
Total Capex	**$246,225**	**$246,225**	**$246,225**	**$246,225**	**$246,225**	**$1,231,125**	**$10,460,750**	**-$9,229,625**

As this table shows, the revised capex for this Business Case is $1.2 million, which is $9.2 million lower than the original proposal. The difference between these two forecasts primarily reflects AGN's decision not to proceed with the installation of FSVs at new and existing domestic sites located in non-high bushfire risk areas.

4 Summary

For the reasons set out above, AGN has decided to revise its proposed expenditure on this project down to $1.2 million. Consistent with the requirements of Rule 79(1)(a) of the NGR, AGN considers this revised expenditure to be:

- *Prudent* – The expenditure is necessary to maintain and improve the safety of services to customers and the public by ensuring that gas does not flow unimpeded in a bush fire or brush

[9] Sleeman 2015, "*Review of Capex Forecasts for Selected Projects*", 18 November 2015, pg. 10.

fence fire situation, and that protection of life and property is maximised. The expenditure is therefore of a nature that would be incurred by a prudent service provider.

- *Efficient* – The work has been spread evenly across the next AA period to ensure the program can be managed and supervised in an efficient and controlled manner with estimated labour rates based on current contractor tendered rates. The proposed expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur.
- *Consistent with accepted and good industry practice* – Identifying and reducing risks associated with bush and brush fence fires to as low as reasonably practicable is consistent with good industry practice and is reflected in Australian Standard AS4645 (Gas Distribution Network Management).
- *To achieve the lowest sustainable cost of delivering pipeline services* – Reducing risk to as low as reasonably practicable in this case is consistent with the objective of achieving the lowest sustainable cost given the scale of the liability claims that could be made if the distribution network contributes to extended damage and/or personal injury in the event of a bush or brush fence fire.

The capex can therefore be considered consistent with Rule 79(1)(a) of the NGR. The proposed capex is also consistent with Rule 79(1)(b), because it is necessary to:

- maintain and improve the safety of services (Rule 79(2)(c)(i)); and
- maintain the integrity of services (Rule 79(2)(c)(ii)), which includes maintaining the security of supply.

ADDENDUM TO BUSINESS CASE – SA44

PROJECT SUMMARY	
Network	AGN – SA
Project No.	SA44
Project Name	Inlet Data Capture
Risk and Priority	Moderate, Priority 3
Budget Category	Operating Expenditure (Opex) (Non-recurrent Step Change)
Amendments to Original Business Case	No change
Estimated Cost	$1.7 million (real $2014/15) spread evenly over the final three years of the next (2016/17 to 2020/21) Access Arrangement (AA) period. This estimate is unchanged from the original Business Case.
Consistency with NGR	Capturing the details of the inlet services identified as highest risk is consistent with the National Gas Objective and the National Gas Rules (NGR) because it is necessary to maintain and improve the safety of services and reduce the risk of damage to the network, third party property damage and personal injury. The proposed expenditure is also such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services, as required by Rule 91(1) of the NGR.
PROJECT APPROVAL	
Prepared By:	Rob Jones, Asset Information & Systems Manager, APA
Reviewed By:	Dominic Zappia, Manager Planning and Engineering, APA
Approved By:	Peter Sauer, General Manager SA Networks, APA
OTHER RELEVANT DOCUMENTS	
This addendum should be read in conjunction with: • the original SA44 Business Case, which was provided to the AER on 1 July 2015 as Attachment 7.1 to the Access Arrangement Information (AAI); • the 2015 South Australian Network Asset Management Plan, which was provided to the AER on 1 July 2015 as Attachment 8.1 to the AAI; • Wilson Cook, Review of Expenditure of Queensland and South Australian Gas Distributors: Envestra Ltd (South Australia), December 2010, pg. 58; and • AER, Draft Decision: Envestra Ltd Access arrangement proposal for the SA gas network 1 July 2011-30 June 2016, February 2011, pg. 161.	

1 Original Business Case

AGN's original proposal for the next AA period included an opex allowance of $1.7 million for the costs associated with capturing the inlet service details of 9,800 existing Industrial and Commercial (I&C) consumers and 3,300 multi-dwelling development sites which were assessed to be of highest risk. This project is an expansion of an initiative that was approved by the AER[1] for the current (2011/12 to 2015/16) AA period and has been timed to coincide with the roll-out of the new geospatial information

[1] AER 2011, "*Draft Decision: Envestra Ltd Access arrangement proposal for the SA gas network 1 July 2011-30 June 2016*", February 2011, pg. 161.

system (GIS) in 2018/19 to avoid any duplication of costs which would otherwise occur if data (entered prior to 2018/19) was then required to be transferred to the new GIS system.

As outlined in the original Business Case, records of the geographical location of these sites either do not exist or are not readily available to operations staff and/or third parties. Emergency crews are therefore unable to respond as quickly as they otherwise would to gas leaks and, as a consequence, there is an increased likelihood of third party property damage and/or personal injury. The proposed project is intended therefore to improve the safety of services to these sites. It will also mitigate the risk of damage to the network, third party property and personal injury by ensuring this information is available to third parties through the Dial Before You Dig Service and other requests for this information. The untreated risk associated with this project has been rated as moderate.

2 AER's Draft Decision

The collection of inlet service details for 5,000 I&C and multi-dwelling development sites was approved by the AER in the last AA review, on the basis of the advice that it received from its consultant, Wilson Cook, that the collection of this information is "*prudent as it represents good industry practice and will improve safety and service for customers.*"[2]

Notwithstanding the position it took in the last AA review, the AER has not made any provision for the proposed step change of $1.7 million in its 2016-2021 Draft Decision, because it claims the project is "*a discretionary activity aimed at developing more efficient business practices*".[3] Elaborating on this further, the AER stated that an increase in opex to finance the project was not required because the "*costs should be at least offset by future productivity gains and the reductions in other costs if they are efficient*".[4]

AGN's response to the issues raised in the AER's Draft Decision is set out below.

3 AGN's Response

As outlined in the original Business Case and Wilson Cook's 2011 review, the primary driver of the inlet data capture project is **public safety and risk reduction,** not efficiency improvements. AGN therefore disagrees with the AER's characterisation of this project as a "*discretionary activity aimed at developing more efficient business practices*" and its view that the proposed cost should be offset by future productivity gains and cost reductions.

It is not clear from the explanation contained in the Draft Decision how the AER has come to this view given the material that was provided in the original Business Case and the stance that the AER took in

[2] Wilson Cook 2010, "*Review of Expenditure of Queensland and South Australian Gas Distributors: Envestra Ltd (South Australia)*", December 2010, pg. 58 and AER 2011, "*Draft Decision: Envestra Ltd Access arrangement proposal for the SA gas network 1 July 2011-30 June 2016",* February 2011, pg. 161.

[3] AER 2015, "*Attachment 7 – Operating Expenditure | Draft decision: Australian Gas Networks Access Arrangement 2016-21*", November 2015, pg. 7-22.

[4] ibid, pg. 7-24.

the last AA review. The remainder of this section therefore provides further detail on the objectives of the project, its expected benefits and the proposed expenditure.

3.1.1 Project objectives and benefits

Knowledge of the location of inlet services to sites that consume large volumes of gas is, as Wilson Cook noted in its 2011 review, prudent and consistent with good industry practice. AGN does not, however, currently have a comprehensive and accurate data set that shows the location of these assets. The inlet data capture project is aimed at correcting this situation and has as its objectives to:

- Increase public safety by mitigating the risk associated with no inlet service information or inaccurate information at sites that consume large volumes of gas (i.e. I&C and multi-dwelling development sites). Correct and readily available information will enable emergency crews to respond more quickly to reported gas leaks at I&C and multi-dwelling development sites because the time required to locate and isolate supply will be minimised.[5] The availability of this information will therefore minimise the consequences of possible gas escape and build-up in consumer premises, which could put public safety at risk.
- Reduce the incidence of damage to the network, third party property damage and personal injury at these service locations, by enabling more accurate information to be communicated to third parties using the Dial Before You Dig service and other requests for inlet service locations.
- Determine the ownership of major inlet services within multi-dwelling complexes to ensure risks are being managed effectively and that liability is correctly allocated.
- Fulfil AGN's obligation to provide accurate asset information to third parties.

The work required to achieve the above objectives are set out in detail on page 5 of the original Business Case[6], but in short the key activities include:

- updating the information currently held in hard copy as hand drawn sketches;
- acquiring the location of those inlet services where records do not exist;
- loading the information into the GIS so it is readily available to a wide range of operations and other personnel; and
- providing the information to third parties through the Dial Before You Dig electronic mapping services.

In addition to improving the safety of services and reducing the risk of damage to the network, third party property and personal injury, the inlet data capture project will enable:

[5] Note that without this information, emergency crews will have to spend time trying to locate the isolation valve, which will increase the risk that vented gas will arise in confined spaces and cause damage to third party property and personal injury.

[6] AGN 2015, "*Attachment 7.1, Access Arrangement Information for Australian Gas Networks' South Australian Natural Gas Distribution Network*", July 2015.

- leak surveys at I&C and multi-dwelling sites to be carried out more efficiently and effectively;
- meters and service installations that are out of specification, broken or damaged to be identified more readily;
- more accurate network modelling and analysis to be carried out; and
- more accurate response maps to be provided through the Dial Before You Dig service.

The project will also raise awareness amongst I&C and multi-dwelling customers about the location of their service installations and care and maintenance of those services.

As the preceding discussion highlights, the main objective of this project is not to achieve cost efficiencies. It is to improve public safety and reduce the risk of damage to the network, third party property damage and personal injury.

Support for AGN's argument is seen from the fact that AGN has been capturing and providing this information for its Queensland network for many years. This project for the South Australian network will therefore provide increased consistency across the AGN national network.

Other utility industry participants have recognised the benefits of capturing this data and provide inlet service information to services such as Dial Before You Dig (DBYD). Some examples include:

- Telstra who provides inlet service information for all of its services in response to DBYD requests;
- SA Power Networks who provides inlet service information for its underground electricity services via DBYD requests; and
- SA Water who provides inlet service information for its larger industrial and commercial customers, and multi-dwelling residential sites such as retirement villages via DBYD requests.

3.1.2 Proposed expenditure

AGN's proposed expenditure on the inlet data capture service and the timing of this expenditure is set out in Table 3.1. It is worth noting that as mentioned on page 5 of the original Business Case[7] the expenditure presented in this table is in addition to the costs incurred in the 2014/15 base year because additional resources (primarily labour) will need to be employed specifically to carry out the project. It can therefore be viewed as a non-recurrent step change. It is also worth noting that the proposed expenditure is unchanged from the original Business Case and has been included in this addendum for completeness only.

[7] AGN 2015, "*Attachment 7.1, Access Arrangement Information for Australian Gas Networks' South Australian Natural Gas Distribution Network*", July 2015.

Table 3.1: Proposed operating expenditure ($'000 Real 2014/15)

Item	FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21	Total
Labour			475	475	475	**1,425**
Vehicle lease			48	48	48	**144**
Software[8]			63	13	13	**89**
Total			**586**	**536**	**536**	**1,658**

As this table highlights, most of the proposed expenditure is forecast to be incurred in the last three years of the AA period because the project has been timed to coincide with the roll out of the GIS. Deferring the project until this time, will enable the data to be directly input into the new system and avoid costs being duplicated. Further detail on the basis on which this cost estimate has been developed can be found in Attachment A of the original Business Case[9].

4 Summary

For the reasons set out above, AGN remains of the view that a non-recurrent step change of $1.7 million is required in the upcoming AA period and that the costs associated with carrying out this public safety and risk reduction project cannot be assumed to be offset by future efficiency gains as the AER has sought to do.

Consistent with the requirements of Rule 91 of the NGR, AGN considers that the proposed expenditure on this project is:

- *Prudent* – The expenditure is required to improve the safety of services to I&C and multi-dwelling development customers and reduce the risk of damage to the network, third party property damage and personal injury, and is of a nature that a prudent service provider would incur, as Wilson Cook noted in their advice to the AER in 2011.[10]
- *Efficient* – The proposed expenditure can be considered efficient because:
  - the total number of inlet data capture sites has been optimised to target the highest risk sites where the consequence of poor response and or third party damage is greatest; and

[8] As mentioned on page 5 of the original Business Case, this software cost is in addition to the proposed upgrade to the new GIS system

[9] AGN 2015, "*Attachment 7.1, Access Arrangement Information for Australian Gas Networks' South Australian Natural Gas Distribution Network*", July 2015.

[10] Wilson Cook 2010, "*Review of Expenditure of Queensland and South Australian Gas Distributors: Envestra Ltd (South Australia), December 2010*", pg. 58 and AER 2011, "*Draft Decision: Envestra Ltd Access arrangement proposal for the SA gas network 1 July 2011-30 June 2016*", February 2011, pg. 161.

- the costs are based on actual GIS software edit licence cost, contractor costs equivalent to internal labour costs used within APA's Planning Department for similar data capture and GIS records updating and project management costs.

- *Consistent with accepted and good industry practice* – Collecting information on the location of inlet services to sites that consume large volumes of gas is, as Wilson Cook noted in 2011, consistent with good industry practice. Further support for this view can be found in the fact that other AGN sites within Australia (such as AGN Queensland where this information has been captured and provided for many years) and other utilities in South Australia (e.g. SA Power Networks, SA Water and Telstra) already collect and provide this information.
- *To achieve the lowest sustainable cost of delivering pipeline services* – The deferral of the project until the roll out of the new GIS will ensure there is no costly double-handling of the data. The proposed scope of the project is therefore consistent with the objective of achieving the lowest sustainable cost of delivering services.

ADDENDUM TO BUSINESS CASE – SA52

PROJECT SUMMARY	
Network	AGN– SA
Project No.	SA52
Project Name	HDPE camera investigation and repair
Risk and Priority	High, Priority 2
Budget Category	Capital Expenditure (capex)
Amendments to Original Business Case	The programme of work for the High Density Polyethylene (HDPE) camera inspections and repair work that was specified in the original Business Case has been revised in the following ways: • The number of kilometres of HDPE to be inspected as part of SA52 has decreased following the revisions that AGN has made to the Mains Replacement Programme (MRP) in response to the Australian Energy Regulator's (AER) Draft Decision. More specifically, the revised MRP specifies an increased amount of HDPE to be replaced over the next Access Arrangement (AA) period, which has resulted in a reduction in the quantity of HDPE that is the subject of investigation and repair in the next AA period. • The programme of work has been revised to reflect the results of recent actual camera inspections carried out in a pilot programme during September 2015. These inspections have revealed that: – cameras can only be used to inspect mains that have a diameter of DN and above; – the original assumptions that were made about camera crew and excavation and repair crew performance were optimistic with actual productivity being less than assumed; and – the original assumption that was made about squeeze-off frequency was also optimistic, with more squeeze-off sites per km now expected than were anticipated in the original Business Case.
Estimated Cost	$10.0 million (real $2014/15) (reduced from $11.6 million in the original Business Case).
Consistency with NGR	The inspection and repair of the HDPE assets complies with the new capex criteria in Rule 79 of the National Gas Rules (NGR) because it is: • necessary to maintain and improve the safety of services and maintain the integrity of services (Rule 79(1)(b) - Rules 79(2)(c)(i) and (ii)); and • such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services (Rule 79(1)(a)).
PROJECT APPROVAL	
Prepared By:	Steve Polglase, Asset Planning Engineer, APA
Reviewed By:	Jan Krzys, Manager Asset Strategy and Planning, APA
Approved By:	Peter Sauer, General Manager SA Networks, APA

OTHER RELEVANT DOCUMENTS

This addendum should be read in conjunction with:

- the original SA52 Business Case, which was provided to the AER on 1 July 2015 as Attachment 7.1 to the Access Arrangement Information (AAI);
- the SA54 and SA56 business cases, which were provided to the AER on 1 July 2015 as Attachment 7.1 to the AAI;
- the Mains Replacement Plan (MRP), which was provided to the AER on 1 July 2015 as Attachment 8.2 to the AAI;
- the 2015 South Australian Network Asset Management Plan, which was provided to the AER on 1 July 2015 as Attachment 8.1 to the AAI;
- AGN's response to the AER's Information Request 023, which was provided to the AER on 18 September 2015; and
- Attachment 8.10 to the revised AAI "*Response to Draft Decision: Mains Replacement*".

1 Original Business Case

AGN's original proposal for the next Access Arrangement (AA) period included an allowance of $11.6 million to carry out an internal inspection and repair program on Class 575 HDPE distribution mains. As outlined in the original Business Case, this inspection and repair program involves:

- inserting cable cameras into live gas mains to identify points along the HDPE pipeline where brittle crack failures may occur; and
- reinforcing these points with stainless steel clips to reduce the risk of catastrophic failure to as low as reasonably practicable until the mains can be replaced (consistent with the outcomes of the risk analysis presented in the *Response to Draft Decision: Mains Replacement*).

This project was developed in response to a number of incidents that have occurred in the SA network over the last seven years as a result of brittle crack failures of HDPE mains. It is evident from AGN's investigations into these incidents that HDPE is pre-disposed to brittle failures [redacted] with the frequency of failures expected to increase as the material ages. The project to carry out in-line camera inspections and repairs was one part of a broader package of measures that AGN had proposed to implement to reduce the risk to public safety. The other measures included:

- carrying out a targeted replacement of the medium pressure Class 250 and Class 575 HDPE mains (see Attachment 8.2 to the original AAI);
- installing gas vents on high risk class 575 HDPE mains (see Business Case SA56); and
- developing a comprehensive integrity management plan for Class 575 HDPE pipes (see Business Case SA54).

The untreated risk associated with HDPE pipes has been assessed as "High" from both a health and safety and compliance perspective because of the risks associated with a major gas escape contributing to a potential fire or explosion and resulting regulatory implications. As the risk matrix from the original Business Case (see Table 1.1) indicates, carrying out the in-line inspections and repair work is expected to reduce the likelihood of the risk eventuating from 'Possible' to 'Unlikely'. However, the overall risk level is still considered 'High' because if the HDPE results in a major gas escape the consequences for health and safety would still be catastrophic.

Table 1.1: Untreated and residual risks

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Score of Risk Levels
Risk Untreated	Likelihood	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	
	Consequence	*Catastrophic*	*Minor*	*Minor*	*Minor*	*Medium*	*Significant*	*Medium*	
	Risk Level	*High*	*Low*	*Low*	*Low*	*Moderate*	*High*	*Moderate*	*102*
		30	*08*	*08*	*08*	*14*	*20*	*14*	
Residual Risk	Likelihood	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	
	Consequence	*Catastrophic*	*Minor*	*Minor*	*Minor*	*Medium*	*Significant*	*Medium*	
	Risk Level	*High*	*Low*	*Low*	*Low*	*Moderate*	*Moderate*	*Moderate*	*80*
		26	*05*	*05*	*05*	*12*	*15*	*12*	

Source: Attachment C of original Business Case.

2 AER's Draft Decision

In the Draft Decision, the AER noted that while it accepted that the use of an in-line HDPE camera could "*assist in deferring mains replacement at a relatively low cost*" it could not be satisfied that the proposed expenditure was conforming capex without a Business Case or cost-benefit analysis.[1] There was no other basis provided by the AER for its decision not to make any provision for the proposed camera inspection of HDPE mains in its Draft Decision.

Through further discussions with AER staff on this issue, the AER noted that while it had access to the original Business Case for the HDPE camera investigation and repair work (SA52), it was looking for more of a quantitative assessment of the following options that were identified in the original Business Case and the reduction in risk associated with each:

1. using the HDPE cameras to identify points along the HDPE pipeline where brittle crack failures may occur and reinforcing these points (the selected option); and
2. replacing all of the Class 575 HDPE mains (i.e. in addition to replacing the Class 250 mains).

AGN's response to the issues raised in the AER's Draft Decision is set out below.

3 AGN's Response

AGN's proposal to carry out in-line camera inspections and repairs of the HDPE network is, as noted in the original Business Case, an integral part of a broader package of work that is designed to reduce the risk associated with HDPE to as low as reasonably practicable, consistent with Australian Standard AS4645 (Gas Distribution Network Management).

In this regard, it is worth noting that the proposal to carry out in-line camera inspections and repairs is not a substitute for mains replacement. Rather, as noted in the *Response to Draft Decision: Mains Replacement*, all of the Class 250 and 575 HDPE mains that are identified as posing a risk need to be replaced. It is not, however, practicable to replace all these mains in the next AA period. AGN has therefore prioritised the replacement of mains deemed to have a higher risk of brittle crack failure and looked at other ways to manage the risks associated with the remaining HDPE mains until they can be replaced. The proposal to carry out in-line camera inspections and repairs is a critical element of this risk mitigation programme and AGN remains of the view that this measure should continue into the next AA period and that the proposed expenditure satisfies Rule 79 of the NGR.

AGN understands from the material contained in the AER's Draft Decision that it is not questioning the need to carry out the in-line camera inspections and repairs. Rather, its concern is with the information that AGN provided on the options that were considered as part of the original Business Case and the risk reduction associated with each. Further detail on these options is provided in the remainder of this Addendum, which commences with an overview of the revisions that AGN has made to the scope of the original Business Case to reflect:

- the changes that have been made to the HDPE element of the MRP (see *Response to Draft Decision: Mains Replacement*); and

[1] AER 2015, "*Attachment 6: Capital expenditure | Draft decision: Australian Gas Networks Access Arrangement 2016-2021*", November 2015, pg. 6-38.

