Response to the ERA's Draft Decision on required amendments to the Access Arrangement for the Mid-West and South-West Gas Distribution System

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Contact Person

Sally McMahon
General Manager Regulatory and Risk
Phone: 0421 057 821
Email: sally.mcmahon@atcogas.com.au

ATCO Gas Australia

ACN 089 531 957
81 Prinsep Road
Jandakot WA 6164
Phone: +61 8 6163 5000
Website: www.atcogas.com.au

Postal Address

PO Box 3006
Success WA 6964

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Glossary

AA4	Fourth Access Arrangement Period
ABS	Australian Bureau Statistics
ACT	Australian Competition Tribunal
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
AGA	ATCO Gas Australia
ALARP	As Low As Reasonably Practicable
AMS	Asset Management Strategy
ARORO	Allowed Rate of Return Objective
ASX	Australian Stock Exchange
ATO	Australian Tax Office
BDM	Business Development and Marketing
CCA	Current Cost Accounting
CEPU	Communications, Electrical and Plumbing Union
CGS	Commonwealth Government Securities
DBYD	Dial Before You Dig
DGM	Dividend Growth Model
Draft Decision	Decision on Proposed Revision to the Access Arrangement for the Mid-West and South-West Gas Distribution System
DRP	Debt Risk Premium
EA	Enterprise Agreement
ECS	Economics Consulting Services
EDD	Effective Degree Day
EGWWS	Electricity, Gas, Water, Water and Sewerage
EMCa	Energy Market Consulting associates
ERA	Economic Regulation Authority
ESD	Energy*Safety*
EY	Ernst and Young
FBT	Fringe Benefits Tax
FFM	Fama French Model
FRC	Full Retail Contestability
GDS	Gas Distribution System
GPAC	Gas Powered Air Conditioning
HCA	Historical Cost Accounting
HGDB	Hypothetical Gas Distribution Business
HIA	Housing Industry Association

HIFG	Housing Industry Forecasting Group
IPART	Independent Pricing and Regulatory Tribunal
ITAA	Income Tax Assessment Act 1997
ITSA	I-Tek IT Services Agreement
KPI	Key Performance Indicator
LAFHA	Living Away From Home Allowance
LIG	Less Inflationary Gain
LRMC	Long-run Marginal Cost
MRP	Market Risk Premium
MSF	Managed Services Fee
NDV	Network Data Visualisation
NGL	National Gas Law
NGO	National Gas Objective
NGR	National Gas Rules
NPV	Net Present Value
PCF	Pressure Correction Factor
PTRM	Post Tax Revenue Model
QCA	Queensland Competition Authority
RFP	Request for Proposal
RPP	Revenue and Pricing Principles
SAIFI	System Average Interruption Frequency Index
SL CAPM	Sharpe Lintner CAPM
UAFG	Unaccounted For Gas
WAGN	Western Australian Gas Network
WPI	Wage Price Index

1. Executive summary

1. ATCO Gas Australia (**AGA**) submits its response to the Economic Regulation Authority's (**ERA**) *Draft Decision on Proposed Revision to the Access Arrangement for the Mid-West and South-West Gas Distribution System* (herein referred to as the **Draft Decision**).

2. The ERA's Draft Decision, released on 14 October 2014, requires 45 amendments to AGA's March 2014 proposal. The amendments, if implemented, will significantly reduce AGA's proposed expenditure, capital base, tax expense, expected revenue and return on investment for the fourth access arrangement period 1 July 2014 to 31 December 2019 (**AA4**). The ERA has also made changes to key performance indicators, reference tariffs and aspects of the template haulage contract.

3. AGA accepts and has implemented 26 of the ERA's 45 required amendments and has made the relevant changes to the access arrangement and associated documents. On a number of matters, such as the return on working capital and the standing charge for residential customer tariffs, AGA accepts the ERA's position and methodology, and will amend the access arrangement accordingly when related issues have been addressed.

4. The ERA's amendments to revenue, expenditure, forecast demand and return on investment have not been accepted by AGA. AGA accepts and has proposed some reduction in revenue and continues to propose price reductions for customers. However, AGA considers implementing the Draft Decision exactly as written would result in an access arrangement that limits customers' access to natural gas, compromises network safety and security, and does not promote efficient investment, and has broader adverse implications for investment by service providers in Western Australia.

5. As a result, AGA submits that the Draft Decision, if implemented, would result in an access arrangement that does not satisfy the National Gas Objective (**NGO**):

> *to promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas.*[1]

6. AGA submits that its proposals satisfy the NGO and in particular, is in the best interest of customers, and submits a revised proposal to that effect. The revised proposal is summarised in section 1.2 below, however, AGA wishes to explain its reasons for not implementing all required amendments and discuss the effect of the Draft Decision if it was implemented.

7. AGA also refers to and relies upon the evidence of its expert and the expert report of HoustonKemp which has considered the ERA's Draft Decision, the errors identified by each of AGA's experts and forms the opinion that correcting the errors would be materially preferable in achieving a contribution to the NGO.[2]

1.1 Effect of the Draft Decision

8. As a package of revisions, AGA considers the ERA's amendments do not promote the long-term use of natural gas in Western Australia. The amendments also have the potential to lower the value of investing in WA energy infrastructure.

9. The Draft Decision excludes $394.3 million of network operating and capital expenditure from AGA's proposed expected revenue for the AA4 period. This includes a $97.4 million reduction in safety and asset replacement capital investment and a $204.5 million reduction in expenditure required to grow the network and allow new customers to connect to the gas network.

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1 National Gas Law (WA), Section 23.

2 Appendix 1.1 Evaluation of Economic Regulation Authority's Draft Decision against the National Gas Objective, Greg Houston, HoustonKemp, 27 November 2014.

10. Though exclusion from AGA's proposed revenue does not prohibit AGA from making the investment, it means the expenditure will not be recovered via reference tariffs. In a private sector commercial environment speculative investment (expenditure not covered by tariff revenue) is not feasible given the risk of exclusion from the future capital base. As a result, AGA is highly unlikely to secure sufficient funding from its investors to conduct works which are not covered by tariff revenue. This issue is magnified by the rate of return provided for by the ERA, which AGA submits does not allow for efficient expenditure by AGA that satisfies the NGO. Effectively, the ERA's Draft Decision significantly reduces the amount AGA can invest to operate, grow and improve the network.

1.1.1 Impact on growth

11. The ERA's Draft Decision disallows the continuation of existing levels of investment and new investment proposed to enable new 'greenfield' housing and commercial developments to connect to natural gas. Greenfield developments are generally new subdivisions on undeveloped land where AGA can install gas mains in common trenches with other utilities. Sharing new trenches with other utilities is the most cost effective installation method possible.

12. The ERA Draft Decision considers only customers located within 20 metres of the existing network can be connected efficiently. The ERA refers to this as 'brownfield' development, which AGA is obligated to connect under its Gas Distribution Licence.

13. AGA has connected between 15,000 and 22,000 new homes and businesses to the network per year for the past 8 years. If all greenfield expenditure is excluded as per the ERA's Draft Decision, only around 2,000 customers will be connected each year in the AA4 period.

14. AGA has already connected more than 17,000 customers in 2014 and has built its resources to meet this level of new connections for the AA4 period. However, if AGA must lower this connection rate to 2,000 per year, AGA will be seriously adversely impacted in this area of its business, particularly the risk of impacts on its workforce amendment of its connection policies and decreases to its customer commitments. AGA also notes that given the AA4 period commenced on 1 July 2014, any capital expenditure relating to greenfield development since then is at risk of being excluded from the AA5 capital base.

15. The decision to limit growth investment compromises AGA's proposal to make the network more accessible for customers. It also inhibits development of an energy market with greater competition, sustainability and choice for Western Australians. For example, if AGA implements the Draft Decision as prescribed, nearly 90,000 new homes built over the next five years would not have access to a natural gas supply. Homeowners would be left to rely predominantly on electricity for their energy needs and their options to offset rising electricity bills by switching to alternative fuel sources would be diminished. Should these customers choose to pay for the gas network to be extended to their properties in the future, connection charges would be higher as laying a new gas main through already developed areas is more expensive and disruptive than simply extending the network as part of a greenfield project by common trench installations with other service providers.

16. Figure 1–1 shows a map of the proposed greenfield development areas for the AA4 period. If the related growth expenditure is excluded from the projected capital base, these areas will not have access to a natural gas supply. This outcome is not consistent with the NGO, and many customers that value the use of natural gas will be prevented from access to it. Disallowing greenfield growth expenditure does not promote efficient use of natural gas or investment in gas infrastructure in Western Australia.

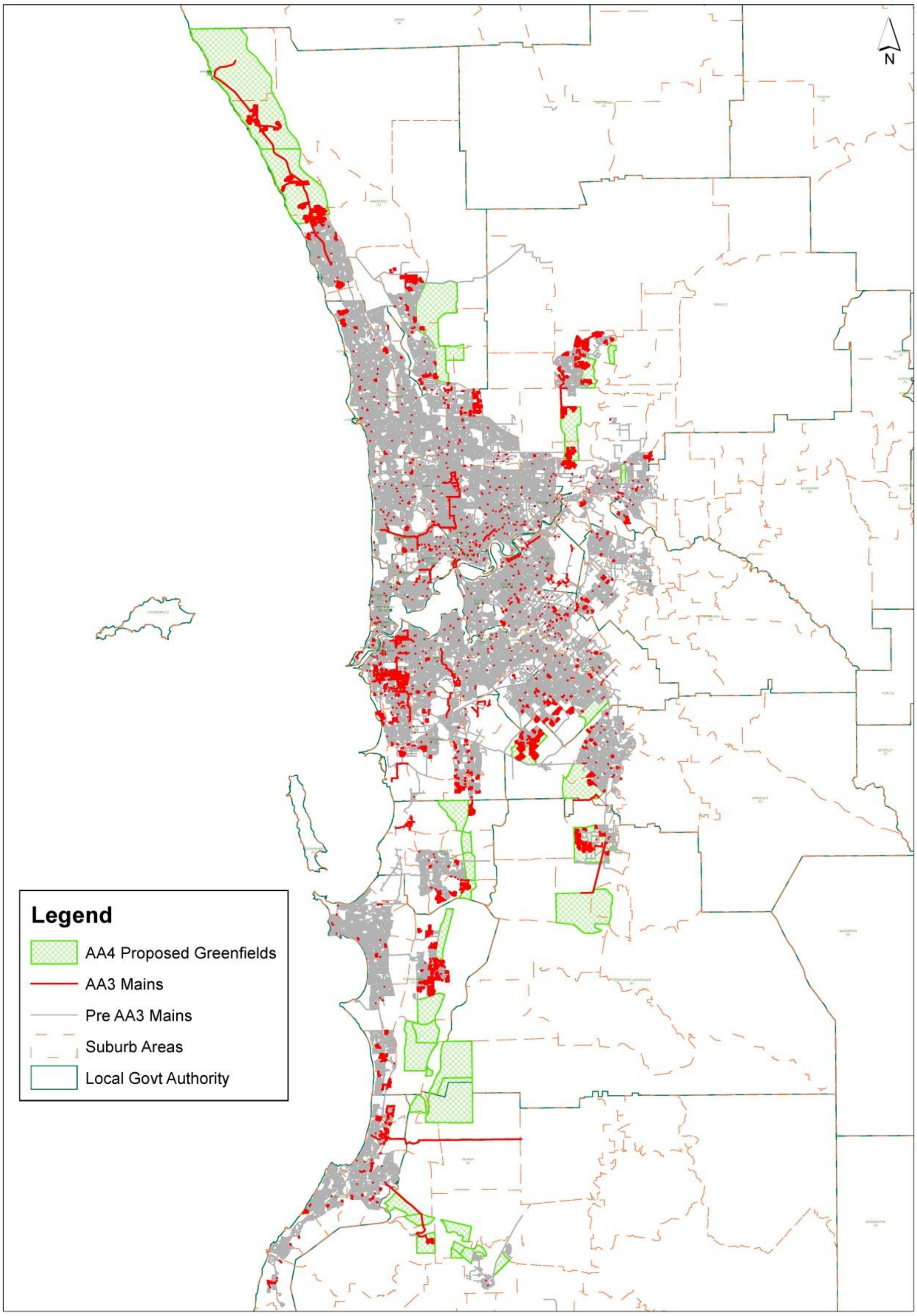

Figure 1–1: Proposed greenfield development locations during AA4

1.1.2 Impact on network safety and security of supply

17. The Draft Decision excludes almost $100 million of proposed expenditure on network safety and security of supply. Under the ERA's Draft Decision up to 60,000 customers would be at risk of a long term interruption[3] of supply if a single major network issue occurred. AGA proposes to reduce this risk by installing additional pathways for gas to supply the network. This is a risk mitigation approach adopted by other gas distribution system operators and approved by the AER.[4]

18. AGA proposes expenditure to reduce the number of customers at risk of gas supply interruption from a single major network issue to no more than 25,000, as an outage affecting more than 25,000 customers could not be restored in an acceptable timeframe. However, the ERA considers the 25,000 customer threshold is too low and has disallowed expenditure to address the risk. Put simply, this will render the gas network less resilient and large sections of the network will be at greater risk of experiencing long term loss of supply.

19. AGA's priority remains to keep customers, its workforce and the community safe. AGA has developed a Safety Case[5] to reduce the risk of operating the gas network to low or as low as reasonably practicable (**ALARP**). The Safety Case is required by the *Gas Standards Act 1972* and *Gas Standards (Gas Supply and System Safety) Regulations 2000*, and complies with Australian Standards[6]. It was also reviewed and accepted by the gas industry safety and technical regulator, Energy*Safety*. The lower expenditure outlined in the Draft Decision seriously adversely affects AGA's ability to fully comply with its regulatory obligations under its approved Safety Case.

20. In summary, the outcomes of lower safety and security of supply expenditure, when combined with reduced growth investment, demonstrates that the Draft Decision is not in the long term interest of consumers with respect to network access, price, safety, reliability and security of supply of natural gas.

1.1.3 Impact on investment in Western Australia and the energy market

21. The impact of the Draft Decision would seriously adversely affect the value to consumers of regulated services in Western Australia compared to similar businesses elsewhere in the country. This is due to the rate of return on investment, which is considerably lower than provided historically and significantly below the rate currently allowed in other Australian states and territories and approved by the AER and the Australian Competition Tribunal (ACT).

22. The ERA provides for an overall nominal rate of return of 5.94%, composed of a return on equity of 6.80% and cost of debt of 5.36%. This return on equity is more than 2% lower than the Australian Energy Regulator has provided for other gas distribution networks. AGA will have a significantly lower rate of return than a regulated gas distributor in another state providing the same regulated services over a corresponding time period. The rate of return provided for in the Draft Decision is also more than 3% lower than the ERA provided for AGA's network previously.

23. The adverse impact of these reductions will be significant. A low return reduces the network operator's ability to attract the funding necessary to support network investment. A low return also provides an adverse encouragement which will reduce investment to a minimalistic short term 'stay-in business' mode, foregoing

3 Greater than 4 weeks.

4 Envestra, Allgas, Multinet and SP Ausnet all mitigate loss of supply by installing alternative gas pathways.

5 AGA (formerly WAGN), Gas Distribution Safety Case, July 2011.

6 AS/NZS 4645.1: 2008 Gas Distribution Networks and AS2885.1: 2007 Pipelines – Gas and Liquid Petroleum.

opportunities to grow the network efficiently for the long term benefit of consumers and minimising replacement of ageing infrastructure. The adverse encouragement of such an approach serves only to postpone network safety and security of supply projects with associated deterioration in asset performance and leads to a higher life cycle cost as expenditure is adversely encouraged and will become reactive and inefficient.

24. While AGA remains committed to keeping the network safe and operationally efficient, the ERA's proposed rate of return does not promote efficient investment. The return on equity determined for AGA is lower than any other regulated utility in the ATCO Group. This will make it difficult for AGA to compete for capital amongst other entities in the ATCO Group and to secure funding, thereby adversely encouraging a minimal short term investment focus, which will impact the quality of service AGA can provide to gas customers. AGA also submits that the return on debt is not sufficient to cover the costs of an efficient debt management strategy, which again places services at risk.

25. The rate of return proposed has the potential to reduce the value of investing in other services such as gas transmission and electricity networks. This may discourage private ownership and investment in Western Australia, placing additional pressure on State government tax payer funded finances. A situation where private investors are discouraged from investing in and improving the provision of utility services results in a long term drain on state taxpayers.

26. Further, the Draft Decision limits opportunity to develop a sustainable and competitive energy market. The price advantage of natural gas over electricity is greater now than it has been in the past ten years, which is invigorating interest in natural gas appliances. New natural gas technologies such as on site gas fired generation, gas fired air conditioning and fuel cells are also becoming available.

27. By inhibiting efficient investment and growth in the network, opportunities to embrace new technologies and develop sustainable energy solutions may be forsaken. If implemented, the Draft Decision would restrict access to natural gas and have a serious negative impact on the consumer market competitiveness of natural gas with other energy sources, particularly electricity. This scenario does not provide for a sustainable energy mix in Western Australia.

1.1.4 Impact on long term pricing

28. AGA appreciates a major driver of economic regulation is price. With this in mind, in March 2014 AGA lodged a proposal that delivers initial average annual price decreases of around $9 in real terms for residential (B3) customers, while still allowing the business to make the required network investment.

29. Assuming the lower network costs are passed through to end users by gas retailers, the effect of the ERA's Draft Decision is initial short term average annual price decreases of around $70 on a network bill of $240 for an average residential customer. However, much of AGA's proposed investment in safety, reliability and growing the network would not occur.

30. AGA is aware of the importance of price. There are readily available energy substitutes for natural gas applications, particularly from electricity and LPG; therefore there is a considerable incentive to keep gas prices competitive. The National Competition Council recently approved light-handed regulation of the Envestra gas distribution network in Queensland[7]. The decision acknowledged the precarious competitive position of gas and that this competitiveness will not be reduced by a move to light handed regulation. AGA is in a similar situation and strives to provide competitive

[7] Light Regulation of Envestra's Queensland Gas Distribution Network, 5 Nov 2014.

price advantage for its customers and consumers which satisfy the NGO, but the prices must also be sustainable.

31. While AGA understands the ERA's proposed price cut will be valued by customers in the short term, it is important lower costs are not achieved at the expense of efficiency, safety, reliability and the provision of natural gas supply to future customers in the longer term. Lower growth expenditure during the AA4 period means fewer new customers will have access to gas supply, however, the ongoing need to maintain and invest in the network does not diminish over time. Therefore the costs of ongoing investment would be spread across a static customer base, resulting in higher costs borne by each customer in the longer term.

32. AGA proposes to invest efficiently in the network now, increase the number of connections and achieve real and sustainable cost reductions over the long term. The Draft Decision does not enable this. As gas retailers are under no obligation to pass through network tariff reductions to end users, it is feasible that the actual gas price reductions end users receive may be less than proposed by the ERA in the Draft Decision or delayed.

33. AGA is already among the lowest cost gas distribution business in Australia. It has been the lowest cost gas distribution business on a per customer basis since 2007, and will remain the second lowest cost business during the AA4 period based on AGA's proposals.[8] Figure 1–2 shows that on a cost per kilometre basis, AGA's costs are the lowest by a significant margin compared to all other regulated gas distribution businesses in Australia and will remain so despite AGA's proposed expenditure increase for the AA4 period. However, the ERA requires AGA to reduce its operating costs.

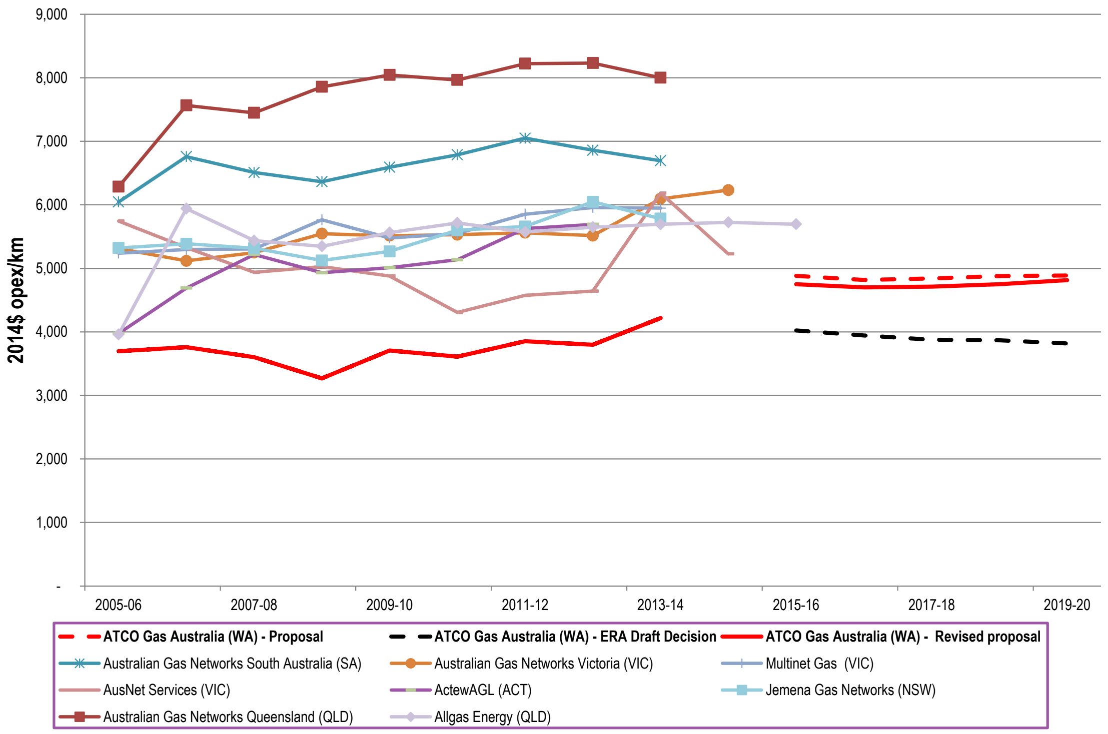

Figure 1–2: Operating expenditure per km, Australian gas distribution businesses

34. AGA submits the gas price reductions proposed by the ERA do not satisfy the NGO. AGA already operates at an efficient cost and the ERA has not provided sufficient rationale that meets the requirements of the NGR for the proposed price decrease. The ERA's own revenue modelling[9] shows the Draft Decision results in AGA's earnings being sufficiently low for it **not** to pay corporate income tax from 2015 to 2019. This is

8 Acil Allen, Gas Distribution Benchmarking – Partial Productivity Measures, 2014.

9 Set out in Table 4 of the Draft Decision.

inconsistent with that which would be expected of a sustainable commercial enterprise or an efficient benchmark entity.

1.2 AGA's response

35. AGA has reviewed the ERA's required amendments carefully. AGA has responded to each of the matters raised in the Draft Decision and provided further supporting evidence.

36. AGA notes the ERA appointed consultants EMCa to review the March 2014 proposal from a technical standpoint. AGA supports this general approach and welcomes the rigour applied to its expenditure proposal.

37. In many cases, AGA notes that the ERA has accepted EMCa's advice without providing its own analysis or rationale for making the determination nor referred to supporting evidence. In such instances where economic oversight is not provided, AGA responds to the matters raised as best it can and requests that the ERA exercises its discretion in its Final Decision to consider the broader commercial implications of its technical expert's recommendations and to ensure that as submitted by AGA, the NGO is satisfied.

38. AGA submits that the advice of AGA's gas industry technical and safety experts and submissions by the gas industry technical and safety regulator, EnergySafety must be accepted over the advice of EMCa based on the relative expertise and experience of the experts.

39. AGA remains committed to keeping customers, the community and the workforce safe, while providing greater energy choice for Western Australians. AGA understands the need to balance this service provision with a reasonable price to end users which satisfies the NGO, and the ERA's role in approving an access arrangement that achieves this balance and satisfies the NGO.

40. AGA therefore submits a revised proposal, summarised below.

1.2.1 Revised access arrangement proposal

41. AGA maintains its objectives to:

- Maintain the safety of customers, the community and AGA employees
- Improve reliability and service
- Provide greater access to gas supply for customers
- Set up the business to deliver real price reductions in over the longer term

42. AGA's revised proposal balances achieving these objectives with the outcomes if it were to implement the ERA's Draft Decision. Taking the ERA's required amendments into consideration, AGA's submits total investment required for the AA4 period is $999 million, comprising $407 million in operating expenditure and $592 million in capital investment. This is 6% less than the March 2014 proposal as presented in Figure 1–3 . AGA's revised proposal adopts the more stringent key performance indicators required in the Draft Decision.

43. Expected revenue via reference tariffs to cover this investment is $1.03 billion, 10% less than originally proposed and 33.8% more than the ERA's Draft Decision. The expected revenue includes a return on investment to cover debt and equity costs of 5.73% and 10.51% respectively.

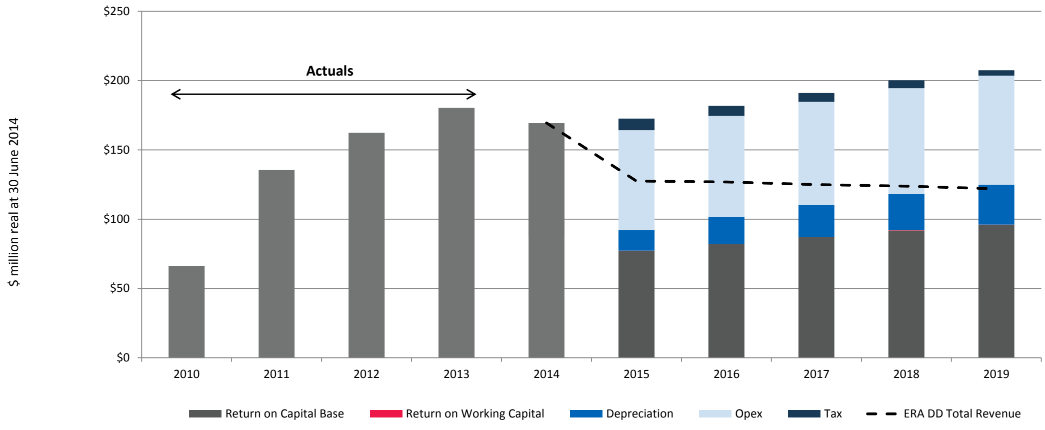

Figure 1–3: Proposed amended comparison

44. The real average annual reduction in prices across all customers is 1.8%. An average B3 residential customer consuming 15 GJ per year will receive a modest reduction in the network price from $238 to $234 in 2015, and then prices will remain flat for the remainder of the period. Table 1–1 presents the average annual change in tariff by tariff class.

Table 1–1: Price path (annual change in average price in Real $, forecast CPI of 2.5%)

Tariff	2015	2016	2017	2018	2019	Average annual % change
A1	-3.1%	0.5%	-2.4%	-3.3%	-3.4%	-2.4%
A2	-1.5%	-1.2%	-2.3%	-2.4%	-2.9%	-2.1%
B1	-4.0%	-1.2%	-1.6%	-1.7%	-1.7%	-2.1%
B2	-1.8%	1.0%	0.2%	0.0%	0.0%	-0.1%
B3	-4.6%	0.7%	-0.2%	-0.5%	-0.8%	-1.1%
All customers	**-3.9%**	**-2.0%**	**-0.6%**	**-1.0%**	**-1.4%**	**-1.8%**

45. Key elements of the revised proposal and matters raised in the Draft Decision are discussed in the following sections.

1.2.1.1 Demand forecast

46. AGA submits revised demand forecasts, which have been updated to reflect the latest consumption data, and the impact on retail prices resulting from the removal of the carbon tax. The revised forecasts are provided in Figure 1–4 below compared to the ERA's forecast consumption. AGA notes that the ERA forecasts total consumption to increase despite gross connections reducing dramatically under its Draft Decision (see Figure 1–5).

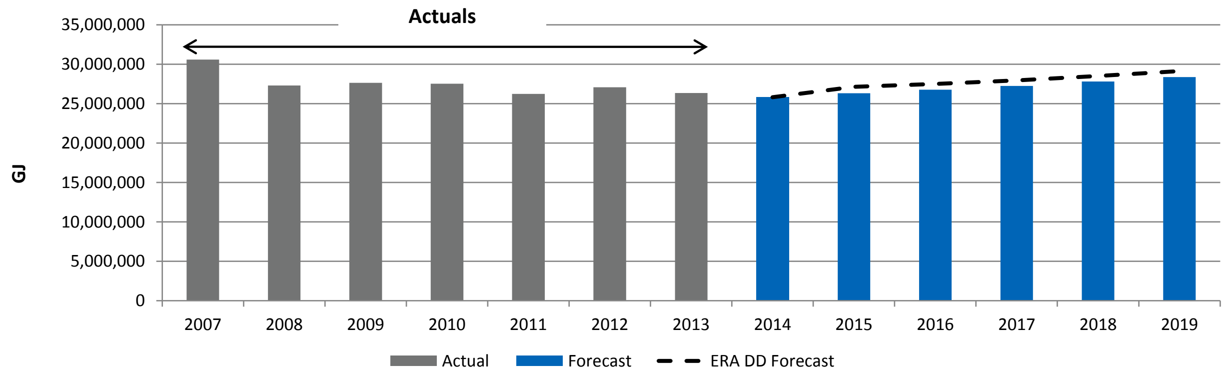

Figure 1–4: Total consumption

AGA has included forecast customer numbers associated with greenfield development and its revised business development and marketing expenditure proposal. AGA disagrees with the ERA's forecast that average consumption per B3 customers will remain constant from 2014 to 2019 and provides evidence in Chapter 4 to support this. AGA also considers the ERA's forecast average per customer consumption of 80 GJ for B2 customers and 12 GJ for B3 customers contains errors. Again, evidence to support this view is provided in Chapter 4.

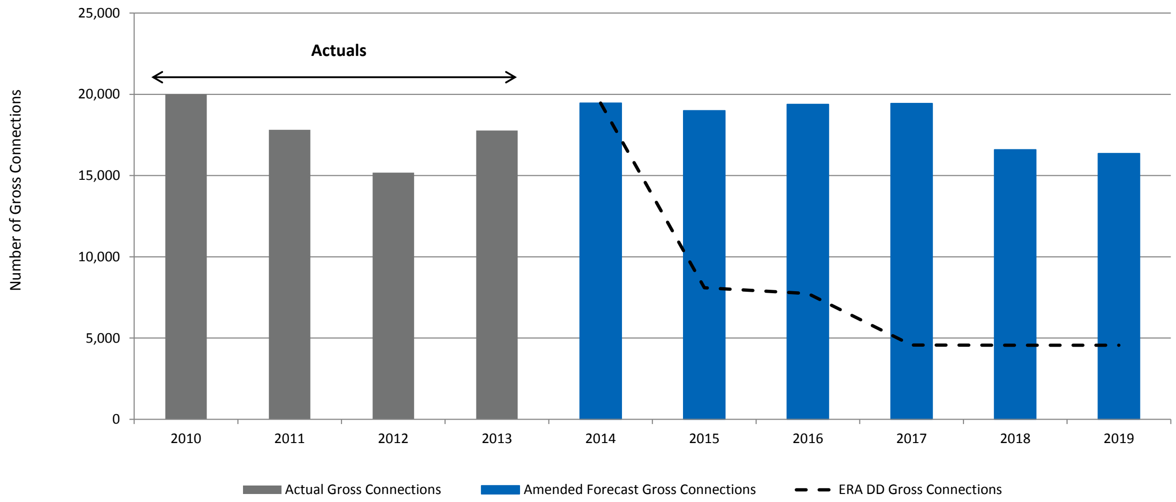

Figure 1–5: Number of gross connections

1.2.1.2 Opening capital base

47. AGA considers the $9.9 million of AA3 capital expenditure excluded from the opening capital base is conforming capital expenditure under rule 79 of the NGR.

48. Specifically, AGA considers the Jandakot Blue Flame Kitchen has a strong connection with safety and is conforming capital expenditure. As a prudent natural gas supplier AGA considers its responsibility to keep consumers safe should not end at the meter box. The Blue Flame Kitchen initiative directly helps improve consumers understanding of gas, how their homes are connected to the network and how to use gas safely. This is targeted at helping reduce the risk of serious harm or incident in the home, which has an impact on network safety generally. The Blue Flame Kitchen also provides a platform for demonstrating AGA's role and responsibilities in responding to gas safety issues. Therefore AGA submits the initiative's link to safety is justifiable under rule 79 of the NGR.

49. Expenditure associated with the Jandakot sewerage extension has been included in the opening capital as AGA has provided evidence in Chapter 7 to show there was no double count of costs. AGA also provides evidence that explains the variance in reported IT expenditure and justifies inclusion of expenditure related to the three IT projects EMCa deemed were non-conforming capital.

50. AGA accepts some variation to the originally proposed capital base due to CPI adjustment and the revised end of period capital expenditure position. AGA submits the opening capital base for the AA4 period is $1,007.9 million.

1.2.1.3 Forecast capital expenditure

51. AGA submits forecast capital expenditure of $592 million. Figure 1–6 shows this revised proposal compared with the March 2014 submission and the ERA's Draft Decision.

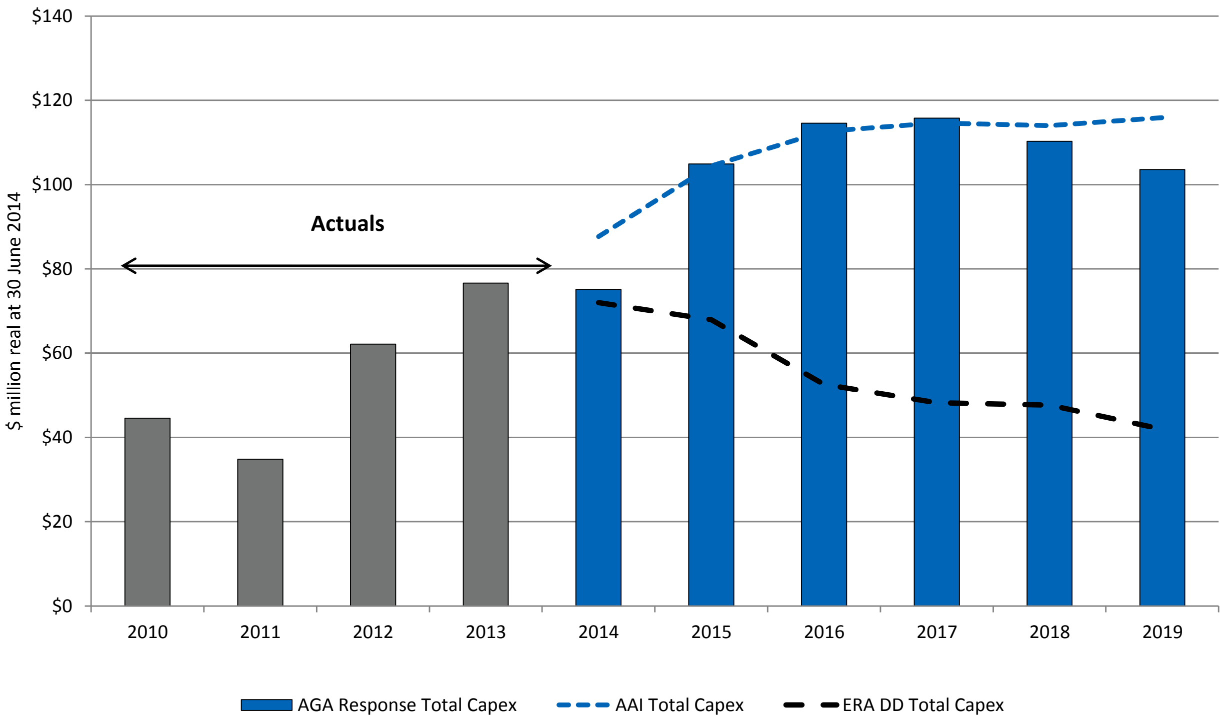

Figure 1–6: Forecast capital expenditure

52. AGA proposes all greenfield growth expenditure is included in the expenditure forecast. AGA provides evidence in Chapter 8 that demonstrates this expenditure is efficient, satisfies rule 79 of the NGR and will need to be incurred during the AA4 period. Based on revised demand and increased customer number projections, forecast capital expenditure is $233.9 million, $5.4 million greater than originally proposed.

53. The comparatively small increase in network growth capital expenditure is offset by reductions of $19.5 million in network sustaining capital expenditure and $2.3 million in IT capital respectively.

54. Total network sustaining capital is $291.8 million, and covers investment to address network security and safety risks. This revised proposal is $19.5 million lower than originally proposed due to the deferral of some unprotected metallic mains asset replacement and several interdependency projects to the AA5 period. However, network sustaining capital still includes investment to comply with AGA's Safety Case, Australian Standards and reduce the threshold of customers supplied by a single source of supply to a maximum of 25,000.

55. Forecast IT capital expenditure is $26.3 million. This $2.3 million reduction results from lower expenditure in July to December 2014 due to the transition from I-Tek to WIPRO, removal of costs associated with forecast

regulatory changes and removal of a portion of IT hardware that is now addressed as part of the IT services agreement with WIPRO.

56. Capital expenditure on structures and equipment is $40.2 million, $1.7 greater than proposed in the March 2014 submission. This increase is due to a carry-over of the Mandurah Depot, warehouse upgrade and fleet from AA3. AGA submits the proposed Busselton Depot will be required during the AA4 period in order to meet customer service targets. Evidence to support this is provided in Chapter 8.

57. AGA agrees to remove the proposed Osborne Park Blue Flame Kitchen expenditure from AA4 revenue; however it may revisit the initiative during the AA4 period. The Blue Flame Kitchen is designed to raise community awareness of how to use gas safely. The concept is to engage community groups, typically schoolchildren, and show them how to use gas safely, what to do if they smell gas and what action to take in an emergency. While the ERA does not consider the outcome is directly related to *network* safety, AGA submits the initiative directly supports *safety in the home* and raises public awareness of a natural resource that is under-utilised and the long term consumer benefits of which are not adequately explained and thereby not fully understood in Western Australia.

58. AGA remains committed to increasing people’s understanding of natural gas and helping keep consumers safe. AGA will look at further community engagement programs during the period and reserves the right to adopt appropriate interactive and innovative methods of gas safety education similar to other utility service providers such as Western Power and Water Corporation.

1.2.1.4 Forecast operating expenditure

59. AGA submits forecast operating expenditure of $407 million which is 2.3% lower than the March 2014 proposal. AGA has reduced network operating expenditure, IT operating expenditure and corporate costs.

60. Figure 1–7 shows the revised proposal compared with the March 2014 submission and the ERA’s Draft Decision.

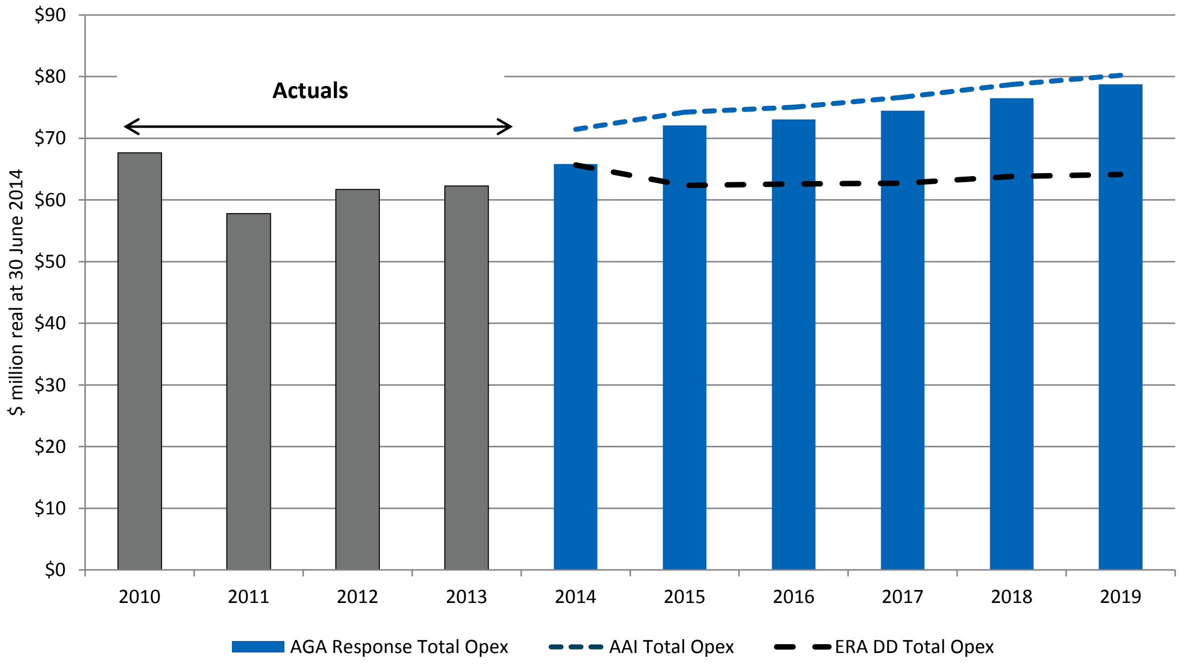

Figure 1–7: Operating expenditure

1.2.1.5 Rate of return

61. AGA submits an overall rate of return of 7.64%. This includes a cost of debt of 5.73% and cost of equity of 10.51%.

62. AGA's proposed rate of return departs from the ERA's Rate of Return Guidelines and the ERA's Draft Decision. As set out in more detail in Chapter 9 and the accompanying expert reports, the ERA's approach does not comply with the requirements set out in the NGR and does not achieve the allowed rate of return objective. As discussed, the ERA's rate of return, particularly the return on equity does not provide a sufficient return to promote efficient investment and is likely to result in services only being delivered where an obligation exists or a subsidy is provided. AGA remains of the view that in order to satisfy NGR requirements and the allowed rate of return objective it is necessary to consider all available and relevant data, estimation methods, financial models and evidence.