- the results of initial in-line camera inspection trials that were carried out after the original Business Case was submitted.

3.1 Revisions to the scope of the original Business Case

As outlined above, it has been necessary to make a number of revisions to the scope of the original Business Case to reflect the changes that AGN has made to the MRP and the findings from the recent in-line camera inspection trials. An overview of these changes is provided below.

3.1.1 Changes to the MRP

As noted in the original Business Case all the Class 575 HDPE within the AGN network (~1,440 km) is at risk of failure and will require replacement at some point in the future. Not all of this length of main can, however, be replaced in the short term. AGN has therefore sought to prioritise the replacement of these mains.

In the original MRP, AGN proposed to replace all of the Class 250 HDPE mains and 158 km of Class 575 HDPE mains in the next AA period.[2] Since its original submission, AGN has progressed work in relation to risk analysis and modelling that has allowed it to update its priority of mains to be replaced[3], resulting in the length of Class 575 HDPE mains to be replaced in the next AA period increasing from 158 km to 574 km.

AGN's decision to revise the MRP in this manner has been based on the application of a quantified risk model (QRM). This model uses a risk based approach, which combines cast iron, unprotected steel and HDPE material types, and ranks them according to the quantified risk. The highest risk mains from the combined list are then taken forward into the replacement plan. The application of this model has resulted in the highest risk areas containing Class 575 HDPE being scheduled for replacement in the next AA period. Further detail on the revisions that have been made to the HDPE component of the MRP can be found in *Response to Draft Decision: Mains Replacement*.

Given the revisions that have been made to the MRP, it has been necessary to revise the scope of the SA52 Business Case to reflect the reduction in the length of the Class 575 HDPE mains that will need to be subject to an alternative risk mitigation strategy, which is now around 840 km for the next AA period.

3.1.2 Experience with recent camera inspections

Since submitting the original Business Case, AGN has completed initial in-line camera inspections on 2.5 km of a 9 km pilot precinct. These inspections, which were carried out in September 2015 and were referred to in AGN's response to the AER's Information Request 023, have revealed the following:

1. The inspection camera technology can only inspect mains that have a diameter of DN50 and above.

[2] AGN 2015, *"Mains Replacement Plan"*, provided to the AER on 1 July 2015 as Attachment 8.2 to the AAI, pg. 25.

[3] Please refer to "Attachment 8.10 Mains Replacement Response" provided to the AER with our Revised AA Proposal on 6 January 2016.

2. Many more squeeze-off locations per kilometre have been identified than were expected (i.e. 50 metres between squeeze offs versus the 60 metres that was assumed in the original Business Case).
3. The distance that the camera cable can reach is less than expected (i.e. 60 metres in either direction versus the 75 metres that was assumed in the original Business Case).
4. The length of main that can be inspected per day is 33% lower than expected (i.e. 300 metres per day versus the 450 metres per day that was assumed in the original Business Case).
5. Wear and tear of the camera cable is higher than expected.

Given these results, and the increased length of HDPE proposed for replacement in the revised MRP, AGN has re-evaluated the suburbs that will be subject to the HDPE camera inspection and repair work and, in doing so, sought to develop a more accurate estimate of the likely volume of camera inspection sites and squeeze off sites that can be repaired. The results of this re-evaluation indicate the following:

- In line camera inspections are now proposed to be carried out on around 440 km of the Class 575 HDPE mains, and
- the risks on the remaining circa 400 km (principally mains with diameters smaller than DN50) will be managed by other more indirect measures, such as targeted leak surveys, which will enable leaks to be identified earlier.

The cost of carrying out these targeted leak surveys can be accommodated through the base year opex, so AGN is not seeking any additional allowance for this work. The remainder of this Business Case Addendum therefore focuses on the option of carrying out in-line camera inspection and repairs.

Attachment A provides further detail on how this re-evaluation has been carried out.

3.2 Managing the risk on Class 575 HDPE mains that will not be replaced in the next AA period

While the revised risk-based replacement of HDPE mains outlined above will result in the elimination of the highest risks in the HDPE network, the continued operation of Class 575 HDPE mains in the next AA period will leave AGN exposed to an unacceptably high risk [redacted] unless measures are put in place to effectively manage those risks.

In the original Business Case, AGN considered the following options to manage these risks:

- Option 1 – Do nothing.
- Option 2 – Use camera inspection technology to find and reinforce points where brittle crack growth can occur on Class 575 HDPE.
- Option 3 – Eliminate the risk of possible failure points by replacing all Class 575 HDPE in the next AA period.

Given the changes to the scope of the original Business Case outlined above and the initial findings of the in-line camera inspection trials, AGN has revisited the cost-benefit analysis that was carried out in the original Business Case. The results of this revised analysis are summarised in the table below for the following options:

- Option 1 – Do nothing.

- Option 2 – Use camera inspection technology to find and reinforce points where brittle crack growth can occur on the 440 km of Class 575 HDPE that can be inspected by in-line cameras.
- Option 3 – Eliminate the risk of possible failure points by replacing all of the Class 575 HDPE in the next AA period (rather than the subsequent AA period (i.e. post 2020/21)).

Table 3.1: Revised analysis of the costs and benefits of the options

Item	Option 1 Do Nothing	Option 2 Camera inspections and repairs	Option 3 Replace 870km of Class 575 HDPE pipe
Costs/Risks	If nothing is done to reduce the risks associated with HDPE pipes on the 840 km of Class 575 HDPE pipes that remain in place after the next AA period it will leave AGN [redacted] exposed to regulatory compliance penalties and significant compensation claims, particularly if it can be shown that AGN did not manage risks to as low as reasonably practicable. This option is also inconsistent with Australian Standard AS4645.	Camera inspections and repairs: 440 km at $22,800 per km While this option reduces the likelihood of the risk arising, the overall risk level is still 'High' because if a major gas escape does occur, the consequences for health and safety will be catastrophic (see Table 1.1).	Cost per km: $202,000[4]
Benefits	No upfront capital costs.	This option has the following benefits: • It will manage the risks associated with the HDPE Class 575 mains and, in so doing, defer the need to undertake replacement. This will, in turn, allow a more manageable replacement program to be implemented and capital requirements to be spread over time. • It will result in a reduction in the likelihood of the risk arising from 'Possible' to 'Unlikely'. • It will provide valuable actual field data on the locations of squeeze-offs, and the environment within which they exist (soil types, cover – concrete, bitumen, earth etc, and proximity to buildings). This data will feed into the on-going development of the QRM, and inform planning for future replacement programs.	This option will eliminate all the risks associated with HDPE pipes in the next AA period.

[4] This cost is consistent with the replacement costs contained in *Response to Draft Decision: Mains Replacement.*

Given the nature of the risks outlined above, the 'Do nothing' option (Option 1) is not considered a viable option and has therefore been dismissed.

Of the remaining two options, Option 2 is the lower cost option ($22,800/km versus $202,000/km) but has a higher residual risk than Option 3. This is because, unlike Option 3, which will completely eliminate the risk, the find and fix measures in Option 2 are just temporary measures that are designed to delay crack propagation and reduce the volume of gas escape in the event of a leak developing. Put simply, Option 2 is designed to reduce the risk posed by HDPE to a more acceptable level in the next AA period while Option 3 is designed to completely eliminate the risk posed by HDPE (i.e. risk management versus risk elimination in the next AA period).

While AGN's preference would be to eliminate all the risk posed by HDPE through the replacement option (Option 3), it would be both impractical and costly to undertake this work in a single AA period given all the other HDPE pipes that need to be replaced in the next AA period. The more prudent option in this case is therefore to implement the in-line camera inspection and repair programme in the next AA period (Option 2). Costing $22,800 per km, this risk-based option, in combination with the revised mains replacement strategy, will reduce the HDPE related risks to as low as reasonably practicable in a manner that balances cost and risk, consistent with Australian Standard AS4645 (Gas distribution network management).

3.3 Revisions to forecast capex

Table 3.2 sets out the changes that AGN has made to the scope and annual cost of the in-line camera inspection and repair programme and the reason for these changes, while Table 3.3 sets out the revised capex for each year of the next AA period. The information contained in these tables has been estimated on the following basis:

- A total of 8,833 excavations are assumed to be required for exposing camera inspection sites and excavating and reinforcing squeeze off sites.
- One and a half camera crews are assumed to be used to investigate and find squeeze-off points and other brittle crack failure points. This work will be carried out by AGN's asset management service provider, APA, and the forecast cost of this work is based on APA's unit rates.
- Two and a half crews are assumed to carry out the associated excavation and repair works (i.e. excavation/reinstatement of camera insertion points, and excavation, repair and reinstatement associated with each defect). This work will be carried out by external contractors who will be selected through a competitive tender process.

Table 3.2: Revisions to the Original Business Case

Item	Original Business Case	Revised Business Case	Reason for Revision
Class 575 inserted – km	500	201	The reduction reflects the change to the MRP and the fact that cameras can only be used to inspect DN50 diameter pipelines and above
Class 575 direct lay – km	850	238	
Inserted squeeze off sites/km	17	20	The original Business Case assumed 60 m between squeeze offs but the latest inspections indicate a 50 m distance between squeeze offs.
Direct lay squeeze off sites/km	5	5	Unchanged
Inserted mains squeeze off locations	8,333	4,060	The reduction reflects the changes to the MRP and the results of the recent inspections, which has led to a reduction in mains length that needs to be inspected but more sites per km
Direct lay mains squeeze off locations	4,250	1,190	
Total squeeze off sites	12,583	5,200	This reduction reflects the change to the MRP. While the total squeeze off sites is equal 5,250, the Response to Mains Replacement allows for 5 km of HDPE inserted mains to be replaced on a piecemeal basis, so it has been assumed 2.5 km of this occurs in the high risk HDPE suburbs.
Camera inspection hole frequency (m)	150	120	This reduction reflects the finding from the recent inspection that cameras can only inspect 60 m (not 75 m) each way from an inspection hole.
Camera inspection excavation sites	9,000	3,633	The lower number in this case reflects: • the changes to the MRP, which has resulted in a reduction in mains length that needs to be inspected; and • the findings from the recent inspection, which indicate that one excavation can only be carried out every 120 m and not the 150 m that was assumed in the original Business Case.
Total excavations required	21,583	8,833	This reduction reflects the changes to the MRP, which has resulted in a reduction in mains length that needs to be inspected.
No. of camera crews	2	1.5	[redacted]
No. of excavate and repair crews	4	2.5	[redacted]
[redacted]	[redacted]	[redacted]	This reduction reflects the findings of the recent inspections, which indicate that camera crews can inspect 60 m either side of hole and 2.5 holes per day per crew (down from 70 m and 3 holes in the original Business Case).
[redacted]	[redacted]	[redacted]	This reduction is based on the findings from the recent inspections.
Total sites excavated per day	16	7	This reduction is based on actual experience in the recent inspections.
Annual Cost Assumptions ($ million real $2014/15)			
[redacted]	[redacted]	[redacted]	This reduction reflects the reduction in the number of camera crews from two to 1.5 (camera crew costs [redacted] including vehicle)
[redacted]	[redacted]	[redacted]	This increase reflects the 2014/15 contractor schedule of rates for similar activities.
[redacted]	[redacted]	[redacted]	This reduction reflects the reduction in camera sites and squeeze off sites
Total annual cost	$2.3 m	$2.0 m	This reduction reflects the effect of all the changes outlined above.
Total cost for next AA period	**$11.6 m**	**$10.0 m**	

Table 3.3: Revised capex ($'000 real $2014/15)

Item	FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21	Total
Camera Crew	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**1,500**
Repair Crew	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**6,380**
Materials	421	421	421	421	421	**2,105**
Total	**2,000**	**2,000**	**2,000**	**2,000**	**2,000**	**10,000**

4 Summary

For the reasons set out above and in the Response to the Mains Replacement, AGN is of the view that the risks associated with the Class 575 HDPE mains should be managed by:

- replacing the highest risk Class 575 HDPE mains in the next AA period through the updated MRP; and
- managing the risks on the remaining Class 575 HDPE mains that will not be replaced in the next AA period by using in-line cameras to inspect and repair around 440 km of Class 575 HDPE mains and carrying out targeted leak surveys on the remaining 400 km (i.e. on the Class 575 HDPE mains with diameters smaller than DN50).

The cost of carrying out the in-line camera inspections and repairs in the next AA period is expected to be $10.0 million (real $2014/15). In AGN's view, the proposed expenditure on these measures is:

- *Prudent* – The expenditure is necessary in order to maintain the integrity of services and to reduce the risk to human health and safety and property to as low as reasonably practicable in the next AA period. It is also of a nature that a prudent service provider would incur.
- *Efficient* – Carrying out the camera investigations and repair work is more cost effective than replacing all the HDPE Class 575 pipes in the next AA period and represents an efficient balance of costs and risks. The manner in which AGN intends to carry out the inspections and repair work (i.e. through a mix of internal and external resources, with external contractors to be selected through a competitive tender) can also be considered efficient.
- *Consistent with accepted and good industry practice* – Minimising network risk and maintaining public safety are fundamental requirements for a gas network operator and reflects accepted and good industry practice. Reducing the risk to as low as reasonably practicable in a manner that balances cost and risk is also consistent with Australian Standard AS4645.
- *To achieve the lowest sustainable cost of delivering pipeline services* – Carrying out in-line camera inspections and repairs is a more cost effective option than replacing all Class 575 HDPE mains in the next AA period and is therefore consistent with the objective of achieving the lowest sustainable cost of delivering pipeline services.

The proposed expenditure can therefore be considered consistent with Rule 79(1)(a) of the NGR. It is also consistent with Rule 79(1)(b) of the NGR, because it is necessary to:

- maintain and improve the safety of services (79(2)(c)(i)); and
- maintain the integrity of services (79(2)(c)(ii)), which includes maintaining the security of supply.

ATTACHMENT A – Estimation of number of squeeze-off sites

A.1. Selection of Suburbs

AGN has estimated the length of HDPE mains that can be subject to camera inspection (total and mains that have a diameter greater than DN 50 because the camera cannot inspect any smaller diameter than DN 50) by suburb using GIS data and then excluding those suburbs where HDPE replacement is expected to occur as part of the MRP.

The remaining suburbs are then divided between older suburbs, where mains have been inserted, and newer suburbs, where mains have been direct laid.

A.2. Suburbs where mains inserted

Estimating the number of squeeze offs in suburbs where mains have been inserted involves using customer, mains length and property data from the GIS, and an estimate of the number of services a mains insertion crew can renew per day to arrive at an average distance between squeeze offs for each suburb. At a high level, this process involves the following steps:

1. Calculating the number of customers per km of DN50 pipe in each suburb using information on the length of DN 50 HDPE pipe and the number of customers.
2. Calculating the penetration rate (number of customers divided by the number of properties) for each suburb using information on the total number of properties and number of customers per suburb.
3. Using the penetration rate calculated in step 2 to estimate the number of blocks per suburb that have a gas main past them, from which the average block size per suburb can then be calculated.
4. The block size and the number of services a mains renewal crew can renew per day govern the distance of main renewed each day, and thus between squeeze offs. The average number of services renewed per day is typically seven.
5. Using the length of DN 50 HDPE main from step 1 and the distance between squeeze-offs from step 4 in each suburb, an estimate of the number of squeeze offs in the suburb can be derived.
6. The total number of squeeze offs and total length of DN50 HDPE main across all older suburbs can then been used to estimate the 50 metres between squeeze offs used further in the calculations.

The outcome of this estimation methodology has been compared with the results of the pilot program carried out in the suburb of Parkside in September 2015. The actual distance in Parkside between squeeze offs was an average of 37 metres, which compares favourably with the estimate of 35 metres for Parkside derived from the above methodology.

A.3. Suburbs where mains have been directly laid

The number of squeezes offs in direct lay suburbs has been calculated using information on the distance main laying crews typically lay new HDPE in new subdivisions, or existing suburbs with no gas mains in them. This has been assessed as an average of 200 metres.

Using this 200 metres and the length of DN 50 HDPE pipe in each suburb results in an estimate of the number of squeeze offs in these suburbs.

ADDENDUM TO BUSINESS CASE – SA59

PROJECT SUMMARY	
Network	AGN– SA
Project No.	SA59
Project Name	Mobility Integration
Risk and Priority	Moderate, Priority 3
Budget Category	Capital Expenditure (capex)
Amendments to Original Business Case	In response to the Australian Energy Regulator's (AER's) Draft Decision, AGN has: • provided more information on the problems with the current paper-based processes to substantiate its investment in the Mobility Integration project; • carried out a more detailed assessment of the costs and benefits of the Mobility Integration project to determine whether it yields a positive economic value as required by Rule 79(2)(a) of the National Gas Rules (NGR), which it does; and • decided not to try and recover the $0.3 million operating expenditure (opex) allowance associated with this project.
Estimated Cost	• Capex: $9.0 million (real $2014/15) (this allowance is unchanged from the original Business Case); and • Opex: $0 (as noted above AGN has excluded the $0.3 million opex allowance from the Revised Access Arrangement (AA) Proposal).
Consistency with NGR	The revised Mobility Integration project is justified under Rule 79(1)(b) of the NGR because the overall economic value of the proposed expenditure is positive (Rule 79(2)(a)) and the expenditure is also necessary to maintain and improve the safety of services, maintain the integrity of services and comply with regulatory obligations (Rules 79(2)(c)(i)- (iii)). The proposed expenditure is also such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services, as required by Rule 79(1)(a).
PROJECT APPROVAL	
Prepared By:	Peter Butler, Manager Network Support Services, APA
Reviewed By:	Heather Reynolds, Vendor Manager IT, APA
Approved By:	John Ferguson, Group Executive Networks, APA
OTHER RELEVANT DOCUMENTS	
This addendum should be read in conjunction with: • the original SA59 Business Case, which was provided to the AER on 1 July 2015 in Attachment 7.1 to the Access Arrangement Information (AAI); • the 2015 South Australian Network IT Investment Plan, which was provided to the AER on 1 July 2015 in Attachment 8.4 to the AAI; and • Attachment 8.12: KPMG 2015, *"SA Australian Gas Networks Limited: IT Cost Benchmarking"*, 8 December 2015.	

1 Original Business Case

AGN's original proposal for the next (2016/17-2020/21) AA period included an expenditure allowance of $9.3 million (capex: $9 million and one-off opex: $0.3 million)[1] for the Mobility Integration project.

As noted in the original Business Case, the Mobility Integration project involves the implementation of an enhanced mobile communications platform, which will be integrated into the Enterprise Asset Management (EAM) suite of IT applications[2] and Geospatial Information System (GIS) and will enable field data to be captured into core operational systems and real-time information to be transmitted to the field. The implementation of this project will enable AGN to implement more efficient:

- work management processes and practices in the field and will also support more informed decision making (for example, mobile solutions can support job assignments, provide field crews with instructions and real-time asset information, and facilitate the timely transfer of information between the field, back-office systems and customers); and
- end-to-end business processes that automate EAM and GIS functionality through mobility (for example, by automating paper-based and manual processes).

Apart from providing for greater efficiency in the field and across the business, the Mobility Integration project is also expected to result in improvements in customer service delivery (for example, by reducing response times and providing accurate and timely information on outages and service requests), the safety and integrity of services and compliance with regulatory obligations.

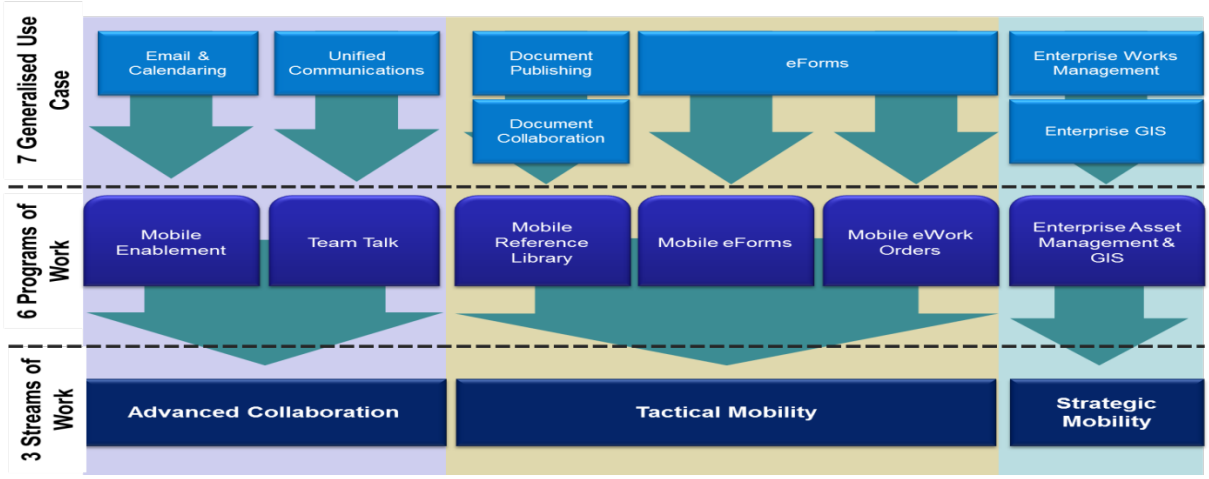
AGN's proposed investment in this project is being guided by the Mobility Roadmap depicted in

[1] All costs in this Business Case are expressed in $2014/15 values.

[2] The suite of applications include the Asset Management System, Health, Safety and Environment platform, payroll and document management

Figure 1.1 As this figure shows, mobility functionality is being progressively implemented into the business through the Advanced Collaboration, Tactical Mobility and Strategic Mobility workstreams. The Mobility Integration project forms part of the Strategic Mobility workstream, which is the final step on the AGN Mobility Roadmap.

Figure 1.1: AGN Mobility Roadmap



2 AER Draft Decision

The AER did not make any provision for the capex component of the Mobility Integration project in its Draft Decision because it claimed not to be satisfied that the proposed expenditure was justified under Rule 79(2).[3] Elaborating further on this decision, the AER stated that it was not satisfied that the project was required for any of the reasons set out in Rule 79(2)(c) and that while the project appeared to generate some ongoing cost savings for AGN, it did not have a net positive economic value as required by Rule 79(2)(a).[4] The AER went on to add that:

> *"…this project appears to be 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 these costs."*[5]

The opex component of the Mobility Integration project was also rejected by the AER.[6] In doing so, the AER noted that it does not typically allow step changes for any short-term cost to a service provider of implementing efficiency improvements because it expects a service provider to bear such cost and to make efficient trade-offs between these costs and future efficiencies.[7]

3 AGN's Response

Before addressing the specific matters raised in the AER's Draft Decision, it is worth noting that unlike many of its gas and electricity distribution counterparts, who started on the mobility journey five or

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3 AER 2015, "*Attachment 6 – Capital Expenditure | Draft decision: Australian Gas Networks Access Arrangement 2016-21*", November 2015, pg. 6-43.

4 Ibid.

5 Ibid.

6 AER 2015, "*Attachment 7 – Operating Expenditure | Draft decision: Australian Gas Networks Access Arrangement 2016-21*", November 2015, pg. 7-22.

7 Ibid, pg. 7-23

more years ago, AGN is yet to invest in mobility solutions. AGN is therefore behind many of its peers on the mobility journey.

The service providers that AGN is aware have already invested in mobility and are continuing to invest in this area include SA Power Networks (SAPN), Ergon Energy, Energex, AusNet Services (gas), Multinet, United Energy and Jemena (gas and electricity).[8] As far as AGN can ascertain from the relevant regulatory determinations, the AER has approved the proposed expenditure by each of these service providers on mobility solutions.[9] The AER's decision not to approve AGN's Mobility Integration project in the Draft Decision is therefore somewhat surprising, particularly given the findings of a recent IT benchmarking study that KPMG has carried out (see Appendix A and Attachment 8.12), which indicate that:

- AGN has underinvested in IT relative to its peers and further investment is required in order to catch-up to the rest of the industry; [10] and
- even with AGN's proposed investment in the Mobility Integration project in the next AA period, its proposed expenditure on IT is expected to be either below or trend in line with the industry average in the next AA period.

These views are reflected in the following extracts taken from the KPMG report:

> *"AGN SA's IT expenditures have been at the lowest level of the industry in the previous AAP. Expenditure increases in the current AAP and forecast increases for the next AAP, bring AGN SA in line with the industry."* [11]
>
> *"The under investment in IT the previous AAP, led AGN SA to be out of step with industry on its technology capabilities."* [12]
>
> *"AGN SA's IT Totex, Capex and Opex benchmark results are consistently below or in line with the industry benchmark mean. This suggests that IT expenditures are comparably efficient to the Australian utility industry, for both actual and planned IT expenditure forecasts."* [13]

Setting these observations aside, AGN understands from the explanation contained in the Draft Decision that the AER's main concerns with the Mobility Integration project are that:

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8 SAPN, *"IT Field Force Mobility Business Case",* 3 July 2015, Ergon Energy, *"Forecast Expenditure Summary Information, Communication and Technology, 2015 to 2020",* pg. 4, Energex, *"ICT Services Expenditure, 2015-20 regulatory proposal",* October 2014, pg. 5, AusNet Services, *"Electricity Distribution Price Review 2011-2015 Regulatory Proposal",* November 2009, pg. 158, Multinet, *"Gas Access Arrangement Review January 2013-December 2017 AAI",* 30 March 2012, pg. 85, Jemena Gas Networks, *"2015-20 AAI, Appendix 6.3 IT Strategy and Asset Management Plan",* June 2014, pg. 9, Jemena Electricity Networks, "*2016-20 Electricity Distribution Price Review Regulatory Proposal",* Attachment 7-3, 30 April 2015, pg. 87 and United Energy, *"Capital Expenditure Overview – ICT, 30 April 2014",* pg. 11.

9 AER, "*Final Decision: SAPN determination 2015-16 to 2019-20*", Attachment 6, pg. 6-120, AER, "D*raft Decision: JGN Access Arrangement 2015-20*", November 2014, Attachment 6, pg. 6-42, AER, "*Preliminary Decision: Jemena distribution determination 2016 to 2020*", October 2015, Attachment 6, pg. 6-94, AER, "*Final Decision: Ergon Energy determination 2015-16 to 2019-20*", October 2015, Attachment 6, pg. 6-120 and AER, *"Final Decision: Energex determination 2015-16 to 2019-20",* October 2015, Attachment 6, pg. 6-10. The AER has also previously approved the allowances sought by AusNet services (gas) and Multinet for mobility related projects.

10 KPMG 2015, "*SA Australian Gas Networks Limited: Information Technology Cost Benchmarking*", December 2015, pg. 6.

11 Ibid, pg. 6.

12 Ibid, pg. 8.

13 Ibid, pg. 6.

- the problems with the current paper-based manual processes were not clearly articulated in the original Business Case;
- the capex component of the project was not shown to yield a positive economic value in the original Business Case; and
- the opex component of the project is a short-term cost of implementing efficiency improvements and should not be recovered from consumers.

AGN's response to the first two of these concerns is set out in further detail below, but in short:

- the manual, paper-based processes that are currently in place are costly and inefficient and are limiting AGN's ability to improve service delivery to customers, drive further efficiencies and make a range of other improvements to the safety and integrity of the services; and
- the proposed expenditure on the Mobility Integration project does yield a positive net economic value over a 10 year period and is therefore justifiable under Rule 79(2)(a) of the NGR.

AGN therefore disagrees with the AER's decision not to approve the capex component of the Mobility Integration project. In relation to opex, AGN has, for the purposes of this business case, decided to accept the AER's decision not to include a step change for the opex associated with the project. The proposed expenditure on the Mobility Integration project has therefore been revised down from $9.3 million to $9 million.

Further information on the deficiencies in the current system and the economic analysis that AGN has carried out is provided in Sections 3.2 and 3.3.

3.1 Problems with the current system

AGN's South Australian Network currently relies on paper-based manual processes for the majority of its field based activities, including work management, health, safety and environment (HSE) management, technical work procedures and asset information collation. While the AER has suggested that there are *"not significant problems with the current system*", the use of these processes is costly and inefficient because information must be manually entered into numerous systems, which can result in data integrity issues, double handling of information and delays in the information becoming available.

The use of these processes also exposes AGN to a range of safety, operational and financial risks[14] and means that AGN is constrained in its ability to:

- realise the full benefits of the EAM system, including more efficient resource management, resource location and response times;[15]
- improve service delivery to customers through faster response times and providing real-time status updates on network outages and service requests;

[14] AGN, "*SA59 Business Case"*, 1 July 2015, Section 3.

[15] The EAM Project has been designed to capture more data about work on assets, as well as capturing asset and financial data at a detailed job level. This will result in significantly more data being captured in the field and will enable improved asset management decision-making, as well as improving efficiencies around reporting obligations. The benefits of the additional data have been captured within the EAM Project benefits, without reflecting the significant increased costs associated with capturing this data utilising existing paper-based processes.

- improve the safety of services by, for example, providing field crews with real time safety related information and up to date asset data through the Dial Before You Dig service and employees and contractors' mobile devices;
- improve the integrity of services through more informed decision making and reductions in operational errors from manual processing of data;
- comply with regulatory and market obligations through the timely reporting of accurate information; and
- avoid future cost increases through optimised mobile workforce management and improved decision making.

The continued use of these processes will also mean that AGN will fall further behind its peers who have already invested in mobility solutions and real-time information provision.

Further detail on some of the specific problems AGN has identified with the current paper-based system and how the Mobility Integration project will overcome these issues is provided below.

3.1.1 Work management through the EAM system

The EAM system was implemented on 22 June 2015 and has introduced a number of new work management processes into the SA Network, including discrete work orders for jobs (over 100,000 jobs per annum), purchase orders linked to individual jobs, stringent work and financial approval processes, recipient created tax invoices and linked inventory and purchasing processes. The design of the EAM system was developed in accordance with industry best practice to ensure appropriate asset management and data capture required for critical asset management decision making. The introduction of this control and linkages to discrete jobs out of a single system has resulted in purchasing and payments becoming linked to the completion of work. The automated nature of the EAM system has also introduced specific business rules that require specific data at particular points in the work order life cycle to ensure work is planned, scheduled, dispatched, completed and data entered seamlessly.

Since implementing the EAM system it has become clear that using paper-based processes in conjunction with the EAM system is giving rise to a range of significant issues and costs due to incorrect field data capture, data entry errors and delays in the receipt of information from the field. Specifically, the paper-based processes are introducing inefficiencies and additional costs into the business as additional data capture requirements add to effort required for data entry, validation and storage. Some of the specific problems that have arisen since the EAM system was introduced include:

- contractors not being paid due to incorrect data being provided and/or entered through the paper-based process;
- work information, such as labour costs, and asset information not being captured due to the requirement to focus on critical processing to ensure suppliers are paid; and
- inventory not being purchased in a timely manner due to timing issues in receipt of field data.

Evidence is also surfacing of data entry correction in regulatory reporting, paperwork going missing and having to rely on chasing-up carbon copies of missing paperwork.

In this case, implementing the Mobility Integration project is critical to ensuring that:

- accurate and timely data is provided by over 100 internal field staff and 330 contractors and for the 100,000 work orders that are managed by the EAM system;
- work is managed effectively within the business; and
- contractors' payments are correct and timely and inventory is purchased in a timely manner.

The Mobility Integration project will also enable the related data capture costs associated with the EAM project to be avoided. Because these costs have only emerged in the last six months (i.e. post 22 June 2015) they do not form part of AGN's base year opex, so the reduction in costs brought about by this aspect of the Mobility Integration project has been classified as Cost Avoidance.

3.1.2 Health and Safety Information

AGN has a robust HSE Management system in place, which requires the following type of information to be recorded and stored for future reference for audit purposes and in the event of a HSE incident:

- Job Hazard & Environment Analysis (JHEA);
- Site Traffic Management Plans; and
- Hazardous Task Permits.

Field staff are also required to have ready access to current safety documentation such as Safe Work Method Statements (SWMS), technical work procedures, plant and equipment Safe Operating Procedures and Material Safety Data Sheets (MSDS).

Continuing to manage this safety related information through paper-based processes is exposing AGN's staff and contractors to a number of health and safety risks because the information can quickly become outdated and contractors/staff may not have access to the required safety documents when on site.

The Mobility Integration project in this case will address the health and safety related risks outlined above, by ensuring that:

- safety sheets are available for entry in the field and can be efficiently stored following completion;
- up-to-date maps and asset details are available in the field; and
- up-to-date work instructions are available to staff when working on assets in the field.

3.1.3 Regulatory Obligations

AGN is required to comply with a number of significant regulatory obligations under the Health and Safety legislation, technical regulations, the Retail Market Procedures and the National Energy Retail Law and Rules. At present, AGN is required to provide over 100 reports to various regulatory bodies on a monthly, quarterly or annual basis. While there are robust processes in place to capture the data required for this reporting, the data gathering processes are highly manual, require ongoing manual validation checks and balances and can impact on the timeliness and integrity of the reporting.

This Mobility Integration project in this case will enable:

- data validation to occur in the field before being stored in Enterprise systems;
- up-to-date data to be input into relevant systems to facilitate timely regulatory reporting; and

- manual data gathering and data validation processes to be avoided.

3.1.4 Other issues with the current system

Box 3.1 provides further detail on some of the other inefficiencies and limitations that AGN has identified with the current paper-based processes and how the Mobility Integration project would address these issues.

Box 3.1: Other Issues with the current system

- **Data Entry -** The South Australian Network currently relies on paper-based processes to capture field data, which is then manually entered into various systems, such as the Asset Management System, GIS or Human Resources (HR). The Mobility Integration project will significantly reduce manual data entry effort as the data is captured directly in the relevant system and subsequently results in tangible benefits. Mobile field data capture will also bring AGN in line with its peers.
- **Data Integrity -** Due to the current paper-based processes to capture field data, there are significant manual data validation and error handling processes required to ensure data integrity. The Mobility Integration project will reduce the validation, error handling and correction effort as validation processes are implemented on mobile devices and field data entry processes are more tightly controlled through mobile application design. This will, in turn, result in tangible benefits in the form of avoided costs. Data validation at the time of capture will bring AGN in line with its industry peers.
- **Efficient workforce management -** The Mobility Integration project will provide field crews with required work information in the field, resulting in increased work efficiency. An example of a tangible cost saving from this improved effectiveness is the ability to have crews starting from home as they can receive their work directly to their mobile device. The provision of real time information to the field crew will also increase their effectiveness in dealing with service requests through an understanding of the assets they are attending and the associated customer requirements. This also results in improved customer service and staff collaboration.
- **Customer service -** The Mobility Integration project will improve the accuracy and quality of customer information and improve service delivery to customers in a number of ways. For example, the provision of real time information to the field crew on the customer's request and the status of any work that has already been done will improve the customer's experience and avoid any doubling up of work. The ability to assign field crews that are in closest proximity will also ensure field crews can respond rapidly to emergency work in accordance with our regulatory obligations. The project will also enable accurate and timely information to be provided to customers on outages and the status of their service requests. Real time data gathering and associated customer service benefits will bring AGN in line with our industry peers. The value of this information to customers was specifically noted by stakeholders in the stakeholder engagement program that AGN carried out prior to the submission of the proposed AA, as noted in the Stakeholder Insights Report prepared by Deloitte:

  > *"Customers expressed a desire for more communication from AGN and provided guidance on when they prefer immediate 'real-time' channels versus more traditional communications. Specifically, customers are seeking more personalised communications regarding issues affecting their supply, property or local area such as SMS, email and website notification for unplanned outages"* [16]

  This improved customer service offering is not achievable utilising the existing paper-based processes because they do not facilitate the capture and provision of 'real-time' information.
- **Safety -** The implementation of the mobility solution will enhance network health and safety from a public and staff perspective. Public safety will be improved through improved response to emergencies and access to accurate asset data such as Dial Before You Dig information. Employee and contractor safety will be improved through access to improved asset data, streamlined safety tools and processes and live access to corporate knowledge, such as latest version of technical work instructions and training manuals.
- **Maintaining the integrity of services -** The Mobility Integration project will facilitate the gathering of data that can be utilised for improved decision making through use of the Business Intelligence (BI) tools. While categorised as an intangible benefit due to the requirement for use of the BI tools, the ability to gather this data is critical to optimising asset decision-making and improving the integrity of the services. There will also be less operational errors from manual processing of data, which will improve the integrity of the services provided.

- **Provide the foundation for improved decision-making -** The Mobility Integration project will provide field crews with real time access to asset performance history, which will enhance asset management decision-making in the field and more broadly across the business, including targeted maintenance and asset replacement activities to maintain asset integrity. The provision of real time information to the field crew will also increase their effectiveness in dealing with service requests through an understanding of the assets they are attending and the associated customer requirements. This will, in turn provide for improvements in productivity, utilisation and collaboration.

3.1.5 Conclusion

As the preceding discussion reveals, the current manual paper-based processes are:

- costly and inefficient;
- exposing AGN to a range of safety, operational and financial related risks; and
- limiting AGN's ability to achieve further:
  - efficiencies in the field and across the business; and
  - improvements in customer service delivery, the safety and integrity of services and compliance with regulatory obligations.

It is for these reasons that AGN, like many of its peers, is proposing to invest in mobility solutions and real-time information provision through the Mobility Integration project.

AGN's proposed investment in this area is being guided by the Mobility Roadmap in

[16] Deloitte Access Economics, *"Australian Gas Networks stakeholder insights report",* February 2015, pg. 16.

Figure 1.1. When developing this roadmap AGN was cognisant of the need to avoid being an early adopter of mobility given the risks involved in implementing these types of solutions without having a good understanding of the business processes. It is for this reason that AGN decided to implement the EAM system and embed business processes before moving on to implement the mobility solutions.

AGN was also cognisant of the need to implement mobility in a staged manner given the risks that the business would be exposed to if a full mobility solution was introduced before other core enterprise systems and processes were completely embedded into the business. It is for this reason that the original Business Case only considered two options for the next AA period: the 'Do Nothing' option and the foundational Mobility Integration project. Once the Mobility Integration project is bedded down, AGN will consider whether to proceed to the next stage and to carry out the work required to access the full functionality of the solution and unlock further benefits, which includes optimising planning and scheduling, street level routing and dynamic field work management.

Further information on the work that will be involved in implementing the Mobility Integration project can be found in Section 2 of the original Business Case.

3.2 Economic Value of the Mobility Integration Project (Rule 79(2)(a))

The original Business Case did not include a cost-benefit analysis for the Mobility Integration project because the project was considered to be justified under Rule 79(2)(c). While AGN remains of the view that the project can be justified on this basis, it has also assessed whether the project can be justified under Rule 79(2)(a). The results of this assessment indicate that the overall economic value of the proposed expenditure on the Mobility Integration project is positive (i.e. the present value of the project's benefits outweighs the project's costs over a 10 year period). AGN therefore disagrees with the AER's decision not to approve the capex component of the Mobility Integration project.

Further detail on the cost-benefit analysis that AGN has carried out and the assumptions underlying this analysis is provided below.

3.2.1 Cost benefit assessment

Table 3.1 sets out the assumed profile of the Mobility Integration project's costs and benefits and the project's net present value (NPV), which has been calculated on the basis of the following assumptions:

- **Measurement period**: A 10 year measurement period has been adopted because it reflects the ongoing and long-term nature of the project's benefits. It is also in keeping with the measurement period used by other regulated entities when carrying out this analysis.[17]
- **Project benefits ($2014/15)**: The project benefits consist of a mix of tangible and intangible benefits, with the tangible benefits including avoided costs and cost savings while the intangible benefits include the safety, customer service, compliance and decision making benefits in Box 3.1. The assumptions AGN has made when quantifying these benefits are set out in Table 3.2, but it is worth noting that it has only been possible to quantify a sub-set of these benefits. The benefits in Table 3.1 and the NPV therefore understate the economic value of the project.

[17] SAPN, *"IT Field Force Mobility Business Case Addendum 1",* Attachment G.15, 3 July 2015.

- **Capex ($2014/15):** The capex in the next AA period is unchanged from the original Business Case (i.e. $9 million) and reflects the cost of implementing the IT infrastructure. In subsequent AA periods, the proposed capex includes the costs of ongoing Applications Renewals ($200,000 every two years)[18], which is based on the same assumptions that AGN used for the Applications Renewals business case (SA57) that was approved by the AER in the Draft Decision.[19]
- **Discount rate:** a discount rate of 3.76%, which is the real pre-tax Weighted Average Cost of Capital (WACC) that is consistent with the parameters adopted in the AER's Draft Decision.

As the final row in Table 3.1 shows, the Mobility Integration project is expected to yield a positive economic value of **$3.3 million** over a 10 year period and is therefore justifiable under Rule 79(2)(a) of the NGR.

[18] Note: AGN has included the costs associated with ongoing applications renewal for the purposes of fully assessing the Mobility Integration's costs and benefits over the 10 year period. The apps renewal costs do not form a part of the proposed capex of this Business Case over the next AA period.

[19] AER 2015, "*Attachment 6 – Capital Expenditure | Draft decision: Australian Gas Networks Access Arrangement 2016-21*", November 2015, pg. 6-41.

Table 3.1: Mobility Integration Costs and Benefits

MOBILITY INTEGRATION											
Discount Rate (Real Pre-tax WACC)	**3.76%**										
Capex	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**
	0	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
Real Capex ($2014/15)	(1,866)	(2,099)	(2,798)	(2,194)		(200)		(200)		(200)	
Discounted Capex	(1,866)	(2,023)	(2,599)	(1,964)		(166)		(154)		(143)	
Capex NPV	**(8,916)**										
Benefits											
Avoidance	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
Work order data entry (additional)	0	325	325	390	455	455	520	520	585	585	585
Work order field completion	0	150	150	150	300	309	318	328	338	348	358
Filing & Storage	0	0	30	40	41	42	44	45	46	48	49
Data validation	0	70	70	95	150	155	159	164	169	174	179
Real benefits total ($2014/15)	**0**	**545**	**575**	**675**	**946**	**961**	**1,041**	**1,057**	**1,138**	**1,154**	**1,172**
Discounted Benefits	0	525	534	604	816	799	834	816	847	828	810
Cost Avoidance NPV	**7,414**										
Savings	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
Work order Data Entry (existing)	0	195	195	195	195	195	195	195	195	195	195
Timesheeting	0	0	0	0	50	50	50	50	50	50	50
Reduced Work procedure printing	0	70	70	70	70	70	70	70	70	70	70
Safety sheets	0	40	40	40	120	120	120	120	120	120	120
Reduced depot trips	0	0	70	70	150	250	312	312	312	312	312
Real benefits total ($2014/15)	**0**	**305**	**375**	**375**	**585**	**685**	**747**	**747**	**747**	**747**	**747**
Discounted Benefits	0	294	348	336	505	570	599	577	556	536	516
Cost Savings NPV	**4,836**										
PROJECT NPV	**3,334**										

The other point to note from Table 3.1 is that the project is expected to generate opex cost savings of $1.1 million ($2014/15) over the next AA period. These cost savings, in effect, offset the opex related IT platform and application support costs for the Mobility Integration project that were identified in the original Business Case (i.e. $0.9 million over the next AA period or $0.3 million per annum). AGN has decided therefore **not** to make any provision for the opex component of this project in its proposed opex allowance, consistent with the AER's Draft Decision.