63. AGA has revised its estimate of the nominal post tax weighted average cost of capital to:

- Update the various parameters to account for movements in the market conditions since the March 2014 submission
- Update the weighting methodology used to estimate the return on equity by applying a weighted average to the output of four relevant models for estimating the cost of equity, resulting in an estimate 10.51%
- Modify the approach for measuring the cost of debt to the Draft Decision to an estimate based on a hybrid methodology. The hybrid methodology combined with an allowance for debt raising and hedging costs results in a cost of debt estimate of 5.73%

64. AGA's revised nominal post-tax rate of return estimate of 7.64% has been arrived at having regard to all available and relevant data, estimation methods, financial models and evidence. It therefore reflects the best estimate available. AGA's proposed rate of return complies with the NGR, specifically the allowed rate of return objective, the national gas objective and the revenue and pricing principles.

1.2.1.6 Tax

65. AGA accepts the ERA's revised asset lives, the ERA's calculation to maintain a one year lag between spending capital and commissioning the relevant asset, and the calculation of debt servicing costs.

66. However, AGA proposes capital contributions and commercial meter sets remain in the tax asset base for the purpose of calculating the tax liability. These assets are required to provide reference services and so the tax liability that arises from the contributions must be included in the calculation of total revenue. AGA provides evidence in Chapter 12 that demonstrates all users benefit from customers connecting, so it is appropriate that the tax liability on capital contributions is included in total revenue.

67. AGA proposes to retain the prime cost method of tax depreciation rather than the diminishing cost method. AGA agrees with the ERA that a benchmark efficient entity would choose to minimise its tax costs, however AGA considers that the prime cost method does this is over the long term.

1.2.1.7 Depreciation

68. AGA submits the correct way to avoid a double count of inflation is to not index the capital base, and proposes the same approach to depreciation as provided in its March 2014 submission. While AGA understands the need to make an inflationary adjustment to ensure tariffs recover no more than the expected revenue, the ERA's method of adjusting the depreciation amount by adding a new building block does not comply with rule76 of the NGR.

69. AGA submits that the ERA has an opportunity to adopt the correct method of not indexing the capital base, which eliminates the double count of inflation. This approach satisfies rules 76, 87 and 89 of the NGR. AGA also proposes a transitional approach to move to a non-indexed capital base, which minimises the short-term price impact on customers.

70. Not indexing the capital base provides appropriate incentives for efficient investment, whereas indexing the capital base does not. Therefore AGA submits a depreciation amount of $116.5 million for the AA4 period.

1.2.1.8 Reference services and template haulage contract

71. AGA has implemented the majority of the ERA's required amendments relating to reference services, other access arrangement provisions and the template haulage contract. AGA submits many of the ERA's amendments in this area are reasonable and help provide a better outcome for customers consistent with the NGO. In some cases the amendments have been implemented with some modifications. Detailed discussion of this is provided in Chapters 15 and 17 of this document.

72. AGA also accepts the ERA's approach to the structure of tariffs and how each component of tariffs varies over time. However, AGA submits a smoother price path provides a better approach to pass price reductions through to retailers without imposing cash flow challenges on the business.

1.3 Contribution to the NGO – Making the Decision Which Contributes to the NGO to the Greatest Degree

73. Under the National Gas Law ("NGL"), the ERA must make its decision in a manner that will or is likely to contribute to the achievement of the NGO.[10]

74. Where there are 2 or more possible decisions that could be made, the ERA must also:

- make the one that it is satisfied will or is likely to contribute to the achievement of the NGO to the greatest degree (defined in the NGL as **"**the preferable designated reviewable regulatory decision"); and

[10] see s28(1)(a) of the NGL

- specify the reasons for the basis of that satisfaction.[11]

75. AGA has retained a number of experts who have reviewed the Draft Decision and who have expressed certain opinions in relation to the Draft Decision including that the ERA has fallen into error in a number of respects as outlined in the reports.

76. ATCO has taken into account those reports when preparing its revised proposal.

77. In addition, ATCO has retained HoustonKemp to express its opinion on whether, if the Draft Decision is repeated in the Final Decision, the ERA will have met the contribution to NGO requirement referred to above.[12] The report concludes:

- if the Draft Decision is repeated, it will not meet the requirement to make a decision in a manner that will or is likely to contribute to the achievement of the NGO;
- that taking into account the whole of the matters raised in the Expert Reports and the other matters identified in the HoustonKemp report the ERA will not have met the preferable decision requirement referred to above.

1.3.1 Outline of HoustonKemp Report

78. In broad outline, the report deals with the following matters:

- It sets out a sound basis for determining whether if it repeats the Draft Decision, the Final Decision will have met the NGO objective, principally by reference to the content of the objective as informed by fundamental economic efficiency principles (in particular productive allocative and dynamic efficiencies), each of the building blocks within the NGRs, and the Revenue and Pricing Principles.
- It concludes that if the Rules which establish the building blocks and components within the blocks are not complied with, the objective will not, or will be unlikely to be, met, principally because the non-compliance evidences economic inefficiencies, which in turn are not in the long term interests of consumers.
- It assesses the Draft Decision by reference to the above matters and concludes that if the decision is repeated as the Final Decision, it will contain material inefficiencies which will result in a failure to meet the NGO objective.
- In particular, among other things:
  - it concludes that the rate of return methodology relied upon by the ERA contains allocative and dynamic inefficiencies which are not in the long term interests of consumers.
  - As to the cost of debt, it notes in the above regard that the inefficiency principally arises because the strategies for managing the debt portfolio assumed by the ERA are not replicable in the real world.
  - As to the cost of equity, it notes in the above regard that the ERA relies on a single cost of equity model which substantially under-states the likely cost of equity when compared to an estimate derived at by ATCO's expert based on multiple models and extensive further analysis not undertaken by the ERA.
  - As to depreciation, it notes that the ERA's methodology does not promote efficient investment or use of gas services.
  - As to tax treatment, it notes that the ERA's methodology may discourage asset improvement expenditure and does not promote efficient investments in gas services.

11 As to paragraphs (a) and (b) above, see s28(1)(b)(iii) of the NGL.

12 Appendix 1.1 Evaluation of Economic Regulation Authority's Draft Decision against the National Gas Objective, Greg Houston, HoustonKemp, 27 November 2014

  - As to operating and capital expenditure, it notes that the ERA's methodology does not promote efficient operation of or investment in gas services.
  - As to demand forecasts, it notes that the ERA's estimates, which have substantial downward bias, will cause ATCO not to be able to recover its, and not to be able to undertake investment in network infrastructure which would otherwise be efficient.
- Overall, HoustonKemp conclude that the NGO contribution requirement will not be met unless the corrections/adjustments contended for by ATCO are made.
- Further, HoustonKemp conclude overall that the Draft Decision if repeated in the Final Decision will not satisfy or be likely to contribute to the achievement of the NGO to the greatest degree.

1.3.2 Summary

79. In the light of the HoustonKemp report, each of the expert reports upon which it relies, and the balance of ATCO's submissions forming part of its revised proposal, ATCO submits that unless the errors and other matters are corrected/adjusted for the ERA:

- will not have met the requirement to make a decision that will or is likely to contribute to the achievement of the NGO; and
- will have made a decision which it should not be satisfied will or will be likely to contribute to the achievement of the NGO to the greatest degree.

1.4 Conclusion

80. AGA has implemented 26 of the ERA required amendments, and submits a revised proposal that includes lower revenue proposals and reduced prices for customers. While the revised proposal does not implement the Draft Decision exactly as written, AGA submits it achieves a fair balance between the need to invest in the Western Australian natural gas network and to maintain competitive gas prices, and satisfies the NGO.

81. AGA has not wholly adopted the ERA's amendments as it considers that, as a package of revisions, the Draft Decision does not promote the use of natural gas in Western Australia, does not promote efficient investment in natural gas services and therefore does not satisfy the NGO.

82. If implemented, the expenditure reductions in the Draft Decision would prevent new customers from accessing natural gas supply. Network costs will be spread over a static customer base and ultimately become more expensive over time.

83. AGA provides further information to support the amount of expenditure required to ensure this scenario doesn't arise. However, to make certain the expenditure can be delivered it is important the rate of return can attract sufficient capital from the ATCO Group (and other investors) to fund the investment.

84. The return on equity provided by the Draft Decision is not adequate nor sufficient to support efficient investment. Exclusion of expenditure from the tariff revenue, compounded with a low rate of return means funding to support investment will be difficult to secure. Speculative investment will not occur. Therefore AGA has provided evidence to assist the ERA in its review of the rate of return determination and consider the commercial implications of its Final Decision.

85. AGA submits that its proposals provide an access arrangement that meets the NGO and supports the ERA's achievement of its aim *to promote a competitive, efficient and fair commercial environment for consumers and businesses in the gas, electricity, water and rail industries for the long term benefit of Western Australians.*[13]

[13] ERA, *Annual Report 2013/14*, 2 October 2014, page 3.

86. AGA therefore submits this revised proposal, which implements the ERA's required amendments where appropriate and provides evidence to address matters raised in the Draft Decision that preclude implementation of the ERA's required amendments.

87. AGA submits its proposals satisfy the NGO, enable a sustainable gas supply and allows for the maintenance of Western Australian gas distribution networks as a viable investment, helping facilitate a competitive Western Australian energy market and meeting the long term interests of consumers.

1.5 Structure and approach

88. The remainder of this document details AGA's revised proposal in response to the ERA's Draft Decision on proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System released on 14 October 2014.

89. This document is structured so that it addresses each of the ERA's 45 required amendments in the same order as they appear in the Draft Decision. For each amendment AGA:

- Summarises the ERA's decision
- States whether the required amendment has been implemented

and where applicable:

- Explains the rationale for not implementing the amendment
- Provides evidence to address matters raised by the ERA in the Draft Decision and support AGA's position in this revised proposal

90. This amended revised proposal should be read in conjunction with the amended revised access arrangement accompanying AGA's response to the ERA's Draft Decision. AGA submits that the amended proposed revision to the access arrangement complies with the *National Gas (Access) Act (WA)* 2009 and the requirements of the *National Gas Rules (version 19, January 2014)*.

2. Pipeline services

ERA required amendment 1

Clause 4.1 should be amended as follows:

4.1 Pipeline Services

ATCO Gas Australia offers the following Pipeline Services by means of the AGA GDS to Prospective Users:

a) Reference Services, being the Haulage Services; and
b) ~~Non Reference Services.~~ Reference Services, being the Ancillary Services; and
c) Non-Reference Services.

AGA Response: accept

Summary Only – AGA has implemented the amendment to clarify that Ancillary Services are reference services.

2.1 Summary of ERA decision

91. The ERA has required an amendment to specify that ancillary services are a reference service to improve clarity and consistency between the Access Arrangement Information and the Access Arrangement.

2.2 AGA response

AGA has implemented required amendment 1

3. Total revenue

ERA required amendment 2

The Authority requires that ATCO amend the proposed revised access arrangement values for total revenue (nominal) to reflect the values in Table 4.

AGA Response: do not accept

Summary Only – AGA does not consider the values in Table 4 of the Draft Decision result in an access arrangement that complies with the National Gas Objective , the National Gas Rules or the RPPs.

3.1 Summary of ERA decision

92. The ERA requires total revenue to reflect the values in Table 4 of its Draft Decision. This includes the *removing an amount relating to an inflationary gain in calculating the return on capital and working capital using a nominal rate of return and a nominal value of the capital base/working capital requirements.*[14] The ERA considers that the inflationary gain relates to the return on assets rather than the nominal depreciation[15] and has treated inflationary gain as a separate item in the revenue building block, rather than offsetting depreciation or the return on asset.[16]

93. Table 3–1 represents the ERA's required amendments to total revenue.

Table 3–1: ERA's approved total revenue building blocks AA4

Nominal $ Million	July to Dec 2014	2015	2016	2017	2018	2019	Total
Forecast Operating Expenditure	32.26	64.46	66.16	67.77	70.48	72.43	373.56
Return on Projected Capital Base	29.52	61.36	64.76	67.14	69.17	71.07	363.02
Depreciation of Projected Capital Base	15.06	36.23	39.98	43.22	46.80	50.58	231.87
Estimated Cost of Corporate Income Tax	8.13	-	-	-	-	-	8.13
Imputation Credits	(4.07)	-	-	-	-	-	(4.07)
Estimated Return on Working Capital	0.14	0.10	0.14	0.16	0.17	0.19	0.90
Less Inflationary Gain							
Return on Projected Capital Base	(11.23)	(23.14)	(24.42)	(25.31)	(26.08)	(26.79)	(0.35)
Return on Working Capital	(0.05)	(0.04)	(0.06)	(0.06)	(0.07)	(0.07)	(1.18)
ERA Draft Decision Total Revenue	**69.76**	**138.98**	**146.56**	**152.92**	**160.47**	**167.40**	**836.10**

14 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 92.

15 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 544.

16 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 94.

3.2 AGA response

AGA has not implemented required amendment 2

94. AGA considers the values in Table 4 of the Draft Decision do not result in an access arrangement that complies with the National Gas Rules or the National Gas Law.

95. Greg Houston in their report, Economic Review of the ERA's Draft Decision against the National Gas Objective (Appendix 1.1) finds that:

- It sets out a sound basis for determining whether if it repeats the Draft Decision, the Final Decision will have met the NGO objective, principally by reference to the content of the objective as informed by fundamental economic efficiency principles (in particular productive allocative and dynamic efficiencies), each of the building blocks within the NGRs, and the Revenue and Pricing Principles.
- It concludes that if the Rules which establish the building blocks and components within the blocks are not complied with, the objective will not, or will be unlikely to be, met, principally because the non-compliance evidences economic inefficiencies, which in turn are not in the long term interests of consumers.
- It assesses the Draft Decision by reference to the above matters and concludes that if the decision is repeated as the Final Decision, it will contain material inefficiencies which will result in a failure to meet the NGO objective.
- In particular, among other things:
  - it concludes that the rate of return methodology relied upon by the ERA contains allocative and dynamic inefficiencies which are not in the long term interests of consumers.
  - As to the cost of debt, it notes in the above regard that the inefficiency principally arises because the strategies for managing the debt portfolio assumed by the ERA are not replicable in the real world.
  - As to the cost of equity, it notes in the above regard that the ERA relies on a single cost of equity model which substantially under-states the likely cost of equity when compared to an estimate derived at by ATCO's expert based on multiple models and extensive further analysis not undertaken by the ERA.
  - As to depreciation, it notes that the ERA's methodology does not promote efficient investment or use of gas services.
  - As to tax treatment, it notes that the ERA's methodology may discourage asset improvement expenditure and does not promote efficient investments in gas services.
  - As to operating and capital expenditure, it notes that the ERA's methodology does not promote efficient operation of or investment in gas services.
  - As to demand forecasts, it notes that the ERA's estimates, which have substantial downward bias, will cause ATCO not to be able to recover its, and not to be able to undertake investment in network infrastructure which would otherwise be efficient.

96. Overall, HoustonKemp conclude that the NGO contribution requirement will not be met unless the corrections/adjustments contended for by ATCO are made. Further, HoustonKemp conclude overall that the Draft Decision if repeated in the Final Decision will not satisfy or be likely to contribute to the achievement of the NGO to the greatest degree.

97. Note this section 3.2 discusses the **inflationary gain building block only**. Forecast expenditure, return on projected capital base, depreciation of projected capital base, estimated cost of corporate income tax, imputation credits and estimated return on working capital are discussed in chapters 6 and 8, 9, 10, 11, 12, and 13 of this document respectively.

98. AGA has not incorporated the inflationary gain building block into its revised proposal because:

- The ERA is incorrect in its view about the reasons for the inflationary gain. The inflationary gain does not relate to the return on assets (indeed under the NGR it cannot); rather it results wholly from the indexation of the capital base for inflation (which is not required under the National Gas Rules and can be avoided)
- Working capital is not subject to indexation, so to remove an amount for inflationary gain would result in less total revenue than that properly calculated under rule 76 of the NGR and required by the RPP
- Rule 76 of the NGR sets out a complete listing of the building blocks and does not provide for a new separate building block to be added

3.2.1 The double count of inflation results from indexation of the asset base not the return on capital

99. AGA maintains its original position that the double count of inflation only arises as a result of applying indexation to the capital base[17]. The best way to avoid this problem is to not index the capital base. The NGR do not require the capital base to be indexed. The potential for the capital base to be indexed for inflation is acknowledged in rule 89(1)(d) of the NGR. However, this rule contemplates but does not *require* indexation of the capital base for inflation, noting it can occur where the accounting method approved by the regulator permits.

100. AGA considers the only way to remove a double count of inflation is to remove it in the calculation of the depreciation building block[18]. This is because the NGR require a nominal rate of return to be applied (so the double count cannot be removed from the return on capital because it if it were the return would be real) and no other building blocks are allowed. Removing the double count from the depreciation calculation is allowed as long as the depreciation schedule is compliant with rule 89 of the NGR, which outlines the criteria for the depreciation schedule and the circumstances where deferral of depreciation may occur. If transparency is desired, the removal of inflation from depreciation building block can be expressly acknowledged and shown, but it remains the case that the NGR only recognise that removal can be from depreciation.

101. AGA recognises that a change from an approach where the capital base is indexed to one where it is no longer indexed can result in higher short-term prices for customers. In its March 2014 submission AGA proposed a transitional approach to reduce the price impact on customers. AGA resubmits this transition whereby the Australian Energy Regulator's (**AER**) Post Tax Revenue Model (**PTRM**) method (which removes the double count associated with indexation from the depreciation building block) applies during AA4 to the indexed opening capital base and all new capital during the AA4 is not indexed.

102. AGA's proposed total revenue calculation complies with rule 76 of the NGR (which specifies the building blocks for total revenue), rule 87 of the NGR (which specifies the requirements for the return on the capital) and rule 89 of the NGR (which outlines the criteria for depreciation). The ERA's required amendment does not comply with these rules.

3.2.2 Working capital

103. AGA understands why the ERA has removed an amount relating to the inflationary gain. Under the ERA's approach it needs to ensure that AGA is not compensated twice for inflation that arises as a result of an indexed asset base and the application of a nominal rate of return. This issue is not relevant for working capital.

104. AGA's proposal **does not index the working capital** and there is no double compensation for inflation**.** AGA will therefore not adopt an inflationary adjustment in its calculation of return on working capital.

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17 A view also supported by Greg Houston in his report, *Evaluation of ERA's Draft Decision on ATCO's Depreciation allowance*, HoustonKemp, November 2014 (Appendix 11.1), p.4.

18 Appendix 11.1 Evaluation of ERA's Draft Decision on ATCO's Depreciation allowance, HoustonKemp, November 2014, p.5.

105. More detailed discussion of AGA's response to working capital is provided in Chapter 13 (Return on working capital) of this document.

3.2.3 Rule 76 of the NGR does not permit new building blocks to be added

106. Including a separate building block is not provided for in the National Gas Rules. Rule 76 of the NGR prescribes total revenue is to be determined for each regulatory year of the access arrangement period using the building block approach in which the building blocks are:

> *(a) a return on the projected capital base for the year (See Divisions 4 and 5); and*
>
> *(b) depreciation on the projected capital base for the year (See Division 6); and*
>
> *(c) the estimated cost of corporate income tax for the year (See Division 5A); and*
>
> *(d) increments or decrements for the year resulting from the operation of an incentive mechanism to encourage gains in efficiency (See Division 9); and*
>
> *(e) a forecast of operating expenditure for the year (See Division 7)*

107. The NGR is explicit in regard to what the building blocks are and no permission is given for the service provider or the ERA to introduce any additions during an access arrangement review.

108. AGA recognises that the double count for inflation that is the result of an indexed asset base must be addressed where a nominal rate of return is applied to an indexed asset base. However, the ERA's inclusion of a separate building block is not permitted.

109. Furthermore, as a policy matter, if it was intended that a separate building block was required as a result of the change to rule 87 of the NGR, it would have been incorporated in the changed rule. The ERA raised the double count of inflation issue and the conflict with prescribing a nominal rate of return with the AEMC during the rule determination process. However, no additional building block was developed.

3.2.4 Total revenue proposal

110. Table 3–2 shows AGA's amended proposed total revenue for AA4. As discussed above AGA has not included a separate inflationary gain building block.

111. AGA's revised positions on the forecast expenditure, return on capital and depreciation building blocks are discussed in Chapters 6 to 13.

Table 3–2: AGA's amended proposed total revenue building blocks AA4

$ million real at 30 June 2014	July to Dec. 2014	2015	2016	2017	2018	2019	Total
Return on capital base	37.6	77.1	81.9	87.0	91.8	95.9	471.3
Return on working capital	0.1	0.2	0.2	0.2	0.2	0.2	1.1
Depreciation	4.8	14.8	19.3	22.9	26.0	28.8	116.6
Opex	32.2	72.1	73.1	74.5	76.5	78.7	407.1
Tax	6.8	8.4	7.2	6.4	5.7	3.9	38.4
AGA amended proposal total revenue	**81.5**	**172.6**	**181.7**	**191.0**	**200.2**	**207.5**	**1,034.5**

112. Figure 3–1 shows how the total revenue in AA4 compared to total revenue during AA3 and the ERA's Draft Decision.

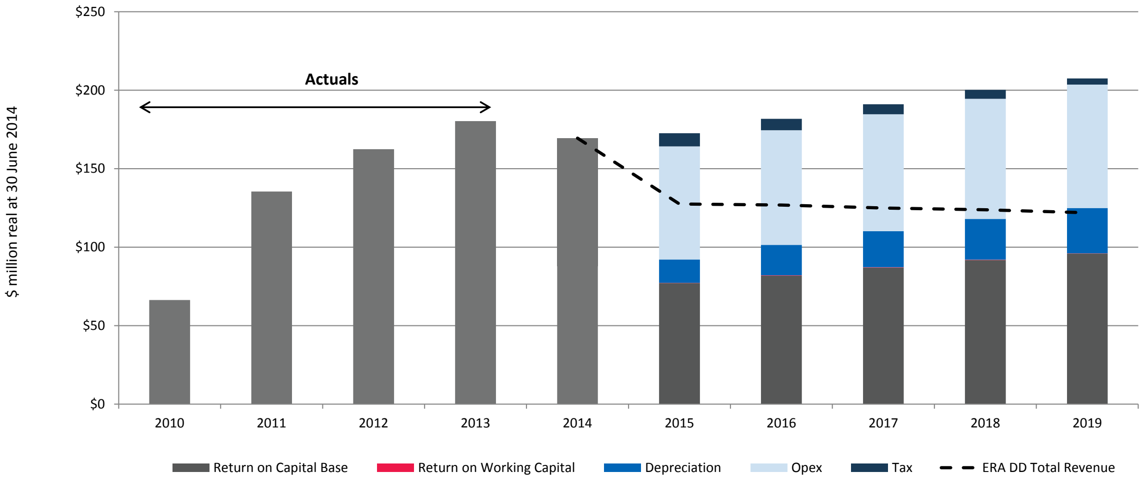

Figure 3–1: Total revenue

4. Demand forecast

ERA required amendment 3

The Authority requires that ATCO update the GDS demand forecast for the fourth access arrangement period in accordance with Table 8.

AGA Response: AGA does not accept this amendment

Summary Only – AGA does not consider the values in Table 4 of the Draft Decision result in an access arrangement that complies with the NGO, the NGR or the RPPs because the ERA has not adopted a robust forecast methodology for consumption resulting in a consumption forecast being too high and the ERA has not accepted the proposed greenfield connections resulting in the forecast connections being too low.

4.1 Summary of ERA decision

113. The ERA requires AGA to update its volume and connection forecasts to reflect the ERA's amended forecast for B2 and B3 customers. The ERA accepts AGA's methodology for forecasting A1, A2 and B1 connection and usage forecasts.

114. It is not apparent whether the ERA or EMCa identified any particular issues with AGA's B2 and B3 forecasting methodology as none are identified in the Draft Decision. Instead, arbitrary adjustments were made to the outcomes resulting from this methodology. The ERA has:

- Adjusted customer numbers to remove the new connections associated with the greenfield growth capital expenditure forecast on the basis that the greenfield growth capital expenditure is not economic
- Included the additional customers AGA proposed would result from the marketing and business development activities whilst disallowing the additional expense associated with those activities (which the ERA considers can be delivered within 2013 levels of expenditure)
- Adopted an average usage for new B2 and B3 customers of 80 GJ and 12 GJ respectively
- Adopted an assumption that forecast average usage per customer for B2 and B3 customers will remain constant at 2014 levels

4.2 AGA response

AGA has not implemented required amendment 3

4.2.1 ERA adjustments to customer numbers

115. The ERA's adjustments to connection numbers relate directly to its required amendments to forecast growth capital expenditure and forecast operating expenditure for business development and marketing. AGA has not accepted these amendments to forecast expenditure, which are discussed further in Chapter 8 (Projected capital base) and Chapter 6 (Operating expenditure) respectively. A summary of AGA's position relating to this expenditure adjustment is discussed below.

4.2.1.1 Marketing and business development

116. The ERA has included the additional customer numbers associated with the proposed additional marketing and business development in its adjusted demand forecast, despite reducing the allowed expenditure on

these activities to 2013 levels. The ERA *considers that the portion of the expenditure that it has deemed as efficient would deliver the forecast customer number growth*[19] without providing any basis for this conclusion.

117. AGA does not accept that the additional customer numbers and consumption will be achieved if marketing and business development expenditure remains at 2013 levels. Expenditure on business development and marketing in 2013 consisted mainly of internal labour costs toward market research activities. This level of expenditure is not sufficient to cover the active market campaigns proposed during AA4 (See 6.2.3.2).

118. Further, AGA has assessed the expected impact on customer numbers and consumption from the additional marketing and business development activities to be undertaken during AA4 on an incremental basis. The additional connections and consumption will require additional activities (and expense) compared to 2013. Therefore, to include the additional consumption and customers in the absence of providing forecast expenditure for these activities would result in an over estimate of demand.

4.2.1.2 Adjustment for disallowed greenfield growth expenditure

119. AGA does not accept the ERA's amendment to remove all expenditure on greenfield development areas. This is because the net present value (**NPV**) analysis relied upon by EMCa and subsequently the ERA to make this determination is flawed. To prevent the connection of these customers when they would be willing to pay for the connection is inconsistent with the efficiency principles under the National Gas Objective. Figure 4–1 below illustrates the effect of the ERA's required amendment to disallow connections in greenfield development areas compared to AGA's historical and forecast gross connections.

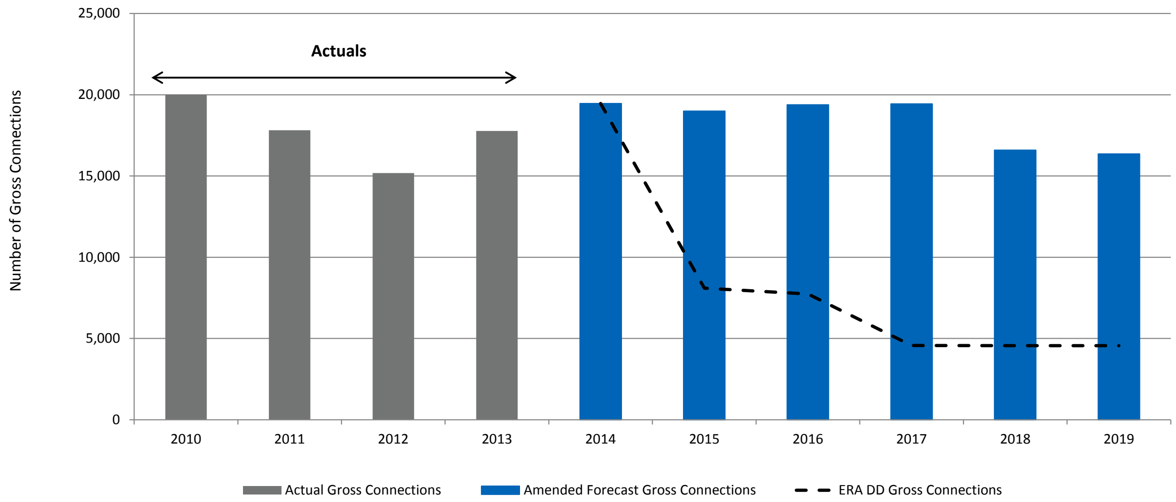

Figure 4–1: Gross new connections

120. AGA has revised its expenditure on greenfield development areas to be consistent with its revised forecast of new customers. The revised forecast of new customers is higher than the forecast in the March 2014 proposal as the forecast is heavily influenced by historical connection numbers and stronger growth in customer numbers has been experienced in 2014.

121. Given the ERA identified no issues relating to the methodology adopted by AGA to forecast connection numbers, the same methodology has been adopted for the updated new customer forecast provided in Section 4.2.3.2 AGA revised demand forecast.

[19] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 120.

4.2.2 ERA adjustments to average per customer consumption forecast

122. The ERA made two adjustments to the average per customer consumption forecast for B2 and B3 customers:

- The ERA rejects the results of the Core Energy forecast methodology for the average forecast per customer and instead adopted a forecast on the basis that the average per customer consumption for B2 and B3 customers will remain the same as 2014 for the AA4 period
- The ERA adopts an average per customer consumption for new customers of 80 GJ and 12 GJ for B2 and B3 customers respectively by taking the usage for most recently connected customers

123. AGA has not accepted these adjustments because it does not consider they provide the best estimates of forecast consumption for the AA4 period. The adjustments also contain errors. AGA considers the ERA's forecast of customer numbers and volumes does not comply with rule 74 of the NGR as it has not been *arrived at on a reasonable basis*[20] and does not *represent the best forecast or estimate possible in the circumstances.*[21]

124. AGA considers the forecasts developed by Core Energy[22] on the basis of a robust and commonly accepted methodology (which the ERA has adopted in respect of A1, A2 and B2 customers and has not identified any specific concerns with) represent the best forecast for the AA4 period. Although AGA's initial submission incorporated the total forecast for average consumption for B3 customers, the forecast appeared flat due to the inclusion of the impact of proposed business development and marketing activities. Without these activities, the Core Energy methodology and the historical trend identifies that the average consumption per customer will continue to decline. This is also acknowledged by the ERA's consultant EMCa due to the *continuing decline each year in the annual volumes for newly connected B3 customers.*[23]

125. The following sections describe the errors in the ERA's customer consumption forecasts.

4.2.2.1 Lack of weather adjustment

126. The ERA's forecast ignores the impact from weather. It is widely accepted (including by the Australian Energy Market Operator (AEMO) and the AER), that the weather influences gas demand and this influence must be taken into account before assessing the underlying historical growth in demand. Using non-weather adjusted data means observations may be influenced by unseasonal weather events. This is the case with consumption data from 2013, which EMCa used as a basis of its analysis. Due to the unseasonably warm weather conditions experienced in Perth during 2013, average consumption levels are understated compared to what would be experienced in normal weather conditions.

4.2.2.2 Adopting the 2014 average annual consumption overstates average usage

127. The ERA adjusts the demand forecasts such that the average usage per customer for existing B2 and B3 customers to remain at 2014 levels.[24] The decline in annual average consumption incorporated in the Core Energy forecast is based on regression analysis and adjustments of known influencing factors for new customers. The methodology and assumptions supporting the forecast is outlined in the Core Energy Report.[25] It is recognised across the energy sector that customers periodically swap out old appliances with newer more energy efficient appliances which results in less energy required for the same energy outcome.

[20] National Gas Rule 74(2)(a).

[21] National Gas Rule 74(2)(b).

[22] Appendix 4.2 Expert Witness Report on the Authority's Adjusted Demand Forecast, Paul Taliangis, Core Energy Group opinion dated 25 November 2014.

[23] EMCa, ATCO Gas Australia Connections Forecast June 2014, paragraph 241.

[24] ERA 2014, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 119.

[25] Appendix 4.1 Gas Demand Forecast, Mid-West and South-West Distribution System Core Energy Group November 2014.

New customer demand per connection is derived by deducting the weighted average 6 star impact of 1.098 GJ from the weighted average demand for all connections as summarised in Table 4–1: Average usage per customer for B3 connections.

Table 4–1: Average usage per customer for B3 connections November 2014

Connection type	2014	2015	2016	2017	2018	2019
Weighted average usage (all connections)	14.67	14.45	14.32	14.25	14.21	14.16
Average usage of new connections with impact of 6 star rating	13.58	13.35	13.22	13.15	13.11	13.06

128. The ERA and EMCa criticised the previous Core Energy's forecast customer usage for B3 customers, as present which stabilises at around 14.8 GJ per customer from 2015[26] on the basis of evidence of continuing *decline each year in the average annual volumes for newly connected B3 customers.*[27] Despite this, the ERA has adopted a flat forecast for B3 customer usage for the entirety of AA4 at a *higher* amount than Core Energy's forecast (approximately 15 GJ per customer).

129. AGA considers EMCa has understated the annual usage of the most recently connected customers. This is because EMCa has used data that only reflects the first year of usage. Core Energy has estimated average use per residential customer by adjusting the forecast average demand for the impact of the 6-star building standard.[28] This is a better method of forecasting new customer demand because the usage of new customers in the first and second year of connection is not representative of the likely continued usage. This is due to several factors such as the dwelling remaining unoccupied or the full suite of planned appliances not yet installed.

130. As demonstrated in Table 4–2 below, in all instances for customers connected since 2009, the consumption of B3 customers is at its lowest in the first year and steadily increases over the subsequent years. Core Energy notes that, *The ERA approach relies on the observation of gas consumption in a first year of connection for a new customer, which is not representative of the average mature consumption.*[29] Therefore, assuming that average consumption per customer will remain static over time is likely to overestimate average consumption per customer for new customers.

Table 4–2: Weather adjusted average consumption of newly connected B3 customers (GJ)[30]

Year customer connected	2009	2010	2011	2012	2013
Pre 2009	18.2	17.4	16.1	16.2	16.1
2009		13.4	13.6	14.3	14.6
2010			12.1	13.7	14.1
2011				11.5	12.6
2012					11.8

26 Table 5: Forecast B3 Customers and average consumption per customer: ATCO Access Arrangement Information March 2014.

27 ERA 2014, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 117.

28 Appendix 4.1 Gas Demand Forecast, Mid-West and South-West Distribution System Core Energy Group November 2014, Section 6.5.

29 Appendix 4.2 Expert Witness Report on the Authority's Adjusted Demand Forecast, Paul Taliangis, Core Energy Group opinion dated 25 November 2014, section 5.1.4.

30 In response to EMCa 56, AGA provided the actual (non-weather adjusted) average consumption for newly connected customers.

131. Figure 4–2 shows the average annual consumption for newly connected B3 customers.

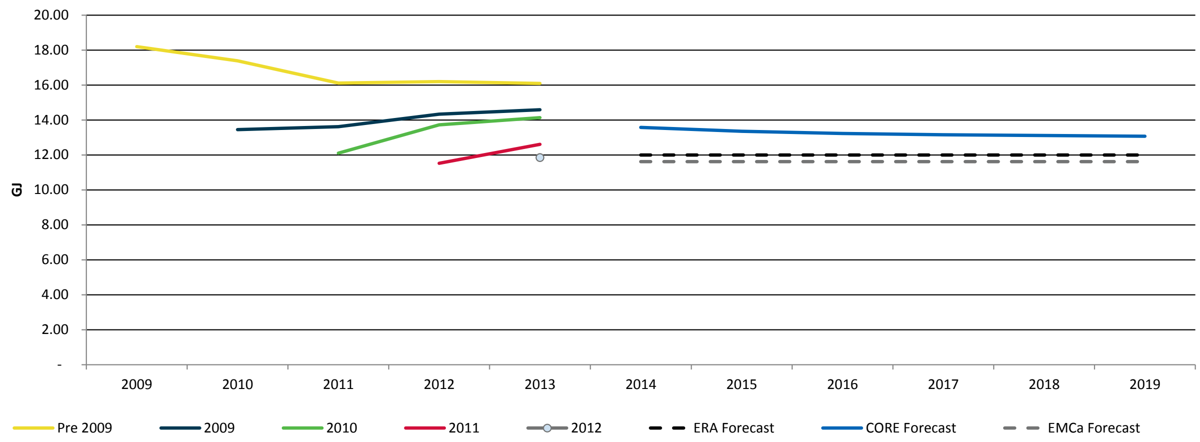

Figure 4–2: Average annual usage of new B3 customers

132. The ERA's estimate for the average consumption for B2 customers is 80 GJ. This was broadly consistent with the historical average consumption of new B2 customers in their third year of connection (when the consumption is expected to represent ongoing usage) as shown in Table 4–3: Weather adjusted average consumption of newly connected B2 customers (GJ) below.

Table 4–3: Weather adjusted average consumption of newly connected B2 customers (GJ)

Year customer connected	2009	2010	2011	2012	2013
Pre 2009	172.5	166.5	163.1	162.2	160.2
2009		79.6	81.8	80.3	81.4
2010			68.6	76.1	81.9
2011				74.7	80.3
2012					56.1

133. However, the forecast average usage for B2 connections during AA4 is much greater than 80 GJ and forecast to decline each year (as shown in Table 4–4). Forecast average consumption for B2 customers is expected to be much higher in AA4 as a result of AGA making the AL10 meters available for B3 connections. This enables customers that would previously have been classified as a B2 customer as a result of their consumption being greater than the capacity of the AL8 meter, now being able to utilise the AL 10 meter under a B3 Reference Tariff. It is expected that approximately half of customers (approximately 250 customers) that would previously been classified as B2 now being classified as B3. The result is a higher average consumption for B2 customers. The impact in the average consumption of B3 customers is marginal because 250 customers is a small proportion of the new B3 customers expected each year.

Table 4–4: Average usage per customer for B2 connections

Connection type	2014	2015	2016	2017	2018	2019
Demand per connection (GJ)	124	119	114	111	108	106

4.2.3 AGA revised demand forecast

134. AGA has updated its demand forecast to include a further year since its last forecast. New connection forecasts have been provided by ECS[31] and Core Energy has updated the demand forecast. The updated forecast has taken into account:

- Actual connection and consumption data for the period to 31 October 2014 with an estimate for November and December 2014
- Impact on retail prices as a result of the removal of the carbon tax

135. The following sections set out AGA's revised demand forecast.

4.2.3.1 Forecast methodology

136. AGA developed its volume and connection forecasts with the assistance of Economics Consulting Services (**ECS)** and Core Energy. ECS prepared the forecast B3 customer connections based on recent macro-economic indicator forecasts such as building activity, population growth and the number of homes choosing to connect to gas.