Further detail on the assumptions that AGN has made about the project's benefits and capex is provided below.

3.2.2 Expected Benefits

The benefits of the Mobility Integration project consist of a mix of tangible and intangible benefits. The tangible benefits include cost savings and costs avoided as a result of:

- reductions in manual data entry, data validation, printing, filing and storage; and
- the availability of corporate systems in the field and appropriate data validation metrics, which will result in improvements in what would otherwise be non-productive field time.

Specifically, the tangible benefits of the Mobility Integration project include:

- **Cost savings:** The cost savings arising from the removal of the existing paper-based manual systems and processes. These savings are expected to affect a range of activities including work order data entry, timesheets, work procedure printing, the completion of safety documentation and trips to the depot.
- **Avoided costs:** The costs avoided by the Mobility Integration project include the data entry, data validation, filing and storage costs associated with the new EAM system. As noted in Section 3.1.1, the EAM system requires additional data to be collected in the field (e.g. asset data, work completion information and purchase order data) and since its implementation in late June 2015 has resulted in significant additional resources being dedicated to data entry, collation and data validation activities to ensure this data is accurately entered into the system. The implementation of the Mobility Integration project will allow these costs, which do not form part of AGN's base year opex, to be avoided, which is why they are classified as avoided costs.

Table 3.2 provides further detail on the nature and value of some of these tangible benefits and the assumptions AGN has made when estimating their value. Before looking at this table, it is worth noting that the estimates in this table have increased from the original Business Case because:

- the costs associated with the manual paper-based processes have risen significantly since the rollout of EAM on 22 June 2015, with more resources having to be employed to deal with the increased data capture as outlined in Section 3.1.1 and greater clarity around the costs of these resources[20]; and

[20] Note: cost savings have increased compared to the submitted business case due to clarification on existing data entry costs following the implementation of EAM and recognition of Safety Sheets and Reduced Depot Trips as reductions in existing costs rather than avoidance of future cost increases. This cost saving increase has been reflected in a corresponding decrease in cost avoidance benefits and the overall benefits remain the same as originally submitted.

- the benefits have been measured over a 10 year period, which is consistent with the ongoing and long term nature of the benefits and in keeping with the approach used by other regulated entities when carrying out this analysis.

Table 3.2: Tangible benefits

Benefit		Assumptions	Estimate of Benefit by Year ($'000, real $2014/15)										
			1	2	3	4	5	6	7	8	9	10	Sum
Cost Avoidance*													
Work order data entry	Work order data entry has increased significantly since the introduction of the EAM and to cope with this additional work, AGN SA has employed [redacted] additional full time employees (FTEs) to process the additional data at an average cost [redacted].	The Mobility Integration project will result in a reduction in the number of FTEs required for work order data entry. The reduction in FTEs will be greatest in the first year ([redacted]) as the solution is rolled out to the high impact areas. Further reductions in the number of FTEs will be achieved in subsequent years as the mobility solution extends to other areas. The costs avoided by the project will also increase over time because without the project more FTEs would need to be employed to deal with the growth in work orders arising from organic growth in the network.	325	325	390	455	455	520	520	585	585	585	**4,745**
Work order field completion	Work order data collation has increased since the introduction of EAM because the new system requires information on asset data, work completion and purchase order data to be input.	The Mobility Integration project will reduce the data gathering efforts, which are assumed to require [redacted] per work order across approximately 100,000 work orders per annum. The rate assumed for a field resource [redacted]. The increased costs are assumed to progressively reduce as the project is rolled out into the business, starting with the high impact areas. The costs avoided by the project are also expected to increase over time because without the project, more data would need to be collated as the number of work orders increases in response to organic growth in the network.	150	150	150	300	309	318	328	338	348	358	**2,749**
Filing and storage	The increased data collation requirements of EAM have resulted in increased filing and storage by administrative staff.	The Mobility Integration project will result in a reduction in filing and storage costs. The avoided costs will progressively increase as paper-based orders are removed. The avoided costs are estimated [redacted] FTE in year 2 (cost of $30k), but will increase over time because without the project, more data would need to be filed and stored as the number of work orders increase in line with organic network growth.	0	30	40	41	42	44	45	46	48	49	**386**

Benefit		Assumptions	Estimate of Benefit by Year ($'000, real $2014/15)										
			1	2	3	4	5	6	7	8	9	10	Sum
Data validation	Current evidence suggests that 10-15% of the work order information collated through the EAM manual data gathering process require validation or error correction. This data relates to asset information such as incorrect meter change out information, purchase orders not claiming the correct service performed or incorrect labour/materials information. To ensure correct data is input into the system, this data needs to be validated or corrected prior to entry.	The Mobility Integration project will substantially reduce the data validation step because data will be entered directly from the field. The costs avoided in this case have been estimated assuming that data quality checks are carried out on 100,000 work orders per year and 12,000 require [redacted] effort to validate data or chase up errors. It is also assumed a Supervisor at a rate [redacted] is required to follow up on the errors given the complexity of the issues and the difficulty in physically locating work crews to clarify data on work orders. The avoided costs are assumed to progressively increase as the project is rolled out into the business (which will start in high impact areas). They also increase over time because without the project, more data would need to be validated as the number of work orders increase in response to organic network growth.	70	70	95	150	155	159	164	169	174	179	**1,384**
Cost Savings													
Work order data entry	In addition to the EAM related work order data entry costs that will be avoided, the project will result in a reduction in data entry requirements for existing work order data.	The project is assumed to result in a reduction [redacted] FTEs at a cost [redacted] per annum.	195	195	195	195	195	195	195	195	195	195	**1,950**
Timesheet data entry	One of the functions that will be rolled out with the project is the Oracle Time and Labour ('OTL'), which will enable field staff to complete their timesheets directly rather than completing them manually and then sending them to administrative staff to enter into Oracle.	This aspect of the project is expected to result in a saving of $50k per annum from the fourth year of the project. This functionality will roll out in Year 4 due to other functionality providing higher levels of benefits being rolled out earlier in the project.	0	0	0	50	50	50	50	50	50	50	**350**

Benefit		Assumptions	Estimate of Benefit by Year ($'000, real $2014/15)										
			1	2	3	4	5	6	7	8	9	10	Sum
Work procedure printing	The project will result in the elimination of the costs associated with distributing technical work procedures to staff and contractors (i.e. printing, document control and distribution costs), because these documents will be made available directly in the field.	SA Networks currently incurs approximately $70k per annum on printing and distributing technical work procedures to the appropriate staff and contractors. These costs are therefore assumed to be eliminated once the project is implemented	70	70	70	70	70	70	70	70	70	70	**700**
Safety documents	Field personnel are currently required to manually complete a range of safety documentation (e.g. JHEA, Traffic Management Plans and Work Permits). The completion of these documents will be included as a functionality of the mobility solution, which will enable more efficient recording of this information in the field.	The estimated cost savings in this case assume that the 100,000 work order completed in the field each year requires a JHEA to be completed and that the mobility solution results in a time saving [redacted] per JHEA. It is also assumed 5% of those work order require other safety documents, such as Traffic Management Plans or Permits, and that the mobility solution results in a time saving [redacted] per document. These documents are generally completed by field crews at a cost [redacted]. This functionality will roll out in Year 4 due to other functionality providing higher levels of benefits being rolled out earlier in the project.	40	40	40	120	120	120	120	120	120	120	**960**
Reduced depot trips	The current paper-based processes mean field crews must start from a depot each day and need to visit the depot during the week to pick up paperwork or be provided with other required work or employee information. The introduction of the Mobility solution will provide field staff with work in the field, which will enable them to start work from home as well as access to corporate applications, providing important information such as computer based training	To realise these benefits, the mobility functionality needs to be progressively rolled out (i.e. work order management followed by corporate applications) and business processes need to be improved to take advantage of the various additional functionality. The benefits in this area will therefore take longer to realise, which is why they are assumed to be progressively realised until they reach a maximum level in the sixth year. The cost savings in this case have been calculated by assuming that two trips per week can be saved, resulting in [redacted] time saving per trip, [redacted]. Based on approximately 100 FTEs, this results in a saving of [redacted] hours per year at [redacted] when this mobile functionality is maximised.	0	70	70	150	250	312	312	312	312	312	**2,100**

Benefit		Assumptions	Estimate of Benefit by Year ($'000, real $2014/15)										
			1	2	3	4	5	6	7	8	9	10	Sum
	courses, tool box talk information and Safety Alerts.												

* AGN's expenditure on these activities commenced in July 2015, so do not form part of its base year opex. The benefits are therefore considered an avoided cost.

In addition to the benefits set out in Table 3.2, there are a number of other tangible benefits associated with the move from manual paper-based systems and processes to mobile solutions that are either too difficult to quantify, or are not expected to have a material effect on the cost-benefit assessment. These include benefits such as:

- reduced printing, postage and stationery costs;
- reduced handling costs for paperwork returning from the field; and
- reduced effort in chasing up missing paperwork.

There are also a number of significant **intangible** benefits that cannot be quantified, including safety, customer service and regulatory compliance benefits outlined in Box 3.1. While these benefits have been excluded from the NPV analysis in Table 3.1, they are genuine benefits. The project benefits and NPV analysis contained in Table 3.1 will therefore understate the full economic value of the project.

3.2.3 Capex

The capex component of the Mobility Integration project is expected to cost:

- $9 million in the next AA period to design, build and implement the new mobility solution, which will be carried out over a four year period commencing in 2017/18; and
- $0.2 million every second year in subsequent AA periods for applications renewals, which has been calculated using the same assumptions that AGN used for the Application Renewals Business Case (SA57) that was approved by the AER in the Draft Decision.[21]

Table 3.3 provides further detail on the capex forecast for the next AA period, which is unchanged from the original Business Case.

Table 3.3: Mobility Integration capex ($'000s real $2014/15)

	FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21	**Total**
Mobility infrastructure	0	1,866	2,099	2,798	2,194	**8,958**

The AER did not comment on the level of the proposed capex in its Draft Decision. It is worth noting though that the methodology AGN used to develop this forecast[22] is the same methodology that it used for the GIS project, which the AER accepted in the Draft Decision. AGN therefore remains of the view that its proposed capex for the next AA period satisfies:

- Rule 74 of the NGR – that is the forecast has been arrived at on a reasonable basis and represents the best forecast in the circumstances; and
- Rule 79(1)(a) of the NGR – that is the proposed expenditure is such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services.

[21] AER 2015, "*Attachment 6 – Capital Expenditure | Draft decision: Australian Gas Networks Access Arrangement 2016-21*", November 2015, pg. 6-41.

[22] AGN, *SA59 Business Case*, section 5.

Further support for this view can be found in the results of the IT benchmarking study that KPMG has recently completed, which are outlined in Appendix A (see also Attachment 8.12). As the results of this study show:

- AGN's IT total expenditure (totex), capex and opex indicators are *"consistently below or in line with the industry benchmark mean"*, which KPMG noted meant that AGN's IT expenditure could be viewed as being "*comparably efficient to the Australian utility industry, for both actual and planned IT expenditure forecasts."* [23]
- even with the proposed investment in the Mobility Integration project AGN's proposed IT capex is below or trending in line with the industry average.

Although not stated in KPMG's report, AGN's outperformance of the industry average in the current AA period, in part, reflects its decision not to be an early adopter of mobility, which has been a significant cost for a number of AGN's peers. It also reflects AGN's prudent and efficient approach to implementing IT projects and the emphasis it places on conservatism and the delivery of a manageable IT program on time and within budget.

Timing of the proposed expenditure and deliverability of the project

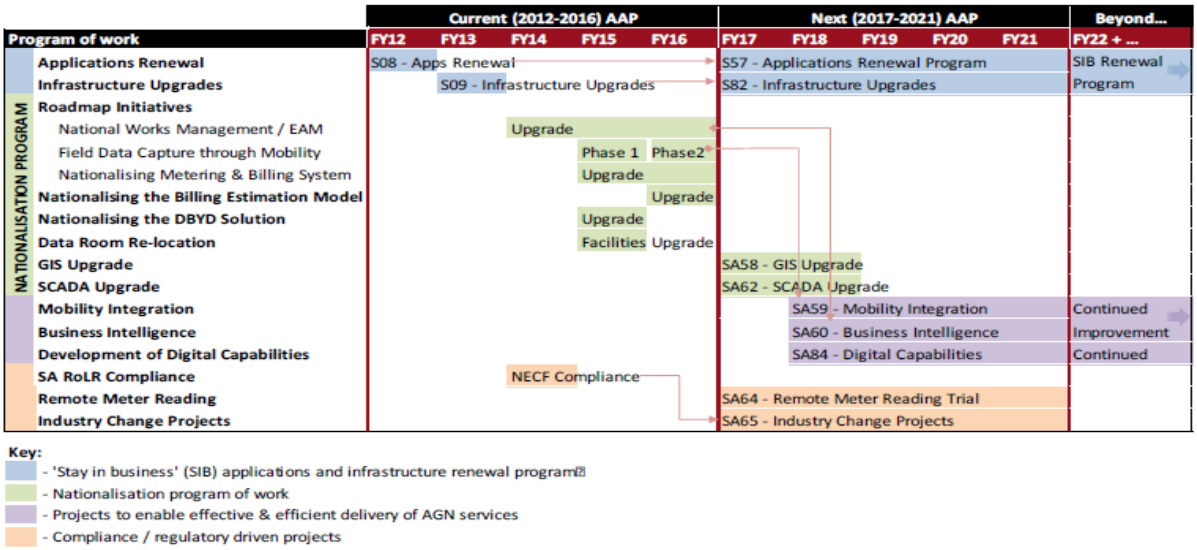
Work on the Mobility Integration project is due to commence in 2017/18 and be completed by 2020/21. While the timing of this project coincides with when work on the Business Intelligence and Digital Capabilities projects is due to commence (see Figure 3.1), AGN's IT provider, APA, has a proven track record in delivering significant IT projects for AGN and its own business on time and within budget. [24]

For example, in the current AA period APA has implemented the Enterprise systems for AGN (e.g. Oracle Financials, Metering & Billing, Asset Management (EAM), Dial Before You Dig and a Data Centre) and a number of other significant IT projects for other areas of its business (e.g. SCADA Upgrades, GIS Implementations and Transmission Market grid services). APA's ability to implement all of these projects on time and within budget reflects its prudent, efficient and structured approach to implementing significant IT projects. It also clearly demonstrates APA's capability to implement the Mobility Integration project in accordance with the timing outlined above and to deliver the expected benefits of the project.

[23] KPMG 2015, "*SA Australian Gas Networks Limited: Information Technology Cost Benchmarking*", December 2015, pg. 6.

[24] AGN 2015, "*Attachment 8.4 Information Technology Plan, Access Arrangement Information for Australian Gas Networks' South Australian Natural Gas Distribution Network*", July 2015.

Figure 3.1: AGN IT Program of Work



4 Summary

Having considered the matters raised by the AER in the Draft Decision, AGN remains of the view that its proposed investment in the Mobility Integration project can be considered conforming capex for the purposes of Rule 79 of the NGR. AGN has, however, decided not to recover the $0.3 million opex allowance associated with this project from consumers. AGN's proposed expenditure on this project has therefore been reduced from $9.3 million in the next AA period to $9 million.

Consistent with the requirements of Rule 79(1)(a), AGN considers that the revised expenditure is:

- *Prudent* – The expenditure is necessary in order to maintain the safety of services and to comply with regulatory and market obligations. The project will also yield a positive economic value and is of a nature that a prudent service provider would incur. The structured and risk-averse approach that APA applies when carrying out major IT projects on behalf of AGN, such as the Mobility Integration project, also highlights the prudence of the proposed expenditure.
- *Efficient* – The Mobility Integration project is cost effective and will enable AGN to avoid some significant EAM related data costs, achieve operational efficiencies in the field and across the business and minimise the risk to human health and safety and customer and business interruptions. The expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur. Further support for this view can be found in the results of KPMG's IT benchmarking analysis, which show that:
  - AGN has outperformed the industry average over the last two AA periods; and
  - even with AGN's proposed investment in the Mobility Integration project in the next AA period, its proposed expenditure on IT is expected to be either below or trend in line with the industry average in the next AA period.
- *Consistent with accepted and good industry practice* – It is good practice to seek to continue to develop service levels in-line with opportunities from new technologies. This is demonstrated by recent applications by other network businesses in both the gas and electricity distribution sectors for implementation of mobility applications and the AER's approval of these proposals.

- *To achieve the lowest sustainable cost of delivering pipeline services* – The integration of mobility solutions will reduce manual processing and costs and will assist with the provision of improved data for decision making. It will therefore contribute to the achievement of the lowest sustainable cost of delivering pipeline services over the longer term.

The proposed capex is also consistent with Rule 79(1)(b), because it:

- yields a positive net economic value as required by Rule 79(2)(a); and
- is necessary to maintain and improve the safety of services (Rule 79(2)(c)(i)), maintain the integrity of services (Rule 79(2)(c)(ii)) and comply with regulatory obligations (Rule 79(2)(c)(iii)) (see Box 3.1).

Appendix A: KPMG IT benchmark study

KPMG's IT benchmark study was completed in December 2015 and can be found in Attachment 8.12 of the AAI.

The benchmark study used information from gas, electricity and water utilities and compared AGN's costs against that of the sample mean, across a range of indicators, including:

- IT total expenditure (totex) indicators (i.e. IT totex as a percentage of totex and IT totex per customer);
- IT capex indicators (i.e. IT capex as a percentage of total capex, IT capex per customer and IT capex per employee); and
- IT opex indicators (i.e. IT opex as a percentage of total opex, IT opex per customer and IT opex per employee).

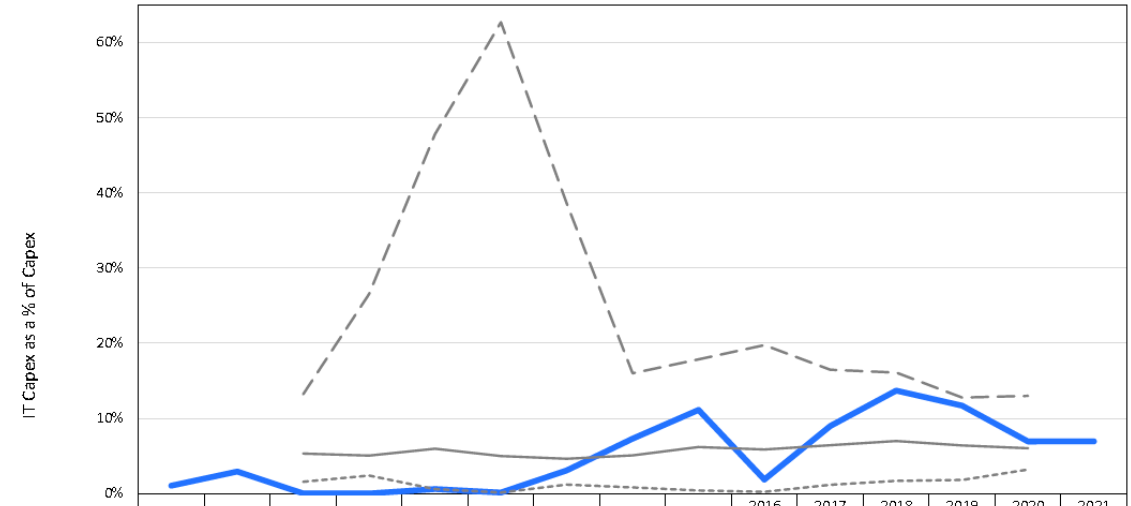
Based on its analysis of these indicators, KPMG made the following overarching observations about the performance of AGN's SA Network:[25]

- AGN's expenditure on IT in the last AA period has been "*evidently low, when compared to industry*".
- AGN's proposed increases in IT expenditure in the current AA period and forecast increase in the next AA period will bring AGN toward the industry benchmarks and will bring its technology capability in line with industry.
- The proposed increase in IT expenditure reflects AGN's increasing reliance on IT to delivery its services, which is *"consistent with industry trend, in the increasing use of IT in the delivery of utility services*".
- AGN SA's IT totex, capex and opex indicators are "*consistently below or in line with the industry benchmark mean"* and indicate that SA AGN's IT expenditure is *"comparably efficient to the Australian utility industry, for both actual and planned IT expenditure forecasts".*

Further insight into the KPMG's IT capex related findings can be found in Figures A.1 and A.2.

[25] KPMG 2015, "*SA Australian Gas Networks Limited: Information Technology Cost Benchmarking*", December 2015, pg. 6.

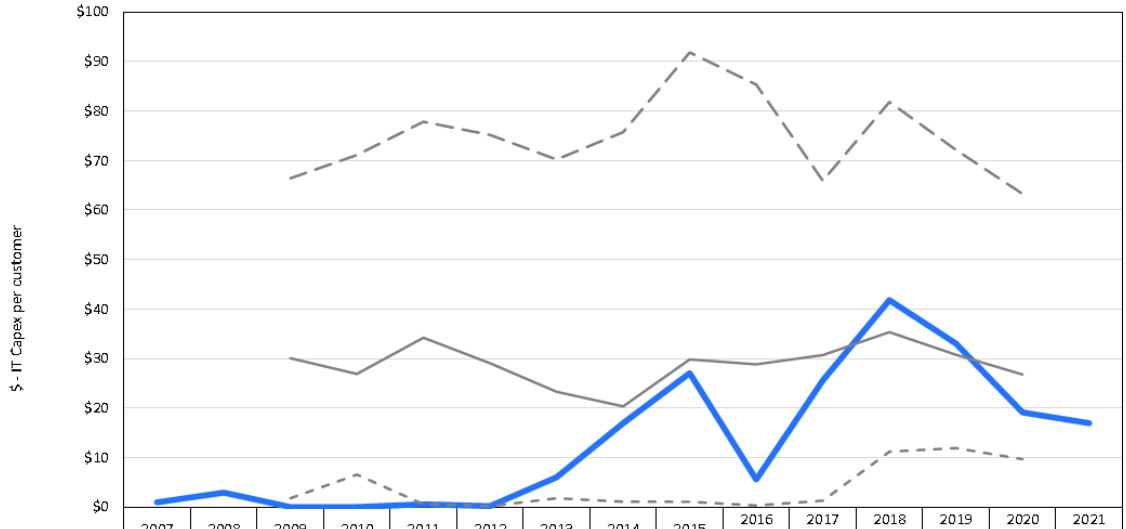
Figure A.1: IT Capex as a percentage of Total Capex



	2007 $Nom Actual	2008 $Nom Actual	2009 $Nom Actual	2010 $Nom Actual	2011 $Nom Actual	2012 $Nom Actual	2013 $Nom Actual	2014 $Nom Actual	2015 $Nom Actual	2016 $Real 2016 Forecast	2017 $Real 2016 Forecast	2018 $Real 2016 Forecast	2019 $Real 2016 Forecast	2020 $Real 2016 Forecast	2021 $Real 2016 Forecast
SA AGN	1.0%	2.9%	0.0%	0.0%	0.6%	0.1%	3.1%	7.3%	11.1%	1.9%	9.0%	13.7%	11.7%	6.9%	6.9%
Mean			5.3%	5.0%	6.0%	5.0%	4.6%	5.1%	6.2%	5.9%	6.4%	7.0%	6.4%	6.0%	
Minimum			1.6%	2.4%	0.6%	0.1%	1.2%	0.8%	0.4%	0.2%	1.2%	1.7%	1.8%	3.2%	
Maximum			13.2%	26.5%	47.8%	62.7%	38.6%	16.0%	17.8%	19.7%	16.4%	16.1%	12.7%	13.0%	
N. Org	3	3	14	16	18	21	22	16	21	21	19	17	17	12	2

Note: Benchmark calculated as IT capital expenditure divided by the gas business capital expenditure
The mean line in the graph above represents the weighted average across all included participants, the mean is calculated when there are data available from three or more organisations for the year.

Figure A.2: IT Capex per Customer



	2007 $Nom Actual	2008 $Nom Actual	2009 $Nom Actual	2010 $Nom Actual	2011 $Nom Actual	2012 $Nom Actual	2013 $Nom Actual	2014 $Nom Actual	2015 $Nom Actual	2016 $Real 2016 Forecast	2017 $Real 2016 Forecast	2018 $Real 2016 Forecast	2019 $Real 2016 Forecast	2020 $Real 2016 Forecast	2021 $Real 2016 Forecast
SA AGN	$1	$3	$0	$0	$1	$0	$6	$17	$27	$6	$26	$42	$33	$19	$17
Mean			$30	$27	$34	$29	$23	$20	$30	$29	$31	$35	$31	$27	
Minimum			$2	$7	$1	$0	$2	$1	$1	$0	$1	$11	$12	$10	
Maximum			$66	$71	$78	$75	$70	$76	$92	$85	$66	$82	$72	$63	
N. Org	2	3	14	16	18	21	23	17	20	20	18	16	16	12	2

Note: Benchmark calculated as IT capital expenditure divided by the number of properties supplied by SA AGN at the end of the year
The mean line in the graph above represents the weighted average across all included participants, the mean is calculated when there are data available from three or more organisations for the year.

As both of these figures highlight, AGN's IT capex has, for the most part over the last two AA periods, been substantially below the industry mean and in the next AA period will either be below or trend in line with the industry average. Elaborating further on these two indicators, KPMG made the following observations:

IT capex as a percentage of total capex

"AGN SA's IT capital investments in the previous AAP and in the early years of the current AAP have been below the industry mean… Overall, the results indicate AGN' SA's IT capex level has been below industry and will trend in line with industry, following the IT Capex investment peaks."[26]

IT capex per customer supplied

"AGN SA has been the lowest and below the industry mean, prior to the IT Capex forecast peak in 2018 and 2019. The planned IT capex over the next AAP will enable AGN SA to catch-up to industry IT expenditure level. The results suggest SA AGN's IT capex are in general, comparably below the industry."[27]

[26] Ibid, pg. 15.

[27] Ibid, pg. 16.

ADDENDUM TO BUSINESS CASE – SA60

PROJECT SUMMARY	
Network	AGN– SA
Project No.	SA60
Project Name	Business Intelligence
Risk and Priority	Moderate, Priority 3
Budget Category	Capital Expenditure (Capex)
Amendments to Original Business Case	In response to the Australian Energy Regulator's (AER's) Draft Decision, AGN has: • provided more information on the problems with the current reporting, information management and decision making systems that are currently in place; and • carried out a more detailed assessment of the costs and benefits of the Business Intelligence project to determine whether it yields a positive economic value as required by Rule 79(2)(a) of the National Gas Rules (NGR), which it does.
Estimated Cost	Capex: $8.6 million (real $2014/15) (unchanged from the original Business Case).
Consistency with NGR	The Business Intelligence project is justified under rule 79(1)(b) of the NGR because the overall economic value of the proposed expenditure is expected to be positive (Rule 79(2)(a). The expenditure is also necessary to maintain and improve the safety of services, maintain the integrity of services and comply with regulatory obligations (Rules 79(1)(b) and 79(2)(c)(i)- (iii)). The proposed expenditure is also such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services, as required by Rule 79(1)(a).
PROJECT APPROVAL	
Prepared By:	Peter Butler, Manager Network Support Services, APA
Reviewed By:	Heather Reynolds, Vendor Manager IT, APA
Approved By:	John Ferguson, Group Executive Networks, APA
OTHER RELEVANT DOCUMENTS	
This addendum should be read in conjunction with: • the original SA60 Business Case, which was provided to the AER on 1 July 2015 in Attachment 7.1 to the Access Arrangement Information (AAI); • the 2015 South Australian Network IT Investment Plan, which was provided as Attachment 8.4 to the AAI; and • Attachment 8.12: KPMG 2015, *"SA Australian Gas Networks Limited: IT Cost Benchmarking"*, 8 December 2015.	

1 Original business case

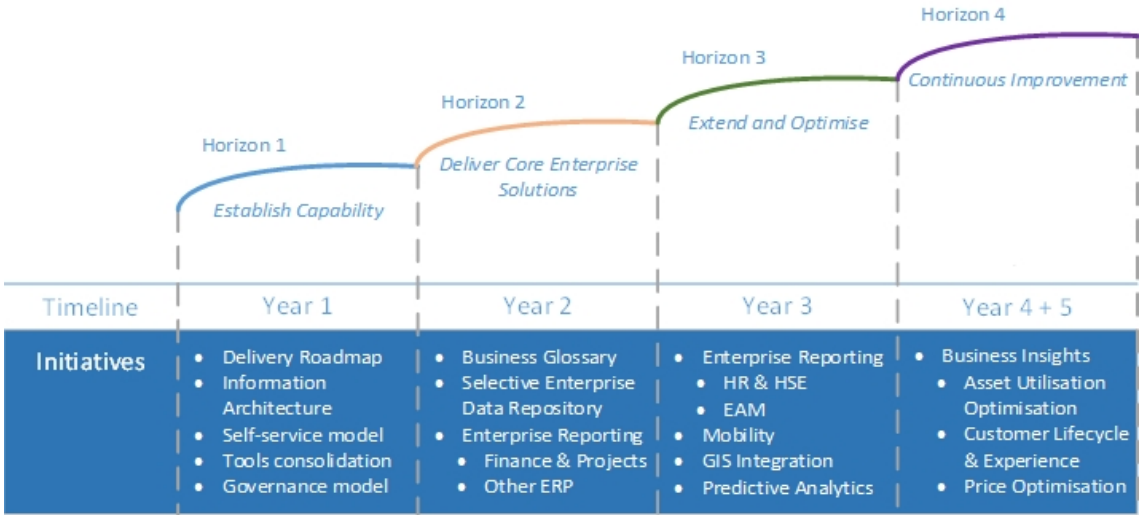
AGN's original proposal for the next (2016/17 to 2020/21) Access Arrangement (AA) period included an allowance of $8.6 million for the Business Intelligence project.

As noted in the original Business Case, the Business Intelligence project involves the implementation of a Business Intelligence Toolset that will be integrated into other Enterprise business applications. The overarching objectives of the BI Toolset are to improve data quality, streamline reporting and allow for greater access to information to enable more informed and efficient decisions to be made throughout the business (i.e. through better access to information and better quality and more accurate information). The BI project is also expected to result in the implementation of more efficient end-to-end business processes and improvements in customer service, the safety and integrity of services and compliance with regulatory obligations.

AGN's proposed investment in this project is being guided by the Enterprise Information Management Strategy roadmap, which has been developed with the assistance of SMS Information & Technology

Consultants (SMS Consultants) and is depicted in Figure 1.1. In this figure, the Business Intelligence project is referred to as the 'Selective Enterprise Data Repository'. Further detail on this roadmap can be found in Section 2 of the original Business Case.

Figure 1.1: Enterprise Information management Strategy and Roadmap



2 AER Draft Decision

The AER did not make any provision for the Business Intelligence project in its Draft Decision because it claimed not to be satisfied that the proposed expenditure was justified under Rule 79(2) of the NGR.[1] Elaborating further on this decision, the AER stated that:[2]

- it was not satisfied that the project was required for any of the reasons set out in Rule 79(2)(c) (e.g. to maintain and improve the safety of services and/or to comply with regulatory obligations); and
- while the project generates some ongoing cost savings, it does not have a net positive economic value as required by Rule 79(2)(a).

In relation to the latter of these points, the AER also noted that:

> *"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."* [3]

3 AGN's Response

Before addressing the specific matters raised in the AER's Draft Decision, it is worth noting that AGN is surprised by the AER's rejection of the Business Intelligence project given that it has previously

[1] AER, *"Draft Decision: Australian Gas Networks Access Arrangement 2016-2021",* November 2015, Attachment 6, pg. 6-43-6-44.

[2] Ibid.

[3] Ibid.

approved the allowances that other service providers have sought to carry out similar projects, including Energex, Jemena Gas Networks (JGN), Jemena Electricity Networks (JEN), Multinet and AusNet Services[4] Unlike these service providers, AGN is yet to implement any business intelligence solutions. AGN is therefore behind many of its peers on this front and is now in catch up mode.

The AER's rejection of the Business Intelligence project is also surprising given the findings from the following independent reviews that have been carried out in the last two years:

- **KPMG IT benchmark study** (see Appendix A and Attachment 8.12 for more detail): In a recent benchmarking study that KPMG has carried out for AGN, KPMG found that:
  - AGN has underinvested in IT relative to its peers and further investment is required in order to catch-up to the rest of the industry; [5] and
  - even with AGN's proposed investment in the Business Intelligence project in the next AA period, AGN's proposed expenditure on IT is expected to be either below or trend in line with the industry average in the next AA period.

  These views are reflected in the following extracts taken from the KPMG report:

  > *"AGN SA's IT expenditures have been at the lowest level of the industry in the previous AAP. Expenditure increases in the current AAP and forecast increases for the next AAP, bring AGN SA in line with the industry."* [6]
  >
  > *"The under investment in IT the previous AAP, led AGN SA to be out of step with industry on its technology capabilities."* [7]
  >
  > *"AGN SA's IT Totex, Capex and Opex benchmark results are consistently below or in line with the industry benchmark mean. This suggests that IT expenditures are comparably efficient to the Australian utility industry, for both actual and planned IT expenditure forecasts."* [8]

- **SMS Consultants information management review** (see section 3.1.1 for further detail): In March 2014 SMS Consultants found that AGN's information management capability is relatively immature in terms of being able to transform data that is collated into information that can be used to drive improved decision making and well below what it should be aspiring to in the next AA period[9] (see section 3.1.1 for further detail).

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4 AER, *"Draft Decision: JGN Access Arrangement 2015-20"*, November 2014, Attachment 6, pg-6-39, AER, *"Preliminary Decision: Jemena distribution determination 2016 to 2020",* October 2015, Attachment 6, pg. 6-94 and AER, *"Final Decision: Energex determination 2015-16 to 2019-20",* October 2015, Attachment 6, pg. 6-10. AusNet Services, *"Electricity Distribution Price Review 2011-2015 Regulatory Proposal",* November 2009, pg. 158, Multinet, *"Gas Access Arrangement Review January 2013-December 2017 AAI",* 30 March 2012, pg. 85

5 KPMG 2015, "*SA Australian Gas Networks Limited: Information Technology Cost Benchmarking*", December 2015, pg. 6.

6 Ibid, pg. 6.

7 Ibid, pg. 8.

8 Ibid, pg. 6.

9 SMS Management & Technology, "*Enterprise Information Management Strategy and Roadmap*", March 2014.

Setting these observations aside, AGN understands from the explanation contained in the Draft Decision that the AER's main concerns with the proposed Business Intelligence project are that:

- the problems with AGN's existing systems were not clearly articulated in the original Business Case; and
- the project was not shown to yield a positive economic value in the original Business Case.

AGN's response to these concerns is set out in further detail below, but in short:

- the existing reporting, information management and decision making systems are disparate, difficult to access, costly to operate, inefficient and are limiting AGN's ability to make informed and efficient decisions, drive further efficiencies, comply with regulatory obligations and make a range of other improvements to the safety and integrity of the services and customer service; and
- the proposed expenditure on the Business Intelligence project does yield a positive net economic value over a 10 year period and is therefore justifiable under Rule 79(2)(a) of the NGR.

AGN therefore disagrees with the AER's decision to reject its proposed expenditure on the Business Intelligence project.

Further information on the deficiencies in the current reporting, information management and decision making systems and how the Business Intelligence project will address these issues is provided in Section 3.1, while Section 3.2 sets out the results of the analysis that has been carried out to determine if the project will yield a positive economic value.

3.1 Deficiencies in the existing information management and reporting systems

AGN's current data analytics, reporting and decision making systems require the consolidation of large amounts of information across a disparate and unconnected range of applications. This, in turn, gives rise to:

- manual and inefficient reporting processes, with a substantial amount of manual work required to collate, consolidate and disseminate information;
- business risks and inefficiencies because information is fragmented across business lines and systems and manual processes always introduce the risk of inaccuracies and duplication of data and information; and
- regulatory compliance and health and safety risks.

The current systems are also affecting AGN's ability to:

- make timely and efficient decisions about assets (i.e. maintenance versus replacement), work force management and other areas of the business, because information on what is currently happening within the business is not readily available; and
- achieve risk reductions in other areas of the network (for example, through the development of the Reliability Forecasting model to optimise High Density Polyethylene (HDPE) replacement and modelling to optimise Cast Iron Mains Replacement – see Box 3.1).

Box 3.1: Link between the Business Intelligence project and risk reductions in parts of the network

The Business Intelligence project can help to reduce safety related risks and improve the integrity of services in specific parts of the network, by providing the tools required to efficiently, accurately and effectively develop asset management models, such as the HDPE reliability forecast model and Cast Iron Mains Replacement model.

The Business Intelligence project will increase AGN's capability to carry out this type of modelling and to manage the safety and integrity of services because it will provide for a greater degree of data integration across systems. For example, to develop the HDPE reliability forecast model that was proposed as part of Business Case SA54, AGN will require information on pipe age, repair data and material analysis to estimate the expected failure rates of Class 575 HDPE pipe and more effectively manage the longer term integrity of HDPE (including optimising maintenance and future replacement strategies).

The data that is required to develop this model is currently held in several independent systems (Maximo, GIS, Customer metering etc). Developing the model in the absence of the Business Intelligence toolset would therefore require significant manual processing, which will result in longer time frames being required for the analysis, and the potential for errors and omissions when compared with electronic integration and analysis tools that would be made available through the Business Intelligence project.

As outlined in Business Case SA54, the longer term HDPE integrity management plan, including the development of the reliability forecast model, is part of a four pronged approach to increase public safety by reducing the risk of brittle failures on the HDPE network and the potential of an increased incidence of major gas fires/explosions [redacted] and damage to property. The Business Intelligence project would contribute to this reduction by providing the tools to more efficiently, accurately and effectively undertake the analysis and model development. In other words, the Business Intelligence project would assist in developing a model that can help to reduce the [redacted] risk inherent in the HDPE network at a lower cost and with greater efficiency.

Further detail on the specific problems that AGN has identified with its existing information management, system and data structures and reporting processes is provided below.

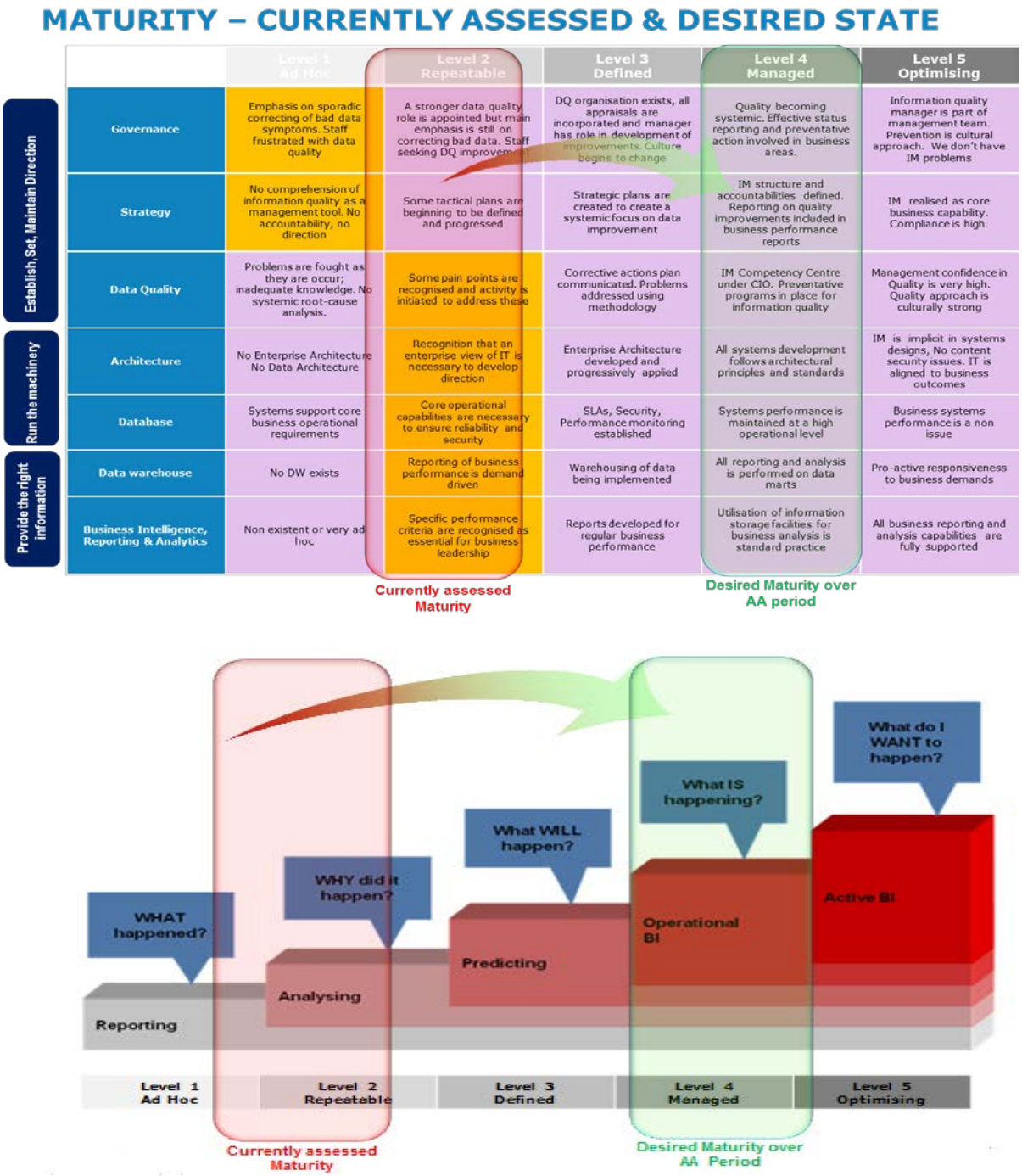
3.1.1 Information Management

In a review conducted by SMS Consultants in March 2014, AGN's current approach to information management was found to be relatively immature in terms of being able to transform the data that is collated into information and driving improved business decisions from that information. Specifically, SMS Consultants found that on a scale of one to five, with one being poor and five being optimal, AGN's information management system was at Level 2 (repeatable).

Level 2 was described by SMS Consultants as businesses that are able to provide repeatable data management processes (for example collation and reporting) but where information management is ad hoc, demand driven and reactive, rather than being structured and consolidated, providing proactive user driven use of information.