137. EMCa raised concerns around the population growth assumptions beyond 2015:

> *The ECS report has assumed the highest considered population growth rate at less than two per cent as the basis of forecast new customers. The report provides three population growth assumptions, the highest of which commences at 2 per cent and declines to 1.8 per cent per year over the period from 2015 to 2019. The central population growth assumption is 0 to 0.2 per cent per year lower, and the lowest population growth assumption is around 0 to 0.2 per cent per year lower again.*[32]

138. The revised ECS forecast[33] incorporates the latest housing industry forecasts from the Housing Industry Association (**HIA**) and the Western Australian Housing Industry Forecasting Group (**HIFG**), which extend out to 2018. The WA housing industry has seen an increase in housing starts over 2012-13 and this trend has been reflected in actual connections over the second half of 2013 and 2014. The ECS forecast was based on the housing industry forecasts, which are lead indicators of future connections; the forecast in the AAI was based on the latest forecasts available at that time. ECS have since provided an updated forecast incorporating the latest HIA and HFIG forecast of housing starts, AGA has updated its connection forecasts to incorporate the latest available information.

139. Table 4–5 presents the updated ECS B3 connection forecast compared to the connection forecast submitted in the initial AAI in March 2014.

140. The ECS forecast was based on the housing industry forecasts, which are lead indicators of future connections; the forecast in the AAI was based on the latest forecasts available at that time. ECS have since provided an updated forecast incorporating the latest HIA and HFIG forecast of housing starts, AGA has updated its connection forecasts to incorporate the latest available information.

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31 Appendix 4.3 ATCO Gas Australia Connection Forecast Economics Consulting Services (ECS) June 2014.

32 ERA Draft Decision to the proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System 14th October 2014, paragraph 117.

33 Appendix 4.3 ATCO Gas Australia Connection Forecast Economics Consulting Services (ECS) June 2014.

Table 4–5: ECS forecast gross connections

B3 connection forecast	Jul to Dec 2014	2015	2016	2017	2018	2019
ECS B3 Forecast	8,113	16,349	16,522	16,564	16,564	16,564
AL10 Meter	125	250	250	250	250	250
AAI B3 Connections	**8,238**	**16,599**	**16,772**	**16,814**	**16,814**	**16,814**
ECS B3 Forecast	0	17,359	18,002	18,059	15,224	15,004
Estimate for July to December 2014	9,182					
AL10 Meter[34]	0	250	250	250	250	250
Amended Proposal B3 Connections	**9,182**	**17,609**	**18,252**	**18,309**	**15,474**	**15,254**

141. The 2014 ECS forecast for B3 customers is higher than the 2013 ECS forecast in 2015, 2016 and 2017. This variance is due to higher than expected dwelling starts in 2013 and 2014. Due to the lag between building properties and connecting them to the gas network, connection rates are expected to remain high until 2017, after which time they will revert to levels consistent with the HIA and HIFG forecasts. A comparison of the 2013 and 2014 ECS forecast is shown in Figure 4–3 below.

142.

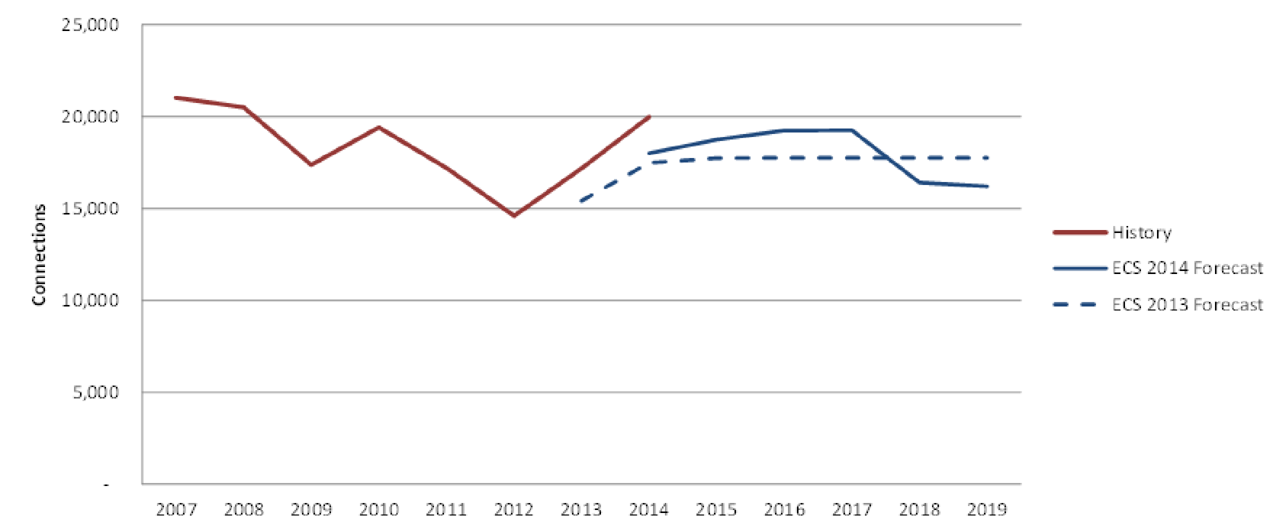


Figure 4–3: Comparison of 2013 and 2014 ECS B3 connections forecast

143. The 2014 ECS forecast of new B3 connections is factored into the Core Energy model to forecast B3 demand over the AA4 period. Core Energy forecasts the gross new connections and then adjusts the gross connections by the historical disconnection rate. The difference is the net new connections.

144. The disconnection rate is determined by dividing the number of disconnections by the total number of connections. In its review of the original Core Energy forecast EMCa raised concerns that:

34 The AL10 meter will not be available until the date the Access Arrangement comes in to effect as these meters are not allowed under the current definition of the B3 Reference Service.

The demand forecast assumes that annual customer disconnections represent close to 20 per cent of the assumed number of new customer connections. This may indicate an overly pessimistic customer forecast.[35]

145. AGA points out that the disconnection rate referred to by EMCa is not the same as that used by AGA and Core Energy. The rate used by EMCa is the number of disconnections divided by new customers only. AGA does not consider this a meaningful measure as the disconnections each year have virtually no relationship with the number of new connections. The disconnection rate used by AGA and Core Energy is quite stable over time whereas the disconnections as a proportion of new connections are extremely volatile. This is shown in Figure 4–4 below.

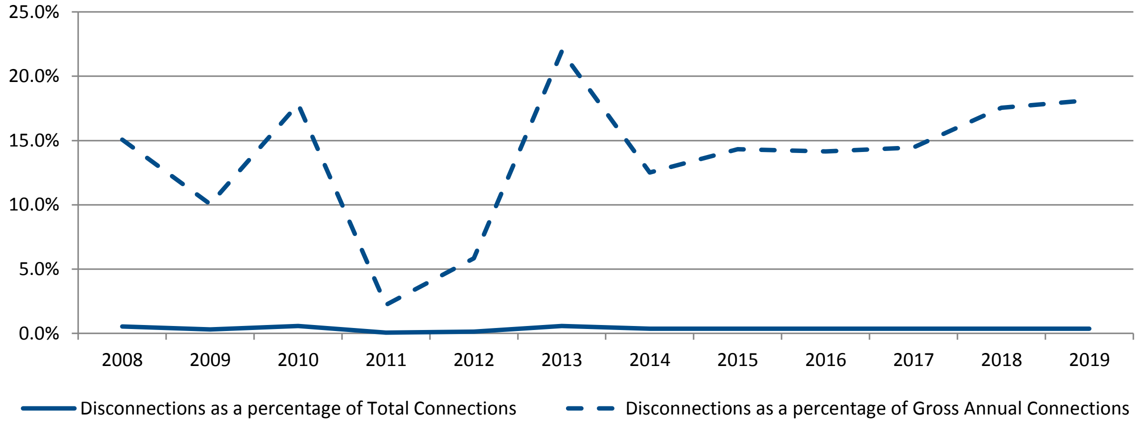


Figure 4–4: Disconnections as a % of total and gross annual connections

146. Disconnection rates in Figure 4–4 have been updated from the 2013 Core Energy forecast to reflect the latest 2014 data. AGA has experienced a fairly flat historical trend for disconnections as a percentage of total B3 connections.

4.2.3.2 Revised demand forecast

147. AGA has revised its demand forecasts as follows:

- Included connections associated with the proposed customer initiated greenfield growth capital expenditure
- Updated B3 connection forecast for the June 2014 ECS Report. This forecast is based on the most contemporary forecast information available
- Applied average annual usage per customer for new B2 and B3 customers as forecast by Core Energy and presented in Table 4–2 and Table 4–3
- Applied average usage per customer for existing B2 and B3 customers as per the 2014 Core Energy forecast
- Updated A1 and A2 and B1 forecasts to reflect newly identified information[36]
- Table 4–6 summarises AGA's overall demand forecast (connection numbers and consumption) for the AA4 period. The methodology and results are presented in the 2014 Core Energy report[37].

35 ERA 2014, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 117.

36 Three new customers and one customer transferring from the B1 tariff class

37 Appendix 4.1 Gas Demand Forecast, Mid-West and South-West Distribution System Core Energy Group November 2014.

Table 4–6: Revised demand and connection forecasts AA4

Tariff Class	2014 July to Dec	2015	2016	2017	2018	2019
A1						
Connection numbers (Average)	73	73	74	74	74	74
Demand (GJ)	6,016,711	11,572,769	11,720,093	11,883,212	12,105,157	12,350,313
A2						
Connection numbers (Average)	107	110	114	116	118	121
Demand (GJ)	995,527	1,964,815	2,038,598	2,093,755	2,160,501	2,232,868
B1						
Connection numbers (Average)	1,402	1,436	1,483	1,531	1,581	1,632
Demand (GJ)	874,652	1,662,033	1,687,385	1,725,834	1,771,171	1,819,523
B2						
Connection numbers (Average)	10,254	10,542	10,873	11,193	11,500	11,793
Demand (GJ)	647,044	1,242,503	1,230,679	1,225,760	1,222,733	1,218,670
B3						
Connection numbers (Average)	671,425	681,905	697,319	713,026	727,285	739,964
Demand (GJ)	5,153,602	9,845,779	9,969,056	10,132,051	10,291,692	10,431,445
Total						
Connection numbers (Average)	683,261	694,066	709,863	725,940	740,558	753,583
Demand (GJ)	13,687,536	26,287,899	26,645,812	27,060,612	27,551,254	28,052,819

4.2.3.3 Impact of marketing and business development activities

148. AGA has revised its expenditure on business development and marketing activities as outlined in Chapter 6 (Operating expenditure) and as a consequence the forecast impact of these activities on customer numbers and consumption has been revised.

149. AGA's revised marketing and business development activities are expected to add 4,048 customers and 339,761GJ consumption during the AA4 period.

150. Table 4–7 below presents the forecast increases in connections and volumes associated with the revised marketing and business development program. The forecast reflects the number of connections and impact on consumption identified for each of the incentive programs (as outlined in section 6.2.3.2). Without the additional expenditure associated with these programs and the supporting marketing and community programs, the best forecast of customers and consumption remains that outlined in section 4.2.3.2 (Revised demand forecast) above.

Table 4–7: Forecast impact of market and business development program on demand

Tariff Class	2015	2016	2017	2018	2019
A1					
Connection numbers (Total)					
Demand (GJ)					
A2					
Connection numbers (Total)	2	4	6	8	10
Demand (GJ)	17,931	53,796	90,402	128,223	167,286
B1					
Connection numbers (Total)	4	8	12	16	20
Demand (GJ)	9,594	18,960	28,257	37,523	46,755
B2					
Connection numbers (Total)					
Demand (GJ)	7,280	12,133	16,986	21,839	26,692
B3					
Connection numbers (Total)	994	1,750	2,506	3,262	4,018
Demand (GJ)	12,943	38,748	56,232	81,120	99,027
Total					
Connection numbers (Total)	1,000	1,762	2,524	3,286	4,048
Demand (GJ)	47,748	123,637	191,877	268,705	339,760

4.2.3.4 Summary of the impact of the ERA adjustments to AGA forecast demand

151. The ERA's forecast demand results in an overestimate of consumption and an underestimate of connections. If not corrected, this will reduce the likelihood of AGA recovering the total revenue over the AA4 period as a result of Reference Tariffs being lower than they should be. Return on capital and capital investment being too low will drive inefficiently low levels of investment.

152. The ERA's overestimation of consumption is driven by:

- Not normalising actual consumption data for weather impacts
- Not factoring in increasingly energy efficient household and appliances in average customer consumption levels, meaning lower consumption.
- Incorporating consumption in the first years of a newly connected customer when forecasting average demand for new customers, as consumption is usually lower in the first year of connection.
- Inclusion of additional consumption expected from proposed additional marketing and business development activities without allowing for the additional expenditure associated with such activities.

153. The underestimate of connections is driven by:

- Disallowing capital expenditure associated with connections in greenfield development areas (and some brownfields connections)
- Reducing connection of new customers to only those located within 20m

- Not updating the connection forecast for the higher than forecast connections in 2014

154. The forecast demand and connections adopted by the ERA in the Figure 4–5 below.

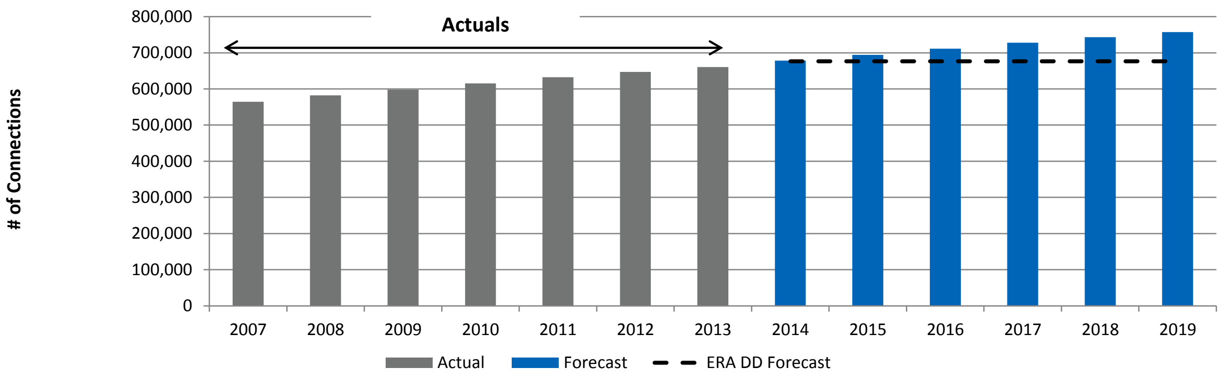


Figure 4–5: AGA actual and forecast connections compared with the ERA's forecast connections

155. The table below presents the connection numbers and consumption for each tariff class to be used for the purpose of determining total revenue and Reference Tariffs which includes AGA's revised forecast of the impact of marketing and business development initiatives. The connection numbers shown in Table 4–8 are all average connections.

Table 4–8: New connections and overall demand for AA4

Tariff Class	2014 July to Dec	2015	2016	2017	2018	2019	Annual average growth rate
A1 tariff							
Connection numbers	73	73	74	74	74	74	0.1%
Demand (GJ)	6,016,711	11,572,769	11,720,093	11,883,212	12,105,157	12,350,313	1.3%
A2 tariff							
Connection numbers	107	111	117	121	125	130	4.0%
Demand (GJ)	995,527	1,982,745	2,092,394	2,184,157	2,288,724	2,400,155	4.6%
B1 tariff							
Connection numbers	1,402	1,438	1,489	1,541	1,595	1,650	3.5%
Demand (GJ)	874,652	1,671,627	1,706,345	1,754,091	1,808,694	1,866,278	2.5%
B2 tariff							
Connection numbers	10,254	10,542	10,873	11,193	11,500	11,793	3.1%
Demand (GJ)	647,044	1,249,783	1,242,812	1,242,746	1,244,572	1,245,362	-0.1%
B3							
Connection numbers	671,425	682,402	698,689	715,147	730,154	743,578	2.2%
Demand (GJ)	5,153,602	9,858,722	10,007,804	10,188,283	10,372,812	10,530,472	1.5%
Total							
Connection numbers	683,261	694,566	711,242	728,076	743,448	757,225	2.2%

Tariff Class	2014 July to Dec	2015	2016	2017	2018	2019	Annual average growth rate
Demand (GJ)	13,687,536	26,335,646	26,769,448	27,252,489	27,819,959	28,392,580	1.6%

156. Figure 4–6 illustrates AGA's actual and forecast total demand as well as the ERA's forecast total demand.

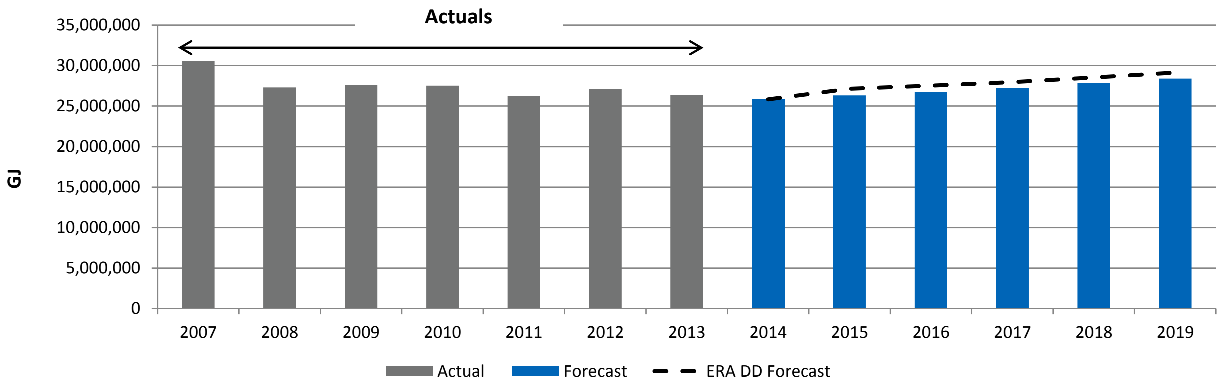


Figure 4–6: AGA actual and forecast demand compared with the ERA forecast demand

5. Key performance indicators

ERA required amendment 4

The authority requires that ATCO amend KPI targets as per Table 10 of the Draft Decision.

The authority also requires that ATCO develop an asset health KPI, and propose a target for it for the fourth access arrangement period.

AGA Response: accept with modifications

Summary Only - AGA has accepted the KPI targets for the customer service performance indicators and two network integrity performance indicators. AGA has not accepted the target for SAIFI due to an error identified in the data provided nor has it accepted the operating cost KPIs as a result of not accepting the ERA's required amendments 5 and 8 relating to operating expenditure and forecast customer connections.

5.1 Summary of ERA decision

157. The ERA requires AGA to amend key performance indicator (**KPI**) targets as per Table 10 of the draft decision. Table 10 is replicated below.

Table 5–1: ERA's draft decision

Key Performance Indicators	AGA Proposed Target	ERA Approved Target
Customer Service		
Domestic customer connection within five days	>97 per cent	>99.5 per cent
Attendance to broken mains and services within one hour	>97 per cent	>99.7 per cent
Attendance to loss of gas supply within three hours	>97 per cent	>99.7 per cent
Network Integrity		
Total public reported gas leaks per one kilometre main	<0.8	<0.7
System Average Interruption Frequency Index (**SAIFI**)	<0.005	<0.0035
Unaccounted for Gas (**UAFG**)	<2.9 per cent	2.57 per cent
Expenditure		
Operating expenditure per kilometre of main (2019)	$6,068	$4,774
Operating expenditure per customer connection (2019)	$116	$92

158. The ERA's technical consultants EMCa assessed AGA's proposed KPI targets and propose targets it considers to be more reasonable based on the following:

- *Derived proxy for customers' expectations for the six customer service and network integrity KPIs, by considering ATCO's past performance and available benchmark information from other Australian gas distribution utilities*
- *Link between ATCO's proposed KPIs, KPI targets and expenditure over the fourth access arrangement period*

- *Likelihood of attainment of the targets, based on the information that ATCO has provided in its proposed revises access arrangement, and in response to subsequent information requests from EMCa*[38]

159. EMCa has also given more weight to recent performance, using average service performance over the most recent three-year period.[39]

160. The ERA also requires AGA develops an asset health KPI to provide a link between network management and the service level that is experienced by customers.[40] AGA must propose a health KPI target for AA4.

5.2 AGA response

AGA has implemented the required amendment, with some modifications.

161. AGA accepts the approach to setting KPI targets to reflect the three year average performance levels for the customer service performance indicators and network integrity performance indicators, and also accepts the UAFG target as required. However, AGA making these amendments is dependent on it not adopting the ERA's required amendment 5 (operating expenditure) and 8 (projected capital base). Where the allowed expenditure is reduced or the return on investment is lower than proposed by AGA in the revisions to the access arrangement, AGA does not accept these targets. AGA will propose new targets if those reductions transpire.

162. The targets proposed by AGA in its access arrangement information are those contained in the Asset Management Strategy (**AMS**) and relevant to ensuring compliance with the Gas Distribution System (**GDS**) Safety Case. AGA is committed to operating a safe and reliable gas distribution system and will endeavour to achieve the more challenging targets set by the ERA. Despite this, AGA considers there is a significant risk that the targets required by the ERA's amendments cannot be met, more so if expenditure levels are reduced. Therefore, the targets in the AMS will not be updated.

163. For example, in relation to the KPI 'Attendance to broken mains and services within one hour' AGA faces increasing challenges posed by traffic congestion, especially as the network grows. AGA mitigates this risk by ensuring optimal resources are able to respond and by using technology such as GPS to ensure resources are deployed efficiently. The 99.7% target requires AGA to attend at least 1296 broken mains and services events out of 1300 each year within one hour.

5.2.1 SAIFI

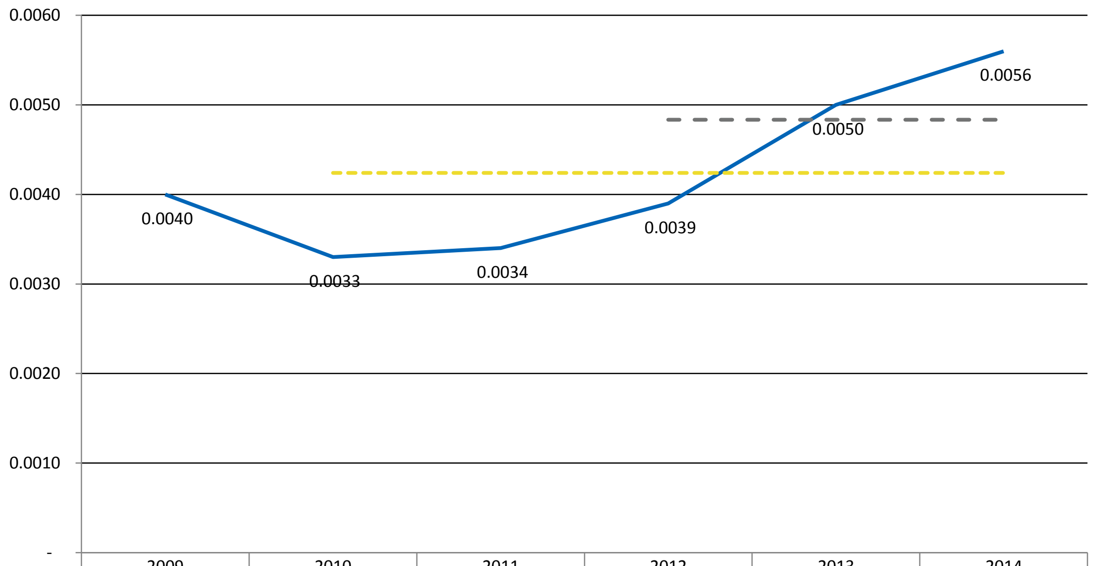
164. AGA has accepted the ERA's methodology for establishing the System Average Interruption Frequency Index (**SAIFI**) target but has identified an error in the data provided in the March 2014 access arrangement information. The March submission incorrectly cited the SAIFI data provided was for 2009 to 2013. The data was in fact for 2008 to 2012. Performance in 2013 was 0.0050. As a result, the most recent three year average performance would be 0.0048.

165. Figure 5–1 shows the corrected chart with the accompanying data. Year-to-date performance indicates AGA performance will lessen further in 2014.

38 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, paragraph 128.

39 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, paragraph 129.

40 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, paragraph 165.



	2009	2010	2011	2012	2013	2014
SAIFI	0.0040	0.0033	0.0034	0.0039	0.0050	0.0056
3 Year Average				0.0048	0.0048	0.0048
5Year Average		0.0042	0.0042	0.0042	0.0042	0.0042

Figure 5–1: SAIFI performance 2009 to 2014

166. Therefore AGA proposes the SAIFI target for AA4 is 0.0048, to reflect the last three years' average performance.

5.2.2 Operating expenditure KPIs

167. AGA has not implemented the ERA's operating expenditure targets. This is a consequence of not accepting required amendments 3 and 5 of the Draft Decision. The two operating expenditure KPIs are an outworking of the revised customer connections, network length and operating expenditure forecast proposed by the ERA. Given this revised proposal submits different operating expenditure, network length and customer number forecasts to the ERA, AGA submits the operating expenditure per kilometre of main and operating expenditure per customer connection KPIs are $5,269 (2019) and $103.14 (2019) respectively. AGA will propose new targets if the revised proposal is not accepted.

168. Table 5–2 summarises AGA's amended KPI targets.

Table 5–2: Summary of AGA's response to required amendment 4

Key Performance Indicators	AGA Proposed Target	ERA Approved Target	AGA Response	AGA Revised Target
Customer Service				
Domestic customer connection within five days	>97 per cent	>99.5 per cent	**Accept**	>99.5 per cent
Attendance to broken mains and services within one hour	>97 per cent	>99.7 per cent	**Accept**	>99.7 per cent
Attendance to loss of gas supply within three hours	>97 per cent	>99.7 per cent	**Accept**	>99.7 per cent
Network Integrity				
Total public reported gas leaks per one kilometre main	<0.8	<0.7	**Accept**	<0.7
System Average Interruption Frequency Index (SAIFI)	<0.005	<0.0035	**Do not accept**	<0.0048
Unaccounted for Gas (UAFG)	<2.9 per cent	2.57 per cent	**Accept**	2.57 per cent
Expenditure				
Operating expenditure per kilometre of main (2019)	$6,068	$4,774	**Do not accept**	$5,269
Operating expenditure per customer connection (2019)	$116	$92	**Do not accept**	$103.14

5.2.3 Proposed asset health KPI

169. The ERA's technical consultant EMCa acknowledged AGA has proposed more indicators than any other gas distribution business in Australia except for ActewAGL and found that *the six non-financial KPIs are sufficient to give AGA the opportunity to show the impact of its expenditure on customer service and network integrity*.[41] Despite this, EMCa, also recommended inclusion of an asset health KPI such as network risk profile, network condition profile and asset class health indicators.

170. AGA supports including an asset health KPI if the ERA provides allowance for one additional FTE ($120,000 per calendar year) in the approved operating expenditure forecast. This FTE would develop, collect and report on the health measure. However, the KPI would not be in place until the fifth access arrangement period.

171. Given the experimental nature of the health index[42] and it being the first of its kind in Australia, AGA considers developing a health index will require considerable time to research and test to ensure it reflects ERA's requirements and adds value to network management. It is unlikely a satisfactory health index would be available until 2016.

172. On the basis of the ERA's approach to set KPI targets based on a three year average, a target would not be available until 2019. Therefore, AGA will not amend its access arrangement to include a proposed target.

41 Energy Market consulting Associates, Review of Technical Aspects of the Proposed Access Arrangement, June 2014, paragraph 210.

42 EMCa was unable to identify an example of a health index being developed, adopted or used by any other gas distribution network in Australia or outside of Australia. Therefore, AGA considers it is reasonable to conclude that the development of an index would be time consuming and experimental.

6. Operating expenditure

ERA required amendment 5

The Authority requires ATCO to amend its forecast operating expenditure for the fourth access arrangement period ($347.48 million in real dollars at 30 June 2014) in line with Table 17 of the Draft Decision.

AGA Response: Do not accept

Summary only - AGA has not implemented the ERA's amendment in relation to operating expenditure because the ERA's forecast would not allow AGA to prudently manage the effective delivery of network and associated business support services, comply with the Safety Case or support growth in the network and customer numbers. In arriving at its forecast operating expenditure, the ERA has not applied a robust methodology or provided sufficient reasons for its expectations of productivity and efficiency

6.1 Summary of ERA decision

173. The ERA has disallowed a total of $73.8 million operating expenditure from forecast operating expenditure for AA4. This reduction is comprised of:

- Lower network operating expenditure ($19.5 million), including:
  - exclusion of labour escalation greater than CPI ($0.4 million)
  - application of an efficiency target to network operating costs ($6.1 million)
- Lower corporate operating expenditure ($38.5 million)
- Lower IT operating expenditure ($14.9 million)
- Lower forecast of UAFG costs ($1.0 million)
- Lower expenditure on ancillary costs ($0.1 million)

Table 6–1: Comparison of AGA revised AAI and ERA draft decision: forecast total operating costs over AA4

Operating cost categories ($ million real at 30 June 2014)	AGA revised AAI	ERA draft decision
Network operating expenditure	183.1	163.6
Unaccounted For Gas (UAFG)	43.7	42.7
Corporate operating expenditure	132.2	93.7
Information Technology operating expenditure	58.6	43.7
Ancillary Services operating expenditure	3.8	3.7
Total operating expenditure	**421.3**	**347.5**

6.1.1 Network operating costs

The ERA's technical consultant EMCa raised concerns with AGA's network operating expenditure forecasting governance, stating:

- *ATCO has not justified the Safety Case thresholds that it has applied.*[43]
- *ATCO has developed its forecasts using a bottom-up approach by incremental aggregation of detailed activity forecasts that have largely been determined by subjective assessments for which the assumptions cannot be independently verified. EMCa considers that the forecasts have not been subject to sufficient top- down challenge, which has lead (sic) ATCO to over-estimate operating expenditure forecasts.*[44]

174. Taking EMCa's concerns into account, the ERA determined:

> *That ATCO's allowance for baseline and incremental recurring operating expenditure should be based on ATCO's proposed level in 2014 and 2015 but capped at ATCO's proposed 2015 level..*[45]

175. Key to the ERA's rationale for capping recurring network operating expenditure is its assumption that:

> *By 2015, ATCO would be in a position to start to realise the types of efficiencies outlined in paragraph 224. This in the Authority's view would result in costs reductions that would more than offset unit cost increases…*[46]

176. Essentially, the ERA is of the view that forecast network operating expenditure is overstated and should be adjusted to account for efficiencies, which it considers AGA's forecasting governance overlooks. Not least, the ERA considers a $6.05 million IT efficiency gain based on conforming IT capital expenditure from the AA3 period should flow through to network operating expenditure items.[47]

6.1.2 Labour input cost escalation

177. In addition to the broad-brush expenditure reductions, labour escalation costs were reduced to CPI only (compared to the CPI +2% proposed) on the basis the ERA considers:

> *ATCO has not demonstrated how it has used the evidence that it provided to derive its estimate…*[48]

178. and

> *the evidence that ATCO provided to the Authority to justify its proposed labour cost escalation rate does not explicitly detail the considerations that ATCO refers to in its proposed revised access arrangement, nor does ATCO's proposed two per cent directly link to the evidence provided... .*[49]

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43 ERA, Draft Decision on Proposed Amendments to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph, 206.

44 ERA, Draft Decision on Proposed Amendments to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 206.

45 ERA, Draft Decision on Proposed Amendments to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 229.

46 ERA, Draft Decision on Proposed Amendments to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 229.

47 ERA, Draft Decision on Proposed Amendments to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 234.

48 ERA, Draft Decision on Proposed Amendments to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 213.

49 ERA, Draft Decision on Proposed Amendments to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 213.

6.1.3 UAFG

179. In line with recommendations from EMCa, the Draft Decision adjusts the UAFG rate and the gas throughput to reflect the ERA's demand forecast. The adjustment to the UAFG rate, down from 2.67% to 2.62% is:

> 180. *So that the starting rate for the UAFG rate for the fourth access arrangement period should be set by reference to the trend line observed for the third access arrangement rather than a single observation…*[50]

181. The ERA states that this revision is required to achieve compliance with rule 74 of the NGR.

6.1.4 Corporate operating expenditure

182. On corporate support costs, the ERA considers AGA has not adequately:

> 183. *justified the need for significant increases in internal support cost* nor *demonstrated the value received from the forecast intercompany charges* [51]

184. For internal support costs, the ERA considers insufficient justification was provided for the increase in regulatory and legal costs above the $2.1 million estimated for managing the AA4 access arrangement revisions. It also considers AGA has not provided information on how the new IT service agreement with WIPRO affects forecast internal IT support costs.

185. For intercompany charges, the ERA considers AGA has not provided information to indicate that there has been an increase in actual services received from the ATCO Group commensurate with the increase in charges.

186. From these conclusions the ERA considers expenditure for 2013 represents the best forecast possible in the circumstances because:

- *ATCO has had an incentive to reduce operating expenditure in the current access arrangement because it can capture the resulting cost savings, so its revealed costs in 2013 should form a reasonable basis for determining the allowance required for corporate support operating expenditure; and*

- *by 2013, ATCO would have had two years to determine the efficient corporate support spending level following its due diligence during the GDS purchase process.*[52]

187. Consequently, it has capped corporate support expenditure at the 2013 level, albeit with an additional $2.1 million applied across the last two years of AA4 to recognise the costs inherent in preparing for AA5.

188. The ERA has taken a similar approach to proposed business development and marketing (BDM) expenditure. EMCa considered that *ATCO has not demonstrated to a sufficient level of confidence that the proposed expenditure will lead to lower sustainable costs for customers*[53] and that the actual BDM expenditure in from 2011 to 2013 can be considered a reasonable and efficient level. Consequently, the ERA also 'capped' the BDM forecast at the 2013 level. The ERA also expressed concern with two elements of AGA's NPV analysis of the BDM expenditure, namely:

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50 ERA, Draft Decision on Proposed Amendments to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 306.

51 ERA, Draft Decision on Proposed Amendments to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 249.

52 ERA, Draft Decision on Proposed Amendments to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 249.

53 ERA, Draft Decision on Proposed Amendments to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 255.

189. *the average consumption assumed for new customers appears high relative to actual consumption data provided*… and *ATCO has not justified the individual BDM initiatives in the overall programme*.[54]

190. EMCa assessed that the focus of BDM expenditure on residential customers may not be justified in relation to the benefits delivered.

191. AGA provided the ERA with an updated licence fee forecast prior to publication of the Draft Decision. The only change to this made by the ERA was to adjust licence fee charges for the WA Energy Disputed Arbitrator in line with historical levels.

6.1.5 IT operating expenditure

192. The ERA has a number of criticisms of the IT operating expenditure forecast, namely:

- A lack of evidence to demonstrate that expenditure on some of the IT AMP projects is consistent with a prudent service provider acting efficiently
- AGA has not demonstrated its capacity to undertake the volume of forecast IT projects
- No evidence to link AGA's increased forecast for IT Licence Fees to the new IT service agreement
- The link between new IT systems and a continually rising IT services fee is not compelling

193. Consequently, the ERA has capped the IT Service Fee forecast at the 2013 level.

6.1.6 Ancillary services operating expenditure

194. The ERA has requested that AGA confirms these services are externally sourced, or if sourced internally, provide further justification on the efficiency of these costs.[55] The Draft Decision adjusts the ancillary service operating expenditure forecast to align with the ERA's adjusted B3 demand forecast.

6.2 AGA response

AGA has not implemented required amendment 5

195. The Draft Decision imposes unreasonable reductions to AGA's forecast operating expenditure for AA4. The ERA has determined that for corporate support operating costs, IT operating costs and marketing and business development operating costs, the efficient costs for AA4 are those that were incurred in 2013. This is compounded by the ERA's determination that labour costs can increase by no more than CPI.

196. For network operating costs, the ERA accepts some increase in expenditure for additional activities associated with the Safety Case but considers any further increases in costs likely to be incurred beyond 2015 would be offset by expected efficiency improvements in addition to a reduction of $1.1 million per year as a result of efficiencies achieved from IT projects. The ERA expects AGA to achieve these efficiencies despite AGA being the lowest cost gas distribution business in Australia on a per customer and per km basis, as found by Acil Allen in its benchmarking report,[56] which was provided with AGA's March 2014 submission.

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54 ERA, Draft Decision on Proposed Amendments to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 265.

55 ERA, Draft Decision on Proposed Amendments to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 316.

56 Appendix 6.1 Gas Distribution Benchmarking Partial Productivity Measures Acil Allen November 2014.

Imposed efficiencies

197. As a result of the significant reductions imposed by the ERA on AGA's operating expenditure, AGA has sought further evidence of its efficiency compared with other gas distribution businesses now and the over AA4 period. In its 2014 gas distribution benchmarking report Acil Allen found that:

- The most meaningful measures of partial operating expenditure efficiency for AGA are operating expenditure per km and operating expenditure per customer
- AGA has the lowest operating expenditure per km of the nine distributors over the period from 2005-06 to 2013-2014. AGA is between 27% and 31% below the sample average and is forecast to remain 21% below the sample average by 2019
- AGA consistently has the lowest or second lowest operating cost per customer. AGA is 31% and 39% below the sample average and forecast to remain amongst the lowest in Australia over the AA4
- Given the low level of AGA normalised operating expenditure, the concern is not that AGA's operating expenditure is at an efficient level but rather whether it is at a high enough level to be sustainable over the longer term

198. The comparison of gas distribution businesses with AGA historical performance and forecast is presented in Figure 6–1. As can be seen from the chart, the ERA's Draft Decision requires that AGA remain lower cost than any other gas distribution business and drives cost lower still.

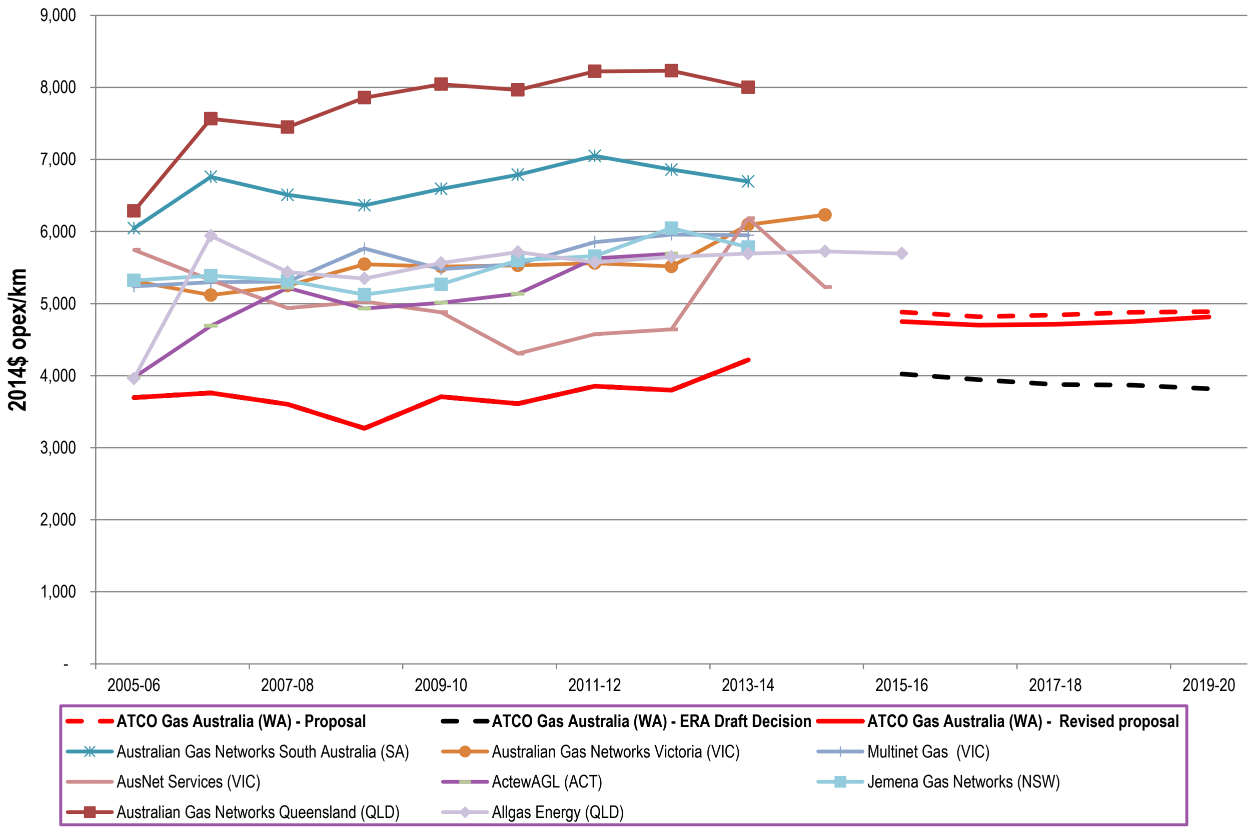


Figure 6–1: Operating expenditure per kilometre: Acil Allen ($ million real at 30 June 2014)

199. With regard to Figure 6–1, operating expenditure per kilometre, Acil Allen comments that AGA *has the lowest opex per km of the nine gas distributors over the period from 2005-06 to 2013-14* and *will remain well below the 2013-14 costs of the other distributors over the AA4 period*.