The figure below provides more detail on the difference between the various levels of maturity and the level of maturity that SMS Consultants stated that AGN should be aspiring to in the next AA period.

Figure 3.1: SMS Consultants Maturity Spectrum



Implementing the Business Intelligence project is one way in which AGN can move from Level 2 to Level 4 because it will enable data to be consolidated across disparate systems, which will provide greater insight into AGN SA's operations and drive improved decision-making.

If, however, the AER decides not to allow AGN to carry out this project, then AGN will remain at Level 2 and continue to experience the following:

- a lack of quality information for decision making;
- repetitive data quality issues impacting reporting periods;

- loss of productivity through a lack of automation and collaboration support for key processes (for example, end of month reporting);
- difficulty in measuring and monitoring business performance against objectives and international benchmarks;
- only static reporting being available and self-service reporting being minimal;
- information being fragmented across business lines and systems;
- business issues not being detected in a timely manner;
- difficulty accessing information;
- excessive manual work being required to collate, consolidate and disseminate information; and
- difficulty in combining data from disparate systems to enable more effective business decisions (for example combining leak data with costs and geospatial location to optimise work coverage areas and improve customer response times, analysis on customer consumption volumes related to density of customer penetration etc.).

Failure to carry out the Business Intelligence project will also mean that AGN is constrained in its ability to transform the increasing volumes of data into information that will improve AGN's decision-making capability. An example of this constraint is the inability to combine financial data with the increased volume of operational data now available through the Enterprise Asset Management (EAM) project. Without this capability, the efficiencies that were expected through the EAM project will not be fully realised.

3.1.2 System and data structures

AGN relies on a variety of business Information Technology (IT) applications to manage the business and generate required reporting and decision-making information. The key applications that are required for the various functions across the business include:

- the Oracle Enterprise Business suite, which contains financial, purchasing and timesheet information;
- Maximo Asset Management, which includes asset data, work management, purchasing and inventory, health, safety and environment (HSE) related information;
- Customer Care & Billing, which includes customer metering and revenue information;
- Geospatial Information System (GIS), which includes geospatial asset data;
- Synergy, which contains capacity modelling information;
- CHRIS21, which includes Human Resources (HR) data; and
- Learning Management System, which includes training and competency data.

Each of these systems is critical to enabling AGN to prudently and efficiently manage its business operations and contain large volumes of data. For example, the systems contain information on:

- over 400,000 individual gas supply points, including meter serial numbers and Meter Installation Numbers (MIRNs), which is growing by approximately 8,000 new connections per annum;
- hundreds of thousands of assets, including meters, services, mains, regulators, valves;
- transactions associated with approximately $270 million of revenues in calendar year 2015, $62 million in operating costs and $152 million in capex across multiple expenditure lines such as labour, materials, contractors and plant and equipment;
- metering and billing data for over 400,000 individual MIRNs;
- over 100,000 work orders per annum, which consist of information on work and asset data, such as work management information, labour and material costs and asset condition data; and
- HR data for over 120 employees including payroll information and training and induction records.

The systems that are currently used to manage the business are separate applications, with disparate data structures that are siloed in terms of consolidating the data to provide meaningful information. For example, the way financial information is maintained in Oracle doesn't necessarily map to work data stored in the Maximo Works Management system. As a result, driving reporting and decision-making at a detailed level using consolidated data from these systems is manual, inefficient and cannot provide the level of analysis required to identify areas of improvements in the business.

The Business Intelligence project will address these issues through the implementation of a data quality governance framework, information management policies and procedures and the alignment of the disparate applications that are used to manage the SA Network. This will, in turn, yield the following benefits:

- standardised, rationalised and consolidated Information Management toolsets;
- minimal manual effort will be required to distribute consolidated information;
- the project will provide a common area to publish and consume AGN-wide information;
- improved operational system performance;
- implementation of standard and best practice reporting and analytics; and
- a reduction in information silos.

3.1.3 Reporting processes

AGN SA is required to produce a large number of reports on a daily, monthly, quarterly and annual basis. These reporting requirements are critical to enabling AGN to prudently and efficiently operate the business, ensure compliance obligations are met and facilitate ongoing decision-making.

Current reporting requires the collation of significant amounts of data from various IT applications, such as Maximo Works Management, Oracle Financials and Customer Care & Billing. This data is then subject to manual manipulation to provide the appropriate reporting to relevant stakeholders, including external clients, internal management and industry regulators. These processes result in duplication of effort and increased potential for manual errors, as well as difficulties in disseminating the information in a timely manner. These reporting issues are also expected to become more

pronounced when the Mobility Integration project is implemented, because this will result in an increase in the volume of data to be collated.

Further insight into AGN's key reporting requirements can be found in Table 3.1.

Table 3.1: Current reporting requirements

Type	Reporting requirements
Regulatory Reporting	The SA Network is required to provide over 100 reports to various regulatory bodies, including the AER, the South Australian Office of Technical Regulator and the Australian Energy Market Operator (AEMO). These reports can be required on a daily, monthly, quarterly, annual or ad hoc basis, depending on the report requirements. Often the report content is replicated across different regulatory bodies and it is critical to provide consistent, accurate information to those bodies to comply with AGN's obligations.
KPI Reporting	Key Performance Indicator (KPI) reporting is required to provide Senior Management visibility on the performance of the business and achievement of key strategic goals. These KPIs cover all aspects of the business, including Employee Health and Safety, Networks Safety and Reliability, Customer Service and Financial Performance. The absence of accurate and timely reporting on these KPIs affects the ability of AGN to respond to business issues that impact the prudent and efficient operation of the SA Network.
Management Reporting	Management reporting is critical to ensuring business managers have the appropriate proactive and historical information required to effectively respond to business issues. This reporting covers operational information required to manage work, financial information required to manage costs and customer information required to deal with customer issues. This management reporting is required to ensure managers have the relevant information to their areas of responsibility to drive their business to achieving the business KPIs.
Financial Reporting	AGN has significant financial information and reporting requirements, including to parent companies, auditors, taxation offices, regulatory bodies (for example Regulatory Information Notices) as well as to internal management. Without this financial information, AGN has an increased risk of financial non-compliance and managers cannot track to agreed budgets and address financial issues in a timely manner.
Asset performance and decision making	AGN produces asset performance reports such as the Distribution System Performance Report, in accordance with AS4645 (Gas distribution network management). These performance reports enable AGN to analyse historical performance and identify priority areas for maintaining the performance of the Network. Without this information, AGN cannot optimise the limited funds available to operate and maintain the SA Network.
Business submissions	Information from the various systems is also required to inform business submissions, such as Business Cases, changes to regulatory requirements and addition of new customers such as large sub-divisions. Without the required business information, there is an increased risk that business submissions will be either reduced or rejected
Customer queries	Customer query reporting includes a variety of customer interactions, including emergencies, connections to gas, status of work and complaints. Reporting is critical in this case to ensuring AGN manages and improves the customer experience by providing managers transparency on where there are customer service issues.

As the information in Table 3.1 reveals, AGN's current reporting system involves a substantial amount of manual work, is delivered in 'silos' across the business and is subject to a number of data accuracy and integrity issues. Together these deficiencies are giving rise to the following issues:

- reporting can only be carried out by a small number of business analysts;

- significant manual effort is required to prepare reports and ensure data accuracy is maintained and validated, which causes duplication of effort and introduces the risk of manual errors;
- difficulties in consolidating data (for example HR stats with HSE statistics, financial data with work statistics);
- the inability to readily receive up-to-date data;
- inefficient duplication of reporting, potentially resulting in different interpretations of data and reporting results;
- data silos within AGN, which are aligned to business functions and cross functional reporting being extremely onerous; and
- difficulties in replicating the reporting results for different time periods.

In the absence of the Business Intelligence solution, these reporting issues will continue to require ongoing manual effort to produce and exposing AGN to compliance risk

The implementation of the Business Intelligence project will overcome these issues by providing for self-service reporting tools, automated periodic reporting and enabling users to access ad hoc reporting information when and where it is required. This will give rise to a number of benefits, including the following:

- consolidated views of data will be available from various systems to enable cross-functional reporting and minimum manual effort will be required to distribute this information;
- information will be easier to access and the user experience improved;
- the same data will be able to be presented to multiple stakeholders in different views;
- improved dissemination of reporting information, including the implementation of 'self-service' reporting, which will mean that users become more self-reliant and able to access varying levels of reporting capability;
- providing the platform for advanced visualisation of data through the GIS application;
- consistency in reporting and presentation of data; and
- provision of an agile reporting platform to facilitate changing reporting requirements from key stakeholders, including external clients and industry regulators.

3.1.4 Other issues with the current system

Box 3.2 provides further detail on some of the other inefficiencies and limitations that AGN has identified with the existing information management, system and data structures and reporting processes and how the Mobility Integration project would address these issues.

Box 3.2: Other issues with the existing systems

- **Data Quality** – The implementation of the Business Intelligence project will result in improvements in the data structure and data quality because it will involve the introduction of robust data governance processes and data validation mechanisms. Improved data quality will also increase the reliability of reporting accuracy and reduce compliance risk associated with potentially inaccurate reporting.

- **Data Analysis** – The new EAM system and the Mobility Integration project will result in a significant increase in the volume of data available to drive improved work management. This data will include detailed information on contractor costs, internal resource planning and scheduling and work-related asset data. This data has been identified in the EAM Project benefits as integral to achieving improved works management. The Business Intelligence toolset is therefore required to fully realise the EAM benefits.
- **Improved decision-making and efficient workforce management** – The current manual and disparate reporting processes within the SA Network results in difficulties in combining cross-functional data to enable consolidated business decision-making. The manual nature of the processes and data quality issues also result in business analysts focusing on production of reports, rather than detailed analysis to enable improved and efficient decision-making. The Business Intelligence project will enable:
  - better asset maintenance and replacement decisions to be made because users will have access to better information and be able to analyse additional asset data made available through the EAM (for example, maintenance records on individual components of assets and different asset types). This will enable maintenance frequencies to be optimised and maintenance to appropriately target specific asset components; and
  - more efficient workforce management because it will provide detailed information on job times, locations and durations, which will be able to be analysed to determine optimised works management structures in terms of regions covered by particular field crews. The Business Intelligence tools will also enable skill sets and types of jobs to be analysed to ensure work in a particular region can be completed by the same resources, rather than inefficiently calling in resources from other regions.

  AGN's decision-making capability will also be improved through:
  - the consolidation of cross-functional data to provide detailed business-wide information;
  - the streamlining of the reporting processes and introduction of the data quality framework that will enable business analysts to focus on analytics;
  - self-service reporting and the provision of analytical tools to enable agile decision-making; and
  - the implementation of business intelligence tools to enable analysis of the increased volume and complexity of data provided through the EAM and Mobility Integration projects.
- **Safety and integrity of services** – The Business Intelligence project will help to maintain and improve the safety of services because it will provide more extensive access to accurate information about assets and the ability to predict failures will result in a safer network. It will similarly help to preserve the integrity of services through rapid and accurate access to asset information. The Business Intelligence tools will also contribute to a reduction in safety related risks and improve the integrity of services in specific parts of the network by providing the tools required to efficiently, accurately and effectively develop asset management models, such as the HDPE reliability forecast model and Cast Iron Mains Replacement model.
- **Compliance with Regulatory and Market Obligations** – To comply with regulatory and market obligations, significant volumes of data that are currently recorded on paper must be manually entered into various systems such as Maximo, Customer Care & Billing and Oracle Financials, collated manually via paper and entered into various systems. The manual entry of this data gives rise to the risk of inaccurate data being provided to regulatory and market bodies, which could have implications for others in the market. The Business Intelligence project will reduce this risk by reducing the risk of inaccurate data capture and through the introduction of a data quality framework and improved capability to test the data's veracity.
- **Customer service -** The Business Intelligence project, in conjunction with the Mobility Integration project, will improve service delivery to customers by enabling AGN to provide real time responses to queries. The value of this information to customers was noted in the stakeholder engagement program AGN carried out prior to the submission of the proposed AA, as noted in Deloitte's Stakeholder Insights Report:[10]

  "Customers expressed a desire for more communication from AGN and provided guidance on when they prefer immediate 'real-time' channels versus more traditional communications. Specifically, customers are seeking more

[10] Deloitte Access Economics 2015, *"Australian Gas Networks stakeholder insights report"*, February 2015, pg. 16.

personalised communications regarding issues affecting their supply, property or local area such as SMS, email and website notification for unplanned outages"

This improved customer service offering is not achievable utilising the existing paper-based processes because they do not facilitate the capture and provision of 'real-time' information.

- **Marketing -** The Business Intelligence project will enable data from the GIS and CC&B (Metering and Billing) systems to be combined to identify high gas consumption areas with gas penetration gaps that can then be used to target marketing in those areas.

3.1.5 Conclusion

As the preceding discussion confirms, AGN's current data analytics, reporting and decision making systems require the consolidation of large amounts of information across a disparate and unconnected range of applications. It also requires a substantial amount of manual effort to collate, consolidate and disseminate this information. Apart from being inefficient, the operation of these systems in this manner is exposing AGN to a range of risks and operational inefficiencies and limiting AGN's ability to:

- achieve further asset and work management related efficiencies through improved decision making;
- maintain and improve the safety and integrity of services, comply with regulatory obligations and seek out improvements in customer service delivery; and
- efficiently and effectively manage other safety and integrity related risks in the network, such as the risks posed by HDPE Class 575 pipes.

It is for these reasons that AGN, like many of its peers, is proposing to invest in Business Intelligence tools.

3.2 Economic Value of the Business Intelligence Project (Rule 79(2)(a))

The original Business Case did not include a cost-benefit analysis for the Business Intelligence project because it was considered to be justified under Rule 79(2)(c). While AGN remains of the view that the project can be justified on this basis, it has also assessed whether the project can be justified under Rule 79(2)(a). The results of this assessment indicate that the overall economic value of the proposed expenditure on the Business Intelligence project is positive (i.e. the present value of the project's benefits outweighs the project's costs over a 10 year period). AGN therefore disagrees with the AER's decision not to approve the proposed expenditure on this project.

Further detail on the cost-benefit analysis that AGN has carried out and the assumptions underlying this analysis is provided below.

3.2.1 Cost-Benefit Assessment

Table 3.2 sets out the assumed profile of the Business Intelligence project's costs and benefits and the project's net present value (NPV), which has been calculated on the basis of the following assumptions:

- **Measurement period**: A 10 year measurement period has been adopted because it reflects the ongoing and long-term nature of the project's benefits. It is also in keeping with the measurement period used by other regulated entities when carrying out similar analysis.[11]
- **Project benefits ($2014/15)**: The project benefits consist of a mix of tangible and intangible benefits, with the tangible benefits including opex cost savings, opex related avoided costs/EAM benefits and capex related avoided costs. The intangible benefits, on the other hand, include the safety, integrity, customer service, compliance benefits outlined in Box 3.2 and the systems and data structures, reporting and information management benefits outlined in Sections 3.1.1-3.1.3. While the intangible benefits are significant, it has not been possible to quantify their value. The benefits in Table 3.2 therefore only include the tangible benefits and so understate the true economic value of the project.
- **Capex ($2014/15):** The capex in the next AA period is unchanged from the original Business Case (i.e. $8.6 million) and just reflects the cost of implementing the IT infrastructure. In subsequent AA periods, the proposed capex includes the costs of ongoing Applications Renewals ($200,000 every two years), which is based on the same assumptions that AGN used for the Applications Renewals business case (SA57) that was approved by the AER in the Draft Decision.[12]
- **Discount rate:** A discount rate of 3.76% has been used, which is the real pre-tax Weighted Average Cost of Capital (WACC) that is consistent with the parameters adopted in the AER's Draft Decision.

As the final row in **Table 3.2** shows, the Business Intelligence project is expected to yield a positive economic value of **$2.4 million** over a 10 year period and is therefore justifiable under Rule 79(2)(a).

The other point to note from this table is that the opex cost savings and related operational efficiencies will enable AGN to deliver eight out of the nine proposed step changes in the next AA period (for further detail regarding this, please refer to Attachment 7.8 of our Revised AA Proposal), without necessitating an increase in AGN's opex allowance. As such, AGN is no longer proposing to include the eight step changes (totalling approximately $8.3 million) in its opex allowance (i.e. because the implementation of the Business Intelligence project will generate sufficient cost savings and operational efficiencies in the next AA period to offset these costs).

For example, it is envisaged that the Business Intelligence project will improve AGN's capability to develop the type of HDPE risk model described in the original Business Case SA54, which will ultimately be a key input into the longer term integrity management of HDPE (including optimising maintenance and future replacement strategies). As such, AGN has not sought additional expenditure for Business Case SA54 in its Revised AA Proposal on the basis this Business Intelligence project is approved.

Further detail on the assumptions made about the project's benefits and capex is provided below.

[11] SAPN, *"IT Field Force Mobility Business Case Addendum 1",* Attachment G.15, 3 July 2015.

[12] AER 2015, "*Attachment 6 – Capital Expenditure | Draft decision: Australian Gas Networks Access Arrangement 2016-21*", November 2015, pg. 6-41.

Table 3.2: Business Intelligence Costs and Benefits

BUSINESS INTELLIGENCE											
Discount Rate (Real Pre-tax WACC)	**3.76%**										
Capex	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**
	0	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
Real Capex	(1,976)	(3,895)	(2,597)	(96)		(200)		(200)		(200)	
Discounted Capex	(1,976)	(3,754)	(2,412)	(86)		(166)		(154)		(143)	
Capex NPV	**(8,692)**										
Benefits											
Savings	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
Opex - Cost Avoidance/EAM Benefits	0	490	490	490	490	490	490	490	490	490	490
Opex - Cost Savings	0	150	150	150	150	150	150	150	150	150	150
Capital Expenditure Savings	0	214	428	642	855	855	855	855	855	855	855
Real benefits total ($2014/15)	**0**	**854**	**1,068**	**1,282**	**1,495**	**1,495**	**1,495**	**1,495**	**1,495**	**1,495**	**1,495**
Discounted Benefits	0	823	992	1,147	1,290	1,243	1,198	1,155	1,113	1,073	1,034
Cost Savings NPV	**11,068**										
PROJECT NPV	**2,376**										

3.2.2 Expected Benefits

The Business Intelligence project will yield a number of tangible and intangible benefits. The tangible benefits include the opex related cost savings, opex related avoided costs/EAM benefits and capex related avoided costs. Further detail on the sources of these benefits is provided in Table 3.3, while Table 3.4 sets out the estimated value of these benefits.

Table 3.3: Tangible benefits

Benefit	Description of benefit
Opex cost savings	
Current data analysis and reporting	The Business Intelligence project will generate data validation, reporting and analysis related efficiencies. The opex cost savings forecast assumes that a Business Analyst [redacted]) that would otherwise be required to develop reports, correct data, validate data etc. is no longer required because the processes are streamlined.
Opex related avoided costs and EAM benefits	
Additional data analysis, reporting data validation and correction	As indicated in the original Business Case, the introduction of the EAM has increased the volume of data available to drive improved work management and as such has increased the costs incurred by AGN in relation to analysis of this data. These costs, which amount to approximately $150,000 p.a., have been incurred since the introduction of the EAM in June 2015 and do not form a part of AGN's base year opex. It is for this reason that they are classified as an avoided cost rather than a cost saving.
EAM benefits realisation	The Business Intelligence project is required to realise the final 20% of EAM benefits as they require significant analysis of data to drive the relevant business change. Based on the Business Intelligence initiative facilitating the last [redacted] of benefits, this project will result in a benefit of $340,000 p.a.
Capex related avoided costs	
Asset Replacement, maintenance and works management decisions	The Business Intelligence project will enable AGN to make more informed decisions about: • *Asset replacement and asset design.* For example, improved capacity modelling may improve engineering design of assets that previously have been conservatively engineered. • *Asset maintenance versus asset replacement.* For example, leak repair information, including detailed costs, can be analysed to determine if a section of main should be replaced or continually maintained. Better access to the additional asset data made available through the EAM will also enable maintenance frequencies to be optimised and maintenance to appropriately target specific asset components. • *Works management.* For example, detailed information on job times, locations and durations, will enable optimised works management structures to be put in place, which will yield further efficiencies. AGN did not attempt to quantify these benefits in the original Business Case because of the complexities associated with trying to value these types of benefits and because it considered the project was justified under Rule 79(2)(c). Following the release of the Draft Decision, AGN has given more thought to the value of these benefits and is of the view that an average 0.75%[13] saving on the average annual forecast capex spend over the next AA period ($114 million) is achievable given the nature of the improvements outlined above. Because the Business Intelligence infrastructure will be rolled out over a four year period, these benefits are assumed to ramp up over the first three years of the project with 25% of the benefits to be achieved in 2018/19, 50% in 2019/20, 75% in 2020/21 and 100% by 2021/22.

[13] On some capex projects the use of business intelligence tools is likely to yield greater savings than 0.75% while for other projects the use of these tools may yield a smaller saving. On average, however, a 0.75% capex saving is expected to be achieved.

Table 3.4: Tangible benefits ($'000 real $2014/15)

Year	1	2	3	4	5	6	7	8	9	10
	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28
Opex - Cost Avoidance/ EAM Benefits	490	490	490	490	490	490	490	490	490	490
Opex – Cost Savings	150	150	150	150	150	150	150	150	150	150
Capex – Cost Avoidance	214	428	642	855	855	855	855	855	855	855
Total	**854**	**1,068**	**1,282**	**1,495**	**1,495**	**1,495**	**1,495**	**1,495**	**1,495**	**1,495**

In addition to the tangible benefits set out in Table 3.4, the Business Intelligence project will also yield a range of intangible benefits, including safety, integrity, customer service, compliance benefits outlined in Box 3.2 and the systems and data structures, reporting and information management benefits outlined in Sections 3.1.1-3.1.3. Given the intangible nature of these benefits it has not been possible to quantify the benefits, so they have not been included in Table 3.4 or the NPV analysis.

In relation to the tangible benefits set out in Table 3.4, it is worth noting the following about the opex related benefits:

- the opex cost avoidance/EAM benefits and opex cost savings are consistent with the benefits that were set out in the original Business Case for the next AA period;[14]
- the opex related cost savings in the next AA period are expected to offset the IT support costs for the Business Intelligence project that were identified in the original Business Case (i.e. $0.45 million over the next AA period), which is why AGN has decided not to make any provision for these costs in its opex allowance; and
- the opex costs that will be avoided by the Business Intelligence project do not form part of AGN's base year opex, which is why they have been classified as avoided costs rather than cost savings.

In relation to the capex related avoided costs, it is worth noting that while AGN considers a 0.75% capex saving is achievable given the nature of the improvements in decision-making that the Business Intelligence project will facilitate, the project will still yield a positive NPV if AGN is only able to achieve 60% of that saving (i.e. a 0.45% capex saving, which is equivalent to around $515,000 p.a.).[15] AGN is therefore confident that the project will yield a positive economic value, as required by Rule 79(2)(a). Further support for this view can be found in the fact that the NPV analysis excludes the value of the intangible benefits outlined above, which while difficult to quantify, are significant.

[14] AGN, *"Original Business Case SA60",* Table 4, 1 July 2015.

[15] Note that these benefits will be passed directly through to consumers at the commencement of the subsequent AA period when actual capex is rolled into the Regulatory Asset Base.

3.2.3 Capex

The Business Intelligence project is expected to cost:

- $8.6 million in the next AA period to design, build and implement the new Business Intelligence toolset, which will be carried out over a four year period commencing in 2017/18; and
- $0.2 million every second year in subsequent AA periods for applications renewals, which has been calculated using the same assumptions that AGN used for the Application Renewals Business Case (SA57) that was approved by the AER in the Draft Decision.[16]

Table 3.5 provides further detail on the capex forecast for the next AA period, which is unchanged from the original Business Case.

Table 3.5: Business Intelligence capex ($'000s real $2014/15)

	FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21	**Total**
Business Intelligence	0	1,976	3,895	2,597	96	**8,564**

The AER did not comment on the level of the proposed capex in its Draft Decision. It is worth noting though that the methodology AGN used to develop this forecast[17] is the same methodology that it used for the GIS project, which the AER accepted in the Draft Decision. AGN therefore remains of the view that its proposed capex for the next AA period satisfies:

- Rule 74 of the NGR – that is the forecast has been arrived at on a reasonable basis and represents the best forecast in the circumstances; and
- Rule 79(1)(a) of the NGR – that is the proposed expenditure is such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services.

Further support for this view can be found in the results of the IT benchmarking study that KPMG has recently completed, which are outlined in Appendix A (see also Attachment 8.12). As the results of this study show:

- AGN's IT total expenditure (totex), capex and opex indicators are *"consistently below or in line with the industry benchmark mean"*, which KPMG noted meant that AGN's IT expenditure could be viewed as being "*comparably efficient to the Australian utility industry, for both actual and planned IT expenditure forecasts";* [18] and
- even with the proposed investment in the Business Intelligence project AGN's proposed IT capex is below or trending in line with the industry average.

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16 AER 2015, "*Attachment 6 – Capital Expenditure | Draft decision: Australian Gas Networks Access Arrangement 2016-21*", November 2015, pg. 6-41.

17 AGN, "*SA60 Business Case"*, submitted to the AER on 1 July 2015 in Attachment 7.1 to the AAI , Section 5.

18 KPMG 2015, "*SA Australian Gas Networks Limited: Information Technology Cost Benchmarking*", December 2015, pg. 6.

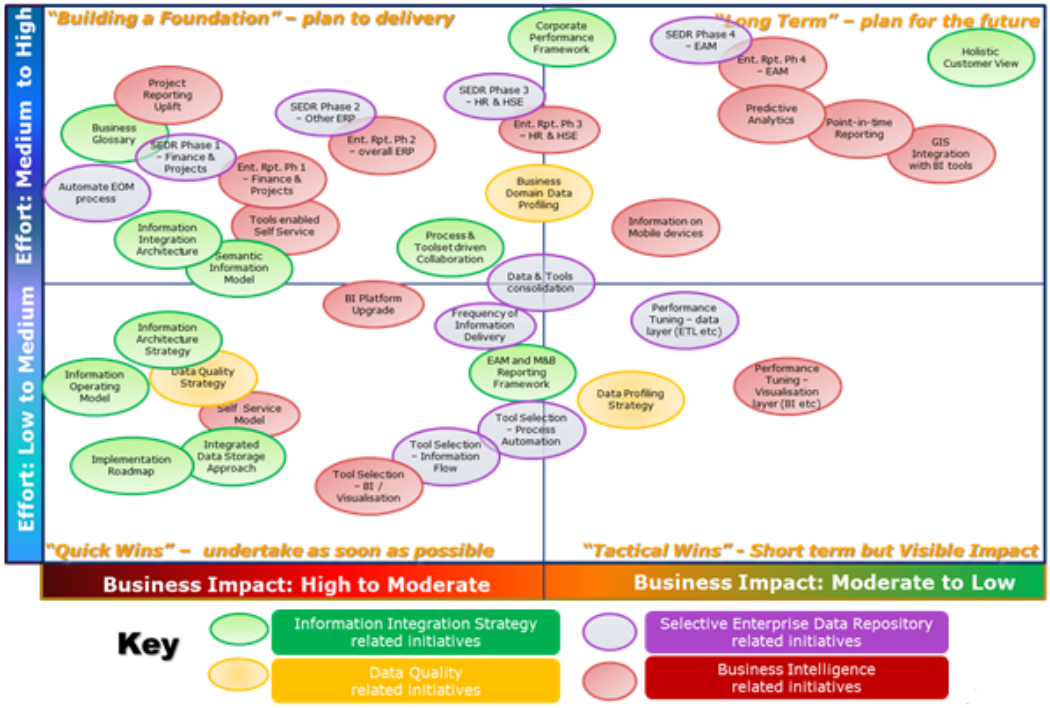
Although not stated in KPMG's report, AGN's outperformance of the industry average in the current AA period, in part, reflects its decision not to be an early adopter of this technology, which has been a significant cost for a number of AGN's peers. It also reflects AGN's prudent and efficient approach to implementing IT projects and the emphasis it places on conservatism and the delivery of a manageable IT program on time and within budget.

Timing of the proposed expenditure and deliverability of the project

Work on the Business Intelligence project is due to commence in 2017/18 and be completed by 2020/21. A four year roll out period has been chosen because the project consists of a number of high and low effort components that must be progressively implemented over an extended period of time through a staged implementation (see Figure 3.2). The staged implementation will also:

- enable the incremental rollout of the Business Intelligence functionality as the various Enterprise IT Systems are brought into the Business Intelligence framework, which will, in turn, enable some 'quick wins' (i.e. business benefits) to be realised early while also laying the foundation for future business intelligence capability; and
- reduce the project's delivery risk and ensure the data, system, processes and governance structures are implemented effectively.

Figure 3.2: Business Intelligence Project

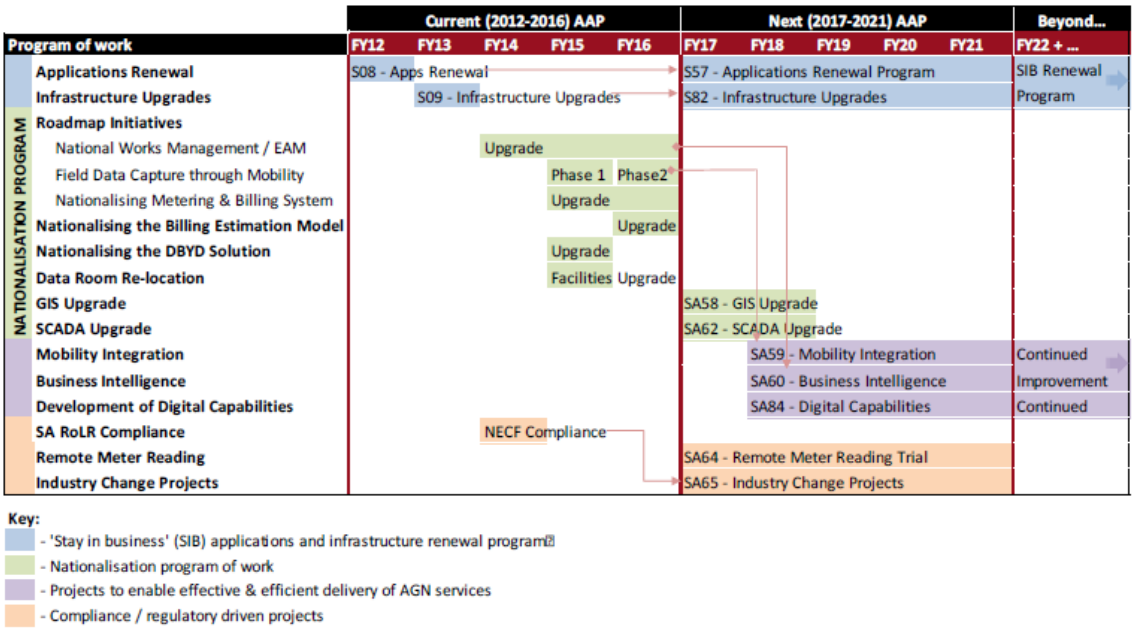


The proposed timing of the Business Intelligence project coincides with when work on the Mobility Integration and Digital Capabilities projects is due to commence (see Figure 3.3). AGN is not, however,

concerned by the overlap because AGN's IT provider, APA, has a proven track record in delivering significant IT projects for AGN and its own business on time and within budget.[19]

For example, in the current AA period APA has implemented the Enterprise systems for AGN (e.g. Oracle Financials, Metering & Billing, Asset Management (EAM), Dial Before You Dig and a Data Centre) and a number of other significant IT projects for other areas of its business (e.g. SCADA Upgrades, GIS Implementations and Transmission Market grid services). APA's ability to implement all of these projects on time and within budget reflects its prudent, efficient and structured approach to implementing significant IT projects. It also clearly demonstrates APA's capability to implement the Business Intelligence project in accordance with the timing outlined above and to deliver the expected benefits of the project.

Figure 3.3: AGN IT Program of Work



4 Summary

For the reasons set out above, AGN remains of the view that the Business Intelligence project can be considered conforming capex for the purposes of Rule 79 of the NGR and the project is capable of being delivered in the next AA period. AGN is not therefore proposing to make any revisions to its proposed capex allowance of $8.6 million for this project.

In terms of the project's consistency with the NGR, AGN considers that the proposed capex satisfies Rule 79((1)(a) because it is:

[19] AGN 2015, "*Attachment 8.4 Information Technology Plan, Access Arrangement Information for Australian Gas Networks' South Australian Natural Gas Distribution Network*", July 2015.

- *Prudent* – The proposed expenditure is of a nature that a prudent service provider would incur because it is necessary to maintain and improve the safety and integrity of services, comply with regulatory and market obligations (see Box 3.2) and will also enable AGN to:
  - make more informed and prudent decisions about asset management, work force management and other areas of the business;
  - seek out improvements in customer service delivery, the safety and integrity of services and compliance with regulatory obligations; and
  - efficiently and effectively manage other safety and integrity related risks in the network, such as the risks posed by HDPE Class 575 pipes.

  The project will also yield a positive economic value.
- *Efficient* – The Business Intelligence project is cost effective and will enable AGN to improve operational efficiency, potential customer and business interruptions and corresponding compliance and financial impacts. The expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur. Further support for this view can be found in the results of KPMG's IT benchmarking analysis, which show that:[20]
  - AGN has outperformed the industry average over the last two AA periods; and
  - even with AGN's proposed investment in the Business Intelligence project in the next AA period, its proposed expenditure on IT is expected to be either below or trend in line with the industry average in the next AA period.
- *Consistent with accepted and good industry practice* – The Business Intelligence project will enable AGN to have rapid access to critical information when making decisions, which is in line with good industry practice. The project will also address the risks of non-compliance with relevant regulatory obligations through improved reporting and analytical capability. The fact that so many of AGN's counterparts are also investing in this area also demonstrates the consistency of this expenditure with good industry practice. SMS Consultants' findings on the relative immaturity of AGN's information management capabilities also highlight the fact that AGN is well behind where it would be expected to be if it its systems were consistent with good industry practice and that investment is required in this area to enable AGN to catch-up to others.
- *To achieve the lowest sustainable cost of delivering pipeline services* – The Business Intelligence project will enable more informed decision making throughout the business and, in so doing, enable AGN to deliver the lowest sustainable cost of delivering pipeline services.

The proposed capital expenditure is also consistent with Rule 79(1)(b), because it

- yields a positive net economic value as required by Rule 79(2)(a); and

[20] KPMG 2015, *"SA Australian Gas Networks Limited: Information Technology Cost Benchmarking"*, December 2015, pg. 6.

- is necessary to maintain and improve the safety of services (Rule 79(2)(c)(i)), maintain the integrity of services (Rule 79(2)(c)(ii)) and comply with regulatory obligations (Rule 79(2)(c)(iii)).

Appendix A: KPMG IT benchmark study

KPMG's IT benchmark study was completed in December 2015 and can be found in Attachment 8.12 of the Revised AA Proposal.

The benchmark study used information from gas, electricity and water utilities and compared AGN's costs against that of the sample mean, across a range of indicators, including:

- IT total expenditure (totex) indicators (i.e. IT totex as a percentage of totex and IT totex per customer);
- IT capex indicators (i.e. IT capex as a percentage of total capex, IT capex per customer and IT capex per employee); and
- IT opex indicators (i.e. IT opex as a percentage of total opex, IT opex per customer and IT opex per employee).

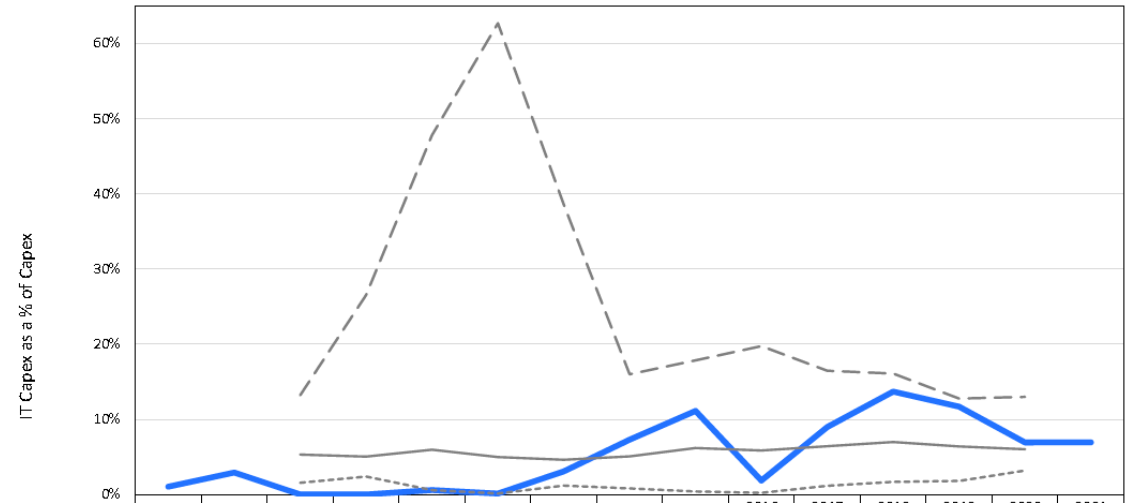
Based on its analysis of these indicators, KPMG made the following overarching observations about the performance of AGN's SA Network:[21]

- AGN's expenditure on IT in the last AA period has been "*evidently low, when compared to industry*".
- AGN's proposed increases in IT expenditure in the current AA period and forecast increase in the next AA period will bring AGN toward the industry benchmarks and will bring its technology capability in line with industry.
- The proposed increase in IT expenditure reflects AGN's increasing reliance on IT to delivery its services, which is *"consistent with industry trend, in the increasing use of IT in the delivery of utility services*".
- AGN SA's IT totex, capex and opex indicators are "*consistently below or in line with the industry benchmark mean"* and indicate that SA AGN's IT expenditure is *"comparably efficient to the Australian utility industry, for both actual and planned IT expenditure forecasts".*

Further insight into the KPMG's IT capex related findings can be found in Figures A.1 and A.2.

[21] Ibid.

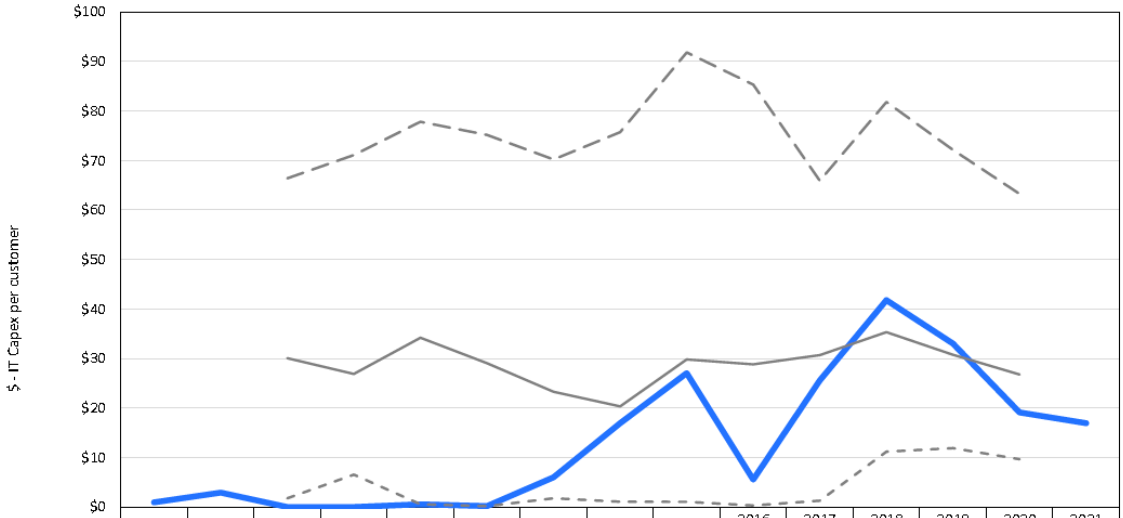
Figure A.1: IT Capex as a percentage of Total Capex



	2007 $Nom Actual	2008 $Nom Actual	2009 $Nom Actual	2010 $Nom Actual	2011 $Nom Actual	2012 $Nom Actual	2013 $Nom Actual	2014 $Nom Actual	2015 $Nom Actual	2016 $Real 2016 Forecast	2017 $Real 2016 Forecast	2018 $Real 2016 Forecast	2019 $Real 2016 Forecast	2020 $Real 2016 Forecast	2021 $Real 2016 Forecast
SA AGN	1.0%	2.9%	0.0%	0.0%	0.6%	0.1%	3.1%	7.3%	11.1%	1.9%	9.0%	13.7%	11.7%	6.9%	6.9%
Mean			5.3%	5.0%	6.0%	5.0%	4.6%	5.1%	6.2%	5.9%	6.4%	7.0%	6.4%	6.0%	
Minimum			1.6%	2.4%	0.6%	0.1%	1.2%	0.8%	0.4%	0.2%	1.2%	1.7%	1.8%	3.2%	
Maximum			13.2%	26.5%	47.8%	62.7%	38.6%	16.0%	17.8%	19.7%	16.4%	16.1%	12.7%	13.0%	
N. Org	3	3	14	16	18	21	22	16	21	21	19	17	17	12	2

Note: Benchmark calculated as IT capital expenditure divided by the gas business capital expenditure
The mean line in the graph above represents the weighted average across all included participants, the mean is calculated when there are data available from three or more organisations for the year.

Figure A.2: IT Capex per Customer



	2007 $Nom Actual	2008 $Nom Actual	2009 $Nom Actual	2010 $Nom Actual	2011 $Nom Actual	2012 $Nom Actual	2013 $Nom Actual	2014 $Nom Actual	2015 $Nom Actual	2016 $Real 2016 Forecast	2017 $Real 2016 Forecast	2018 $Real 2016 Forecast	2019 $Real 2016 Forecast	2020 $Real 2016 Forecast	2021 $Real 2016 Forecast
SA AGN	$1	$3	$0	$0	$1	$0	$6	$17	$27	$6	$26	$42	$33	$19	$17
Mean			$30	$27	$34	$29	$23	$20	$30	$29	$31	$35	$31	$27	
Minimum			$2	$7	$1	$0	$2	$1	$1	$0	$1	$11	$12	$10	
Maximum			$66	$71	$78	$75	$70	$76	$92	$85	$66	$82	$72	$63	
N. Org	2	3	14	16	18	21	23	17	20	20	18	16	16	12	2

Note: Benchmark calculated as IT capital expenditure divided by the number of properties supplied by SA AGN at the end of the year
The mean line in the graph above represents the weighted average across all included participants, the mean is calculated when there are data available from three or more organisations for the year.