200. Under the ERA's Draft Decision, Acil Allen calculates that *by 2019 ATCO's opex per km would be 37 per cent below the current (2013-14) industry average* and *33 per cent below the current lowest cost gas distributor other than ATCO Gas*.

201. In Acil Allen's opinion *this widens what is an already considerable gap between the industry average performance in Australia and ATCO Gas, imposing a requirement to achieve significantly lower costs than 2013-14*.

202. Under AGA's amended proposal for operating expenditure over AA4, AGA *will remain at modest opex per km levels. By 2019 ATCO Gas will still have significantly lower opex per km than current industry cost levels at 21 percent below the 2013-14 sample average and 15 per cent below the lowest cost gas distributor in 2013-14 other than ATCO Gas*.[57]

203. When comparing operating costs per customer in Acil Allen believes , AGA has consistently been *the lowest or second lowest opex per customer*. Furthermore, AGA's operating cost per customer is forecast to remain among the lowest in Australia over the AA4 period.[58]

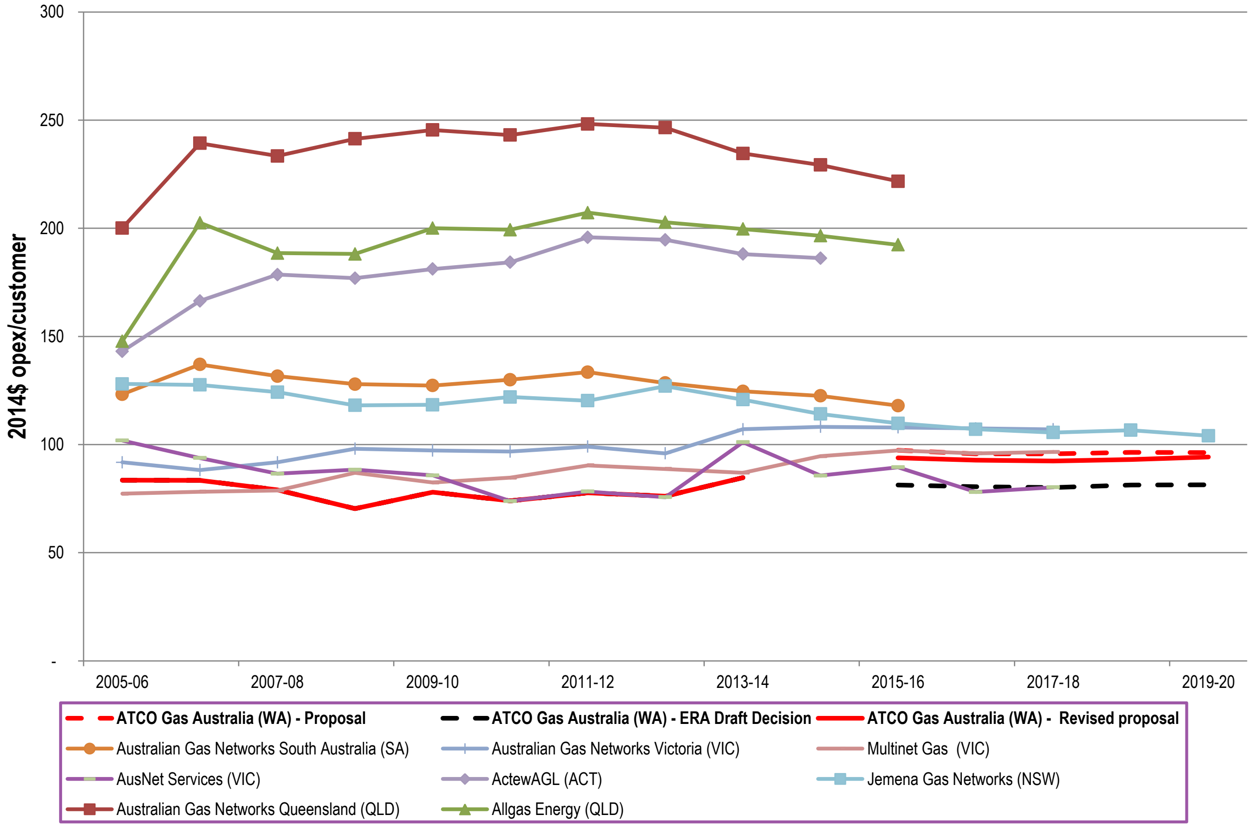
204. 

Figure 6–2: Operating expenditure per customer: Acil Allen ($ million real at 30 June 2014)

205. Under the ERA's Draft Decision, *by 2019 ATCO Gas' opex per customer would be 41 per cent below the 2013-14 industry average, extending further the already significant current gap*.... Under AGA's amended proposal, *opex per customer will remain at low levels*.[59]

206. Acil Allen believes the ERA has provided insufficient reasons to impose such significant efficiency expectations on AGA which can be demonstrated to already be on the efficiency frontier.

57 Appendix 6.1 Gas Distribution Benchmarking Partial Productivity Measures Acil Allen November 2014, page 17.

58 Appendix 6.1 Gas Distribution Benchmarking Partial Productivity Measures Acil Allen November 2014, page 17.

59 Appendix 6.1 Gas Distribution Benchmarking Partial Productivity Measures Acil Allen November 2014, page 18.

207. Acil Allen also considered EMCa's approach to forecasting operating expenditure (which was adopted by the ERA) and identified the expected efficiencies actually imposed on AGA as a result of adopting an efficient base year. The adoption of an efficient base year is the basis of a revealed cost approach.[60] Acil Allen concludes[61] that ERA has incorrectly applied the revealed cost approach by:

- Not using the most recent actual network operating expenditure as the starting point for the forecasting exercise
- Arbitrarily capping the step changes in network operating expenditure at the 2015 proposed level
- Not explicitly considering the impacts of growth and productivity offsets on network, corporate support, BDM and IT support fees over AA4
- Including a relatively arbitrarily determined IT efficiency gain
- Rejecting AGA's proposal for a real increase in labour input costs

208. Consequently Acil Allen has properly applied the revealed cost approach to AGA's operating expenditure (excluding ancillary services and UAFG) and then compared this against the Draft Decision, AGA's March 2014 proposal and a forecast based on extrapolating historical expenditure. Table 6–2 summarises the results.

Table 6–2: Comparison of alternative operating cost forecasts over AA4: Acil Allen

($ million real at 30 June 2014)	Jul-Dec 2014	2015	2016	2017	2018	2019	Total
Revised AAI	**31.4**	**65.9**	**66.7**	**68.1**	**70.0**	**71.5**	**373.7**
Forecast using the revealed cost approach as applied by Acil Allen	30.0	62.1	65.1	68.5	72.3	76.6	374.6
Forecast by extrapolating historical expenditure	32.5	68.6	74.1	77.5	80.5	82.8	416.1
ERA Draft Decision	**27.0**	**54.3**	**54.4**	**54.4**	**55.4**	**55.6**	**301.1**
Variance between revealed cost approach and ERA's Draft Decision	**3.0**	**7.8**	**10.6**	**14.1**	**16.9**	**21.0**	**73.6**

209. This illustrates that operating expenditure (excluding ancillary services and UAFG) forecast using the revealed costs approach at $374.6 million over AA4 is very similar to AGA's original proposal of $373.7 million over AA4.

210. AGA remains of the view that adopting a bottom-up build to forecast operating expenditure for the AA4 period was prudent as a new business owner. Nevertheless, AGA considers the properly applied revealed cost approach provides a robust and relevant comparator for the forecast efficient costs. The revealed cost approach was adopted by the ERA in the Final Decision for Western Power's 2012-2017 access arrangement and is an accepted methodology by the AER and other regulated utility businesses in Australia.

211. The proper application of the revealed cost approach demonstrates that the ERA has applied an additional productivity expectation on AGA of $73.6 million over AA4. Figure 6–3 illustrates the impact of this productivity adjustment.

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[60] Appendix 6.2 Operating Expenditure Forecasting Using the Revealed Cost Approach report (Scale), Acil Allen November 2014.

[61] Appendix 6.2 Operating Expenditure Forecasting Using the Revealed Cost Approach report (Scale), Acil Allen November 2014, page 9.

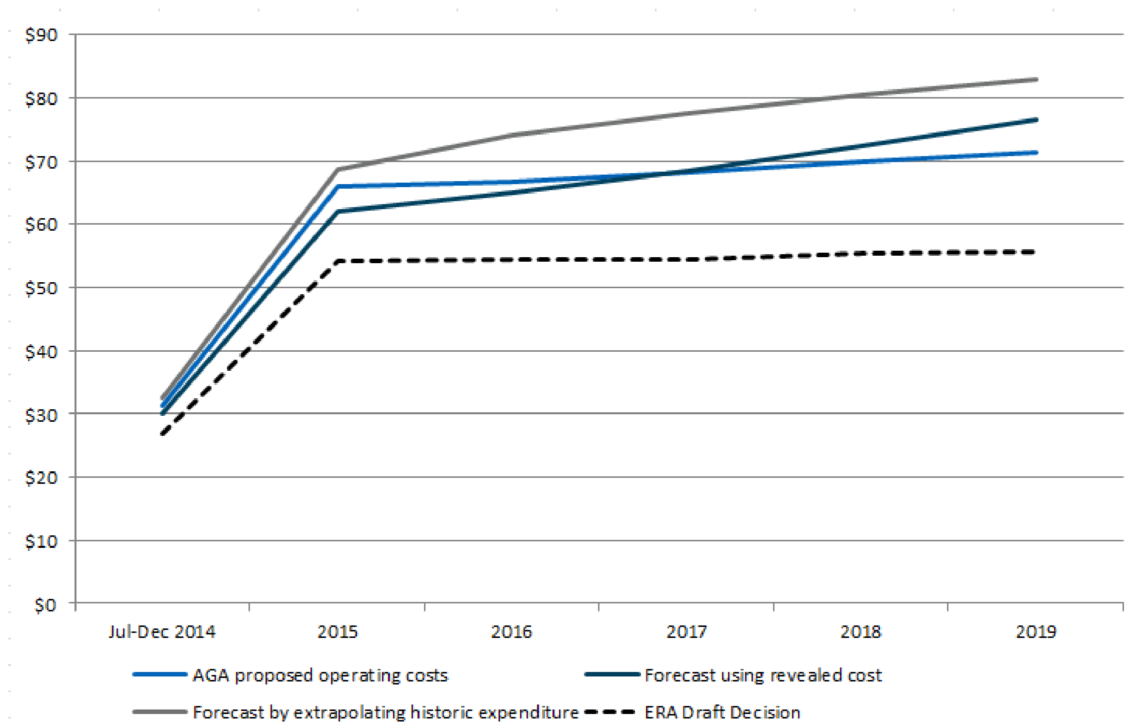

Figure 6–3: Comparison of alternative operating cost forecasts over AA4: Acil Allen ($ million real at 30 June 2014)

212. Figure 6–3 illustrates that the ERA's forecast for operating expenditure (excluding UAFG and ancillary services) is much lower than forecasts using properly applied forecasting methodologies.

213. Evidence from the benchmarking study confirms AGA is already and will continue to be, a low cost provider of gas distribution services during AA4. It is unreasonable to assume efficiencies of the magnitude proposed by the ERA are achievable or sustainable or consistent with the National Gas Objective.

214. On this basis AGA has not implemented required amendment 5.

Summary of response to network operating expenditure amendments

215. AGA does not accept that ERA's approach to forecasting network operating costs is reasonable. AGA understands that the ERA has assumed that any increase in network operating costs post 2015 should be more than offset by:

- Productivity improvements it has assumed will come from capital expenditure on asset replacement, telemetry and monitoring and the optimisation of maintenance and inspection activities
- Implied productivity improvements by not making any allowances for growth in the network or real increases in labour input costs
- An explicit efficiency gain from IT capital projects undertaken in AA3

216. However, the ERA has not made any assessment as to whether these productivity measures actually mitigate increasing network costs.

217. In section 6.2.2 (Network operating costs), AGA provides evidence that demonstrates the efficiency of its network operating expenditure forecast. Efficiencies flowing from IT and network capital projects and operational efficiencies have already been incorporated into network forecasts. AGA also considers scale growth in customer numbers and network extension are reasonable drivers of increasing network activity and costs, as is an increase in labour input costs.

218. AGA's bottom-up forecasting approach has been subject to robust top-down challenge both through the 2014 budget process and in preparing the initial submission for AA4. As a result AGA considers it is not reasonable to freeze recurring network expenditure at 2015 levels and submits baseline and incremental recurring expenditure consistent with its original proposal.

219. AGA uses the findings from an expert report by Zincara, to question the capital and operating costs assumptions the ERA has made or relied upon in its Draft Decision. The report, provided in Appendix 6.3, was prepared by Mr. Edward Teoh, Director, and Brian Fitzgerald, Associate of Zincara P/L who has been providing strategic advice to the energy industry, government and energy regulators on energy infrastructure. In particular, Zincara has carried out a number of reviews on the reasonableness of the capital and operating expenditure for energy infrastructure as part of the Access Arrangement regime in Australia.

220. Zincara has also drawn upon Brian Fitzgerald's 28 years' experience in the gas industry including general and operational management of a Victorian gas utility in his most recent employment with the APA Group as Manager of Envestra's Victorian gas assets (supplying over 620,000 consumers). During that time Brian has been responsible for operational development and input for a number of access arrangements.

221. AGA is satisfied Zincara has conducted a full review of AGA's network operating and capital expenditure forecasts in the AAI, the EMCa report and the ERA's Draft Decision. Zincara has made the following comments in its expert report:

> *Zincara's opinion is in line with EMCa's review in considering ATCO operating performance in AA3 and its reason for nominating 2013 operating expenditure as an appropriate baseline. Zincara however extends this view to consider that good management practice in the present is a reasonable basis for assessment of ATCO's management of its AA4 forecasting. It would seem improbable that prudent management methodologies applied to the existing business would be ignored in preparing forecasts for AA4.*
>
> *Zincara considers that the bottom up approach for the development of incremental recurring expenditure is appropriate and essential to ensure ownership and accountability by operating line managers. Zincara also considers that ATCO governance structure ensures that the costs are critically reviewed.*
>
> *In relation to additional regulatory obligations such as the Safety Case, Zincara is of the view that the additional responsibility identified in the Safety Case is incremental to ATCO's base activities and as such, the cost is therefore incremental to its base costs.*
>
> *Having reviewed the assumptions and approach by ATCO in proposing the Incremental Recurring activities, Zincara is of the view that they represent good practice when compared with ATCO's peers across Australia and typical of a prudent and efficient service provider in compliance with rule 91(1).*[62]

222. Zincara reviewed AGA's incremental recurring expenditure and found that:

> *Based on Zincara's review and assessment of the Incremental Recurring initiatives, it is concerned that capping the baseline and incremental recurring expenditure at 2015 level may in fact constrain ATCO's efforts to operate the networks in accordance with rule 91(1). … Zincara believes that a number of the incremental recurring activities will require additional expenditure beyond 2015 in order to support the activities.*
>
> *In summary it is Zincara's assessment that the estimates are arrived at on a reasonable basis and represent the best forecast possible in the circumstances, in accordance with rule 74.*[63]

[62] Appendix 6.3 Review of ATCO Gas Australia Capital and Operating Expenditure, Zincara, November 2014.

[63] Appendix 6.3 Review of ATCO Gas Australia Capital and Operating Expenditure, Zincara, November 2014.

Summary of response to labour cost escalation amendment

223. AGA does not accept the ERA's decision not to allow any labour Budget escalation greater than CPI for the period. As per its March 2014 submission AGA proposes CPI +2% is a reasonable escalation rate. Section 6.2.1 (Labour cost escalation) provides evidence of how the CPI +2% rate was calculated and is justifiable.

Summary of response to UAFG amendment

224. AGA does not accept the ERA's proposed UAFG rates as EMCa has calculated the UAFG rate for the July to December 2014 period rather than determining an annualised rate. Subsequently, AGA has reforecast its UAFG rate based on the most current UAFG data. AGA has also not accepted the ERA's amended demand forecast and so calculated the UAFG cost based on AGA's revised demand forecast.

Summary of response to corporate operating expenditure amendments

225. AGA does not accept the ERA's application of the revealed cost approach to forecasting corporate support and business development and marketing (**BDM**) operating expenditure. This is supported by Acil Allen's view that the ERA *has implicitly offset any impact of growth with productivity improvements with no commentary in the draft decision as to why there is no allowance for the impact of growth.* [64]

226. In section 6.2.3 AGA provides additional information in support of the step changes in headcount and expenditure in corporate support and BDM. AGA has sought expert advice on the consistency of its bottom-up assessment of efficient costs compared to the ERA's methodology. These reports relate to corporate support, IT and marketing.

Summary of response to Licence fees amendments

227. With regard to licence fees, in section 6.2.3 AGA provides a reforecast based on actual costs and costs expected to be incurred in 2014. AGA intends to recover any deviation from this forecast through the cost pass through mechanism.

Summary of response to IT operating expenditure amendments

228. AGA does not accept the ERA's proposed reductions to IT service fees and usage. This is because the ERA has made its determination based on EMCa's analysis of AGA's former IT services arrangement with I-Tek. In August 2014, AGA advised the ERA of the details of its new IT service agreement with WIPRO. The WIPRO agreement delivers saving of $8.5 million over the AA4 period compared to what had been forecast under the former IT arrangement. In section 6.2.4, AGA explains the link between business drivers and how these impact on the increases in WIPRO's Managed Services Fee.

229. Analysis of the forecast IT operating expenditure has been undertaken by an independent expert who concludes that *the business drivers and the scale increases proposed for IT Management Services expenditure are consistent with the criteria of NGR 91(1*) and *consistent with accepted good industry practice*.[65]

Summary of response to ancillary services

230. AGA does not accept the ERA's amendments to ancillary services operating expenditure as AGA has not accepted the ERA's demand forecast. AGA's revised forecast demand is discussed in Chapter 4 and the revised ancillary services operating expenditure is discussed in section 6.2.6 below.

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64 Appendix 6.2 Operating Expenditure Forecasting Using the Revealed Cost Approach report (Scale), Acil Allen November 2014, page 10.

65 Appendix 6.4 The IT Operating Expenditure of the Access Arrangement for the Mid-West and South-West Gas Distribution System, KPMG November 2014, page 3.

Summary of revised operating expenditure proposal

231. Table 6–3 shows AGA's revised forecast of operating expenditure for the AA4 period.

Table 6–3: AGA's revised AAI and amended proposal: forecast total operating expenditure over AA4

Operating cost elements ($ million real at 30 June 2014)	Jul-Dec 2014	2015	2016	2017	2018	2019	Total
Revised AAI							
Network	15.3	31.4	33.0	33.6	34.5	35.3	183.1
UAFG	4.4	7.6	7.7	7.9	8.0	8.1	43.7
Corporate	11.5	23.9	22.8	23.6	24.8	25.5	132.2
IT	4.9	10.7	10.8	10.9	10.7	10.5	58.6
Ancillary Services	0.3	0.6	0.7	0.7	0.7	0.7	3.8
Revised AAI - Total operating expenditure	**36.4**	**74.2**	**75.0**	**76.7**	**78.7**	**80.2**	**421.3**
Amended proposal							
Network	13.7	31.3	33.1	33.7	34.6	35.4	181.8
UAFG	4.0	7.2	7.4	7.5	7.6	7.7	41.5
Corporate	9.9	22.4	21.3	22.0	23.1	24.6	123.3
IT	4.3	10.6	10.7	10.7	10.5	10.4	57.2
Ancillary Services	0.3	0.6	0.6	0.6	0.6	0.6	3.3
Amended proposal - Total operating expenditure	**32.2**	**72.1**	**73.0**	**74.5**	**76.5**	**78.7**	**407.1**

232. AGA's amended proposal represents a reduction of $14.2 million or 3.4% on the initial proposal. This forecast also includes a real labour escalation rate of 2% per annum.

233. Excluding ancillary services and UAFG, the operating cost forecast is $362.3 million over AA4.

234. The following sections provide detailed discussion of AGA's position on individual operating expenditure items and matters raised by the ERA.

6.2.1 Labour escalation

235. The ERA's Draft Decision does not allow any labour escalation greater than CPI. The ERA has rejects AGA's proposed labour escalation factor *on the basis that the justification provided does not satisfy rule 74 of the NGR*.[66] The ERA considers:

- AGA has not demonstrated how it has used the evidence provided to derive the labour cost estimate; and
- Based on available WPI and EGWWS information, the proposed 2% above CPI could be expected to be the highest increase rather than a prudent average over the AA4 period.[67]

[66] ERA, Draft Decision on Proposed Amendments to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 214.

236. AGA submits labour escalation of 2% above CPI. This is the best forecast in the circumstances and takes into account multiple information sources as applied to AGA's operating environment. In this response to the Draft Decision, AGA provides:

- further explanation of how the CPI+2% forecast was derived; and
- a review of information such as updated WPI data and more recent regulatory forecasts and determinations of labour escalation rates that continues to support the use of a real labour escalation rate of 2% per annum.

How evidence was used to derive the original labour cost estimate

237. In its March 2014 submission, AGA explained that the forecast process used to determine the labour escalation factor for AA4 was the same process as is used on an annual basis to ensure its remuneration levels are efficient and reflect the market.[68] The sources of information used in determining the labour escalation forecast have already been provided to the ERA, these were:

- The AGA and Communications, Electrical and Plumbing Union (**CEPU**) Enterprise Agreement 2013
- Expectations in regard to the AGA and CEPU Enterprise Agreement for 2016
- Expected increases for salaried employees based on observed market practice, salary survey evidence from the HaysGroup, Mercer and Ausrem and Wage Price Index (**WPI**) forecasts

238. The influence of each data source on the labour escalation forecast is dependent upon it meeting a number of criteria:

- **Is the data from a reliable and reputable source?** - Information from established bodies such as government departments and recognised professional institutions such as the Chamber of Commerce and Industry exert a greater influence than data coming from less reliable or reputable sources.
- **Is the data published?** - Information that is published and so subject to challenge exerts greater influence, more so if the there is a published history of data, than information from unpublished sources.
- **Is the information WA specific?** - A data source that relates to employment conditions within WA is likely to be more relevant to AGA than information relating to gas distribution companies in other states, e.g. the WA WPI forecast and ERA approved labour escalation rates for other service providers. Judgement does have to be exercised though as AGA could be considered to be in competition with other gas distributors for skilled staff. Therefore, the labour cost for key staff in other companies in other states is relevant, particularly if AGA needs to attract staff interstate.
- **Is the information industry/utility specific?** - Data that relates to the gas distribution sector is going to be more influential than information that relates to another sector. Information relating to the utility sector will be taken into consideration as there will be some degree of transfer of skills within the sector, regulatory and risk being a good example. Comparison of labour costs for equivalent types of occupations in the utility sector, such as operational field staff, would also be informative.
- **Is the information AGA specific?** - This is consideration of how specific information is to AGA itself. This determining factor is to ensure that AGA's own corporate knowledge, experience and history is fully utilised in labour escalation forecasting, e.g. enterprise agreements for AGA staff and strategic and consultancy advice from the wider ATCO Group.

239. Data sources that meet all of the above criteria are given greater weight in the labour escalation estimate than those that only meet some. If a data source only met one or two of the criteria then it did not have a

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[67] ERA, Draft Decision on Proposed Amendments to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 213.

[68] AGA, Access Arrangement Information, March 2014 section 6.6.1.

direct influence upon the forecast but was used as a sense check. How each piece of evidence was used to inform the labour escalation forecast is presented in Figure 6–4.

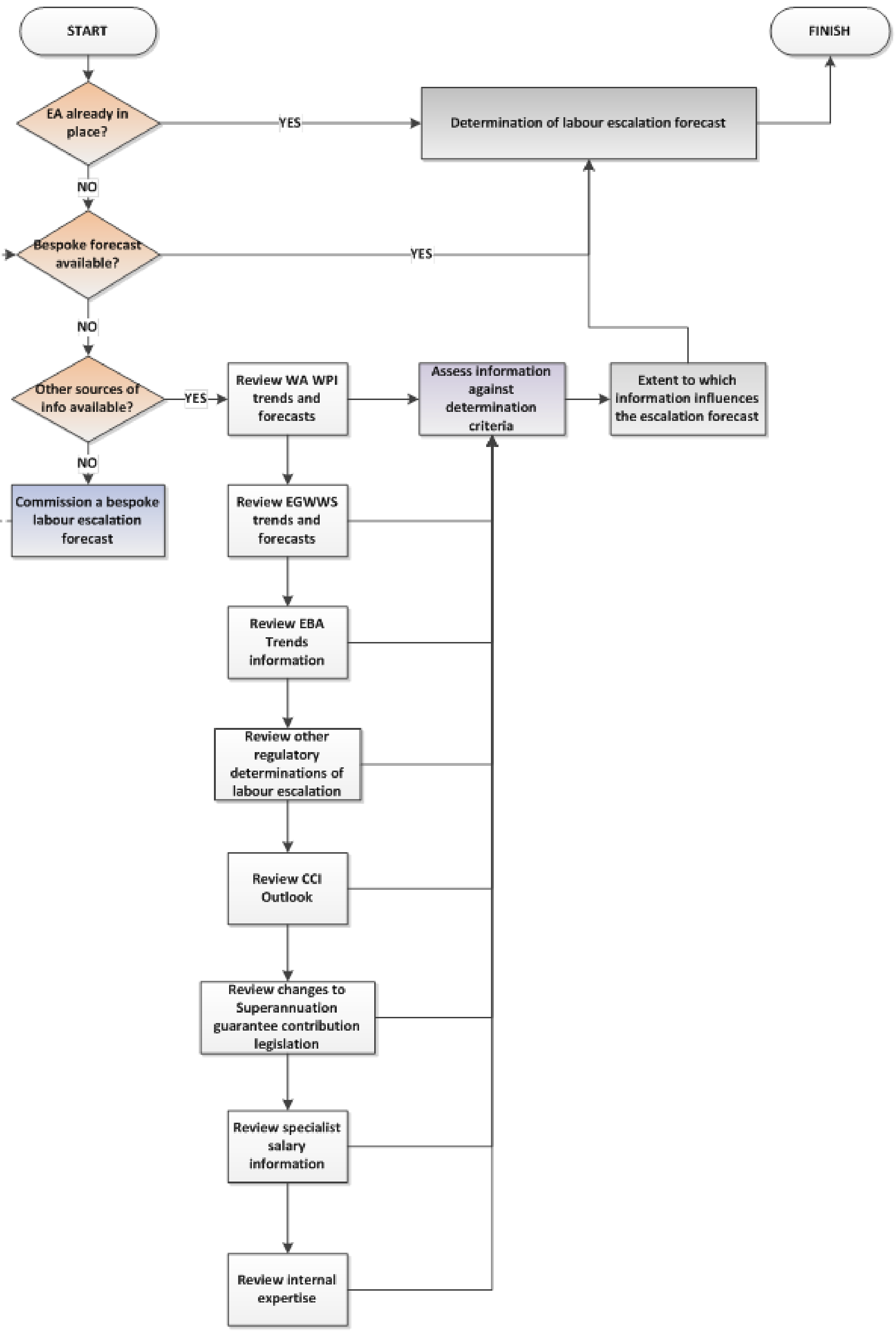

Figure 6–4: Decision process for labour escalation forecast

240. The labour escalation forecasting process began with consideration of AGA's existing Enterprise Agreement (**EA**). This extends to 31 December 2015.

241. AGA then considered WPI trends and forecasts. In the 12 months prior to March 2014, national WPI, WA WPI and the Electricity, Gas, Water, Water and Sewerage (**EGWWS**) WPI trended as shown in Table 6–4 below.

Table 6–4: Past trends in WPI measures (nominal)

Annual percentage change in WPI indices[69]	WPI All sectors	WA WPI	EGWWS WPI	Annual CPI
March 2013	3.2%	3.7%	4.4%	2.0%
June 2013	2.9%	3.4%	3.9%	2.3%
September 2013	2.7%	3.2%	3.3%	2.3%
December 2013	2.5%	3.0%	3.3%	2.4%

242. Table 6–4 reflects the premiums of the WA WPI (0.5% per annum) and EGWWS WPI (0.8% to 1.2% per annum) over the national all sector WPI.

243. At the time the March 2014 was being prepared, the 2013/14 WA Treasury Budget Papers provided a forecast of nominal WA WPI of 3.75% per annum for 2013/14 and 2014/15 and then at 3.5% per annum for 2015/16 and 2016/17.[70]

244. As previously advised, AGA has experienced a divergence in actual labour costs above WA WPI levels and there was no evidence to suggest this trend would not continue. By 2013, AGA's nominal labour costs trend was 1.3% above the WA WPI and 1% above the EGWWS WPI. Assuming this divergence would continue, the initial forecast for labour escalation was 1.3% above forecast WA WPI and in the range of 4.8%-5% nominal or 2.3%-2.5% real.

245. AGA then tested its initial labour escalation forecast against the information provided in support of recent regulatory determinations in Victoria (SP AusNet and Envestra).

- SP AusNet was in the midst of its 2013-2017 access arrangement, having initially proposed real labour escalation for 2015 to 2017 of 3.0%, 1.9% and 2.9% respectively based on forecasting by BIS Shrapnel.[71] In the final determination, published in March 2014, the AER forecast real labour escalation of 1.6% for 2015 and 1.4% in each of 2016 and 2017[72]
- Envestra's Final Decision for its 2013-2017 access arrangement was settled in March 2013, with the AER determining real labour escalation rates of 1.0% for 2015 and 2016 and 0.9% for 2017. [73]
- In WA, the Further Final Decision on Western Power's 2012-2017 access arrangement was published at the end of November 2012. In this determination, the ERA set real labour escalation rates at 2.0% for 2015/16 and 2016/17.[74]

246. In reviewing these three recent regulatory determinations, AGA slightly revised its initial labour escalation forecast of 2.3-2.5% downward to 2% real per annum to reflect the lowering of labour escalation forecasts in the eastern states, and to take account of the most recent WA regulatory determination and AGA's most recent experience. AGA then reviewed its proposed labour escalation forecast with its internal HR specialists, including observed market practice and salary survey evidence from the HayGroup, Mercer and Ausrem. This information supported the adoption of labour cost escalation of 2% real per annum from 2015-2019.

69 ABS website, Series 6345.0 Wage Price Index – Australia, tables 2b and 5b.

70 WA Treasury, Budget Paper No. 3 Economic and Fiscal Outlook, August 2013, page 7.

71 SP AusNet , Access Arrangement Proposal, Appendix 5F "Real cost escalation forecast to 2017", 2013, page iv.

72 AER, SP AusNet Final Determination, Part 3 – Appendices, March 2014, page 5.

73 AER, Envestra Final Determination, Part 3 – Appendices, March 2013, page 5.

74 ERA, Further Final Decision on Proposed Revisions to the Access Arrangement for Western Power, Nov 2012, page 11.

247. The above summary provides a step-by-step description of how AGA has used labour cost information to derive its labour cost escalation forecast. This also demonstrates that the forecast was made on a reasonable basis and so meets the requirements of rule 74 of the NGR.

248. AGA's forecast of labour escalation was endorsed by EMCa following a detailed assessment of:

- Annual and quarterly changes in the total hourly rates of pay for the EGWWS sector
- WA WPI
- Labour cost comparisons between AGA labour costs and WA WPI
- Recent AER determinations
- AGA's qualitative approach

249. Based on its assessment, EMCa stated that *"we consider that a reasonable forecast for ATCO's labour cost escalation is 2% above CPI for the AA4 period."*[75]

Updated information

250. In responding to the draft decision, AGA has taken the opportunity to review the information sources that guide its labour escalation forecasts to take account of updated information available in the intervening months.

251. AGA has reviewed WPI forecast information from two sources, WA Treasury and the most current forecast prepared by BIS Shrapnel for Jemena's 2015-2020 regulatory determination proposals.[76] Historical information has been sourced from the Australian Bureau of Statistics website.[77] This is shown in Figure 6–5 below.

75 EMCa, Review of ATCO Gas proposed AA4, 2014, paragraph 137.

76 Refer to http://jemena.com.au/Gas/Jemena/media/JemenaGasNetworksMedia/Community-Engagement-Document/Our-regulatory-proposal/Appendix%2006.10%20BIS%20Shrapnel%20%e2%80%93%20Input%20cost%20escalation%20report.pdf

77 ABS website, Series 6345.0 Wage Price Index – Australia, table 2b.

Figure 6–5: Actual and forecast WPI (nominal)

252. WA Treasury has commented[78] on the slowing of nominal WPI growth since 2013, attributing this to a faster slowdown in private sector wages (growth of just 3.1% over 2013) compared to public sector (growth of 4% in 2013). Over 2014 and 2015, Treasury expects this trend to continue as businesses focus on restraining cost growth and has reflected this in its forecast of 3.5% pa growth in WA WPI over 2015/16 and 2016/17. Looking further forward Treasury suggests the labour market and domestic outlook will improve and has adjusted its growth forecast for WA WPI back up towards the long term average of 3.9% per annum.

253. BIS Shrapnel[79] in its Input Cost Escalation Report for Jemena also expects Australian All Industries WPI to return to annual growth levels of around 4% per annum. It attributes the slowing of wage growth over 2013 and 2014 to increases in the minimum wage, a significant slowing in some sectors, rising unemployment and weak employment growth. BIS Shrapnel expects wage growth to build as low interest rates stimulate wider economic recovery, and increasing price inflation and a widening skills shortage drives wages upwards. BIS Shrapnel forecasts Australian WPI rates of 3.1% for 2015 rising to 4% by 2020.

254. The latest WPI forecasts for the September 2014 quarter were released on 11 November.[80] The ABS reported a quarter on quarter rise in WPI across all sectors of 0.6%. Annual growth in the nominal WA WPI was 2.5%, a similar growth rate to that in previous quarters.

255. On the basis of the latest release and Treasury and BIS Shrapnel forecasts, AGA considers that both the Australian and WA indices will be trending up to 4% over AA4. Assuming the WA Treasury WPI forecast reaches its long term average of 3.9% by 2020, AGA calculates the average WA WPI for 2015 to 2020 to be 3.7%. This is calculated as a simple average of forecast WPIs (3.5% in 2015, 3.5% in 2016, 3.75% in 2017,

78 WA Treasury, Budget Paper No. 3 Economic and Fiscal Outlook, May 2014, page 37.

79 BIS Shrapnel, Input Cost Escalation, 2014, page 25-26.

80 ABS website, Series 6345.0 Wage Price Index, latest issue Sep quarter 2014, published 12 Nov 2014.

3.8% in 2018 and 3.9% in 2019) consistent with WA Treasury commentary in its 2014/15 Budget Paper No. 3.

256. Figure 6–6 shows historical and forecast information for EGWWS WPI against the Australian WPI. Historical information is also sourced from the ABS website and the forecast EGWWS WPI was developed by BIS Shrapnel as part of Jemena's regulatory proposal.[76]

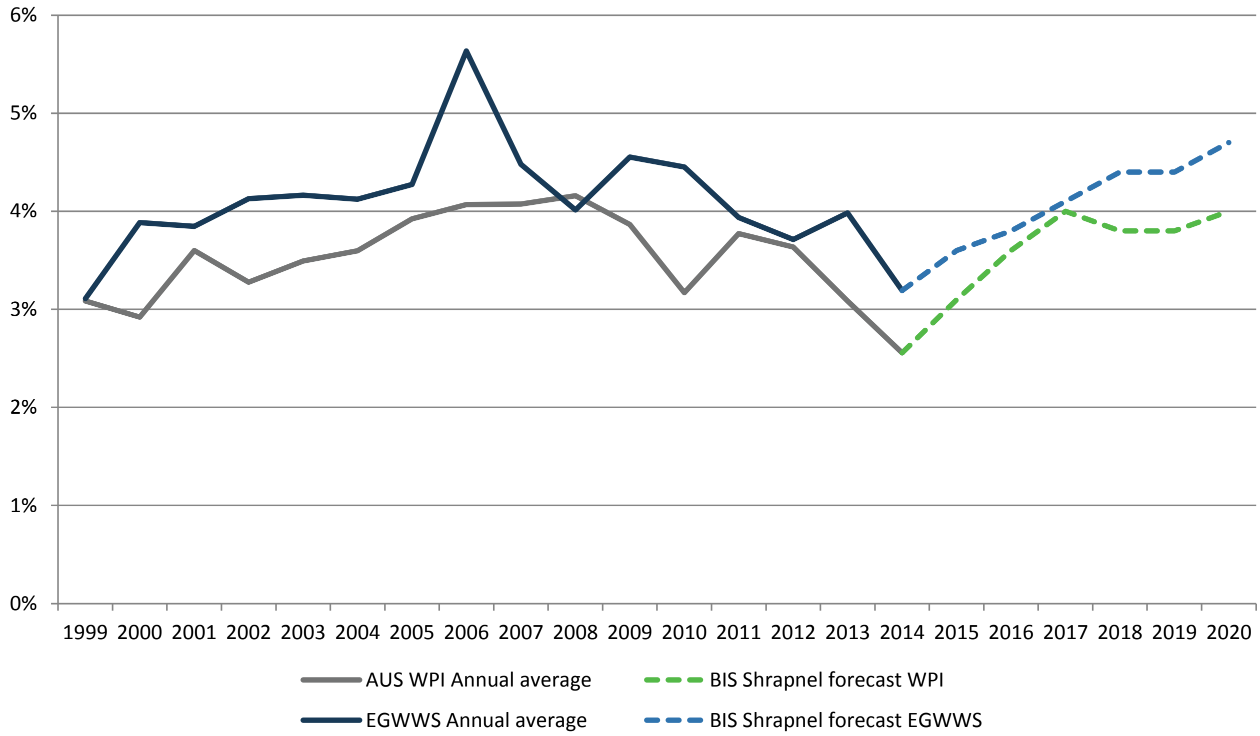

Figure 6–6: Actual and forecast EGWWS WPI (nominal)

257. The EGWWS WPI has consistently trended above all industries WPI and this trend looks set to continue. The latest EGWWS WPI quarterly change was 1.2% nominal with an annual percentage change of 3.2%, reversing the previously observed reduction in annual growth rates. Growth in the EGWWS sector was the second highest behind the Arts and Recreational sector (3.6%). Aligned with signs of a turnaround in annual average growth rates, BIS Shrapnel forecasts nominal EGWWS WPI rising from 3.6% in 2015 to 4.7% by 2020. This represents an average WPI of 4.3%. Continuing wage pressure in the EGWWS sector will be stronger than across all other industries to a premium of 0.6% on average per annum.

258. Other sources of labour escalation forecasts that AGA reviewed are:

- Recent real labour escalation rates approved from 2015-2017 by the AER for eastern states gas distributors Envestra and MultiNet Gas are around 1% per annum.[81] These rates are based on a Deloitte Access Economics prepared for the AER
- In the 2014 Federal Budget, the superannuation guarantee rate was increased by 0.25% to 9.5% in 2014/15 and the rate will remain at this level for the remainder of the AA4 period. As this is a legal requirement AGA has accounted for this amendment in its refreshed labour cost forecast

259. The Trends in Federal Enterprise Bargaining Report is prepared quarterly by the Federal Department of Employment. It lists average annualised wage increases negotiated via enterprise bargaining agreements, including the EGWWS sector. The DoE June report is the latest, published in October 2014 and includes a

81 AER: Final Decisions, Multinet Gas and Envestra, Part 3 – Appendices, page 5.

chart that demonstrates enterprise agreements (named as the Average Annualised Wage Increase) have been trending above WPI by up to 1% over the past 12 months. This chart[82] is reproduced below.