As both of these figures highlight, AGN's IT capex has, for the most part over the last two AA periods, been substantially below the industry mean and in the next AA period will either be below or trend in line with the industry average. Elaborating further on these two indicators, KPMG made the following observations:

IT capex as a percentage of total capex

"AGN SA's IT capital investments in the previous AAP and in the early years of the current AAP have been below the industry mean… Overall, the results indicate AGN' SA's IT capex level has been below industry and will trend in line with industry, following the IT Capex investment peaks."[22]

IT capex per customer supplied

"AGN SA has been the lowest and below the industry mean, prior to the IT Capex forecast peak in 2018 and 2019. The planned IT capex over the next AAP will enable AGN SA to catch-up to industry IT expenditure level. The results suggest SA AGN's IT capex are in general, comparably below the industry."[23]

[22] Ibid, pg. 15.

[23] Ibid, pg. 16.

ADDENDUM TO BUSINESS CASE – SA71

PROJECT SUMMARY	
Network	AGN– SA
Project No.	SA71
Project Name	326 – TP – Murray Bridge Augmentation
Risk and Priority	Moderate, Priority 3
Budget Category	Capital Expenditure (capex)
Amendments to Original Business Case	No significant amendments have been made to the original Business Case but AGN is now proposing to review network demand in 2016 to assess whether the augmentation could be deferred for one or two years from the originally proposed 2017/18, by increasing the operating pressure by 0.1MPa from 1.65MPa to 1.75MPa. This has no impact on the associated cost of this project.
Estimated Cost	$3.0 million (real $2014/15)
Consistency with NGR	The proposed expenditure on the Murray Bridge augmentation complies with the new capex criteria in Rule 79 of the National Gas Rules (NGR) because: • it is necessary to maintain and improve the safety of services and maintain the integrity of services (Rule 79(1)(b) and Rules 79(2)(c)(i) and (ii)); and • it is such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services (Rule 79(1)(a)).
PROJECT APPROVAL	
Prepared By:	Martijn Vlugt, SA Networks Asset Planning Manager, APA
Reviewed By:	Steve Polglase, Asset Planning Engineer, APA
Approved By:	Jan Krzys, Networks Asset Strategy and Planning Manager, APA
OTHER RELEVANT DOCUMENTS	
This addendum should be read in conjunction with: • the original SA71 Business Case, which was provided to the AER on 1 July 2015 as Attachment 7.1 to the Access Arrangement Information (AAI); • AGN's response to the AER's Information Request 007, which was provided to the AER on 4 August 2015; • AGN's response to the AER's Information Request 011 (including Attachments 1 and 2), which was provided to the AER on 11 August 2015; • the 2015 South Australian Network Asset Management Plan, which was provided to the AER on 1 July 2015 as Attachment 8.1 to the AAI; and • the Murray Bridge Structure Plan prepared by Connor Holmes, which is available to download from the Murray Bridge Council website: https://www.murraybridge.sa.gov.au/page.aspx?u=446&c=15406 • Supporting Information 1: Letter from Regional Development Australia (Murraylands and Riverland)	

1 Original Business Case

AGN's proposed Access Arrangement (AA) for the next (2016/17 to 2020/21) AA period includes an allowance of $3.0 million to upgrade the capacity of supply to the Murray Bridge township through the installation of a 2 km DN 150 mm TP steel main from the Murray Bridge Gate Station to the township regulator station.

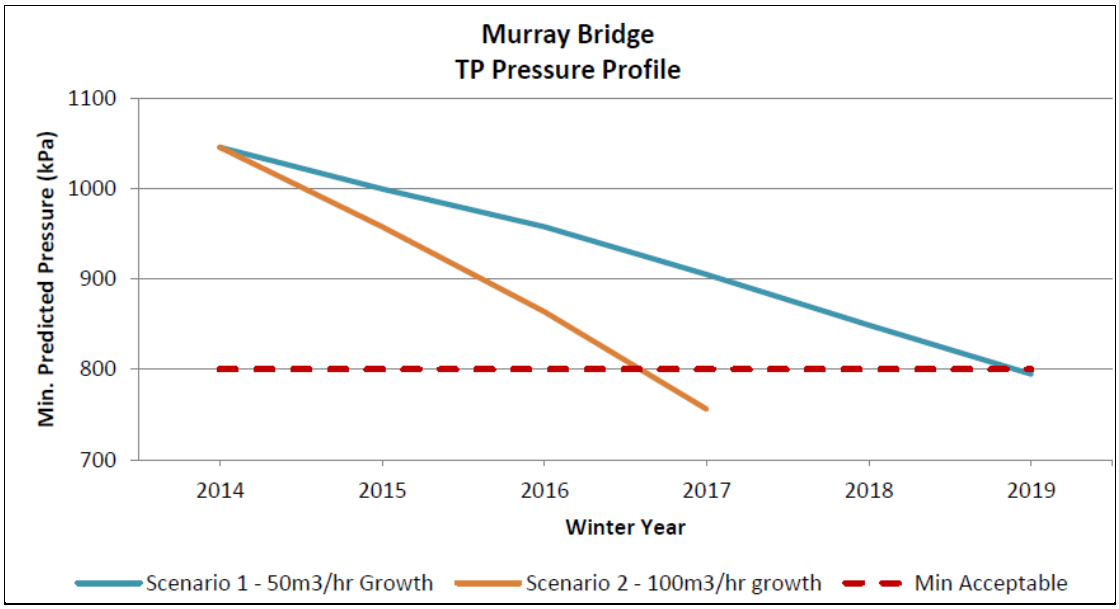
As outlined in the original Business Case, the augmentation is required because the current pipeline has reached capacity. The upgrade is therefore required to maintain a safe and reliable service and accommodate organic growth in the Murray Bridge township in the next AA period.

The proposed upgrade will also facilitate increases in the demand for gas in the region over the next 15-20 years, arising from the new estates that are expected to be developed in the Murray Bridge township[1] and the proposed extension of the network to the Monarto township.

As noted in the response to the AER's Information Request 011, future growth in the Murray Bridge and Monarto townships is not, however, the main driver of this project. The principal driver of this project is that the pipeline has reached its capacity and is unable to accommodate organic growth in the Murray Bridge region over the next AA period. As shown in the original Business Case, this can clearly be seen in the results of the pressure profile modelling set out in Figure 1.1 below. These results are based on the following scenarios:

- Scenario 1: In this scenario, organic growth in the Murray Bridge township is assumed to result in peak hour demand growing by the historic average of 50 m^3 per hour per annum. As this figure highlights, the minimum acceptable pressure is breached around 2019.
- Scenario 2: In this scenario, the development of new estates in the Murray Bridge township is assumed to result in 250-300 new residential connections per annum and peak hour demand growing by 100 m^3 per hour per annum. Under this scenario, the minimum acceptable pressure is breached in 2016/17.

Figure 1.1: Murray Bridge TP Pressure Profile



While not shown in Figure 1.1, the year in which the minimum acceptable pressure is breached under these two scenarios is highly sensitive to the assumptions made about the demand profiles of the four Tariff D customers in the Murray Bridge region, which account for over 90% of the peak-hour demand. Small changes in their demand profiles could therefore bring forward the augmentation requirement. It is for this reason that AGN proposed to carry out an annual review of network demand to confirm

[1] Further information on future growth and development in Murray Bridge can be found in:

- the Murray Bridge Structure Plan prepared by Connor Holmes, which is available to download from the Murray Bridge Council website: https://www.murraybridge.sa.gov.au/page.aspx?u=446&c=15406
- Attachments 1 and 2 to the AGN's response to the AER's Information Request 011, which was provided to the AER on 11 August 2015.

the actual timing of the augmentation but for the purposes of planning and the AA Proposal had assumed the augmentation will be based on Scenario 1 above and will be required in 2019.

2 AER Draft Decision

In its Draft Decision, the Australian Energy Regulator (AER) decided not to make any provision for the proposed Murray Bridge augmentation because, on the basis of the advice it received from its engineering consultant, Sleeman Consulting (Sleeman),[2] it was not satisfied that the proposed expenditure complied with Rule 79 of the NGR. [3]

In his advice to the AER, Sleeman stated that the pressure profile modelling AGN carried out as part of the original Business Case was "*reasonable given the assumptions upon which it is based*" but raised some concerns about the number of new residential connections that were assumed to occur in the Murray Bridge township (250-300 per annum) over the next 15-20 years. Sleeman went on to state that, in his opinion, demand growth in the next AA period could be satisfied by increasing the pressure at which the pipeline currently operates and added that this would mitigate the "*economic risk associated with the premature installation of the proposed pipeline*".[4]

The AER agreed with the views expressed by Sleeman and on this basis concluded that the project is not required in the next AA period.

3 AGN's Response

AGN's responses to the issues that Sleeman and the AER have raised about AGN's growth assumptions and its ability to operate the pipeline at a higher pressure are set out in detail below. In short, AGN remains of the view that:

- the proposed upgrade of capacity is required in the next AA period to meet existing demand and organic growth in Murray Bridge; and
- while it may be possible to defer the upgrade by one to two years by increasing the pipeline's operating pressure from 1.65MPa to 1.75MPa, the capacity upgrade will still need to occur in the next AA period.

These issues are discussed in further detail in Sections 3.1 and 3.2.

Importantly, AGN has received a letter of support from Regional Development Australia (Murraylands and Riverland) expressing disappointment at the AER's Draft Decision not to accept the proposed upgrade:

> *"We are extremely disappointed that the gas mains up-grade to Murray Bridge is not included in your draft approved works going forward. Any restriction in utility availability*

[2] Sleeman 2015, "*Review of Capex Forecasts for Selected Projects",* 18 November 2015, pg. 5-6.

[3] AER 2015, "*Attachment 6 – Capital Expenditure |Draft Decision: Australian Gas Networks Access Arrangement 2016-21*", November 2015, Attachment 6, pg. 6-27.

[4] Sleeman 2015, "*Review of Capex Forecasts for Selected Projects",* 18 November 2015, pg. 5-6.

such as natural gas will impede our region's economic growth and ability to continue to attract new businesses to the region."[5]

3.1 Growth assumptions

Having reviewed the concerns that were raised in the Draft Decision about the AGN's growth assumptions, it would appear that there is some misunderstanding about the extent to which the proposed augmentation is being driven by the expected growth in connections from new developments in Murray Bridge.

As noted in the original Business Case and the response to the AER's Information Request 011, the proposed capacity upgrade is **not** being carried out to meet the expected growth in demand from new estates in the Murray Bridge township. Rather, the upgrade needs to be carried out in the next AA period because the pipeline is already operating close to capacity and, as highlighted in Figure 1.1, is not expected to be able to accommodate:

- organic growth in residential connections and other forms of demand in the Murray Bridge region over the next AA period; or
- small increases in the demand and/or changes in usage profile of Tariff D customers in the next AA period.

The assumptions that AGN has made about these sources of demand are outlined in further detail below.

3.1.1 Organic growth in residential connections and other forms of demand

As outlined in the original Business Case, there are currently around 400 domestic customers in the Murray Bridge township. In 2013 and 2014, the number of domestic connections in Murray Bridge rose on average by 48 per annum, which represents an annual organic growth rate of 13% in the domestic customer base. AGN has therefore assumed that residential connections unrelated to new estate developments will continue to grow in line with historical trends in the next AA period.

In addition to residential customers, demand from small industrial and commercial customers (< 10 TJ per annum) in the region can be expected to increase over the period. Historically, the growth in peak hourly demand from residential customers, small industrial and commercial customers has been $50m^3$ per hour per annum and there is no reason to expect this to differ going forward. AGN has therefore assumed that peak hourly demand will grow by $50m^3$ per hour per annum when assessing the pressure profile of the pipeline.

3.1.2 Tariff D customers

There are currently four Tariff D (>10 TJ) customers in Murray Bridge and in 2014, these four customers accounted for approximately 90% of peak hourly demand. Because these four customers account for such a large proportion of the peak hourly demand, the capacity of the network is highly sensitive to small changes in the demand for gas by these customers and/or changes in their usage profile. In this regard, it is worth noting that:

[5] Regional Development Australia (Murraylands and Riverland), "*Letter of Support*", December 2015.

- the maximum **contracted** hourly demand of the four Tariff D customers is higher than the 2014 peak hour load; and
- in both 2014 and 2015, there have been 31 times when the hourly gas quantities supplied to two of the Tariff D customers either reached, or exceeded, their contracted hourly flows.

As these two points highlight, there is a risk that the hourly demand for gas by this group of customers could result in the capacity of the transmission pipeline being exceeded and cause the pressure in the network to fall below the minimum acceptable level, which could, in turn, result in:

- the loss of supply to about 400 existing domestic consumers; and/or
- AGN having to resort to short term reactionary augmentations, costing more in the long term.

That is, even without any other forms of growth in the region (organic or otherwise), there is a risk that the capacity of the pipeline will be exceeded in the next AA period.

In the original Business Case, AGN assumed that there would be no other Tariff D customers connecting to the network in next AA period. AGN has, however, recently received an enquiry from a prospective I&C customer that is considering setting up in [redacted] The prospective customer is seeking an uninterrupted gas supply of up to [redacted], but as highlighted in Section 3.2, AGN will be unable to meet this demand without the proposed augmentation, even under an increased operating pressure scenario.[6]

3.1.3 Conclusion

As the preceding discussion highlights, the capacity of the Murray Bridge pipeline needs to be expanded to meet the existing demand for gas, that is organic growth in the region. This expansion would also accommodate any small increases or changes in the usage profile of the existing Tariff D customers. If the potential growth in I&C demand was factored in, then the case for expansion would be even stronger, as highlighted by AGN's current inability to meet the prospective I&C customer's demands without further augmentation of the pipeline's capacity.

3.2 Increasing the pressure

In the advice that Sleeman provided to the AER it was suggested that demand growth in the Murray Bridge region in the next AA period could be met by increasing the pressure at which the pipeline operates. While AGN agrees that the pressure at which the pipeline operates could be increased from its current level of 1.65MPa, the extent of the increase is limited by the Maximum Allowable Operating Pressure (MAOP) (currently 1.8MPa)[7] and the requirement that the normal operating pressure be no more than 1.75MPa to allow for effective pressure control below the MAOP. The maximum increase in pressure that could be achieved without upgrading the MAOP is therefore 0.1MPa.

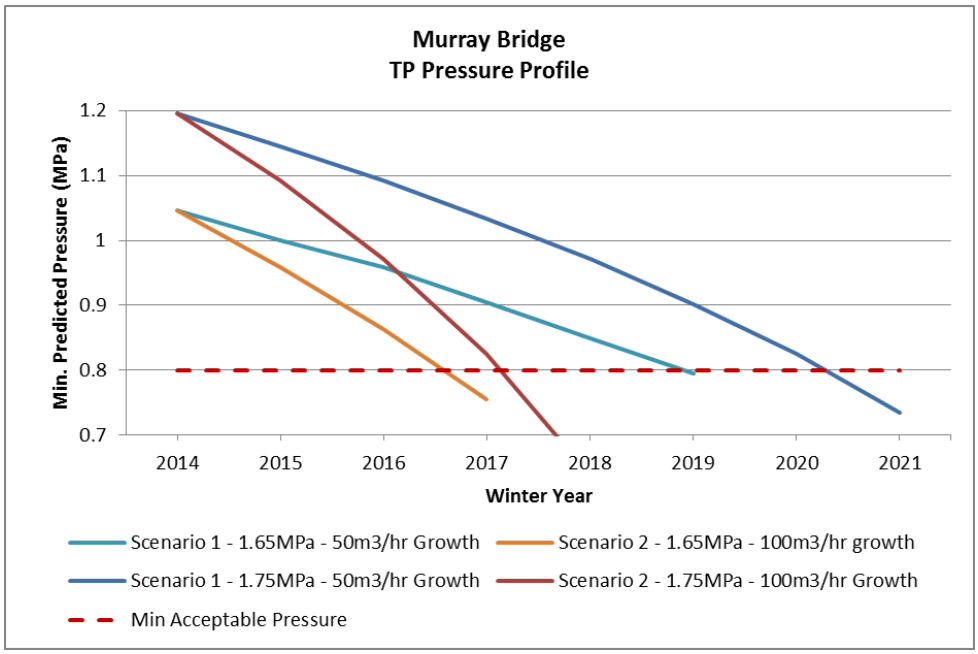
As the pressure profile modelling in Figure 1.2 highlights, even if the pressure of the pipeline was increased to 1.75 MPa a further expansion of the pipeline's capacity would still be required in the next

[6] Letter from Director of Major Projects and Investment Attraction, Investment Attraction Agency to APA Group, undated.

[7] See APA Group, Riverland Pipeline MAOP Review, August 2011, Table 1.3 National Dairies Lateral.

AA period because, even under the lowest growth scenario (Scenario 1: 50m^3 per hour per annum), the pressure will fall below the acceptable minimum by 2020/21. AGN would also incur some additional costs in increasing the pressure (e.g. engineering work, changing some regulator parts and changing pressure settings) although the costs would be relatively low.

Figure 3.2: Murray Bridge TP Pressure Profile – Impact of Increased Pressure



If the pressure was to be increased by more than 0.1MPa, then an upgrade of the MAOP would be required and pressure testing would also need to be conducted, which would require:[8]

- the transmission pipeline to be taken off-line, hydrostatically tested,[9] dried and cleaned; and
- an alternative source of gas (liquified natural gas tanks) to be supplied to Murray Bridge while the transmission pipeline is off-line.

The maximum increase in the MAOP that could be achieved in this case is just 0.09 MPa (i.e. MAOP of 1.89MPa) because of the maximum pressure rating and design temperature of the sub-components in the pipeline and city gate. A 0.09 MPa increase will add around 7% capacity to the network and will be exhausted by 2022 under the organic growth scenario where peak hour demand is assumed to grow by 50m^3 per hr per annum (Scenario 1).

Increasing the MAOP to 1.89 MPa is estimated to cost $1.46 million (see Attachment A) and will only increase capacity by around 7%. Under the organic growth scenario (Scenario 1: peak hour demand increases by 50m^3 per annum) this additional capacity is expected to be exhausted by 2022 at which

[8] See Australian Standard, "*Pipelines – Gas and liquid petroleum Part 3: Operating and maintenance*", AS2885.3-2012.

[9] The hydrostatic test is needed as part of a 'change of operating conditions assessment' that also includes a review of locations classes, management of risk, protection measures, physical condition, etc. of the pipeline. See AS2885.3-2102, section 10.

time a further expansion will be required. In contrast to this option, AGN's proposal to install a 2 km main between the Murray Bridge Gate Station and the township regulator station is expected to increase capacity by at least 180% and satisfy the projected growth in demand in this region for the next 15-20 years.

In AGN's view, the small capacity gain that would be achieved by increasing the pressure of the pipeline does not justify the costs involved and cannot therefore be considered a viable option. Further support for this view can be found in the table below, which compares the present value of the costs of:

- deferring the installation of the 2 km supply main between the Murray Bridge Gate Station and township regulator station to 2022 by increasing the MAOP to 1.89 in the next AA period; *with*
- installing the 2 km supply main in 2019 as proposed in the original Business Case at an estimated cost of $3 million.

As the results in this table highlight, installing the 2 km pipeline in 2019 is the least cost option and is therefore more consistent with Rule 79 of the NGR than the MAOP upgrade option.

Table 3.1: Net Present Value (NPV) Analysis

Option	Description	NPV $'000*
Option 1	2 km supply main in 2019	2,695
Option 2	MAOP upgrade in 2019, 2km supply main in 2022	3,719

* The discount rate (nominal pre-tax WACC) used in this calculation is consistent with the rate of return parameters that were adopted in the AER's Draft Decision

While it is clear from the preceding analysis that installing the 2 km supply main in the next AA period is the more prudent and efficient option, AGN accepts that there may be some time value of money benefits from deferring the augmentation until later in the period by increasing the operating pressure to 1.75MPa (as distinct from increasing the MAOP). AGN is therefore proposing to review network demand in 2016 to assess whether the augmentation could be deferred for one or two years by increasing the operating pressure by 0.1MPa.

4 Summary

For the reasons set out above, AGN remains of the view that the proposed increase in capacity of the pipeline servicing the Murray Bridge township is still required in the next AA period and the proposed expenditure of $3 million is:

- *Prudent* – The expenditure is necessary to maintain and improve the safety of services and to improve the integrity of existing services because operating below the recommended minimum pressure puts the pipeline and reliability of supply at risk. The expenditure is therefore of a nature that would be incurred by a prudent service provider.
- *Efficient* – The cost estimates for this project are based on actual costs for similar works that have been based on competitive tender rates for labour, materials and fittings. The recommended option also represents the most cost effective long-term solution as detailed above. The proposed

expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur.

- *In accordance with good industry practices* – Gas utilities across Australia are obligated to reduce risks within their networks to as low as reasonably practicable as reflected in Australian Standard AS2885.3-2012. Maintaining a safe and reliable supply of gas by maintaining adequate system pressures is consistent with this objective.
- *To achieve the lowest sustainable cost of delivering pipeline services* – Proactively addressing future gas supply issues will avoid short term multiple reactive measures, thereby ensuring the lowest long-term sustainable cost for customers.

The proposed expenditure can therefore be considered consistent with Rule 79(1)(a) of the NGR. It is also consistent with Rule 79(1)(b) of the NGR, because it is necessary to:

- maintain and improve the safety of services (Rule 79(2)(c)(i)); and
- maintain the integrity of services (Rule 79(2)(c)(ii)), which includes maintaining the security of supply.

Attachment A: Breakdown of MAOP Upgrade Cost