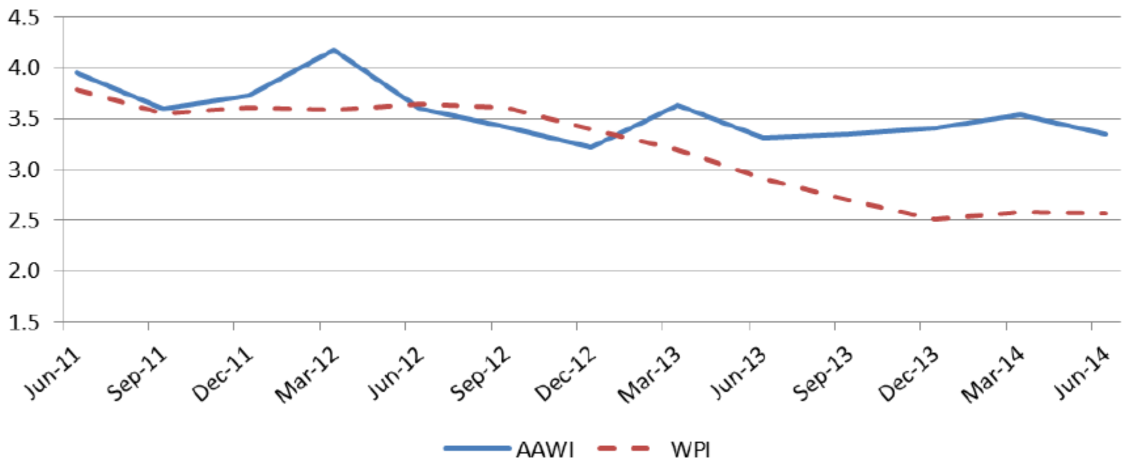

Figure 6–7: EBA Average Annualised Wage Increases (nominal) from Department of Employment

260. Information presented in the report on collective agreements approved in June 2014 shows an annualised wage increase of 3.3% nominal across all sectors. This represents 1,310 agreements, with an average duration of 2.9 years. Comparable information for the EGWWS sector shows a higher average wage increase of 3.7% nominal across 31 agreements with an average duration of 2.7 years. The WA state level shows an average annual growth rate of 3.6% over 196 enterprise agreements with an average duration of 2.9 years.

261. The EBA trend information does not forecast how future enterprise agreements will settle, however, it provides insight that expectations around enterprise agreements will be:

- For higher wage growth than is represented by WPI forecasts; and
- Higher in WA and in the EGWWS sector compared to all states and all industries

262. AGA's current enterprise agreement expires on 31 December 2015. It is not unreasonable to assume expectations for AGA's next collective agreement will also include a premium compared to enterprise agreements settled nationally and across all industries. Although not all AGA's staff participate in the enterprise agreement (approximately two thirds have individual agreements), the enterprise agreement is used as an indicator of wage growth for non-union staff.

Table 6–5: Derivation of forecast labour escalation rate

Element of labour forecasts	%
WA WPI forecast annual average over AA4	3.7
Premium of EGWWS WPI over WA WPI	0.6
AGA labour cost premium over WPI	0.2
Nominal labour escalation forecast per annum	4.5
Less forecast CPI per annum	2.5
Real labour escalation forecast per annum	2.0

82 Department of Employment, Trends in Federal Enterprise Bargaining June Quarter 2014, page 4.

263. Based on historical information AGA's actual labour costs have been trending above WPI on average by 1.4% per annum between 2010 and 2013. However, with a lighter labour market and slowdown in private sector wages growth noted by the WA Treasury in the Budget Papers, this divergence is expected to reduce over AA4.

264. AGA anticipates its labour cost escalator will exceed labour escalation determinations observed in the eastern states due to the history of WA WPI and EGWWS WPI being higher than national WPI. In addition, AGA's 2% real forecast is consistent with the most directly comparable utility, Western Power, as AGA competes directly for resources with this organisation. The ERA approved labour escalation rates at 2% real for Western Power in late November 2012.

265. Rather than rely on a mechanical derivation of labour escalation, AGA has also reviewed information provided by specialist remuneration and recruitment agencies HaysGroup, Mercer[83] and Ausrem. These sources support forecast nominal labour escalation at above 4%.

266. AGA has reviewed its labour escalation forecast in light of the above information and is of the view 2% remains a reasonable labour escalation estimate.[84]

Conclusion on labour cost escalation

267. AGA has explained how each individual source of information influences the derivation of its forecast of labour escalation. AGA has also reviewed each of these information sources in the light of any updated information available, including forecast trends for these variables in support of its proposed labour cost escalation forecast of CPI+2% across AA4. The forecast meets the requirements of rule 74 of the NGR.

268. The impact of AGA's forecast labour cost input forecast on operating and capital expenditure across AA4 is shown in Table 6–6 below.

Table 6–6: Costs associated with escalation in labour over AA4

($ million real at 30 June 2014)	July to Dec 2014	2015	2016	2017	2018	2019
Operating expenditure associated with labour escalation	-	0.2	0.6	0.9	1.4	1.8
Capital expenditure associated with labour escalation	-	0.3	0.8	1.3	1.7	2.2

6.2.2 Network operating costs

269. The ERA requires AGA to amend its forecast network operating expenditure in line with Table 6–7 below.

83 Mercer , Mercer rewards forum, 2014, page 31.

84 Forecast derived from 3.7% WA WPI, plus 0.6% premium from EGWWS, plus recognition of AGA's labour costs exceeding WPI historically, plus consultation with the wider ATCO Group.

Table 6–7: Comparison of AGA revised AAI and ERA draft decision: forecast network operating expenditure over AA4

($ million real at 30 June 2014)	AGA revised AAI	ERA draft decision
Baseline recurring	156.4	149.1
Incremental recurring	24.8	19.2
One off costs	1.9	1.8
Labour cost de-escalation	-	(0.4)
IT efficiency gain	-	(6.0)
Total network operating expenditure	**183.1**	**163.6**

270. The ERA's approved expenditure represents a reduction of $19.5 million or 10.6% of AGA's proposed network operating expenditure over AA4. The ERA requires the following reductions to network operating cost categories:

- Baseline recurring costs reduced by $7.2 million from $156.3 million to $149.1 million and incremental recurring costs reduced by $5.5 million from $24.7 million to $19.2 million
- Labour cost escalation in 2015 set to CPI only, refer to section 6.2.1 above
- Imposition of an IT efficiency gain (equivalent to 10% of approved AA3 IT capital expenditure) resulting in a reduction of $6.1 million to total network operating costs

271. For baseline and incremental recurring network costs EMCa expressed concerns with AGA's bottom-up forecasting approach. EMCa considers[85] that, based on the process described, there was *insufficient governance of and challenge to* a bottom-up approach whereby individual managers manually forecast future maintenance levels at an activity level. In particular, *ATCO has not provided evidence of objective consideration of a number of factors that we would expect to have been explicitly accounted for in such a forecasting process*.

272. Examples provided by EMCa included the relationship between monitoring and maintenance activities, e.g. an increase in expenditure on monitoring should be offset by a decrease in reactive maintenance and the potential for efficiency gains to be derived by optimising baseline and incremental maintenance activities and carrying them out in an aggregated manner particularly where extensive travelling time is included.

273. The ERA accepted AGA's forecast of $1.8 million for one-off costs occurring across AA4.

274. As part of its assessment of IT capital expenditure the EMCa notes[86] that while most of the (IT) business cases *refer to productivity gains from the proposed investments, there is no evidence that ATCO has quantified these gains or taken the gains into account in the proposed opex for AA4*. Consequently, the EMCa proposed that *as the evidence from ATCO is lacking* a 10% annual efficiency dividend from the proposed AA4 IT capital expenditure should be applied to AGA's forecast network operating expenditure. The ERA has adopted the EMCa's recommendation for a 10% efficiency target but calculated it as a proportion of conforming IT capital expenditure incurred during AA3 as it considers gains from the IT capital expenditure incurred during AA3 would flow into network operating expenditure items in AA4.

275. AGA does not accept the ERA's Draft Decision on network operating costs and addresses the following criticisms individually below:

- AGA has not justified the Safety Case thresholds that it has applied

[85] EMCa, Review of Technical Aspects of the Proposed Access Arrangement, 2014, paragraph 502.

[86] EMCa, Review of Technical Aspects of the Proposed Access Arrangement, 2014, paragraph 342.

- Use of bottom-up build with insufficient top down challenge in the network operating forecasting process and
- Lack of evidence that efficiencies from IT capital projects were included in network operating cost forecasts

276. AGA uses the findings from an expert report by Zincara[87], which reviewed AGA's submission to the ERA and the ERA's Draft Decision, to test the capital and operating costs assumptions the ERA has made or relied upon in its Draft Decision.

277. AGA relies on findings from an expert report by Acil Allen[88] reviewing the assumptions the ERA has made about growth and productivity in its application of a revealed cost approach to forecast network operating costs and its consistency with rule 74 of the NGR.

AGA has not justified the Safety Case thresholds that it has applied

278. The Safety Case thresholds are contained in the risk matrix AGA applies when conducting Formal Safety Assessments. The Safety Case requires that AGA's risk matrix complies with the requirements of AS/NZS 4645 and the Safety Case has been accepted by Energy*Safety* on the basis that it does comply with the Standard. This was verified by an external independent audit that accompanied the Safety Case submission to Energy*Safety*.

279. AGA's risk matrix thresholds are compared alongside the thresholds prescribed in AS/NZS4645 and AS2885 in Chapter 8. This comparison demonstrates alignment to the Standards and therefore these risk thresholds cannot be deemed low by industry standards. Therefore AGA rejects EMCa's concerns that AGA has not justified the Safety Case thresholds.

280. Zincara carried out a comparison between AGA's risk management framework to that of AS/NZS4645.1 and also reviewed AGA's risk management practices an in its expert opinion found that:

   - *ATCO's risk thresholds are in accordance with Standards and hence comply with NGR and that they also compare with those of its gas industry peers; and*
   - *ATCO's risk management practice is consistent with that of a prudent service provider acting efficiently in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services*[89]

281. Prior to the Final Decision, AGA urges the ERA to seek advice from Energy*Safety* to ensure alignment with the safety regulator. AGA remains committed to delivering on the Safety Case requirements, and is optimistic that the ERA will support the proposed expenditure to enable AGA to deliver on these Safety Case obligations.

Insufficient top-down challenge in network operating cost forecasts

282. AGA disagrees with EMCa's concerns relating to the lack of a top-down challenge on a bottom-up forecasting approach.

283. As the new owner of the Mid-West and South-West Gas Distribution System a bottom-up budgeting and forecasting process enables AGA to better understand the costs and activities of the gas distribution business rather than simply adopting the outturn in expenditure (and unknown approach) of the previous owner. This is a legitimate methodology and one AGA considers prudent and appropriate as new owners.

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87 Appendix 6.3 Review of ATCO Gas Australia Capital and Operating Expenditure, Zincara, November 2014.

88 Appendix 6.2 Operating Expenditure Forecasting Using the Revealed Cost Approach report (Scale), Acil Allen November 2014.

89 Appendix 6.3 Review of ATCO Gas Australia Capital and Operating Expenditure, Zincara, November 2014.

284. A bottom-up approach is adopted so that departmental budgets are prepared by the employees who have the best knowledge of their own specific areas of operation and how they integrate and are impacted upon by other operations and business plans. There is increased communication between departments as budget managers liaise around common sets of assumptions, for example demand forecasts. This informs AGA Senior Managers of the detailed costs and activity levels within the business and assisted new managers in their understanding and commitment to delivery. As the budget is developed by employees there is greater ownership of the budget and adherence to it.

285. A top-down challenge is incorporated throughout the annual budgeting cycle as outlined in AGA's 'Budget Policy and Procedures 2014'. In 2013, there was also a separate set of challenge sessions by the AA4 Steering Committee. These fortnightly meetings tracked the operating and expenditure forecasts through the business plan process to develop the forecasts for AA4. The sessions were supplemented by legal and specialist advisors as required. Additional detail on this process has already been provided in response to EMCa 31.

286. Figure 6–8 below demonstrates the top-down challenges throughout the 2014 business planning cycle. The first two challenges are conducted by AGA senior executives and then by the Senior Executive Team and the AGA President.

287. The challenge process then moves to the ATCO Australia level, which is typically followed by a second meeting to review action items and required amendments identified in the earlier session. The final two challenge sessions are with the AGA Board and then the ATCO Office of the Chair before the business plan is finally signed off.

288. Zincara reviewed AGA's business planning process including forecasting and challenge processes and found that:

> *In review of these frameworks and processes it is Zincara's opinion that the range of functions and activities established by ATCO for the management of the distribution business align with rule 91(1) and the principles in rule 74(2) and compares favourably with good industry practice among Australian gas distribution businesses.*
>
> *With respect to ATCO using a bottom up approach for the development of incremental recurring proposals for AA4, it is Zincara's opinion that this is appropriate and essential for ensuring ownership and accountability by operating line managers. It demonstrates a mature, effective and good industry practice. In Zincara's view, evidence of governance and challenge processes by senior managers is evident in the business frameworks ATCO has in place. ATCO's performance against its operational KPIs is generally of a good to high standard when compared to gas industry peers. Reference is made to the Australian distribution businesses benchmarking studies and KPI reports*[90]

289. Zincara also considers that ATCO governance structure ensures that the costs are critically reviewed.

> *Zincara therefore believes that expenditure forecasts built-up using a combination of historical unit costs, market tested rates and forecast resource requirements is in accordance with rule 74 (1) and (2).*[91]

[90] Appendix 6.3 Review of ATCO Gas Australia Capital and Operating Expenditure, Zincara, November 2014.

[91] Appendix 6.3 Review of ATCO Gas Australia Capital and Operating Expenditure, Zincara, November 2014.

290.

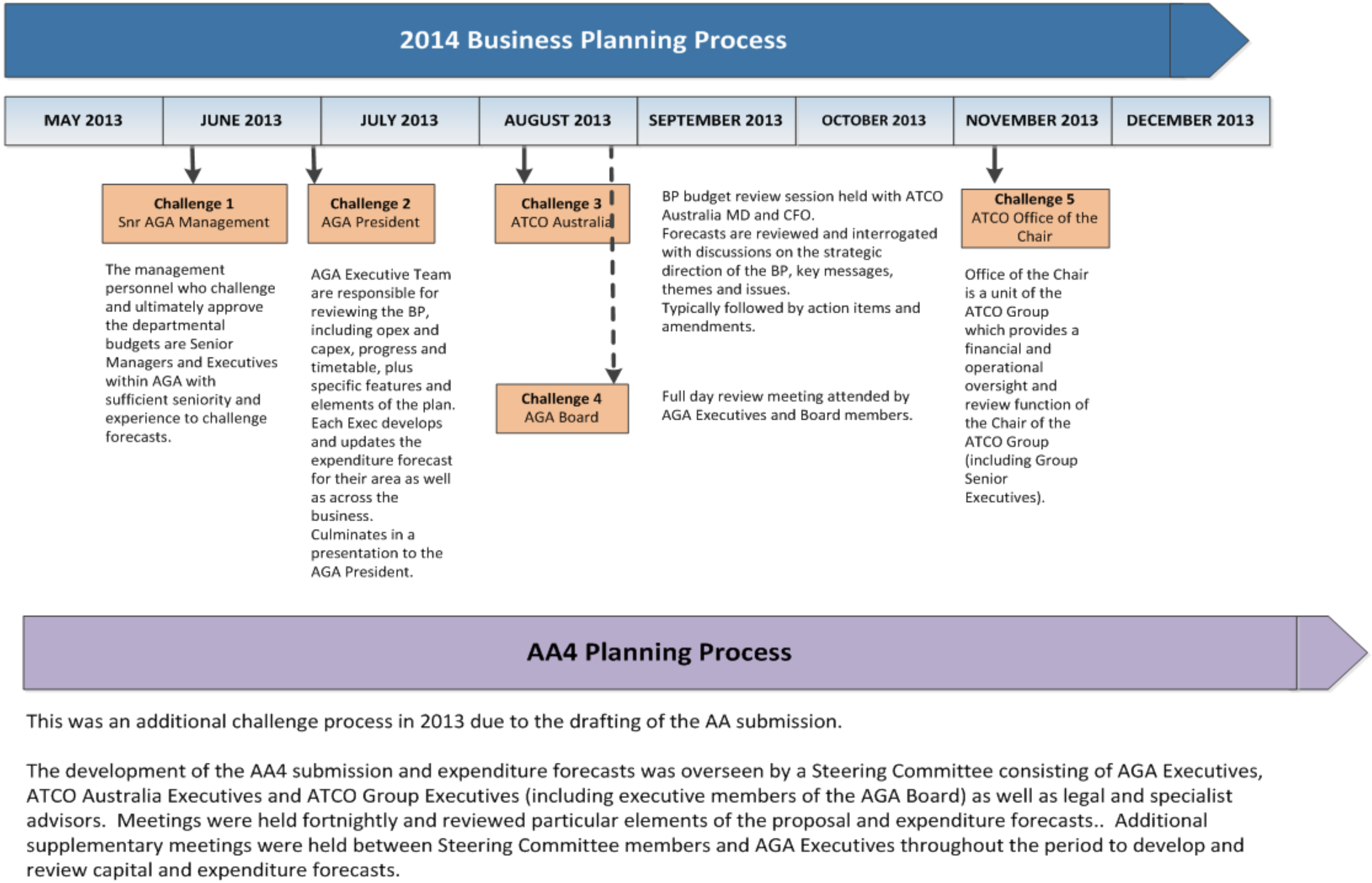


Figure 6–8: Top-down challenge process

Evidence of efficiencies included in network forecasts

291. AGA disagrees with EMCa's view that efficiency gains were not factored into the baseline and recurring network operating expenditure forecasts.

292. AGA has a single, integrated planning team that facilitates operational efficiencies by planning activity types by location and using cross and up-skilled resources to undertake maintenance activities. A thorough description[92] of how the (i) planning optimisation, (ii) operational efficiencies and (iii) multiple information sources are included in key maintenance activities is included in Appendix 6.5, which demonstrates that AGA has arrived at forecasts on a reasonable basis and represents the best forecast or estimate possible in the circumstances.

293. As already provided in the response to EMCa 35, AGA recognises the impact of capital works programs (both network and IT), on operating forecast costs. The impacts of these programs are accounted for in the bottom-up build forecast of network operating costs. AGA has already accounted for approximately $2.4 million of savings in network recurring costs from the impact of network capital programmes and further savings from the impact of the IT Field Mobility project in its forecasts over the AA4 period.

294. The impact of network capital projects on forecast network operating costs is outlined in Table 6-8.

Table 6–8: Savings from capital projects included in network operating cost forecasts

Capital work project ($ million real at 30 June 2014)	Saving in network recurring costs	Total
Unprotected metallic mains replacement	Class 2 Leaks (repair within one week)	0.7
Full and Partial relay of services		
End-of-Life Service Valve Replacement	Class 3 Leaks (repair within 12 months)	1.0
Routine Meter Change	Smell of Gas at Meter	0.7
Meter with Plugs		
Total		**2.4**

295. The impact of IT capital projects on forecast network operating forecasts is illustrated in more detail for the Field Mobility project noted[93] by EMCa in its report. The successful implementation of Field Mobility has resulted in the projected economic benefits being realised and accounted for in forward forecasts and includes avoidance of an additional 6 FTEs, ($660K p.a.), and other operational costs such as printing Field Manuals, fuel and reduced telephony ($400K p.a.), which are taken into account in the bottom up build forecast expenditure.

296. Zincara has reviewed responses already provided to EMCa and found that:

> *response to email EMCa35 advises that as a result of proposed capital works programmes, ATCO is forecasting a 2.5% saving in Network operating expenditure during AA4 which is approximately $4.8m, against forecast of $183m outlined in Section 6.3 of the AAI.*
>
> *While accepting that this information has not been explicitly demonstrated in the AAI, Zincara believes these provide evidence that benefits are incorporated in its budgets and forecasts and*

92 Appendix 6.5 ATCO Gas Australia's Operating Costs.

93 EMCa, Review of Technical Aspects of the Proposed Access Arrangement, 2014, paragraph 343.

that ATCO has prepared a cost efficient forecast using the best available information in compliance with rule 74.[94]

297. Therefore AGA does not accept that network operating expenditure on baseline and incremental activities that support this growth should be capped at 2015 levels, nor should network operating costs be subject to an efficiency target.

Inferential network operating cost forecast

298. A commonly used and alternative approach to bottom-up forecasting is the inferential or revealed cost forecasting approach. AGA has reviewed its bottom-up build approach compared with the adoption of the revealed cost approach prepared by Acil Allen and confirms that, in AGA's circumstances, a bottom-up build is appropriate. However, the inferential approach provides a useful comparison and AGA has utilised the revealed cost analysis prepared by Acil Allen to assess the ERA's Draft Decision's capping of base and recurring network operating costs at the 2015 level.

299. Inherent in the inferential approach is the determination of a base year to which is applied a scale growth factor, escalation of the labour inputs to this growth and a productivity adjustment. Incremental recurring and one off costs are also applied. In its analysis, Acil Allen has applied an inferential approach consistent with how it is applied by regulatory businesses and regulators elsewhere.

300. This is in contrast to the inferential approach methodology applied by the ERA which:

- Did not to include any allowance for growth in the network;
- Assumed that any incremental activities post 2015 will be offset by cost reductions resulting from:
  - capital expenditure for asset replacement and telemetry, which will impact the requirement to carry out unplanned and reactive maintenance;
  - optimising maintenance and inspection activities

Scale growth

301. The ERA has not explicitly denied the existence of continuing network growth beyond 2015 but it has assumed that productivity improvements:

- *should more than offset unit cost increases that ATCO has applied and the cost of any additional incremental activities as part of the Safety Case between 2016 and 2019 that ATCO has assumed*

and that

- *as greenfields subdivision is expected to occur after 2015…then operating expenditure in relation to these projects would occur in the fifth access arrangement period*.[95]

302. In Acil Allens's opinion, in making these assumptions the ERA *has not considered each of the components of the revealed cost approach separately but has made assumptions that certain costs will offset others without any assessment as to whether they will*.[96]

303. As part of its revealed cost analysis on operating expenditure Acil Allen calculated a rate of growth for AGA. Acil Allen utilised an approach previously adopted by Economic Insights in its 2014 report for Jemena[97]. This

94 Appendix 6.3 Review of ATCO Gas Australia Capital and Operating Expenditure, Zincara, November 2014.

95 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 229.

96 Appendix 6.2 Operating Expenditure Forecasting Using the Revealed Cost Approach report (Scale), Acil Allen November 2014, page 7.

methodology calculates a growth rate based on a composite of growth in the quantity of gas throughput and growth in the number of customers. The weightings applied in previous applications of this methodology were considered by Acil Allen and an average calculated for the revealed cost operating cost forecast prepared for AGA. These weighted averages were:

- 49.9% weighting applied to the change in the number of customers percentage; and a
- 50.1% weighting applied to the quantity of gas throughput percentage

304. They were then applied to AGA's forecasts of customer numbers and gas volumes. On this basis Acil Allen derived the rate of growth over AA4 as shown in Table 6–9 below.

Table 6–9: Rate of growth in operating expenditure for AA4: Acil Allen

Year	Customer weighting (%)	Growth in customers (%)	Throughput weighting (%)	Growth in throughput	Rate of growth (%)
July to December 2014	49.9	0.25	50.1	0.47	**0.36**
2015		1.70		1.22	**1.46**
2016		2.63		1.56	**2.09**
2017		2.57		2.27	**2.42**
2018		2.51		2.67	**2.59**
2019		2.45		2.78	**2.62**

305. Acil Allen is satisfied that the AGA growth forecasts for AA4 *satisfies rules 74 and 91 of the NGR* and has summarised this in Figure 6–9 below.[98]

[97] Appendix 6.6 Appendix to Acil Allen (See Appendix 6.2) 2015-20 Access Arrangement Information, Economic Insights - Productivity study and opex output growth June 2014.

[98] Appendix 6.2 Operating Expenditure Forecasting Using the Revealed Cost Approach report (Scale), Acil Allen November 2014, page 25-26.

Requirement of the NGR	How the rate of growth forecast satisfies the NGR
Information in the nature of a forecast or estimate must be supported by a statement of the basis of the forecast or estimate.	The basis of the forecast or estimate of the rate of growth is set out in Table 9.
A forecast or estimate must be arrived at on a reasonable basis A forecast or estimate must represent the best forecast or estimate possible in the circumstances	The rate of growth for ATCO Gas has been forecast based on analysis undertaken by Economic Insights to forecast the rate of growth for Jemena, AusNet Services and Multinet. Economic Insights and its Director, Dr Denis Lawrence, have undertaken a number of studies since 2004 on gas pipeline efficiency performance in Australasia. For the reasons set out in sections 4.1.2 and 4.2.3, it is my opinion that the approach used by Economic Insights to calculate the rate of growth for Jemena, AusNet Services and Multinet should also be adopted for ATCO Gas. The averaging of the results from the Economic Insights results for Jemena, AusNet Services and Multinet to produce a single point estimate of the weightings is consistent with the approach adopted by Economic Insights.
Operating expenditure must be such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services.	For the reasons set out in section 4.1.2, it is my opinion that ATCO Gas, Jemena, AusNet Services, Envestra Victoria and Multinet are operating relatively efficiently. If ATCO Gas continues to increase operating expenditure with growth at a similar rate as these gas distribution network service providers, then it will continue to incur a level of operating expenditure that would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services.

Figure 6–9: How the rate of growth forecast satisfies the NGR: Acil Allen

306. In addition to scale growth, forecasts of recurring incremental activity and costs identify several step changes in key activities beyond 2015. These are listed in Table 6–10 below. Most incremental recurring activities are driven by requirements of the Safety Case and requirements under current legislation such as the Gas Standards Act. Despite this the ERA has reduced these costs by $6.1 million over AA4.

Table 6–10: Incremental step changes in network activity

($ million real at 30 June 2014)	July to Dec 2014	2015	2016	2017	2018	2019	Total
Total incremental step changes							
AGA revised AAI	1.9	2.6	3.5	4.1	4.2	4.7	21.0
ERA draft decision	1.9	2.6	2.6	2.6	2.6	2.6	14.9

307. AGA does not accept the ERA's assumption that any growth beyond 2015 will be offset by productivity. AGA has included operational efficiencies and efficiencies flowing from IT and network capital projects in its forecast of network operating costs. However, the scale growth in the network and the incremental costs required to comply with the Safety Case, legislation and standards are not fully offset by these efficiencies. AGA concludes that both the network footprint and associated network costs to maintain this network will continue to increase beyond 2015.

Productivity

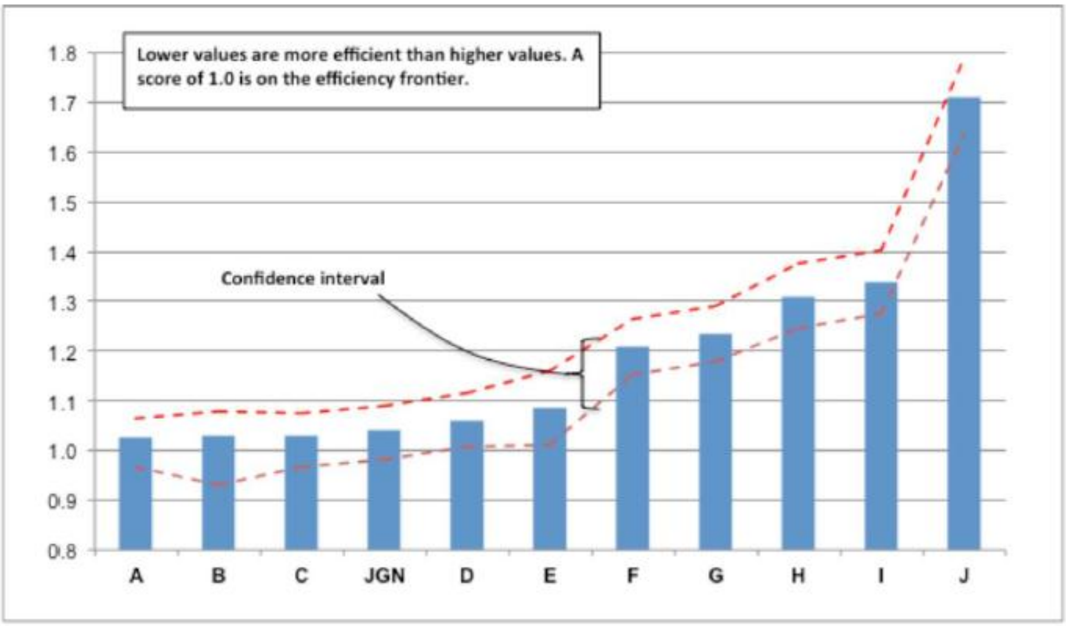
308. In the Draft Decision, the ERA included an explicit IT efficiency gain of 10% on AA3 IT capital expenditure or $1.1 million per annum and assumed implicit productivity improvements associated with:

- The capital expenditure for asset replacements and on telemetry and monitoring
- Optimising maintenance and inspection activity
- Not allowing for the impact of growth or for the real increases in labour costs

309. AGA questions the legitimacy of the 10% efficiency figure given that, in the expert's opinion, *while EMCa has considered a number of factors in determining the level of the annual efficiency dividend, the 10 per cent annual dividend appears to have been relatively arbitrarily determined.*[99]

310. The scale of productivity that AGA can be expected to achieve over AA4 was determined as part of the revealed cost forecast for operating efficiency prepared by Acil Allen. This referenced a productivity report[100] prepared by Economic Insights for Jemena's latest regulatory proposal.

311. In its report, Economic Insights only identified Jemena out of 11 other gas distribution service providers in its chart showing comparative costs inefficiency. This chart is reproduced below.



Source: Economic Insights estimates

Source: Economic Insights, *Relative Opex Efficiency and Forecast Opex Productivity Growth of Jemena Gas Networks*, 14 April 2014, Figure 5.2

Figure 6–10: Economic Insights opex cost function – comparative cost inefficiency (%)

312. Acil Allen used information from the benchmarking study recently undertaken for AGA and 'relationship of best fit' and 'composite index approach' models to infer where AGA lies on the chart above.

[99] Appendix 6.2 Operating Expenditure Forecasting Using the Revealed Cost Approach report (Scale), Acil Allen November 2014, page 9.

[100] Appendix 6.6 Appendix to Acil Allen (See Appendix 6.2) 2015-20 Access Arrangement Information, Economic Insights - Productivity study and opex output growth June 2014.

313. On the basis of its analysis, Acil Allen concluded[101] that:

- *ATCO Gas…most likely to be gas distribution network service providers A, B, C and D*.
- *if Jemena is close to the operating cost efficiency frontier then AGA (as one of the companies represented by A, B, C or D* in Figure 6–10 is also close to its opex cost efficiency frontier; and.
- any future productivity gains for AGA will be at *around the level of 0.86% per annum calculated for Jemena* by Economic Insights.

314. In contrast, the ERA's implicit and explicit efficiency assumptions over AA4 represent a much higher productivity adjustment at $19.15 million on network operating costs, or 10.5% over AA4.

315. AGA considers that a reduction in operating expenditure of this magnitude would see compliance to AGA's Safety Case jeopardised and increase safety risks associated with operating and maintaining the network.

316. Applying the Acil Allen derivations of scale growth and productivity, plus incremental step changes to AGA's 2013 network operating cost figure in order to determine an inferred forecast for AA4 is shown in Figure 6–11 below and compared with AGA's bottom-up amended proposal and the ERA's forecast.

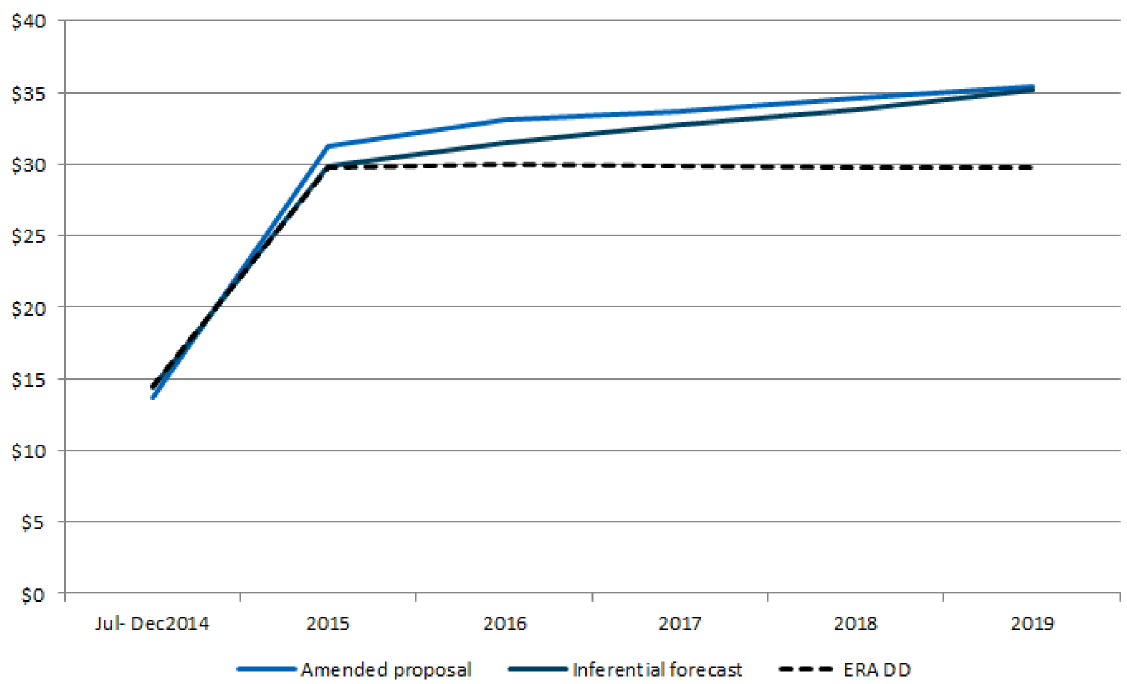


Figure 6–11: AGA amended proposal, inferential forecast and ERA draft decision: forecast network operating costs over AA4 ($ million real at 30 June 2014)

317. This analysis demonstrates the accuracy of AGA's bottom up forecast of network operating costs when compared to an inferential forecast utilising a methodology that for determining scale growth and productivity adjustments is, in the expert's opinion consistent with the requirements of rule 74 of the NGR. These forecasts are also consistent with the growth and productivity AGA can be expected to achieve as a low cost gas distribution service provider who is already operating at its cost efficient frontier and so can only achieve limited additional productivity going forward.

318. Efficiencies embedded in the bottom-up build account for the convergence over AA4 of the amended proposal and inferential forecast.

[101] Appendix 6.2 Operating Expenditure Forecasting Using the Revealed Cost Approach report (Scale), Acil Allen November 2014, p19 & p23.

319. The second conclusion from the analysis is the divergence between the two forecasts of AGA's network costs and the ERA's forecast of network operating costs in the Draft Decision. The increase in AGA's forecasts reflects the phasing of AGA's implementation of the Safety Case and demonstrates that, in contrast to the ERA's assumption, the ongoing requirements to comply with the Safety Case are not wholly offset by productivity gains.

320. Zincara reviewed AGA's incremental recurring expenditure and found that:

> *Based on Zincara's review and assessment of the Incremental Recurring initiatives, it is concerned that capping the baseline and incremental recurring expenditure at 2015 level may in fact constrain ATCO's efforts to operate the networks in accordance with rule 91(1). As noted in Section 5.4.3 above, Zincara believes that a number of the incremental recurring activities will require additional expenditure beyond 2015 in order to support the activities.*
>
> *Zincara's opinion is in line with EMCa's review in considering ATCO operating performance in AA3 and its reason for nominating 2013 operating expenditure as an appropriate baseline. Zincara however extends this view to consider that good management practice in the present is a reasonable basis for assessment of ATCO's management of its AA4 forecasting. It would seem improbable that prudent management methodologies applied to the existing business would be ignored in preparing forecasts for AA4.*
>
> *Having reviewed the assumptions and approach by ATCO in proposing the Incremental Recurring activities, Zincara is of the view that they represent good practice when compared with ATCO's peers across Australia and typical of a prudent and efficient service provider in compliance with rule 91(1).*
>
> *Zincara also acknowledges that some of the incremental recurring expenditure forecasts are related to forecast network growth and this is subject to ERA's decision regarding growth capex. To the extent that this is reduced in the final decision and ERA determines that there is a proportionate reduction in some of Incremental Recurring expenditure, each activity needs to be judged on its merit and the extent that it relates to growth.*
>
> *In relation to additional regulatory obligations such as the Safety Case, Zincara is of the view that the additional responsibility identified in the Safety Case is incremental to ATC's base activities and as such, the cost is therefore incremental to its base costs.*
>
> *In summary it is Zincara's assessment that the estimates are arrived at on a reasonable basis and represent the best forecast possible in the circumstances, in accordance with rule 74.*[102]

321. Therefore, AGA does not accept the ERA's forecast network operating costs and instead retains its initial proposal adjusted to reflect the inclusion of actual expenditure in the July to December 2014 forecast as shown in Table 6–11 below.

Table 6–11: Comparison of AGA's revised AAI and amended proposal: forecast of network operating costs over AA4

($ million real at 30 June 2014)	Jul-Dec 2014	2015	2016	2017	2018	2019	Total
Revised AAI – network operating costs	15.3	31.4	33.0	33.6	34.5	35.3	183.1
Amended proposal - network operating costs	**13.7**	**31.3**	**33.1**	**33.7**	**34.6**	**35.4**	**181.8**
Variance	(1.60)	(0.1)	0.1	0.1	0.1	0.1	(1.3)

102 Appendix 6.3 Review of ATCO Gas Australia Capital and Operating Expenditure, Zincara, November 2014.

6.2.3 Corporate operating costs

322. Corporate operating expenditure is comprised of three categories; corporate support, business development and marketing, and licence fees. The Draft Decision amended all three elements of corporate operating expenditure. The following three sections summarises the ERA's amendments to each of these categories and AGA's response.

6.2.3.1 Corporate support costs

323. The ERA's approved expenditure represents a reduction of $21.8 million or 23.7% on AGA's proposed corporate support expenditure.

324. The ERA has confirmed[103] that provision of corporate support services are a *necessary function of the prudent operation of a large business*. However, it is not satisfied[104] that AGA's forecast corporate support expenditure is *consistent with what a prudent service provider acting efficiently*…*would incur*. The reasons given by the ERA are that AGA has not:

- Adequately justified the need for increases in forecast internal support costs
- Demonstrated the value received from the forecast intercompany charges

325. For internal corporate support costs, the ERA draws particular attention to:

- The step increase in legal and regulatory costs above the 2013 level, with the exception of $2.1 million approved for preparation of AA5
- Its view that AGA did not provide information on what impact the revised IT arrangement would have on its forecast internal IT support costs

326. For intercompany charges, the ERA considers that AGA should demonstrate:

- The degree of governance over the services and support it can access from the Group and that it has exercised prudent judgement to determine the efficiency of these services
- Why internal corporate support costs need to increase to such an extent and at the same time as intercompany charges are increasing

327. The ERA considers corporate support expenditure in 2013 *represents the best forecast possible in the circumstances* and has capped forecast expenditure at this level ($12.3 million) across AA4. The exception being the $2.1 million approved for the preparation of AA5 which has been applied equally across 2018 and 2019.

328. AGA does not accept the ERA's decision on corporate support costs. AGA considers the Draft Decision does not recognise the necessary increase in and value of corporate support resources, both intercompany and internal, required to service a growing business. Therefore, AGA has:

- Explained the increases in corporate support costs from AA3 levels and across AA4, including why both internal and intercompany costs are increasing at the same time
- Provided expert analysis to demonstrate the value received from forecast intercompany charges

[103] ERA (2014): 'Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System', paragraph 249.

[104] ERA (2014): 'Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System', paragraph 249.

- Asked experts KPMG[105] (Confidential Appendix 6.7) to benchmark forecast corporate support costs over AA4 to test the efficiency of that forecast
- Asked experts Acil Allen to examine the revealed cost approach adopted by EMCa and accepted by the ERA
- Revised the corporate support costs to include a reforecast for July to December 2014 based on actuals and a reforecast to the end of the AA4 period. This amends the corporate support operating cost forecast to $88.1 million

Increases in AA4 corporate support costs over AA3 levels

329. AGA disagrees with the ERA's view that 2013 should be used as an efficient base year on which to forecast corporate costs. AGA considers ATCO Group acquired the former WAGN business in July 2011, mid-way through the AA3 period. Operating expenditure in 2013 was low and the business was still managing some residual issues from the acquisition, therefore the 2013 corporate support spend does not represent a steady-state of expenditure or reflect the plans of the ATCO Group to develop the AGA business. Consequently the level of expenditure in 2013 is unsustainable going forward.

330. KPMG's expert analysis[106] highlights that the acquisition of the gas distribution business by AGA led to a change in the balance of corporate support services provided by AGA and ATCO Group, which contributed to the overall underspend of $13 million over AA3. Some functions that had previously been provided by the previous owner, WA Gas Network (**WAGN**), were brought in-house, e.g. HR, Finance and Legal which led to increases in headcount and an overspend against forecast. However, this was more than offset by an underspend of $21 million in intercompany charges.

331. In reviewing the reasons for this underspend, KPMG has *encountered group structures that have not necessarily recharged all corporate management costs from a parent entity to operating entities*.[107] KPMG suggests that a parent company may incur two items of expenditure such as (i) the cost of raising investment capital and (ii) procurement of consulting advice for a pipeline issue. Both of these expenditures would be recoverable under rule 91(1) of the NGR, however the parent may choose to recharge the consultancy advice but not the cost of raising investment capital and continue to record this at the group level. Once consolidated financial statements are reported, any distinction around the recording of different expenses between parent and subsidiary are lost.

332. An example of this for AGA is the $0.4 million step change in intercompany charges between 2013 and 2014, which was queried by EMCa.[108] An analysis of the individual elements that comprise intercompany charges shows that ATCO Group did not recharge HR and internal audit costs to AGA in 2013 but did recharge them in 2014. In addition, between 2013 and 2014 AGA incurred a step change in the cost of Intercompany Licence Fees. The direct allocation methodology for Intercompany Licence Fees is based on business size and the annual addition to group value as represented by annual earnings.

333. From its analysis, KPMG concludes that it does not necessarily follow that *the historic costs, including intercompany costs recorded in AGA represent the entirety of the historic cost of service provision* and that *the intercompany charges recorded for the gas distribution system in the three years to June 2014 represent the full cost of corporate service provision*.[109]

[105] Confidential Appendix 6.7 The Corporate Support Operating Costs of the Mid-West and South-West Gas Distribution System, KPMG November 2014.

[106] Confidential Appendix 6.7 The Corporate Support Operating Costs of the Mid-West and South-West Gas Distribution System, KPMG November 2014, page 25-26.

[107] Confidential Appendix 6.7 The Corporate Support Operating Costs of the Mid-West and South-West Gas Distribution System, KPMG November 2014, page 37.

[108] ATCO Gas Australia response to EMCa 40.

[109] Confidential Appendix 6.7 The Corporate Support Operating Costs of the Mid-West and South-West Gas Distribution System, KPMG November 2014, page 37.

334. This supports AGA's decision to prepare a bottom up forecast of corporate support costs for AA4. AGA's forecast captures increasing labour input costs (as outlined in section 6.2.1) and step changes in costs across the AA4 period aligned with growth in the business and changes in statutory and regulatory requirements. These identified step changes are outlined in Table 6–12 below.

Table 6–12: Assessment of incremental changes to corporate support costs

($ million real at 30 June 2014)	2013	2014	2015	2016	2017	2018	2019
Base year corporate support operating costs	12.3	12.3	12.3	12.3	12.3	12.3	12.3
Labour escalation		0.1	0.3	0.4	0.5	0.7	0.8
Recurring costs							
2013 - Annualised new staff costs		0.4					
2014 – Annualised new staff costs		0.1					
2014 - New FTEs		0.2					
2014 – Intercompany costs[110]		0.4					
2014 – Fringe Benefits Tax		0.3					
2015 – New positions			0.7				
2016 – New positions				0.2			
2017 – New positions					0.3		
Labour escalation							
Cumulative recurring costs		*1.4*	*2.1*	*2.3*	*2.6*	*2.6*	*2.6*
One-off costs							
2014 – Regulatory costs AA4 response preparation		0.8					
2015 – Regulatory costs AA4 final and review			0.5				
2018 – Regulatory costs AA4 preparation						1.1	
2019 – Regulatory costs AA4 preparation							0.7
Sub-total one off costs		*0.8*	*0.5*	*-*	*-*	*1.1*	*0.7*
Roll forward corporate support operating expenditure	-	14.6	15.2	15.0	15.4	16.7	16.4

335. Each of the incremental cost increases is explained in more detail below.

336. In 2013, 4 FTEs joined the business, so only a proportion of the costs associated with the new starters will be captured in actual costs for 2013. Therefore, the full year or annualised costs of staff members who joined during 2013 needs to be taken into account.

Subsequent increases in headcount across AA4 are illustrated in Figure 6–12 below.

110 This is the first time AGA received intercompany charges for ATCO Group audit, HR and Intercompany Licence Fees.

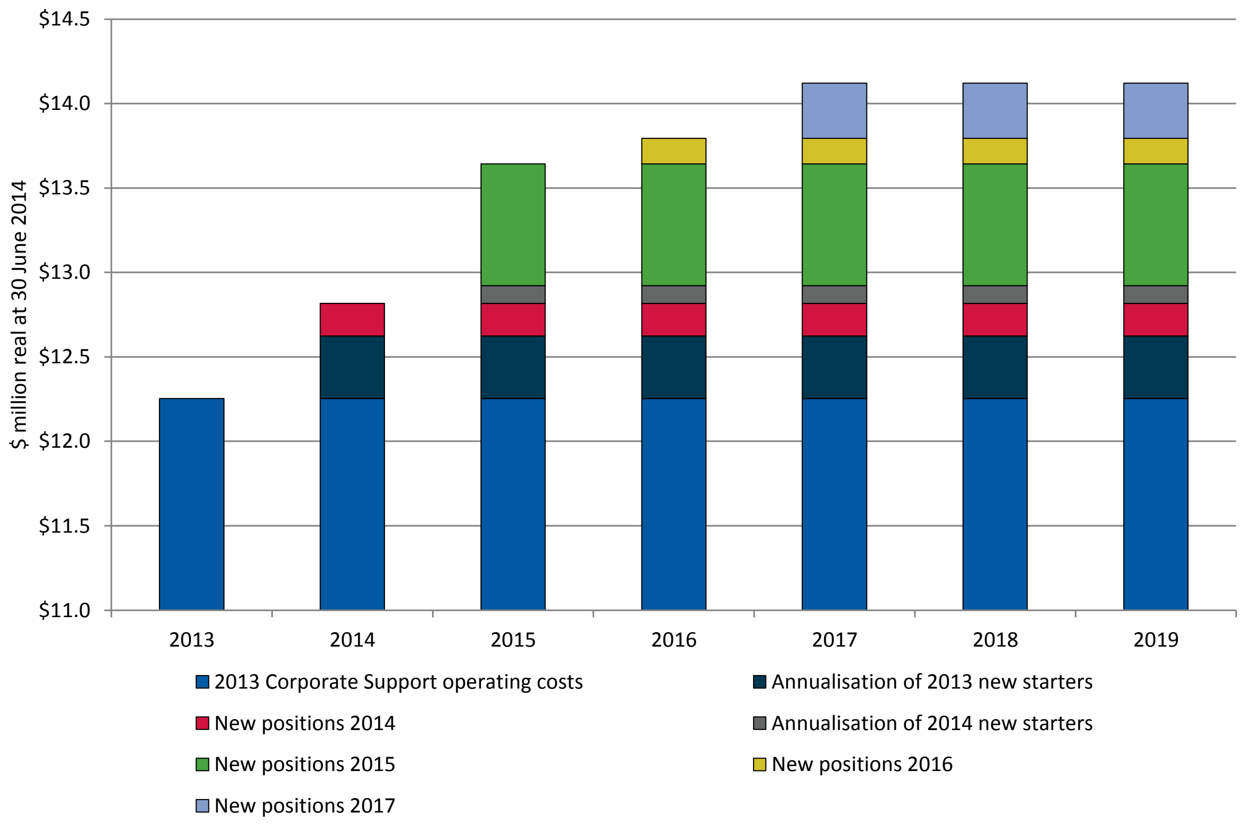


Figure 6–12: Step changes required to base labour costs ($ million real at 30 June 2014)

337. There are six new positions identified for 2015, one for 2016 and two for 2017. These are required to meet the demands of a growing business. Table 6–13 outlines the business need for each of these positions.

Table 6–13: New positions required during AA4

Position	Requirement
New positions in 2015	
Industrial Relations Specialist	This position is forecast to commence in Q3 2015 in preparation for the next round of Enterprise Agreement negotiations as the current EA expires on 31 December 2015. Following the conclusion of said negotiations, this individual will be responsible for (i) ensuring the development of any new policies and the review of existing policies to reflect any changes to employment legislation, (ii) the training and development of Managers and Supervisors in the application of HR policies, procedures and (iii) the provision of ongoing specialist advice.
Learning and Development Specialist	AGA is forecasting and increase in both number of customer connections and in the length and area covered by the distribution network. To service this growth headcount is forecast to grow over AA4. In order to maintain the safe and efficient operation of the network, AGA requires a competent and skilled workforce. With a forecast increase in headcount and approximately 12% of AGA aging workforce likely to retire during AA4 an additional L&D specialist to provide training and development services across AGA to enhance business performance and employee engagement. Without this additional employee the team will not have the capacity to be able to deliver adequate levels of service with current resource levels.
Accounts Receivable Officer	This position is required to respond to the increase in invoices received as a result of rising customer numbers. In addition, AGA is experiencing a rise in defaults and bad debts and

Position	Requirement
	requires additional support to manage these bad debts and collections.
Risk Officer	This position is to support the application of the ALARP test when conducting Formal Safety Assessments. With greater scrutiny of forecast activity and expenditure driven by the Safety Case, additional support is required to ensure optimal governance of this process.
HSE Injury Management Coordinator	As noted above AGA has an aging workforce and with this the potential for muscular-skeletal injuries rises. This individual will develop an enhanced wellness and injury prevention approach to reduce these types of injuries and so optimise the longevity of personnel in operational roles. In addition, the role will be responsible for coordinating of the injury and claims management process and also to conduct incident investigations involving injuries to ensure corrective actions are implemented to mitigate the root causes.
HS&E Field Advisor	The continued geographic expansion of the distribution network, particularly to the north, has impacted on the capacity to deliver HSE support to the volume of maintenance activities occurring across this expanded network. The core functions of this individual are to (i) provide capacity to deliver HSE support in the field, (ii) enhance the HSE incident investigation and reporting process, (iii) implementation of new WA Work Health and Safety Harmonisation legislation in relation to field activities, (iv) provide support to the contract management group through auditing contractor compliance to HESQ standards and (v) driving behavioural change to reduce workplace injuries.
New position in 2016	
Accountant	This position is necessary to respond to business growth driving increased workload in reporting, analysis and finance related controls.
New positions in 2017	
Regulatory Analyst	This position is required to more effectively support the Regulatory team in the development and finalisation of the next Access Arrangement and will be responsible for monitoring the regulatory environment and ongoing Company performance against the NGR and the company's operating licence. Additionally this role will undertake economic regulatory analysis and scenario modelling and will prepare recommendations as it relates to the Access Arrangement and tariff reviews.
Strategic Systems Implementation Technician	The existing incident management system JASPER is currently being replaced by a SAP EHS system. Following completion of the implementation project, this individual will be responsible for ongoing support of the new system and will provide detailed interpretation of HSE data to enable the development of early intervention strategies in response to emerging trends. In addition, the role will provide concise and specific data to be reviewed during the risk assessment process and to meet due diligence obligations under the new WA Work Health and Safety harmonisation legislation.

338. KPMG also reviewed the increases in costs over AA4 and concludes that the increases in headcount represent *specific and limited additional numbers of staff to meet expanded business requirements (consistent with the forecast growth in revenue and business activity) with some escalation of the real labour costs*.[111]

339. In addition to headcount, step changes have also been identified in other expense items as listed below.

[111] Appendix 6.4 The IT Operating Expenditure of the Access Arrangement for the Mid-West and South-West Gas Distribution System, KPMG November 20144, page 34.

Regulatory and Legal

340. AGA initially included $2.4 million in the corporate support forecast to reflect the additional costs of preparing and managing the AA4 access arrangement events and $2.4 million for preparation of AA5 (costs incurred in 2018).

341. The forecasting of additional costs to manage regulatory reviews is well documented in service provider proposals and regulatory decisions, for example:

- In its latest proposal (for the regulatory period 2015-2020), Jemena has forecast $7.6 million to cover the next access arrangement and has spread these costs over 2018, 2019 and 2020
- Multinet forecast an additional $1 million in each of the two years of the current access arrangement to prepare for the next
- As part of its analysis, KMPG benchmarked a cost of $3.6 million for each regulatory review

342. AGA does not accept $2.1 million is sufficient to cover the current access arrangement process. Costs were incurred in 2013 and 2014 to prepare and submit the initial access arrangement revisions proposal. Subsequent costs were incurred to respond to the 160 questions generated by EMCa and the ERA in their review of the proposal. The ERA's Draft Decision and the quantum of the reductions applied by the ERA means AGA is incurring further regulatory related costs to provide the ERA with additional information to demonstrate compliance with the NGR.

343. Based on the actual costs incurred to date and those anticipated to the end of the regulatory process, AGA has reforecast its regulatory costs for AA4 and AA5 as $3.4 million and $3.3 million respectively and applied these one off costs to 2014, 2015 and 2018, 2019.

IT internal costs

344. In its report to the ERA, EMCa noted an increase in internal IT headcount (which is included within the corporate support operating cost category). AGA had 4 internal IT staff in place during its service agreement with I-Tek. Had the I-Tek service agreement continued, an additional 4 FTEs were anticipated to be needed over AA4 to support development and delivery of the IT strategy and the IT asset management plan. Following adoption of the new IT service arrangement with WIPRO, AGA has reviewed its internal IT cost centre and can confirm that three of these positions will no longer be required. The start date for the fourth position, the Strategic Systems Implementation Technician has been delayed until 2017. Consequently, the labour costs associated with this position have been removed from years 2015 and 2016. The internal IT headcount will remain at 4 FTEs until 2017.

Fringe Benefits Tax

345. Changes were made to the Statutory Formula Method of calculating fringe benefits tax (**FBT**) on 10 May 2011 by the Australian Tax Office (**ATO**), which are driving the incremental change in AGA's FBT costs. These rule changes relate to:

- Car fringe benefits
- Living away from home allowance fringe benefits

346. The ATO's changes move the statutory percentages towards a single rate of 20% by 1 April 2014 for vehicles with new contracts entered into from 10 May 2011, transitioning per the table below. The AGA fleet has been refreshed since 10 May 2011 and each year it attracts higher rates of FBT under the ATO's transitional arrangements. Overall, 87 vehicles attracted FBT in the 2014 FBT return and 36 of those vehicles had contracts commencing in either 2013 or 2014, resulting in an increase to car fringe benefits expense of $0.2 million.

Table 6–14: Transition toward a single FBT rate

Total kilometres travelled during the FBT year	Statutory rate applied to determine a persons car fringe benefit				
	Old statutory %	New statutory % from 10 May 2011	New statutory % from 1 Apr 2012	New statutory % from 1 Apr 2013	New statutory % from 1 Apr 2014
Less than 15,000	26	20	20	20	20
15,000 to 24,999	20	20	20	20	20
25,000 to 40,000	11	14	17	20	20
Over 40,000	7	10	13	17	20

347. A living away from home allowance (**LAFHA**) for FBT purposes is an allowance the employer pays to an employee to compensate for additional expenses incurred and any disadvantages suffered because the employee's duties of employment require them to live away from their normal residence.

348. Prior to October 2012, certain benefits provided to employees who were considered to be living away from their usual place of residence were not subject to either Pay As You Go or FBT. From 1 October 2012, legislative changes took effect making LAFHA benefits subject to FBT. This impacted AGA for the first time in the 2012/2013 FBT return (the FBT year is March to April) as 6 months of cost was included (1 October 2012 to 30 March 2013). The following years return for the 2013/2014 FBBT year included 12 months of cost resulting in a year on year increase in LAFHA FBT cost of $0.1 million.

Why both internal and intercompany corporate support costs increase over AA4

349. In its determination on intercompany charges, the ERA suggested AGA should demonstrate why internal corporate support expenditure needs to increase at the same time that intercompany charges are also rising. This implies some negative correlation between the two sets of corporate support operating cost expenses, internal and intercompany.

350. There is some commonality in the names of the corporate support functions provided internally and intercompany. However, if these functions are examined in more detail a degree of delineation is evident between the types of services provided in-house compared to those provided by the ATCO Group. Table 6–15 outlines some of these differences.

Table 6–15: Provision of corporate support services

Corporate support function	Internal delivery	Intercompany delivery
HR	Provision of employee support and recruitment services including workforce planning, compliance with relevant workforce legislation and industrial relations, payroll and personnel administration, training and development support and management and performance management.	Consultancy support, e.g. executive compensation, career ladders, compensation strategy, philosophy and approvals, administration of remuneration and associate benefits for expat employees, Leadership Development program design and delivery.
Finance and Tax	Day-to-day transaction requirements of the business including control procedures, financial accounting and reporting, budgeting and forecasting, cash flow management, accounts payable and receivable, debt collection management, tax compliance, FBT and management accounting and reporting.	Treasury, cash/debt management and banking assistance, evaluating performance against annual operating and capital budgets. Assistance with the preparation of tax planning and specialist tax advice.

Corporate support function	Internal delivery	Intercompany delivery
Health and Safety	Reporting and review of all HSE and gas distribution network incidents including injuries to workers, contractors or the public, first aid, lost time and workers compensation cases.	Consultancy support for HSE training, compliance, incident reporting and follow-up and governance reporting.

351. Looking at the differences in the nature and scope of the corporate support services provided in-house and intercompany, it is incorrect to assume that because one set of costs increases the other would exhibit a corresponding decrease. For example, if Health and Safety headcount increases in order to respond to an increasing number of injuries and workers compensation cases then there would be no reason to assume that consultancy support for HSE would show a corresponding decrease.

352. Furthermore, both internal and intercompany corporate support costs are driven by growth in the business. Internal corporate support costs need to increase in response to the size of the workforce. Intercompany charges allocated to AGA are calculated under the Massachusetts Method from a consideration of gross plant, gross revenue and labour. Consequently as AGA grows its network by connecting more customers and then requires additional staff to service the network then its allocation of intercompany charges (relative to other companies in the group) will also rise.

353. KPMG notes[112] that:

- Internal corporate support services for AA4 are *anticipated to grow from 2014 levels as a result of specific and limited numbers of staff to meet expanded business requirements, consistent with the forecast growth in revenue and business activity*;
- Intercompany costs are forecast to increase in real terms at an average rate of 1.7% *per annum, primarily as the regulated gas business has grown relative to non-regulated Albany and Kalgoorlie*

354. KPMG also finds that AGA's levels of total corporate support expenditure for AA4 are efficient as determined by the comparison of forecast corporate support costs against those that would be incurred by an independent hypothetical gas distribution business and therefore independent of the levels of corporate support experienced in AA3.

Value of intercompany services and charges

355. ATCO Group provides AGA with the benefit of access to in-house executive resources which provide expertise and economies of scale. It is more cost effective for AGA to access a share of these experienced highly skilled resources rather than directly employ them. Services provided by ATCO Group include:

- Assistance with the preparation of tax planning and specialist tax advice
- Treasury, cash/debt management and banking assistance
- Risk management advice through a dedicated audit director
- HR, e.g. executive compensation and group-wide succession planning
- Significant capital projects and transactions including real estate transactions and IT projects
- Regulatory proceedings, litigation and negotiated settlements

[112] Confidential Appendix 6.7 The Corporate Support Operating Costs of the Mid-West and South-West Gas Distribution System, KPMG, page 34.

356. KPMG has reviewed the nature and cost of the support services AGA receives from ATCO Group. These activities and their associated costs take the form of:

- Direct costs attributed back to the group business – activities undertaken or costs incurred by the ATCO Group on behalf of a group business, e.g. office rental costs, which are charged back to the business on the basis of square footage occupied
- General and public costs allocated by the Massachusetts Method – this is for activities and expenditure which benefits all companies within the group, e.g. internal audit, HR and insurance costs

357. In KPMG's expert opinion, the intercompany corporate support services forecast for AA4 *demonstrate that the intercompany charges procure resources, services and rights that form part of the inputs necessary to provide (AGA) with the totality of corporate support services required for it to meet the requirements of NGR91(1)*.[113]

358. The allocation of intercompany charges from to AGA by the Massachusetts Method is based upon an allocation against gross plant, gross revenues and labour, as outlined in AGA's Access Arrangement Information previously provided to the ERA. KPMG reviewed the allocation of forecast intercompany management charges to AGA via the Massachusetts Method for the 2014 calendar year. This resulted in an overall allocation of 70% of intercompany management charges to AGA. This allocation percentage is assumed to be constant across AA4.

359. KPMG reviewed cost allocation variables utilised in other regulatory determinations and confirms that weighted averages of assets, revenue and headcount have all been approved by the AER as consistent with the requirements of the NGR. Consequently, it is not unreasonable to conclude that allocation of intercompany charges using the Massachusetts Method is also consistent with the requirements of rule 93(2) of the NGR.

360. AGA also incurs management costs from ATCO Australia. KPMG reviewed the individual functions that provided this management support and also the costs of this support. KMPG's conclusion[114] was that:

- The weighted average salary used to calculate the costs of management services provided by ATCO Australia was *not excessive and may err on the side of understatement*
- The activities carried out by the ATCO Australia personnel for AGA are *consistent with the corporate support outcomes required of a prudent service provider*
- It is the action of an efficient service provider to utilise shared corporate support services to *minimise the cost of corporate support services to ATCO Gas Australia and the Mid-West and South-West Gas Distribution System*

361. Intercompany charges are further allocated between regulated and non-regulated sections of the network and between reference and non-reference services in line with AGA's Cost Allocation Methodology previously supplied to the ERA.

Efficiency of corporate support forecast

362. KPMG has conducted a benchmarking analysis that compares the type and cost of corporate support activities that would be required for a hypothetical gas distribution business (**HGDB**) with the same principal operating characteristics as the Mid-West and South-West Gas Distribution Systems with the type and cost of AGA's corporate support activities. KPMG has applied a robust, proven and generally accepted benchmarking method that has been previously accepted by the ERA and other regulatory bodies, to assess

[113] Confidential Appendix 6.7 The Corporate Support Operating Costs of the Mid-West and South-West Gas Distribution System, KPMG, page 8.

[114] Confidential Appendix 6.7 The Corporate Support Operating Costs of the Mid-West and South-West Gas Distribution System, KPMG, page 102.

the efficient costs of providing these services.[115] In its report, KPMG assessed the internal corporate support activities carried out by AGA against rule 91(1) of the NGR.

363. KPMG has determined a median benchmarked corporate support cost of $84.7 million over AA4, compared to AGA's amended proposal of $88.11 million. AGA's bottom-up forecast corporate support costs are 8.9% below the high benchmark over AA4. This is illustrated in Table 6–16 below.

Table 6–16: Benchmark corporate support services for AA4: KPMG

($ million real at 30 June 2014)	Jul-Dec 2014	2015	2016	2017	2018	2019	Total
KPMG Benchmark costs							
- High	8.6	17.4	17.5	17.6	17.7	17.8	96.7
- Mid-point	7.5	15.2	15.3	15.4	15.6	15.7	84.7
- Low	6.2	12.8	12.9	13.1	13.3	13.4	71.6
AGA corporate support forecast	6.9	15.9	14.9	15.6	16.7	18.0	88.1
Variance from mid-point	0.6	(0.7)	0.4	(0.2)	(1.1)	(2.3)	(3.3)

364. Figure 6–13 compares corporate support forecast provided by the ERA in the Draft Decision with the corporate support benchmarks calculated by KPMG.

115 Confidential Appendix 6.7 The Corporate Support Operating Costs of the Mid-West and South-West Gas Distribution System, KPMG, 2014, page 55-56.

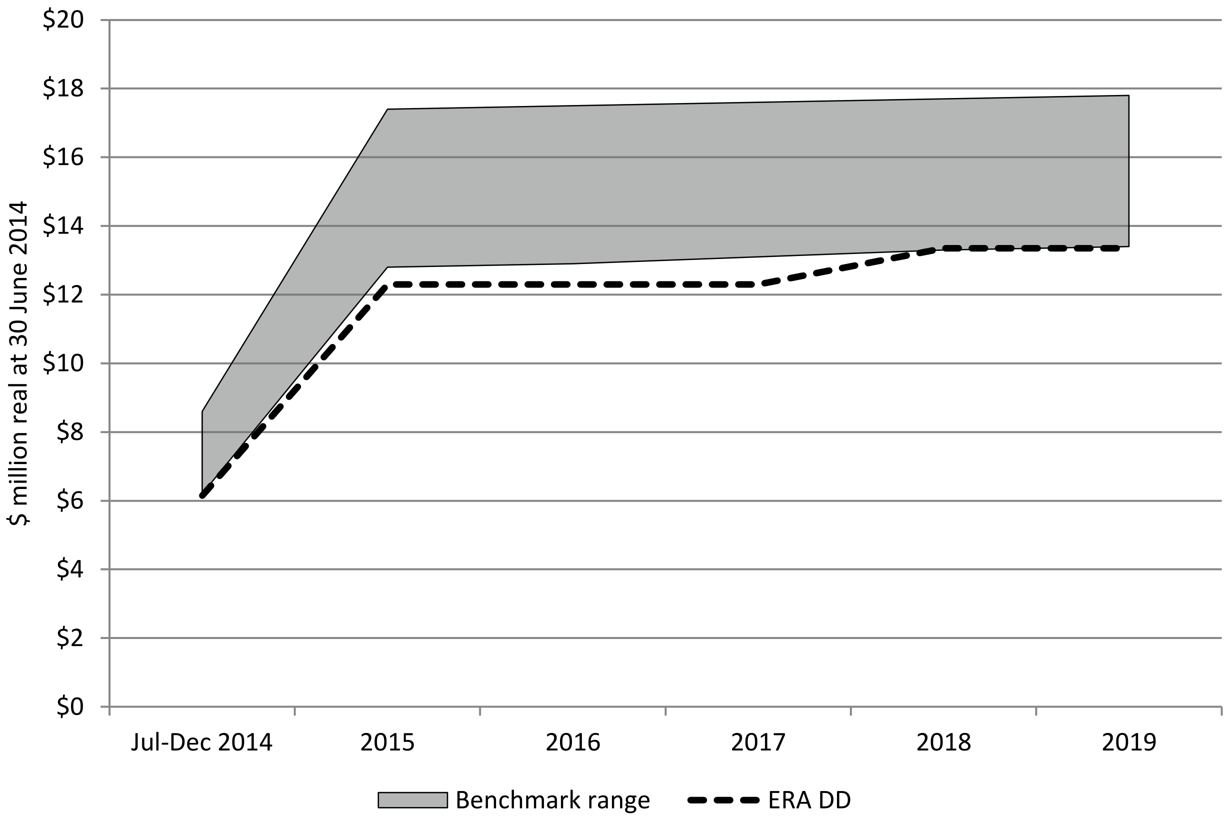


Figure 6–13: Benchmark utility (KPMG) compared to ERA draft decision: forecast corporate support costs over AA4 ($ million real at 30 June 2014)

365. The benchmark costs for the corporate support services forecast per annum for a HGDB from 2015 range from $12.8 million to $17.8 million.[116] In comparison, the ERA's forecast of corporate support costs is 2.7% below the low benchmark.

366. KPMG's expert view is that *the corporate support services for which ATCO Gas Australia has forecast costs in AA4 are services that meet the criteria of NGR 91(1)* and *the benchmarks …demonstrate that the quanta of the …corporate support service expenditure forecast for AA4 are consistent with a wide range of benchmarks that provide a measure of efficient sustainable cost*.[117]

ERA's revealed cost forecast of corporate support costs

367. AGA does not accept the ERA's conclusion that 2013 is an efficient base year from which to forecast corporate support costs. AGA also does not recognise the ERA's version of the revealed cost approach as being an appropriate methodology with which to forecasting corporate support costs.

368. Information provided in the KPMG report confirms that the 2013 does not necessarily *represent the entirety of the historic cost of service provision* for the gas distribution system and that it does not necessarily follow that intercompany charges *in the three years to June 2014 represent the full costs of corporate service provision*. As discussed earlier, AGA considers corporate costs in 2013 were unsustainably low and do not represent an efficient base year.

116 Confidential Appendix 6.7 The Corporate Support Operating Costs of the Mid-West and South-West Gas Distribution System, KPMG, 2014, page 4.

117 Confidential Appendix 6.7 The Corporate Support Operating Costs of the Mid-West and South-West Gas Distribution System, KPMG, 2014, page 8.

369. Acil Allen considers the revealed cost approach applied by EMCa and adopted by the ERA. Acil Allen notes the ERA:

- Included no allowance for the impact of growth
- Disallowed any real increases in input prices
- Included no explicit offset for productivity improvements

370. In the Acil Allen's expert opinion, the ERA has *implicitly offset any impact of growth with productivity improvements with no commentary in the draft decision as to why there is no allowance for the impact of growth* and has *not properly applied the revealed cost approach*.[118]

Revised AA4 corporate cost forecast

371. For the reasons stated above, AGA does not accept the Draft Decision for corporate support costs and submits a revised and slightly lower forecast compared to the March 2014 submission.

372. Table 6–17 shows AGA's revised corporate cost proposal.

Table 6–17: Comparison of AGA's revised AAI and amended proposal: forecast corporate support operating costs over AA4

($ million real at 30 June 2014)	Jul-Dec 2014	2015	2016	2017	2018	2019	Total
Revised AAI - Corporate support	8.0	16.6	15.6	16.3	17.3	17.7	91.5
Amended proposal - Corporate support costs	**6.6**	**15.9**	**14.9**	**15.6**	**16.7**	**18.0**	**88.1**
Variance	(1.1)	(0.7)	(0.7)	(0.7)	(0.6)	0.3	(3.4)

118 Appendix 6.2 Operating Expenditure Forecasting Using the Revealed Cost Approach report (Scale), Acil Allen November 2014, p10

6.2.3.2 Business Development and Marketing

373. The ERA requires AGA to reduce its forecast business development and marketing operating expenditure for AA4 from $24.6 million to $9.7 million and to hold expenditure throughout AA4 at 2013 levels[119].

374. The ERA has accepted its technical expert EMCa's advice that the sensitivity analyses undertaken in its review of AGA's proposal result in a negative net present value for the program. In particular, EMCa advised that:

- The average consumption assumed for new customers seemed high relative to actual consumption data AGA provided in response to relevant information requests; and
- The proposed business development and marketing operating expenditure is relatively high for customer groups that deliver low benefits. In particular, it appears that the significant focus of expenditure on residential customers may not be justified in relation to the benefits

375. Key reasons the ERA considers marketing and business development expenditure be held at 2013 levels are:

- AGA's benchmarking study could not *demonstrate that the investment by other regulated gas businesses has been effective because each of the benchmarked business development and marketing programs are in their infancy*[120]
- Concerns with the underlying assumptions adopted in AGA's NPV analysis and that the NPV would not be positive for 10 years, which EMCa considers is *too high for a business development and marketing program*[121]

376. AGA has not implemented the ERA's required amendment because it considers the strategies and initiatives planned for AA4 will benefit customers. However, AGA has amended its forecast expenditure on business development and marketing as a result of reviewing the activity to date and further investigation on activities likely to be effective during AA4. As a result the amended business development and marketing expenditure has reduced from $24.6 million to $20.8 million.

377. The matters raised by the ERA in its Draft Decision and an overview of AGA's revised business development and marketing program is provided in the following sections.

Effectiveness of business development and marketing activities

378. The benchmarking study provided by AGA in the March 2014 submission shows that its proposed business development and marketing expenditure is commensurate with other gas distribution businesses. However, because the study samples business development and marketing campaigns that were in their infancy, it was not possible to demonstrate that these campaigns were effective. As a result, the ERA considers the study does *not provide evidence that ATCO would be acting efficiently and in accordance with good industry practice in undertaking its proposed program*.[122]

379. To address the ERA's concerns around the effectiveness of such marketing campaigns has identified two recent gas marketing campaigns that have delivered measurable results. These are:

119 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 256.

120 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 261.

121 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 264.

122 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 261.

- Capricorn Estate pilot marketing campaign 2013 (Western Australia)
- Australian Gas Networks (previously Envestra) natural gas advertising campaign 2010 – present (South Australia)

Capricorn Estate

380. AGA submits the recent Capricorn Estate pilot marketing campaign as evidence of the impact of incentive-based gas marketing.

381. The Capricorn Estate is located in Perth's northern suburbs. When the Capricorn Estate was built, natural gas was not yet available in the area. However, the developer installed a dormant gas network to be used until natural gas was available.

382. In 2013, AGA extended the natural gas network to reach Yanchep and as a result, could connect and commission the dormant gas network. The Capricorn Estate consists of 1,140 lots with more than 600 established homes. To assist in reducing the upfront connection cost, as a pilot campaign AGA offered up to $1,000 towards the cost of installation, this was only available to the existing 600 established homes and not any new developments that would come on line.

383. The Capricorn Estate pilot started in August 2013, and included smart car advertising and a direct mail drop to all the residence in Capricorn Estate. A further non-personalised letter drop was carried out in October 2013 and followed up with a postcard drop in November. The campaign resulted in more than 200 new connections. AGA has since incorporated experience from the Capricorn Estate campaign into its business development and marketing initiatives for the AA4 period. AGA is confident the successes of the Capricorn Estate pilot can be replicated and multiplied across the network and provides evidence that similar campaigns will be effective.

Australian Gas Networks natural gas advertising campaign

384. While the introduction of incentive schemes is relatively new to Western Australia, there is evidence of successful incentive programs across Australia from other gas distributors. Australian Gas Networks in South Australia (previously Envestra) has provided AGA with the performance of its advertising campaign since 2010.

385. Natural gas marketing was reintroduced in South Australia in 2010 to reverse the downward trend in new connections and home heating. The overall performance of the advertising campaign and incentives over the five year period has exceeded all expectations with awareness levels and gas preference at all-time highs. The outcome was 28,008 new connections or additional appliances, producing more than 700TJs of load for the network.

Table 6–18: Impact of Australian Gas Network's campaign on new connections and new gas

Year of Australian Gas Networks campaign	Impact – new connections or new gas appliances replacing electric
2010	2,422
2011	5,818
2012	7,282
2013	5,336 (restricted campaign)
2014	7,150 (extrapolated forecast)
Total	**28,008**

Expert opinion

386. To provide further scrutiny of AGA's proposed business development and marketing plan, AGA sought advice from Brent Stewart, an expert in the field of marketing and marketing research.[123] AGA provided Mr Stewart a copy of the ATCO Strategic Marketing Plan prepared by Churchill Consulting, which formed the basis for the proposed business development and marketing activities in the March 2014 submission and this revised proposal.

387. In Mr Stewart's opinion *the ATCO Gas Strategic Marketing Plan by Churchill Consulting is professionally prepared and sound by way of both method and conclusions. It provides a strong foundation for ATCO Gas' BDM strategy and articulates an alignment with ATCO Gas' target market (B2 and B3 customers) with a clear weighting towards residential customers.*[124]

388. Further, Mr Stewart notes the following facts and observations:

- *ATCO Gas has employed professional external experts to assist with the development of its BDM strategy and this forms the basis for ATCO Gas' marketing plan*
- *ATCO Gas has conducted market research through external third parties to better understand the target market*
- *The findings of the market research could reasonably lead ATOC Gas to conclude that advertising and promotion that promotes the benefits of natural gas along with financial incentives could lead to increases in consumption and new connections*
- *ATCO Gas has developed a marketing plan that logically draws from the abovementioned body of work and sets out a clear path of execution, including planned advertising and promotion to raise the awareness of the benefits of natural gas and offer financial incentives for new connections.*[125]

389. Mr Stewart's expert opinion lends credibility to AGA's view that the proposed business development and marketing activities will be effective and that the business would be acting efficiently and in accordance with good industry practice in undertaking its proposed program. AGA therefore considers the proposed business development and marketing expenditure satisfies rule 91 of the NGR.

390. Mr Stewart also expresses his view that the EMCa's conclusion that the 2013 levels of business development and marketing expenditure provide a reasonable basis for the AA4 forecast, is unfounded.

391. In his statement, he refers to the ERA Draft Decision and states,

> *In the subsequent paragraph, the ERA Draft Decision goes on to reference EMCa's conclusion that the BDM expenditure that ATCO has chosen to spend from 2011 to 2013 can be considered a reasonable and efficient level, based on ATCO's commercial incentives to incur operating expenditure at an efficient level and to try and increase demand (Appendix D, paragraph 256). EMCa goes on to state that "EMCa considers that the amount that ATCO has spent on business development and marketing in 2013 provides a reasonable basis for forecast expenditure for the fourth access arrangement period" (Appendix D, paragraph 256). I can find no supporting rationale provided for EMCa's conclusion in this regard.*[126]

[123] Appendix 6.8 ATCO Gas Australia Pty Ltd - Economic Regulation Authority Price Determination: A report prepared by Brent Stewart, November 2014.

[124] Appendix 6.8 ATCO Gas Australia Pty Ltd - Economic Regulation Authority Price Determination: A report prepared by Brent Stewart, November 2014, page 7.

[125] Appendix 6.8 ATCO Gas Australia Pty Ltd - Economic Regulation Authority Price Determination: A report prepared by Brent Stewart, November 2014, page 8.

[126] Appendix 6.8 ATCO Gas Australia Pty Ltd - Economic Regulation Authority Price Determination: A report prepared by Brent Stewart, November 2014, page 8.

Further, Mr Stewart considers the ERA's decision to maintain expenditure at 2013 levels under the expectation that the increase in customer numbers will still be delivered is not supported by evidence. He states:

> *It is my opinion that the available data to support or refute whether maintaining ATCO Gas' BDM expenditure at 2013 levels is equivocal. I am of the opinion that the ERA's Draft Decision to maintain expenditure at 2013 levels (Appendix C, paragraph 118) is without proper foundation. Specifically, I can find no compelling evidence for the statement "the Authority considers that the adjusted business development and marketing operating expenditure would still deliver ATCO's proposed marginal increase in the number of customers" (Appendix C, paragraph 118).*[127]

392. AGA agrees with Mr Stewart's findings and considers the decision to maintain business development and marketing expenditure at 2013 levels for the AA4 period is unreasonable and unsubstantiated. Expenditure in 2013 is discussed further in the following section.

Marketing and business development expenditure during 2013

393. The expenditure undertaken in 2013 represented did not include the program of initiatives proposed for AA4. In 2013, the majority of marketing and business development expenditure related to employee costs and a limited number business development and marketing campaigns. It is not reasonable to expect the forecast outcomes of the AA4 business development and marketing activities can be achieved without delivering the AA4 initiatives. The AA4 initiatives cannot be delivered for the 2013 expenditure levels.

394. During 2013 AGA scaled back its advertising to allow clearer air time following Kleenheat's entry to the market. To avoid confusing customers about AGA's role in the market, AGA considered it prudent to ensure there was a gap between Kleenheat's gas advertising campaign and recommencing AGA advertising. This meant associated expenditure during 2013 was reduced.

395. The remainder of 2013 business development and marketing spend was attributed to labour costs. In 2013, the business development and marketing division comprised 13 people, who undertook the activities listed in Table 6–19: FTE by activity in business development and marketing.

Table 6–19: FTE by activity in business development and marketing

Activity	FTEs
Account management	4.0
Economic modelling and demand forecasting	3.0
Digital communication management	1.0
Campaign delivery and management	2.0
Community engagement	1.0
Management	2.0
Total	**13.0**

396. The sections below provide an overview of the tactical roles.

- **Account management** - there are four dedicated account management FTEs in the Business Development and Marketing team, allocated across four market segments; commercial and industrial, builders, land development, home renovation and appliance. Core responsibilities are:

[127] Appendix 6.8 ATCO Gas Australia Pty Ltd - Economic Regulation Authority Price Determination: A report prepared by Brent Stewart, November 2014, page 8.

- Managing client relationships (local and remote) and providing specialist advice relating to achieving maximum efficiency for their access to and use of the gas network
- Presenting the value proposition of natural gas as a preferred energy source across market segments
- Building client and consumer awareness and confidence of natural gas and associated appliances as a preferred energy source
- Managing any relevant incentive programs associated with natural gas and builders
- Running forums and workshops, attending trade shows
- Representing AGA in relevant planning and business development committees and industry bodies
- Performance reporting

- **Economic modelling and demand forecast -** core responsibilities are:
  - Assessing the commercial and regulatory viability of all new initiatives
  - Developing and implementing economic policy and practices
  - Undertaking detailed analysis for forecasting information to inform major strategic and investment decisions related to spur line extensions, headworks costs, mains extensions and other major infrastructure opportunities
  - Conducting NPV analysis for all growth capital expenditure network expansion proposals and develops and presents pricing strategies to yield optimum returns on investment over the asset life-cycle
- **Digital communication management -** core responsibilities are:
  - Developing and implementing all content for the AGA website, ensuring that it is accessible to customers in order to find accurate information and that informational messaging is presented in a timely and engaging manner to ensure that it is retained
  - Monitoring and contributing of content to key AGA social media platforms including Twitter, Facebook, Instagram, Pinterest, LinkedIn, YouTube
  - Ensuring key safety and benefit lead messaging is available via key channels utilised by the WA community when searching of gas safety messaging and the number to call
  - Ensuring current and accurate content is continually published and refreshed via the above channels with full tracking to improve performance, in line with good industry practice
- **Campaign delivery and management** – while targeted incentive campaigns fall under the remit of the account managers, these roles provide support in the development and coordination of general offline marketing material (i.e. direct mail packs), the AGA brand and promotional activities aimed at increasing awareness of AGA, community engagement initiatives, including the schools program, key safety messages and the value proposition of natural gas
- **Community engagement** - this role is responsible for the development and delivery of all community engagement activity designed to maximise messaging to the broader community regarding safety and the benefits of natural gas. Included in this is the delivery of the schools excursions program, which is aimed at increasing awareness of safety and natural gas awareness delivery, ensuring that future gas users are provided with important information in an engaging manner

397. Given the make-up of the 2013 business development and marketing expenditure, AGA considers it does not represent a reasonable platform for which to forecast AA4 costs and the expenditure level would not allow the proposed business development and marketing activities to be delivered.

Revised NPV analysis

398. To address EMCa's concerns in the ERA's Draft Decision, AGA has revised its approach to the NPV analysis. AGA accepts it is appropriate to use the expected consumption of new customers rather than existing customers.

399. AGA plans to offer at least six incentive programs during the AA4 period. Each program targets a certain customer type and aims to deliver specific outcomes related with those customers. Therefore AGA's revised NPV analysis uses assumptions associated with the outcome of each program.

400. For example, for the infill incentive program the assumption relating to the average consumption of a new customer (13.6 GJ) is consistent with AGA's forecast for the average weather adjusted consumption for B3 customers. However for the gas hot water incentive AGA assumes the higher average usage expected for a B3 customer with a hot water system.

401. Table 6–20 presents AGA's revised NPV analysis by incentive program.

Table 6–20 NPV analysis by incentive program

Program	Infill program	HWS infill	Existing customer HWS	Builder appliance	GPAC	Generation
Targeted number	600 (10% of targeted households)	3,417 (15% of targeted households)	1,500 gas hot water systems	2.500 additional gas appliances	80 systems for B1, 80 systems for B2	10 A2 connections, 20 B1 connections
Customer type	B2, B3	B3	B3	B2, B3	A1, A2, B1	A1, A2, B1
Average consumption	20.8 GJ (assumes 5 star hot water)	20.8 GJ (assumes 5 star hot water)	20.8 GJ (assumes 5 star hot water)	Consumption based on number of appliances	303.3 GJ	N/A
Total load	20,113GJ	162,640GJ	78,000GJ	47,988GJ	121,326GJ	504,864GJ
Incentive payment	$350	$700	$300	$200 to $400 depending on number of appliances	Up to $25,000	Up to $25,000
Assessment period	25 years	25 years	25 years	15 years	10 years	10 years
Allocation of support activity costs	Yes	Yes	Yes	Yes	Yes	Yes
Cost of program ($000s)	222	2,772	468	705	1,071	1,071
Years until the program delivers a positive NPV	**8**	**11**	**5**	**9**	**8**	**4**

402. AGA notes EMCa's concern regarding the payback period for the NPV analysis. However, the assessment period for these programs reflects the economic life of the assets installed to deliver the load. Therefore, as long as the payback period is less than the economic life of the assets, existing customers will benefit from these programs. Historical disconnection rates are very low (see Table 6–21) so any concern about customers not being able to benefit from new connections generated by these business development and marketing initiatives is immaterial.

Table 6–21: Historical disconnection rates

B3	MIRN Count		% of Deregistered
Customers	**Connected in Year**	**2014**	**2014**
2007	21,292	21,243	-0.23%
2008	18,803	18,765	-0.20%
2009	16,659	16,630	-0.17%
2010	18,522	18,506	-0.09%
2011	17,766	17,759	-0.04%
2012	14,814	14,808	-0.04%
2013	16,595	16,595	0.00%

Revised business development and marketing program

403. AGA has reviewed its business development and marketing program to ensure the proposed activities meet the objective and address the findings of the market research. AGA's objective is to increase connections and volume of gas flowing through the gas distribution system, by:

- Raising the awareness of the value in the use of natural gas
- Promoting gas connections and gas appliances
- Engaging market enablers and influencers to promote natural gas
- Researching new technologies

404. AGA's marketing activities for the AA4 period are informed by the ATCO Strategic Marketing Plan prepared by Churchill Consulting, which has been reviewed by independent expert Brent Stewart. In addition to this plan, AGA has conducted a competitor analysis report[128] (attached at Confidential Appendix 6.9), which provides an overview of the various competing technologies, industries and alternative energy sources that impact AGA's pricing and activities. This competitor analysis has also been used to develop the business development and marketing activities during the AA4 period and will continue to be a key point of reference for AGA's service provision.

405. The following sections provide an overview of the marketing and business development programs planned for AA4.

Raising the awareness of the value in the use of natural gas.

406. AGA's market research and analysis identified that WA gas consumers have a low awareness of either AGA or its role. In 2014, AGA undertook a brand awareness campaign to inform the WA community who AGA is and the role it plays in the safe, reliable delivery of natural gas to homes and businesses. The campaign resulted in increased traffic to the AGA website where people were able to find further detail regarding the benefits of natural gas.

407. AGA aims to maintain brand recognition across the AA4 period so that information can be recalled, allowing consumers to make informed decisions when reviewing their energy choices (e.g. building, renovating, moving home, appliance breakdown) along with recognising AGA's role in providing safe, reliable gas supply.

[128] Confidential Appendix 6.9 AGA Competitor Analysis 2014.

408. AGA's community engagement program aims to create and maintain close links with the communities in which it operates. The core values of this policy centre on relevant, timely and long term safety messages to the community and key organisations. This includes the delivery of the schools excursions program (utilising the Jandakot Blue Flame Kitchen) which is aimed at increasing public safety and awareness of natural gas delivery. The school excursion program is aligned with the ACARA curriculum framework and incorporates syllabus components. Students take home material booklets that include safety messages and helpful hints, i.e. uses of natural gas, importance of servicing appliances, cost savings.

409. In addition, partnerships with organisations such as Kidsafe WA and the Migrant Resource Centres will help position AGA as a socially responsible business, committed to the welfare of WA people while complementing AGA's core marketing messages regarding the benefits of natural gas. Promoting gas connections for existing and new builds and promoting the use of gas appliances.

410. AGA has developed a range of incentive programs designed to deliver additional throughput through new connections and increased appliance use. The NPV analysis of these programs is summarised and described below.

Infill program

411. The infill incentive program is scheduled to for 2014 and 2015 to increase new connections to established residential properties. This campaign offers a $350 rebate to homeowners should they choose to connect a gas appliance, and is designed to increase gas penetration rates to domestic properties.

412. This campaign will be supplanted by the Gas Hot Water System (HWS) campaign from 2015 onwards (described below).

Gas hot water system - infill program

413. The gas hot water system infill program is designed to not only connect customers but install a hot water system, which will increase the expected average consumption of the household. Hot water systems alone can result in gas consumption of up to 20.8 GJ per year[129]. A gas hot water system shall be provided as an incentive to customers who take up the offer to convert from their existing all-electric or electric boosted solar hot water system to natural gas.

Gas hot water system – existing customers

414. AGA will offer gas retailers a $300 rebate per customer where an existing customer switches from an existing electric or electric boosted solar hot water unit to a new gas HWS. This program will commence in 2015 and is expected to increase the average gas consumption per connection.

Builder's incentive program

415. This program aims to increase gas consumption of new gas connections by increasing the number of gas appliances installed in newly constructed homes beyond the commonly installed gas hot water system and gas cooktop. A tiered incentive scheme will be offered to builders to install gas connection and gas appliances.

Gas powered air conditioning program (GPAC**)**

416. This program will commence in 2015 and aims to reduce the up-front cost barrier associated with natural gas powered air conditioning and raise awareness of the ongoing cost benefits in commercial and industrial applications. Increased utilisation of gas fired air conditioning not only increases gas throughput relating to the particular installation but could also stimulate broader demand in the long term. Incentives will be offered

[129] Consistent with the expected gas use of a hot water system compliant with Australian Standard AS4552.

from $1,000 - $6,000 per unit installed, with a maximum incentive rebate application of $25,000 available for any single property location. The rebate is directly proportional to the volume of gas consumed.

Gas Generation program

417. This program will commence in 2015 and is intended to promote the utilisation of natural gas generation (Power Generation, Co-Generation or Tri-Generation) as an alternative energy solution, particularly for buildings seeking high Green Star ratings.

418. Similar to the GPAC program, AGA will provide incentives to reduce the current up-front capital cost barrier to entry for customers. The rebate will be offered on the basis of the recipient agreeing to a take or pay arrangement based on forecast gas loads, and capped at $25,000.

Engaging market enablers and influencers to promote natural gas

419. AGA will target key stakeholders such as gas retailers, builders, land developers, government, regulatory bodies, associations and other industry influencers in order to promote the use of natural gas and communicate the benefits of connecting to the network. In addition to the incentive programs described above, AGA will participate in relevant industry forums and seeks to position itself as a recognised voice in ongoing energy debate.

Research new technologies

420. AGA will continue to research and invest in new technologies such as gas fuel cells.

Amended expenditure proposal

421. AGA has amended its forecast expenditure on business development and marketing as a result of reviewing the activity to date and further investigation on activities likely to be effective during AA4. As a result the amended business development and marketing expenditure has reduced from $24.6 million to $20.7 million.

422. The year on year impact is shown in Table 6–22 below.

Table 6–22: Business development and marketing amended forecast expenditure

Forecast	2014	2015	2016	2017	2018	2019	AA4
ERA’s Draft Decision	0.9	1.8	1.8	1.8	1.8	1.8	9.7
Amended proposal	1.5	3.8	3.8	3.8	3.9	3.9	20.8

423. Figure 6–14 presents the change in composition of the business development and marketing activities from 2013 to 2019.

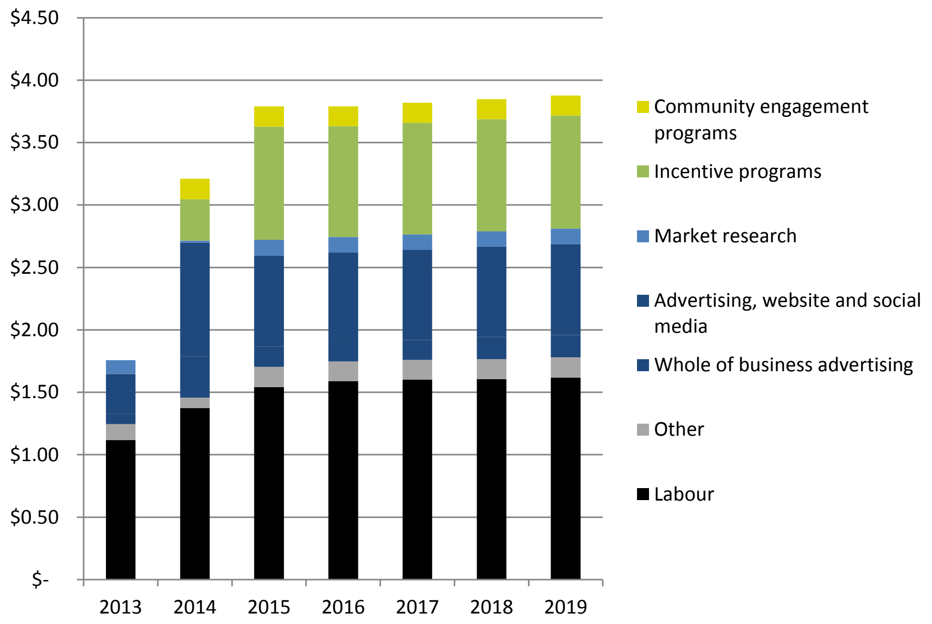


Figure 6–14: Business development and marketing expenditure by activity

Change in marketing and business development expenditure in 2014

424. In addition to the proposed marketing programs described above, forecast expenditure in 2014 is higher than 2013 as it includes the annualised costs of two roles appointed during 2013 and one additional role appointed in 2014. These roles were created consistent with the implementation of AGA's marketing strategy and are described below:

- **Community Engagement Manager** (appointed in November 2013) – responsible for the development and delivery of all community engagement activity and the development and implementation of community engagement partnerships
- **Marketing and Events Coordinator** (appointed in July 2014) - assisting in the development and coordination of offline marketing, brand and promotional activities aimed at increasing awareness of AGA, the community engagement initiative, including the schools program, key safety messages and the value proposition of natural gas
- **Digital Communications Coordinator** (appointed in June 2014) - responsible for the development and implementation of all content for AGA website and other online presence, including Twitter, Facebook, Instagram, Pinterest, LinkedIn and YouTube

425. Increases in non-labour costs between 2013 and 2014 relate to:

- The brand awareness campaign undertaken in March 2014
- Commencement of AGA's community engagement program
- Improvements in the AGA web site and social media to make it easy for customers and the community to find out information about natural gas service benefits, options and processes
- The Yanchep pilot program and development of the infill incentive program

426. These activities were not undertaken during 2013.

Change in marketing and business development expenditure in 2015

427. The increase in expenditure forecast in 2015 includes the annualised costs of the digital communications co-ordinator appointed in July 2014 and the commencement of the remaining incentive programs and expected increase in activity in the existing programs.

6.2.3.3 Licence fees

428. The ERA requires AGA to amend its forecast licence fee operating expenditure from $16.1 million to $14.3 million. In July 2014, the ERA requested additional information from AGA on the breakdown of the licence fee forecast over AA4[130]. AGA provided this information (referred to as ERA 33), which showed a lower forecast of licence fees of $14.4 million than previously provided.

429. The ERA used this information in the Draft Decision, and proposed that ATCO *did not provide a rationale for forecasting a doubling of the actual WA Energy Disputes Arbitrator charges in the forecast*. [131] Consequently, the ERA adjusted the charges for this vendor in line with historical levels to calculate the $14.3 million forecast approved in the Draft Determination.

430. AGA has implemented the ERA's amendment with a minor modification. AGA has updated the forecast to reflect the expected licence fees in 2014 and will then adopt this amount in each year of AA4 unless it is advised of a change by one of the licence fee vendors. The list of vendors and reforecast of licence fees for AA4 is shown in Table 6–23 below.

130 Response to ERA 33 (31 July 2014).

131 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 273.

Table 6–23: Amended licence fee forecast ($000s real at 30 June 2014)

Vendor	Description	Jul-Dec 2014	2015	2016	2017	2018	2019	Total
Department of Commerce	Energy Safety Levy	964.3	1,873.6	1,873.6	1,873.6	1,873.6	1,873.6	10,332.3
Department of Land	Access Rights Charges (historic)	88.2	-	-	-	-	-	88.2
	Access Rights Charges Annual Fee	6.3	6.3	6.3	6.3	6.3	6.3	37.8
Department of Mines and Petroleum	Dangerous Goods Site Licence Annual Fee	-	0.6	0.6	0.6	0.6	0.6	3.0
	Pipeline Licence Annual Fee	1.5	1.5	1.5	1.5	1.5	1.5	9.0
	Pipeline Safety Case Levy Quarterly Fee	4.8	9.6	9.6	9.6	9.6	9.6	52.8
Energy Industry Ombudsman	Annual Fee	12.2	15.0	15.0	15.0	15.0	15.0	87.2
Economic Regulation Authority	Standing Charge – Quarterly Fee	297.4	594.9	594.9	594.9	594.9	594.9	3,271.9
	Gas Licence – Annual Fee	7.4	7.4	7.4	7.4	7.4	7.4	44.4
	Specific charges – Consultant and/or Admin costs	54.8	150.0	-	-	-	150.0	354.8
REMCO	Annual Service Fee	19.3	19.3	19.3	19.3	19.3	19.3	115.8
WA Energy Disputes Arbitrator	Standing Charge for the Gas Distribution Licence – Quarterly Fee	1.8	3.2	3.2	3.2	3.2	3.2	17.8
Total		**1,458.0**	**2,681.4**	**2,531.4**	**2,531.4**	**2,531.4**	**2,681.4**	**14,415.2**

431. AGA's reforecast reflects the licence fee charges invoiced or expected to be received between July and December 2014 and is based on an analysis of licence fee schedules and charges rather than a pro-rata of the full year's costs. For example, the annual Dangerous Goods Site Licence Fee levied by the Department of Mines and Petroleum was received and paid in the first half of 2014 and so does not appear in the Jul-Dec 2014 column above. The forecast for 2015-2019 is based on the annualised total of licence fee charges for 2014.

432. The increase between the ERA's required amendment and AGA's amended forecast is $0.1 million or 0.7%. The difference relates to:

- The reduction in the annual fee charged by the Energy Industry Ombudsman, from $20,000 to $15,000 per annum

- The first ERA invoice for standing charges for the quarter beginning 1 April 2014 that was not received until early September
- The recovery of an annual fee for access rights, levied by the Department of Lands, this was subject to legal review at the time of AGA's previous forecast

433. AGA notes that variations between licence fees actually paid and forecast will be subject to a cost pass through application. Therefore, it is important to provide a specific and accurate forecast for these amounts.

6.2.4 IT operating costs

434. The ERA requires a reduction of $15 million or 25.5% of AGA's proposed IT operating expenditure.

435. The ERA considers IT Licence Fees should reduce by $0.9 million from $14.4 million to $13.5 million. The ERA does not accept the $0.9 million increase in IT Licence Fees that results from the change from the IT service agreement with I-Tek (where IT Licence Fees for AA4 were forecast at $13.5 million) to the new IT service arrangement with WIPRO (where forecast IT Licence Fees are forecast at $14.4 million). Its reasoning is that AGA "*has not provided supporting information that links the IT licence fee forecast with the new IT service agreement update and proposed capital expenditure*".[132]

436. The ERA has reduced IT Service Fees by $14.1 million from $44.1 million to $30.0 million. The ERA notes[133] it is *not satisfied that any proposed increase in the IT services fee from the 2013 level is consistent with NGR 91*. The ERA has two concerns:

- EMCa expected that the new systems would have been 'right-sized' by the end of AA3 as the nominated systems were or would be in place by the end of AA3 and did not see the *need for the IT services fee to increase, particularly if the corporate head count does not grow as dramatically as predicted*.[134]
- EMCa had not seen compelling evidence that AGA has *sufficient capacity and capability to develop and implement the multiple proposed projects, many of which require additional support*. [135]

437. AGA has not implemented the ERA's draft decision on IT operating costs for the following reasons:

- EMCa did not review AGA's revised IT proposal, which was provided to the ERA in August 2014, with further supporting information provided in September 2014.
- The Managed Service Fee forecast for AA4:
  - appears higher than the levels in AA3 because of confusion over the different charging methods
  - is efficient and required to support 'moderate'[136] growth in the business; and
  - as a result of the competitive tender process, the services to be provided will be delivered at a lower cost than under the previous IT service arrangements with I-Tek
- Under the new WIPRO IT service agreement, the capacity and capability to deliver services was tested through the competitive tender process and the risk of delivery now sits with WIPRO, an arms-length service provider.

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132 ERA (2014): 'Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System', paragraph 290.

133 ERA (2014): 'Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System', paragraph 298.

134 EMCa, Review of Technical Aspects of the Proposed Access Arrangement, 2014, paragraph 600.

135 EMCa, Review of Technical Aspects of the Proposed Access Arrangement, 2014, paragraph 600.

136 Appendix 6.4 The IT Operating Expenditure of the Access Arrangement for the Mid-West and South-West Gas Distribution System, KPMG November 2014, page 9.

Confusion over different charging methods

438. The EMCa assessment of the efficiency of AGA's proposed IT operating cost expenditure was conducted on the **previous** I-Tek IT services agreement (**ITSA**) and did not assess the new, competitively tendered WIPRO arrangements. The ERA applied EMCa's conclusions on the efficiency of the I-Tek IT Service Fee to the Managed Services Fee (**MSF**) cost category in the new WIPRO IT model.

439. AGA considers that comparison of the IT Services Fee (I-Tek) and the Managed Service Fee (MSF) is inappropriate because of the fundamental differences between the two IT service funding models and the differences underlying each fee. Therefore, the application of EMCa's efficiency reduction on the I-Tek Service Charge to the WIPRO MSF leads to an unreasonable forecast for the purposes of rule 74 of the NGR.

440. AGA believes further clarification on the fundamental differences between the two IT service models will help to explain why AGA has adopted its position. The different IT activities and services between the I-Tek and WIPRO models are shown below along with how the costs for these services are categorised under the two charging structures.

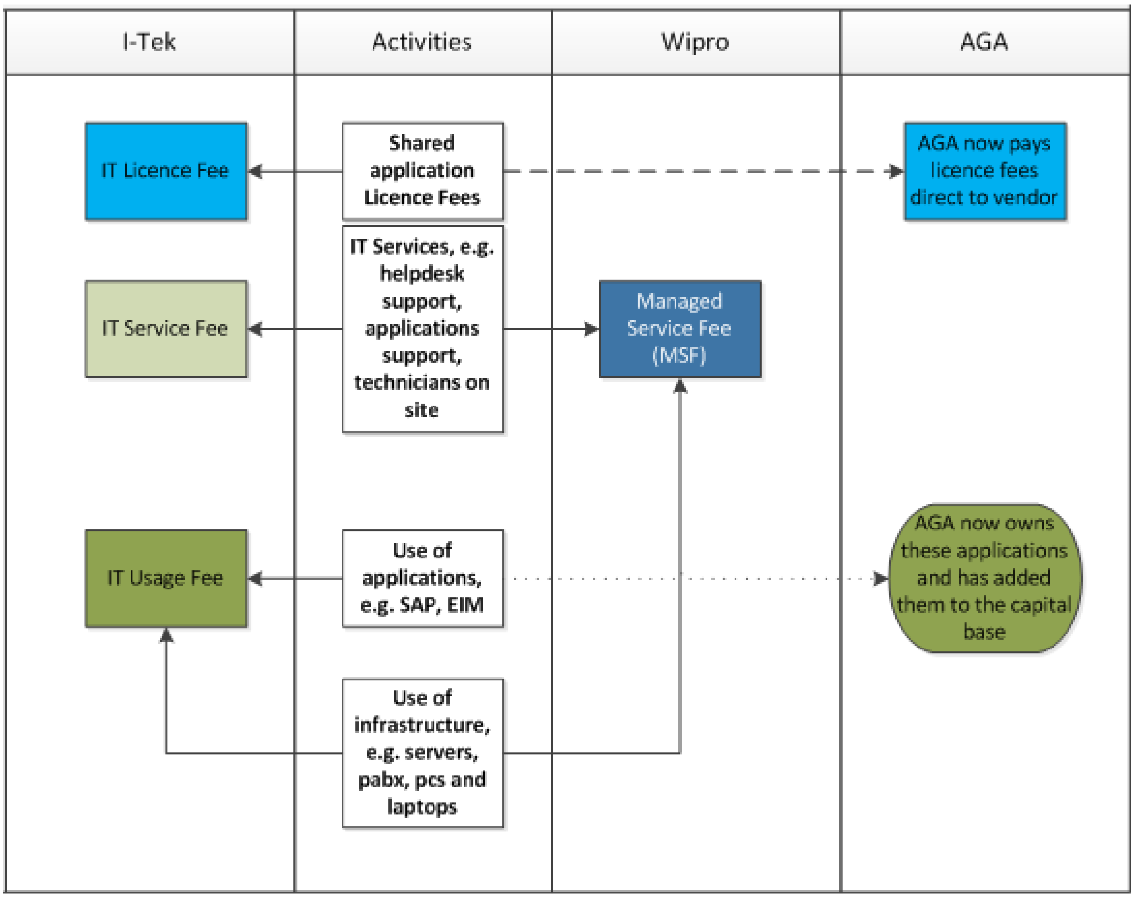

Figure 6–15: Comparison of IT operating cost charging structures: I-Tek and WIPRO

441. The forecasts of selected IT categories under each of the IT service agreements are illustrated in Figure 6–16 below.

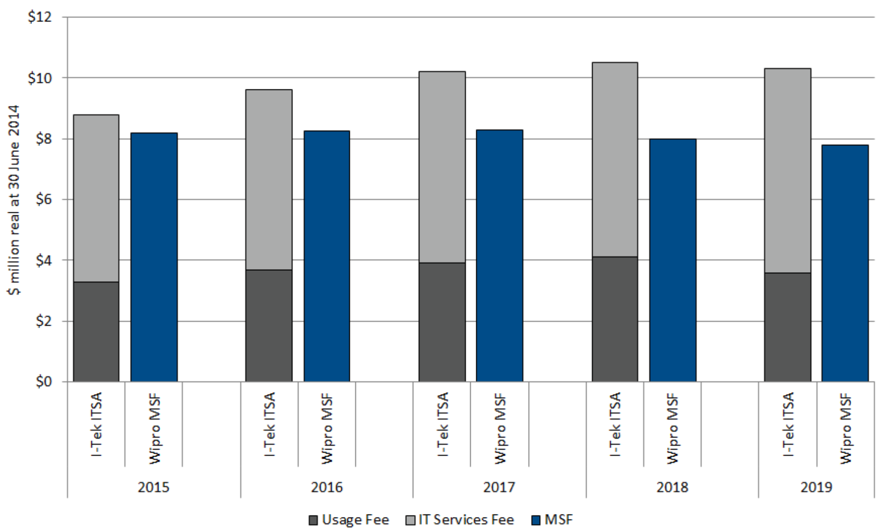

Figure 6–16: IT operating costs by expenditure category: I-Tek and WIPRO excl. IT Licence Fees ($ million real at 30 June 2014)

442. Figure 6–16 illustrates that under the new WIPRO IT agreement, the MSF is:

- Lower than total costs under the previous ITSA
- Reducing over time

443. The previous I-Tek Usage Fee warrants further explanation. Under the previous agreement with I-Tek, AGA was charged an:

- Applications Usage Fee - to use shared applications, e.g. SAP and the document management system EIM
- Infrastructure Usage Fee - to use the infrastructure that I-Tek owned, e.g. servers, PABX and routers. When a system or infrastructure upgrade was required I-Tek would cost and manage the project and recharge or pass this cost through to AGA via the IT Usage Fee. Prior to AGA negotiating a new contract, the IT Usage Fee forecast for I-Tek was rising over AA4 to reflect the planned system and hardware replacement program

444. AGA accepts the Draft Decision on the IT Usage Fee but only for the July to December 2014 period. Beyond this period the IT Usage Fee no longer exists. This is because as a result of the change to a new IT service agreement, AGA purchased key business systems from I-Tek and so an ongoing Applications Usage Fee is no longer required.

445. WIPRO also purchased systems and infrastructure from I-Tek as part of the new IT services agreement. WIPRO now manages all this equipment, including upgrades and replacements. WIPRO undertakes this ‘lifecycle refresh’ activity in order to maintain an agreed level of service with AGA and charges for this service through the MSF. By equating the former IT services fee to the MSF, the effect of the ERA decision is to not allow any costs for these activities (as formerly recovered as the Infrastructure Usage Fee). This approach is not sound. More information on the efficiency of the MSF forecast over AA4 is outlined below.

446. AGA does not accept that the ERA should apply reductions EMCa recommended on the previous I-Tek forecast for AA4 to the new WIPRO IT arrangement as the two models are so fundamentally different.

Efficiency of the Managed Service Fee forecast for AA4

447. In its technical report, EMCa proposed a reduction in IT operating costs on the basis that AGA should have been ‘right-sized’ by the end of AA3. AGA disagrees with this conclusion and proposes forecast IT operating costs are efficient and reflect ongoing growth in the business. Therefore, AGA asked (Appendix 6.4)

independent experts KPMG[137] to provide opinion as to whether there are particular business drivers that would increase AGA's ongoing IT services operating expenditure and how such business drivers should be factored into forecasts of IT operating expenditure.

448. KPMG also benchmarked AGA's forecast IT operating expenditure. This was predominantly against eastern states electricity distribution businesses. In a comparison with electricity distributors, IT expenditure for a gas distribution business would be expected to be lower because of less complexity in network operations and IT requirements. Even so, AGA's forecast IT operating cost per customer is at the very bottom of the benchmarked range. This is shown in Figure 6–17 below.

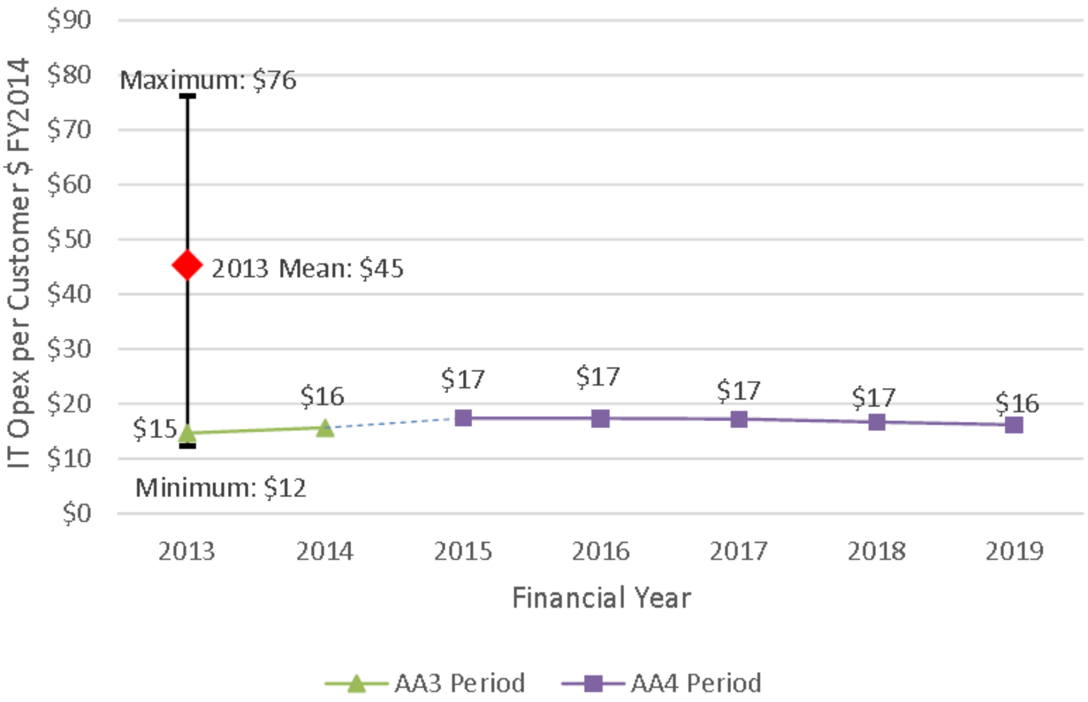

Figure 6–17: AGA's benchmarked IT operating costs over AA4: KPMG

449. KPMG confirms that AGA compares favourably with an industry benchmarking survey.[138] KPMG then considered the individual elements comprising the MSF. Under the I-Tek agreement, the IT Services Fee covered the service element of activity such as helpdesk provision and support, application support and having technicians available on-site. Under WIPRO, the MSF comprises three key tranches of activity; lifecycle refresh, fee for service and growth related.

[137] Appendix 6.4 The IT Operating Expenditure of the Access Arrangement for the Mid-West and South-West Gas Distribution System, KPMG November 2014, page 15.

[138] Appendix 6.4 The IT Operating Expenditure of the Access Arrangement for the Mid-West and South-West Gas Distribution System, KPMG November 2014, page 11.

450. The compilation of the MSF over AA4 is shown in Table 6–24 below.

Table 6–24: Managed Service Fee (MSF) components over AA4

Elements of the MSF ($ million real at 30 June 2014)	AA4	%
Applications Managed services	15.3	34.6
Distributed Server services	17.2	38.9
Data – LAN/WAN	1.0	2.2
Data Storage services	4.6	10.5
Voice and Video services	1.7	3.9
End User Computing services	4.2	9.6
User Connectivity services	0.1	0.3
Total MSF over AA4	44.1	100

451. There are four main business drivers that increase the MSF over time:

- Increase in IT users
- Changes in network operations
- Lifecycle refresh (replacement of aging and near end-of-life infrastructure)
- IT capital projects

Increase in IT users

452. Any increase in the number of users may directly increase Applications Managed services, End User Computing services and User Connectivity services. AGA proposes an increase in these services in line with planned growth in the workforces of 15% over AA4. The expert has reviewed this and in his opinion the moderate growth forecasted….*will have a moderate impact* on the increase in IT operating costs over AA4.[139]

Changes in network operations

453. AGA's forecast increase in the number of customer connections and network extensions is driving a greater volume of network operations and any change in network operations, such as increased regulatory reporting will lead to increases in Data LAN/WAN, Data Storage services and Application Managed services. AGA forecasts a 10% increase in Data and a small increase in Data Storage services. The expert has reviewed this and concludes that *the drivers of these management service areas will have a moderate impact on the increase in IT opex…due to the small rate of forecasted growth*.[140]

Lifecycle refresh

454. As noted above, the MSF includes activities that would have been charged through IT infrastructure usage fee in the I-Tek ITSA. These items, listed below are now the financial responsibility of WIPRO to lifecycle refresh (over a 3-4 year cycle):

- End User Devices, e.g. laptops, desktops including peripherals and printers

139 Appendix 6.4 The IT Operating Expenditure of the Access Arrangement for the Mid-West and South-West Gas Distribution System, KPMG November 2014, page 10.

140 Appendix 6.4 The IT Operating Expenditure of the Access Arrangement for the Mid-West and South-West Gas Distribution System, KPMG November 2014, page 10.

- Servers and Storage, e.g. Wintel and Unix Servers, SANs and back-up technology
- Network equipment, including firewalls, routers and WAN equipment
- Telephony such as PABX, VOIP, IVRs and handsets
- Wireless network infrastructure

455. In the KPMG's opinion *the replacement of aging infrastructure is consistent with prudent management practices in reducing the operational risk*.[141] In addition, AGA has factored efficiency into the WIPRO agreement by decreasing by 20% the number of servers supported in the last two years of AA4.

Operating expenditure from IT capital projects

456. AGA is forecasting $0.93 million of IT operating costs as a result of IT capital projects such as Field Mobility, Integration of Asset Management Systems, Strategic Asset Management feasibility and periodic refresh of applications and infrastructure. The expert has reviewed this element of IT operating expenditure and in his opinion *it is comparatively low to similar projects of other network businesses*.[142]

457. The expert report demonstrates AGA's forecast IT operating costs compare favourably with sector benchmarks and that the increase in the elements of the MSF are in relation to only 'modest' forecasts of growth, and lifecycle replacement is consistent with 'prudent management'. Therefore, AGA does not accept the reductions to IT operating costs proposed in the Draft Decision.

Capability and capacity to deliver multiple IT projects

458. In its report, EMCa expressed concern about AGA/I-Tek's capacity and capability to develop and implement the multiple proposed IT projects, which the ERA noted in its Draft Decision.[143] However, since EMCa conducted its review, AGA now accesses its IT services from a new, global supplier WIPRO. Any concerns around project delivery are mitigated because:

- IT service provision has moved:
  - from a wholly-owned affiliate company (ATCO I-Tek Australia) with an internalised cost pass through and management fee based model
  - to a competitively tendered, fully arms-length IT provider (WIPRO) with an outsourced model based on priced services.
- WIPRO is a global information technology, consulting and outsourcing company with 140,000 employees serving customers in more than 175 cities on six continents
- Direct financial penalties exist for breach of service level agreement

Competitive tender process

459. As previously notified to the ERA, AGA participated in a competitive tender process managed by its parent Canadian Utilities Limited to identify innovative strategic global IT service deliver models and providers with the ability to provide IT services to all ATCO companies worldwide.

460. A shortlist was compiled in September 2013 and then each invitee engaged in a due diligence process and submitted their proposals in January 2014. The proposals were analysed from a qualitative and quantitative

[141] Appendix 6.4 The IT Operating Expenditure of the Access Arrangement for the Mid-West and South-West Gas Distribution System, KPMG November 2014, page 10.

[142] Appendix 6.4 The IT Operating Expenditure of the Access Arrangement for the Mid-West and South-West Gas Distribution System, KPMG November 2014, page 10.

[143] This comparison was with a benchmarking exercise conducted in 2013 and so the expert compared AGA's former IT Services Fee forecast.

perspective and three providers, including WIPRO were contacted for bid clarification and further negotiation. From a further shortlist of two, WIPRO was identified as the preferred party based on:

- WIPRO's assessed experience in relevant ATCO Group industries
- WIPRO's offer was considered more competitive than the other shortlisted party
- WIPRO was assessed as better positioned to leverage I-Tek to expand the business to retain existing people
- Reference checking supported WIPRO's ability to deliver and exceeded the results of competitors
- WIPRO has a positive existing relationship with ATCO Group
- WIPRO's overall approach to the process and its demonstrated understanding of ATCO Group's requirements meant that WIPRO were more likely to execute on their commitments

461. The new arrangement delivers reductions to forecast IT operating costs of $8.5 million or 12.7% compared to the IT operating cost forecast based on the previous IT service agreement with I-Tek. This is illustrated in Figure 6–18 below.

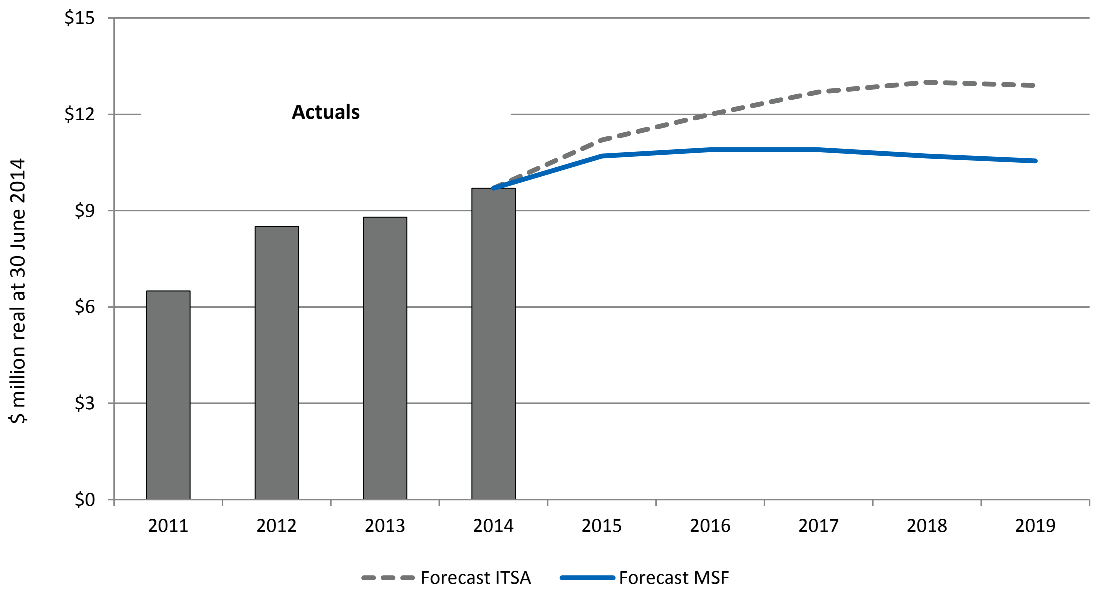

Figure 6–18: Comparison of previous and new IT service arrangements: forecast of IT operating costs over AA4 ($ million real at 30 June 2014)

Conclusion on IT operating costs

462. AGA accepts the Draft Determination for IT Licence Fees from 2015-2019 and for the IT Usage Fee of $0.2 million for July to December 2014.

463. However, AGA does not accept the ERA's approved expenditure for IT managed services of $30.01 million and retains its previous forecast.

464. All IT operating cost forecasts for AA4 have been updated for actuals from July to September 2014 and a reforecast of the last 3 months of the 2014 calendar year. AGA's IT operating expenditure forecast is shown in Table 6–25 below.

Table 6–25: AGA's revised AAI and amended proposal: forecast IT operating costs over AA4

($ million real at 30 June 2014)	Jul-Dec 2144	2015	2016	2017	2018	2019	Total
Revised AAI – IT operating costs							
IT Licence Fees	1.2	2.5	2.6	2.6	2.7	2.8	14.4
IT Usage Fee	0.2	-	-	-	-	-	0.2
IT Service Fee	3.5	8.2	8.3	8.3	8.0	7.8	44.1
Draft decision on IT operating costs	4.9	10.7	10.9	10.9	10.7	10.6	58.7
Amended proposal - IT operating costs							
IT Licence Fees	1.0	2.4	2.4	2.4	2.5	2.6	13.3
IT Usage Fee	1.9	-	-	-	-	-	1.9
IT Managed Services Fee	1.4	8.2	8.3	8.3	8.0	7.8	42.0
Total IT operating costs	**4.3**	**10.6**	**10.7**	**10.7**	**10.5**	**10.4**	**57.2**

6.2.5 UAFG operating costs

465. This represents a reduction of $1.0 million or 2.3% on AGA's proposed UAFG operating expenditure.

466. The ERA considers[144] that AGA's proposal to conduct a competitive tender to acquire UAFG to be *consistent with both good industry practice and rule 91 of the NGR*. Despite this, the ERA has adjusted two elements of the UAFG forecast:

- Total throughput; and
- UAFG rate

467. The ERA stated that it required the first revisions to ensure compliance with rule 74 of the NGR and the second revision to ensure compliance with rule 91 of the NGR.

468. AGA does not accept the ERA's Draft Decision on UAFG costs.

469. AGA acknowledges total throughput used to calculate AA4 UAFG operating expenditure is dependent upon the forecast of gas volumes. As AGA does not accept the ERA's assumed gas throughput as AGA does not accept the ERA's revised demand forecast.

470. AGA does not accept the EMCa calculation of the starting point for the UAFG rate in AA4. This is because the July 2014 starting point is a point on a trend-line and does not account for anticipated seasonality in the UAFG unit rate in the second half of the calendar year. This effectively underestimates UAFG for this period. Typically, B3 customers account for over 70% of UAFG and with increased gas usage for heating over the winter months there is more throughput to B3 meters. A large number of B3 meters and higher throughput can increase UAFG due to both gas loss and potential measurement error.

471. AGA does not accept the reduction of the target UAFG rate to 2.56% as this is derived from a continuation of the trend-line constructed by EMCa and so does not represent an annualised weather adjusted UAFG rate.

144 ERA (2014): 'Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System', paragraph 311.

472. Consequently, AGA has recalculated its annualised, weather adjusted UAFG rates over AA4 based on additional UAFG data available since the last submission to the ERA in July 2014. AGA has also recalculated total throughput based on its own revised demand forecast outlined in Chapter 4. AGA's revised UAFG forecast is shown in Table 6–26.

Table 6–26: AGA's amended proposal: forecast UAFG costs over AA4

($ million real at 30 June 2014)	2014	2015	2016	2017	2018	2019
UAFG rates	2.52%	2.63%	2.62%	2.62%	2.60%	2.58%
Total throughput (Tj)	26,850	26,964	27,424	27,966	28,604	29,266
UAFG forecast ($ million real at 30 June 2014)	4.1	7.2	7.4	7.5	7.6	7.7

6.2.6 Ancillary Services operating costs

473. The ERA requires AGA to amend its forecast Ancillary Services operating expenditure in line with Table 6–27 below.

Table 6–27: AGA revised AAI and ERA draft decision: forecast Ancillary Services operating expenditure over AA4

($ million real at 30 June 2014)	AGA's revised AAI	ERA draft decision
Applying a meter lock	0.63	0.61
Removing a meter lock	0.22	0.22
Deregistering a delivery point	1.33	1.33
Disconnecting a delivery point	0.73	0.73
Reconnecting a delivery point	0.90	0.90
Total Ancillary Services expenditure	**3.81**	**3.79**

474. This represents a reduction of $0.02 million or 0.5% on AGA's proposed Ancillary Services operating expenditure.

475. The ERA has adjusted AGA's forecast ancillary service operating expenditure in line with the adjustments it has made to the B3 demand forecast. The ERA accepts AGA's Ancillary Service tariffs.[145] However, the ERA requires that AGA confirms that ancillary services are performed by external service providers.

476. As noted by the ERA, Ancillary Service tariffs are based on competitive service tenders and AGA can confirm that the ancillary services are predominantly provided by third parties. In particular:

- All meter lock and unlock services are done by contractors on a fixed price basis, AGA provides the padlocks and Valve locking devices, the average cost of which is incorporated into the charge rate
- The Deregistration Requests, Disconnect Service and Reconnect service are done by both AGA (5%) and contractors (95% on a tendered price basis) and pricing includes materials provided by AGA

477. The small proportion of ancillary services conducted by internal labour is efficient as:

[145] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 316.

- The AGA associated labour costs for Deregistration Requests, Disconnect Service and Reconnect service are based on current EBA/award
- There are no overheads allocated to these services

478. AGA has not implemented the required amendment in relation to B3 customers and has updated the demand forecast. As a result, there is an amended proposal for ancillary services operating expenditure. This is illustrated in Table 6–28.

Table 6–28: AGA's revised AAI and amended proposal: forecast Ancillary Services operating expenditure for AA4

($ million real at 30 June 2014)	Jul-Dec 2014	2015	2016	2017	2018	2019	Total
Revised AAI – Ancillary Services							
Applying a meter lock	0.06	0.11	0.11	0.11	0.12	0.12	0.63
Removing a meter lock	0.02	0.04	0.04	0.04	0.04	0.04	0.22
Deregistering a delivery point	0.13	0.22	0.23	0.24	0.25	0.26	1.33
Disconnecting a delivery point	0.06	0.12	0.13	0.14	0.14	0.14	0.73
Reconnecting a delivery point	0.08	0.14	0.16	0.17	0.17	0.18	0.90
Revised AAI Total Ancillary Services operating expenditure	**0.35**	**0.63**	**0.67**	**0.70**	**0.72**	**0.74**	**3.81**
Amended proposal – Ancillary Services							
Applying a meter lock	0.07	0.11	0.11	0.11	0.12	0.12	0.64
Removing a meter lock	0.02	0.04	0.04	0.04	0.04	0.04	0.22
Deregistering a delivery point	0.10	0.22	0.23	0.24	0.25	0.26	1.30
Disconnecting a delivery point	0.04	0.09	0.09	0.09	0.09	0.10	0.50
Reconnecting a delivery point	0.05	0.11	0.12	0.12	0.12	0.12	0.64
Amended proposal - Total Ancillary Services operating expenditure	**0.28**	**0.57**	**0.59**	**0.60**	**0.62**	**0.64**	**3.30**

7. Opening capital base

ERA required amendment 6

The opening capital base for 1 July 2014 in the proposed access arrangement must be amended to reflect the values in Table 26 of this Draft Decision.

ATCO Gas Australia Response: do not accept

Summary Only – AGA considers the $9.9 million of AA3 capital expenditure excluded from the opening capital base is conforming capital expenditure under NGR 79 and provides the ERA evidence to this effect. AGA accepts the ERA's changes to CPI escalation adjustment, with a slight modification resulting in $1.6 million being excluded from the opening capital base rather than the ERA's proposed $1.9 million.

7.1 Summary of ERA decision

479. The ERA has decided that $263.6 million (96%) of AGA's capital expenditure during the AA3 period was efficient and can be considered conforming capital expenditure under rule 79 of the NGR.

Table 7–1: Draft decision approved opening capital base at 1 July 2014

Real $ million at 30 June 2014	Jan to June 2010	2010/2011	2011/2012	2012/2013	2013/2014
Opening Capital Base (AA3)	877.7	896.5	911.2	918.2	962.2
Plus: Capital Expenditure	31.1	41.3	36.1	75.3	79.8
Less: Depreciation	12.3	26.6	29.0	31.4	33.7
Closing Capital Base (AA3)	896.5	911.2	918.2	962.2	1,008.3
ERA Draft Decision Opening Capital Base at 1 July 2014					1,008.3

480. Table 7–2 shows the breakdown of AA3 capital expenditure excluded from the capital base.

Table 7–2: Capital expenditure excluded from opening capital base $ million real at 30 June 2014

Category	ERA Draft Decision
Jandakot Blue Flame Kitchen	0.8
Jandakot sewerage extension	0.7
IT reconciling variance	1.3
IT Field mobility project	3.6
IT GIS project	2.3
IT NDV project	1.2
Total	**9.9**

481. The ERA has excluded a total $11.8 million in its draft decision in regards to the opening projected capital base for AA4, which includes the above plus the impact of the ERA's decision not to accept AGA's proposed methodology for CPI escalation of the capital base and depreciation, as discussed in paragraphs 397 to 401 and 411 to 412 of the ERA's Draft Decision.

7.2 AGA response

AGA has not implemented required amendment 6

482. AGA accepts the ERA's changes to CPI escalation, however it proposes the 24 October 2012 rebased headline CPI Weighted Average of Eight Capital Cities: All-Groups Index applies to the capital base established from January 2010 onwards so that the capital base for the AA3 period is escalated using the same CPI index. The capital base up to 31 December 2009 uses the old CPI index.

483. This means that $1.6 million rather than $1.9 million of the adjustment to the opening capital base is accepted.

484. AGA does not accept the ERA's view that $9.9 million of capital expenditure does not conform to the requirements of rule 79 of the NGR. The following sections address matters raised by the ERA about the excluded expenditure items presented in Table 7–2 above, and submits evidence to support their inclusion in the AA4 opening capital base.

7.2.1 Jandakot Blue Flame Kitchen

485. The ERA's technical consultant EMCa considered the Blue Flame Kitchen to be a marketing vehicle and that the increased business development and marketing program did not satisfy the economic value or incremental revenue tests and the project's link to safety is weak.[146] The ERA concurred with EMCa's view and excludes $0.8 million for the Jandakot Blue Flame Kitchen.

486. AGA does not agree that the project's link to safety is weak and submits that the $0.8 million costs do comply with rule 79 of the NGR.

487. The Blue Flame Kitchen initiative is a key component of AGA's community engagement program. The program's objectives are to increase awareness of the benefits of natural gas and gas safety, in line with AGA's core business of the safe, reliable, cost-effective, environmentally sustainable and customer-friendly distribution of natural gas to customers.

488. The Blue Flame Kitchen was established to drive the safe, responsible use of natural gas. The initiative engages community groups and shows them how to use gas safely, what to do if they smell gas and what action to take in an emergency. Though EMCa may consider the initiative is not directly related to network safety in the traditional network investment sense, the Blue Flame Kitchen promotes safety in the home and raises awareness of a natural resource that is under-utilised and not fully understood in Western Australia.

489. As a prudent natural gas supplier AGA considers its responsibility to keep consumers safe should not end at the meter box. By improving consumers' understanding of gas, how their homes are connected to the network and how to use gas safely, AGA helps reduce the risk of serious harm or incident in the home, which has an impact on safety of the network generally. It also provides a platform for demonstrating AGA's role and responsibilities in responding to gas safety issues. Therefore AGA submits the initiative's link to safety is justifiable under rule 79 of the NGR.

490. Western Australian households predominantly use natural gas for 3 purposes:

- Cooking - a typical household utilising natural gas uses 2.5 GJ per year
- Hot water - a typical household would use from 4 to 12 GJ per year
- Space heating - a typical household would use 3 to 5 GJ per year

[146] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 384.

491. The Blue Flame Kitchen provides a targeted avenue to inform customers about who to call in the event of a gas safety issue and in particular, what to do if they smell gas. This community-based venture was assessed by the business as a prudent, efficient and tangible investment, complementing the other safety awareness campaigns AGA invests in such as Dial Before You Dig (**DBYD**).

492. Within the Blue Flame Kitchen, AGA delivers the School's Excursion Program using observational learning through hands-on experiences that highlight real world lessons on safety and the properties of natural gas. The schools program content is underpinned by the Australian Curriculum, Assessment and Reporting Authority curriculum framework and incorporates the following syllabus components.

- What does gas smell like and why is it important for the odorant to be added?
- What to do when you smell gas to stay safe and prevent incidents occurring?
- Environmental and financial benefits of using gas appliances
- Natural gas innovation and technology to improve the reputation and image of gas (e.g. gas powered air conditioning at facility and vehicles powered by compressed natural gas)
- In the event of a gas leak, the number to call AGA (not your retailer – contrary to research findings in introduction)
- Explanation of the gas network and the importance of the Dial Before You Dig initiative, as a course of action to prevent damage to the network

493. AGA considers the delivery of a safety message targeted at schoolchildren an important and effective method to generate interest in its core safety awareness communication. This view is supported by the child accident prevention foundation, Kidsafe WA, the leading non-government not-for-profit charitable organisation dedicated to the prevention of injuries to children, who are currently in discussion with AGA are using the Blue Flame Kitchen facility to host Kidsafe events.

494. In addition to the benefits of the Blue Flame Kitchen initiative generally, locating a Blue Flame Kitchen within the recently-constructed Jandakot Operations Centre has several advantages:

- Bringing people to Jandakot allows AGA to add further value to the visitors' experience by showcasing natural gas technologies in operation such as gas powered air conditioning, standby generation and compressed natural gas vehicles
- The facility benefits from efficient use of shared facilities services at the Operations Centre such as maintenance, cleaning and security
- Visual content and display material can be updated and presented in a cost efficient manner; ensuring messaging is current, accurate and relevant
- Visitors are able to see the AGA vehicle fleet and maintenance crews which help support the safety messaging whilst also providing a sense of AGA's scope
- Tangible demonstration of AGA's commitment to safety and gas education to the WA community

495. These benefits cannot be realised without the Jandakot Blue Flame Kitchen and so AGA has not removed these costs from its AA3 conforming capital expenditure on the basis that these costs comply with rule 79 of the NGR, specifically rule 79(2)(c)(i).

7.2.1.1 Effectiveness of messaging

496. The experiential learning model, developed by David Kolb in the 1970's identified that there are four elements to learning:

- Concrete experience

- Observation of and reflection on that experience
- Formation of abstract concepts based upon the reflection
- Testing the new concepts

497. While individuals process and retain information with regards to the safe usage of gas and the benefits of its consumption in different ways, focusing awareness solely on print and digital media may not lead to the strongest results. AGA believes that by complementing its print and digital messaging with the tangible experience the Blue Flame Kitchen offers, there is a compound effect of the messaging. This can be seen where children and teachers attending the schools program return to their school and share their experience. This has already been evidenced, where Bertram Primary School has communicated school-wide via their Facebook page (see images below). This digital reinforcement from the school also allows for ongoing engagement with AGA, via social and digital channels from parents, children and teachers.

Figure 7–1: Bertram Primary School Facebook page

Figure 7–2: Bertram Primary School Facebook page

498. School wide communication, via newsletters and social media, is also shared with parents as is the experience by the children themselves. This highlights the cost effective nature of the initiative where a single class can result in the delivery of gas safety and benefit messages to upward of 30 initial children, 500 pupils within a school and 1,000 parents of the children of the school.

499. The value of the schools program is already evident with one school proactively seeking attendance and Bertram Primary seeking 4 classes for the 2015 program.

7.2.1.2 Industry peers' messaging

500. Other utility providers offer community engagement and education programs, however there are no other gas safety-specific programs currently available within Western Australia.

501. Western Power's ShockProof education program has been designed for school age children to promote safety around electricity and to encourage a new generation of energy efficient people to protect the future of our planet. Students learn safety tips to practise inside and outside the home. The education presenter visits school and delivers 30-45 minute presentations on electrical safety and energy efficiency.

502. Water Corporation - The Waterwise Schools Program is aimed at primary school aged children and is focused on water saving education. The program is delivered by dedicated Education Officers and through the provision of teacher resource packs.

503. Aurora Energy (Tasmania) - Aurora's Safety and Electrical Efficiency Program is a service which aims to reduce the risk of electrical incidents and prevent injury by educating children about electrical dangers. It also includes energy efficiency messages.

504. AGA is committed to raising the general awareness of the benefits of natural gas and how to use it safely, using innovative and cost effective methods such as the Blue Flame Kitchen to reach Western Australian households.

7.2.2 Jandakot sewerage extension

505. EMCa considered $0.7 million for the Jandakot sewerage extension appeared to have been double counted as sewerage costs also appear in the Jandakot Redevelopment Project Business Case. Neither the ERA nor EMCa identified any other basis on which expenditure on the extension was not conforming expenditure.

506. The Jandakot sewerage extension and the sewerage connection costs included in the Jandakot Redevelopment Project are two discrete activities. There is no double count of costs. The sewerage extension and was conducted in 2010 under a contribution arrangement with Dampier to Bunbury Pipeline and Western Power. It was not part of the Jandakot Redevelopment Project Business Case.

507. AGA provided a description of the Jandakot sewerage extension completed in February 2010 in response to EMCa query 42. In that response, the project was described as the connection of the existing Jandakot site to deep mains sewerage to avoid potential future compliance issues with existing on site treatment of sewage. The Jandakot site is within a Priority 2 Drinking Water Zone. This classification imposes obligations on owners of such sites to ensure the protection from potential contaminants to the drinking water supply.

508. In response to EMCa query 27, AGA provided a copy of the Jandakot Redevelopment Project Business Case dated March 2012. Under the scope on page 17, the connection of the new building and the existing warehouse to the deep sewerage system and existing septic systems to be decommissioned is noted. This is a discrete and separate scope from the original extension of the deep mains sewerage to the Jandakot site in 2010.

509. Therefore AGA considers the $0.7 million Jandakot sewerage extension costs are not double counted and are conforming capital expenditure per rule 79(2)(c) of the NGR and should be included in the AA4 opening capital base.

7.2.3 IT capital expenditure

510. The ERA determined $8.4 million of IT capital expenditure for the AA3 period is not compliant with rules 77(2) and 79(1)(a) of the NGR. The $8.4 million consists of $7.1 million relating to three specific projects shown in Table 7–3 below, and $1.3 million for a variance between $18.2 million referred to in AGA's March 2014 Access Arrangement Information and the $19.5 million proposed in the access arrangement proposal.[147]

Table 7–3: IT capital projects excluded in draft decision in $ million real 2014

Project name	AA3 actuals	Draft Decision
Field mobility	4.7	1.1
ESRI upgrade (GIS)	2.8	0.5
Network Data Visualisation (**NDV**)	2.6	1.4

[147] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 392.

7.2.3.1 Variance in reported IT expenditure

511. AGA provided two IT capital expenditure figures of $19.5 million and $18.2 million in the AAI. The ERA states that AGA has not provided any evidence to justify the variance between the two IT capital expenditure figures and, in the absence of such evidence, it cannot approve the $1.3 million as conforming capital expenditure.[148]

512. AGA provided evidence to justify this variance as part of the access arrangement review process, responding to queries from the ERA's technical consultant, EMCa. In response to EMCa query 84 and EMCa query 88, AGA advised the $18.2 million referred to in Table 51 of the AAI was not the correct expenditure amount for IT capital expenditure for the AA3 period. Instead, AGA provided the reconciliation shown in Figure 7–3.

513.

	$ real 2014	Included at EMCA 84 response table row:
Pressure monitoring data visualisation	1.1	1
Telemetry replacement	1.0	1
IT Telemetry and monitorring included in table 51	2.1	1
Other IT projects and expenditure included in table 51	16.1	3
Total IT expenditure at table 51	**18.2**	
Other miscellaeous IT telemetry not included in table 51	0.1	1
Network telemetry and monitoring (line 2 ECMA84)	0.1	2
Structures and equipment IT CAPEX (Monitors etc:)	0.9	4
Other miscellaneous IT expenditure not included at table 51	0.1	3
Rounding error	0.1	
Total IT CAPEX	**19.5**	

ECMA 84 response table	**$ real 2014**	**EMCA 84 response table row**
IT Telemetry and monitorring	2.2	1
NetworkTelemetry and monitorring	0.1	2
IT Dept CAPEX	16.2	3
Structures and equipment IT CAPEX (Monitors etc:)	0.9	4
Total IT	19.5	

Figure 7–3: Reconciliation provided by AGA in response to EMCa query 88

514. The costs that were left out of the March 2014 Access Arrangement Information by mistake are provided in Table 7–4 below. These costs were included in the regulatory financial statements reviewed by PwC and submitted to the ERA in August 2014.

148 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 389.

Table 7–4: Reconciling variance – IT AA3 capex

Reconciling Variances	$million real at 30 June 2014
Network telemetry and monitoring	0.1
Structures and equipment IT CAPEX (Monitors etc.)	0.9
IT Dept capex - rounding	0.1
IT telemetry and monitoring - rounding	0.1
Other miscellaneous IT expenditure	0.1
TOTAL	**1.3**

515. An explanation of the reconciling variances shown in Table 7–4 is provided below:

- Network and telemetry monitoring – this was an administrative error. The costs were not initially included because the expenditure was not part of an IT project and not managed by the IT division. The ERA has accepted that AGA's other network and telemetry capital expenditure is conforming expenditure.
- Structures and equipment IT capex (Monitors etc) – this was an administrative error. The costs were not initially included because the expenditure was not managed as an IT project as the assets are held across all divisions. It is a low value asset pool, primarily made up of desktops, laptops, docking stations, printers, fax machine, truck radios and mobile and satellite phones. A detailed view of the assets included in this total is available
- Rounding errors (in IT Debt CAPEX and IT Telemetry and monitoring) occurred in the translation of the historical capex to the business driver categories, and resulted in a reported total of $19.3 million instead of $19.5 million

516. These reconciling variances between actual expenditure and divisional specific expenditure were not identified until queried by EMCa. AGA provided clarification on this variance in response to EMCa query 84 and EMCa query 88.

517. AGA has not removed this variance from its AA3 conforming capital expenditure on the basis that these costs were omitted due to administrative errors only, and do comply with rule 79 of the NGR.

7.2.3.2 Field Mobility project

518. The ERA accepted EMCa's assessment that the *rationale for the overall Field Mobility project is sound*[149] but questioned the expenditure due to a lack of evidence of (i) what was spent; (ii) what it was spent on; (iii) why it was spent – including compelling justification; (iv) what procurement process was followed; (v) documented rationale for the variation from original business case with the appropriate financial approvals.[150]

519. In response to EMCa query 13, AGA provided three documents – the Phase 1a Project Mandate, Phase 2 business case and Phase 3 business case.

520. AGA did not provide the business case for Phase 1, which left EMCa unable to reconcile the expenditure incurred with the original AA3 submission and the business case approved levels. This omission was a mistake resulting from the change in ownership of the GDS during the delivery of this project, which caused changes to the naming conventions and descriptions for the business cases associated with this project.

149 EMCa, Review of Technical Aspects of the Proposed Access Arrangement, June 2014, page 91.

150 EMCa, Review of Technical Aspects of the Proposed Access Arrangement, June 2014, Table 14, page 91.

521. The business case for Phase 1 is provided in Confidential Appendix 7.1.[151]

522. Table 7–5 summarises the cost variations for each phase of the Field Mobility Project.

Table 7–5: Field Mobility business case budget and actual expenditure

Phase and description	Business case budget	Actual expenditure	Variation
Phase 1 - definition	0.3	0.3	-0.0
Phase 1A - project mandate	1.1	0.3	-0.8
Phase 2	3.7	3.7	-0.0
Phase 3	0.5	0.4	-0.1
Total	**5.6**	**4.7**	**-0.9**

523. Each phase was individually assessed for compliance with rules (79)(1) and (2) of the NGR, and each phase had its own business case and was subject to standard project management disciplines.

524. The Field Mobility Project delivered all requirements as per the defined scope of each phase, and was overall underspent ($4.7 million) compared to the internal business case approved expenditure ($5.6 million) and within 2 per cent of the approved AA3 expenditure levels ($4.6 million).

525. **Phase 1** (definition) included the work required to prepare the business case for the full Field Mobility Project, Conceptual (IT) architecture, Request for Proposal (**RFP**) framework/process and the RFP document. A business case for Phase 1 was approved in January 2010 with a budget of $0.2 million and justified under NGR 79(2)(c)(i) to maintain and improve the safety of the services being provided and NGR 79 (2)(c)(ii) to maintain the integrity of services.

526. **Phase 1A** (project Mandate was approved in November 2010 with a budget of $1.05 million and justified under NGR (79)(2)(c)(i) on the basis that it would ensure field workers would have access to and follow accurate technical and safety procedural documentation. It was justified under NGR (79)(2)(c)(ii) on the basis it would provide an alternate service for the provision of job information to field crews before the existing Telstra fax service was decommissioned. NGR (79)(2)(c)(iii) applies by ensuring field workers have access to the correct documented procedures at all times as required by Energy Safety, Worksafe WA and certifying body **(**DLCS**)** and NGR (79)(1)(a) applies as a result of the increased functionality for field mobility crew to support further improvements in field service activities.

527. The Field Mobility project was suspended in May 2011, while Phase 1A was only partially complete, pending the change in ownership of the gas distribution system.

528. **Phase 2** delivered the procurement, design, configuration, testing, and implementation of the overall field mobility solution. This led to the introduction of a tablet-based solution, using the selected software which integrated with the existing works and asset management system. It also included elements of Phase 1A which had not been completed before the change in ownership.

529. It was justified based on compliance with rules 79(1) and (2) of the NGR by:

- Returning a positive NPV of $1.0 million over ten years
- Ensuring workers have access to the most current, correct technical and safety procedural documentation, network mapping via automated update process
- Replacing the decommissioned Telstra mobile fax service used by field crews

[151] Confidential Appendix 7.1 2009/2010 Business Case WAGN Filed Mobility Project (IT), issue date December 2009.

- Embedding the safety processes into the job flow and automated capture of job data for auditing and regulatory reporting through the automation of provisioning of Field Manual documentation, ensuring improved compliance with regulations

Procurement process

530. The Field Mobility Project was initiated under the ownership of WAGN. In 2010, WAGN initiated a request for proposal process, seeking the most appropriate provider from a technical, commercial, delivery and support and quality perspective as well as price.

531. A number of vendors were approached and responded to the request. Yambay Technologies Pty Ltd was successful in securing preferred vendor status, due to a number of reasons including its offering of an off the shelf solution, SAP integration experience and its ability to meet all the requirements of the RFP. A fixed price contract was agreed with Yambay and a master services agreement signed in March 2012.

Change management

532. The Field Mobility project was managed in line with PRINCE2 project management and supported by the AGA project governance framework.

During Phase 2 there was a single project variation approved. This variation included changes in scope resulting from the workshops between AGA and Yambay during the design stage. Due to the fixed price nature of the contract there was no variation to the budget, however the resulting additional scope items required an extension to the delivery schedule.

533. The change in ownership in the early stages of Phase 1A resulted in a temporary halt to the project. Upon recommencement the requirements of Phase 1A were incorporated into the overall Phase 2 requirements. Each phase required a separate business case and cost justification prior to proceeding.

Benefits realised

534. AGA's response to query EMCa query 57 identified that the impact of the entire Field Mobility Project (all phases) is expected to save at least $2 million over the AA4 period as a result of avoiding addition labour costs, as well as over $400k in printing cost savings by eliminating the need to update paper based field manuals. As noted in the network operating expenditure section (refer to section 6.2.2), these savings are incorporated in the operating expenditure forecast for AA4.

535. Therefore AGA has not removed this expenditure from the opening capital base as it is conforming capital expenditure under rule 79 of the NGR.

536. In AA3, there was also a forecast expenditure of $1.8M for Field Mobility Phase 2. This was a separate project and should not be confused with the multi phased Field Mobility projects completed in AA3. This Field Mobility Phase 2 project did not take place in AA3 and is now included in the AA4 expenditure forecast (AGA-05 – Field Mobility Enhancements).

7.2.3.3 ESRI upgrade GIS project

537. The ERA determined $2.3 million of the capital expenditure on the ESRI upgrade project does not comply with rule 79 of the NGR on the basis of the EMCa's assessment.

538. EMCa were unable to reconcile the full project expenditure value with only the Phase 1 business case and close out report provided in response to EMCa query 13. AGA did not provide the business case for the initial preliminary phase, phase 2 and phase 3.

539. The business case for the preliminary scoping, phase 2 and phase 3 are provided in Confidential Appendix 7.2 and Confidential Appendix 7.3.

540. The scope of the original ESRI/GIS project included in the AA3 forecast was supposed to be a straightforward upgrade to keep ESRI software and related GIS applications in line with required vendor maintenance and support levels. Actual expenditure on the project was significantly greater as the system had to be fully replaced due to performance issues and removal of vendor support.

541. Table 7–6 summarises the cost variations for each phase of the ESRI/GIS project.

Table 7–6: GIS business case budget and actual expenditure in $million real June 2014

Phase and description	Business case budget	Actual expenditure	Variation
Preliminary scoping	0.1	0.1	-0.0
Phase 1 – initiation, performance remediation, design	0.6	0.6	-0.0
Phase 2 – replacement of AssetView	1.8	1.8	-0.0
Phase 3 – deployment of new software and updates due to NDV	0.3	0.3	-0.0
Total	**2.8**	**2.8**	**-0.0**

542. **Preliminary scoping** – while developing the business case for the upgrade of the GIS tool (AssetView), the scope of the project was expanded to investigate and identify a potential solution to the performance issues the business was experiencing with AssetView.

543. It was recognised that the project would be significantly greater in scope than initially identified. Therefore the project was separated into three distinct phases to manage the enhanced scale.

544. **Phase 1**:

1. Review performance issues and develop a technical solution
2. Review the GIS system architecture and design the future state
3. Review and confirm the functionality of AssetView required by AGA (AssetView is the browser component of the GIS system)
4. Develop an AssetView replacement prototype using the Geocortex GIS web browser product
5. Estimate the cost of implementing the future changes and the cost of redeveloping AssetView using Geocortex

545. During Phase 1, the AssetView vendor ceased support of the product which resulted in the need to replace the product. AGA could not continue with an unsupported GNIS solution which is critical to safe network operation and to the provision of DBYD plans to excavators.

546. The business case for Phase 1 was approved in July 2012 with a budget of $0.7 million and justified under NGR 79(2)(c)(i) to maintain and improve the safety of the services being provided, NGR 79(2)(c)(ii) to maintain the integrity of services, and NGR 79(2)(c)(iii) to comply with requirements of the AGA Safety Case.

547. **Phase 2** focused on the replacement of AssetView with Geocortex. There were a number of key elements required in order to effectively replace the previous solution with a newer version. These key elements were:

- Upgrade ESRI product suite to version 10.1
- Database upgrade to 11G
- Windows Server Upgrade to 2008
- Alignment to Infrastructure Upgrade project to the new UCS architecture

- Replacement of GIS viewer AssetView using new technology platform - Geocortex and
- Analysis and remediation of adverse performance issues

548. The business case for Phase 2 was approved in December 2012[152] with a budget of $1.8 million and justified under NGR 79 (2)(c)(i) to maintain and improve the safety of the services being provided, NGR 79 (2)(c)(ii) to maintain the integrity of services, and NGR 79(2)(c)(iii) to comply with requirements of the AGA Safety Case.

549. **Phase 3** aligned the deployment with the availability of the new infrastructure from the network infrastructure upgrade project and develop the required interfaces between NDV and the GIS using Geocortex.

550. The business case for Phase 3 was approved in January 2014[153] with a budget of $0.3 million and justified under NGR 79(2)(c)(i) to maintain and improve the safety of the services being provided, NGR 79(2)(c)(ii) to maintain the integrity of services, and NGR 79(2)(c)(iii) to comply with requirements of the AGA Safety Case.

Procurement process:

551. The majority of costs incurred for GIS related to new hardware and software licences, and development costs relating to configuration and customisation to meet AGA's business needs.

552. A short list was prepared of two off the shelf products to replace AssetView. The requirements included the supply, development, installation, and post implementation support costs from the successful vendor. All other costs were incurred by ATCO I-Tek or AGA related costs.

Change management

553. As a result of the performance issues, the scope of the initial project was redefined, enhanced, and separated into three distinct consecutive phases to provide greater control and management of the costs. Each phase required a separate business case and cost justification prior to proceeding.

554. Phase 2 required a minimal project variation to budget and schedule, which was submitted and approved. This variation was required to accommodate the concurrent Network Infrastructure Project. There were no variations to scope, schedule or cost for Phase 1 or 3.

7.2.3.4 Network Data Visualisation (NDV) project

555. The ERA determined $1.2 million of the capital expenditure on the NDV Phase 1 project does not comply with rule 79 of the NGR on the basis that no information has been provided to support the overspend on the project.

556. EMCa stated that Phase 1 and Phase 2 provide a sound case for the upgrade work…and the business cases are comprehensive in most aspects[154], furthermore EMCa stated that *based on the information in the close out reports the expenditure has been efficient*[155], but questioned the additional $1.2 million of expenditure in AA3 due to a lack of support. EMCa was also concerned that efficiency gains were not quantified.

557. The NDV project was delivered under the same governance and project management systems as all IT projects. However, AGA has been unable to locate documentation for $0.7 million which occurred prior to AGA's acquisition of the business.

[152] Confidential Appendix 7.2 AGA GNIS Upgrade Project Phase 2 – Business Case.

[153] Confidential Appendix 7.3 AGA GNIS Upgrade Project Phase 3 – Business Case.

[154] EMCa, Review of Technical Aspects of the Proposed Access Arrangement, June 2014, page 91.

[155] EMCa, Review of Technical Aspects of the Proposed Access Arrangement, June 2014, page 91.

558. AGA provided the Phase 1 and Phase 2 business cases in response to EMCa query 13. The business cases for the 2014 Post Implementation Enhancements of $0.4 million were not provided. The business case value for the 2014 Post Implementation Enhancements was $0.4 million. The 2014 Post Implementation Enhancements was managed as two distinct initiatives across 2013 and 2014. The business cases for the 2014 Post Implementation Enhancements (two enhancement projects) are provided in Confidential Appendix 7.4 and Confidential Appendix 7.5.

559. The Phase 2 business case, which was supported in full by the EMCa and the ERA in the Draft Decision, was in fact for $0.8 million ($0.7 million in 2012 and $0.01 million in 2013). AGA has identified that the support provided for Phase 2 by EMCa seemed to exclude $0.01 million of expenditure undertaken in 2013. This should be added to the 2012 expenditure.

560. The business case for the first enhancement project was approved in October 2013[156] with a budget of $0.2 million. This project focused on improving the modelling process, particularly with regards to network emergency response management. It provided additional network utilisation reporting functions and the automation of severity factor calculations rather than reliance on manual calculations. The project was justified under NGR 79(2)(c)(i) to maintain and improve the safety of the services being provided, NGR 79 (2)(c)(ii) to maintain the integrity of services

The business case for the second enhancement project was approved in January 2014[157] with a budget of $0.2 million to be completed by June 2014. The project provided a new user interface to allow the operator to new updated gas models. The project was also justified under NGR 79 (2)(c)(i) to maintain and improve the safety of the services being provided, NGR 79(2)(c)(ii) to maintain the integrity of services.

561. The breakdown of the various stages of the project and the associated expenditure is outlined by Table 7–7 below.

Table 7–7: NDV business case budget and actual expenditure phase 2 and phase 3 (enhancements)

Phase and description	Business case budget	Actual expenditure	Variation
Phase 2	0.7	0.7	-0.0
Post Implementation Enhancements 1 (2013)	0.2	0.2	0.0
Post Implementation Enhancements 2 (2014)	0.2	0.1	-0.1
Total	**1.1**	**1.0**	**-0.1**

Procurement process

562. The nature of the business requirements for the NDV application were such that there was no commercial ‘off the shelf’ product that was able to meet AGA’s needs without significant customisation. Therefore the NDV application is a bespoke development that integrates a number of AGA’s other systems through the use of the webmethods (which AGA was already using for the metering and billing applications) integration product. The majority of the costs incurred on the project were predominantly for development costs from specialist application developers.

Change management

563. The Post Implementation Enhancements (2014) were completed $0.1 million under budget. The full scope of this has not been completed as the project was delayed due to completion of the GIS project. A project variation was not required.

[156] Confidential Appendix 7.5 AGA 2013-01-B NDV Enhancements Business Case.

[157] Confidential Appendix 7.6 AGA 2014-03 NDV Continuous Improvements Business Case.

564. Phase 2 was completed under budget with no project variations. The original business case specified expenditure across 2012 and 2013. Two close out reports were prepared for each year.

7.2.4 Non regulated and non reference service allocation

565. AGA has reviewed that indirect capital expenditure consisting of property plant and equipment expenditure and IT capital expenditure for the period January 2010 to December 2019 as required by paragraph 359 of the draft decision.

7.2.4.1 IT non regulated and non reference services – allocation impact

566. All IT capital projects for the period January 2010 to December 2019 were reviewed to determine an appropriate proportion of expenditure to exclude.

567. Costs were allocated according to the number of users or IT devices related to performing services in the unregulated networks or performing non reference services or the number of delivery points relating to regulated or unregulated networks where appropriate.

568. The impact of this review was an increase in allocation to the non regulated and non reference service network. Table 7–8 below shows the financial impact of this change on IT capital expenditure in AA3. This impact has been considered in the amended proposal for AA3 IT capex.

Table 7–8: Change in IT capital expenditure for AA3 due to unregulated and non reference allocation

Real $ million at 30 June 2014	Jan to June 2010	2010/2011	2011/2012	2012/2013	2013/2014	Total
Amended proposal - old method	0.0	0.1	0.1	0.1	0.1	0.3
Amended proposal – change	0.0	0.0	0.0	0.0	0.0	0.1
Amended proposal – new method	0.0	0.1	0.1	0.1	0.1	0.5

7.2.4.2 PPE non regulated and non reference services – allocation impact

569. A review of the portion of property plant and equipment directly relating to the Albany and Kalgoorlie unregulated networks has occurred.

570. The table below shows the proportion of property plant and equipment expenditure excluded. This impact has been considered in the amended proposal for AA3 PPE capex.

Table 7–9: Change in PPE capital expenditure for AA3 due to unregulated and non reference allocation

Real $ million at 30 June 2014	Jan to June 2010	2010/2011	2011/2012	2012/2013	2013/2014	Total
Amended proposal - old method	0.0	0.2	0.1	0.1	0.6	0.9
Amended proposal – change	0.0	0.1	0.0	0.1	0.3	0.5
Amended proposal – new method	0.0	0.2	0.1	0.2	0.9	1.4

7.2.5 CPI adjustment

571. On 24 October 2012, the Australian Bureau of Statistics published a headline CPI Weighted Average of Eight Capital Cities: All-Groups Index, which rebased the index to 100 for the financial year 2011/12. AGA

used the latest ABS CPI to escalate or de-escalate dollar amounts from real to nominal in the periods prior to 2012. The ERA considered this approach did not maintain the historical values as the rebased CPI leads to rounding errors as acknowledged by the ABS. Instead, the ERA adopted an approach where the values prior to the re-basing use the old CPI series and the values after the re-basing use the new series.

572. The ERA has adopted an approach where values prior to the re-basing are escalated or de-escalated using the old CPI series, and values after the re-basing are escalated or de-escalated using the new series.

573. Through to 31 December 2009, AGA has used the old series to maintain the opening capital base value as per the AA3 final decision. From 1 January 2010 onwards, the new CPI index published by the ABS in October 2012 has been used. AGA believes the use of a single series throughout an AA period ensures that there is alignment with the application of rule 73(3) of the NGR which states that All financial information must be provided, and all calculations made, consistently on the same basis.

574. The net impact of this is shown in the below Table.

Table 7–10: CPI adjustments on opening capital base – draft decision and AGA

$million real June 0214	ERA draft decision	AGA	Variance
Opening capital base adjustment	-2.0	-1.7	0.3
AA3 capital expenditure adjustment	-0.3	-0.4	0.0
AA3 depreciation adjustment	0.5	0.4	0.1
Total impact on closing capital base	**1.9**	**1.6**	**0.3**

7.2.6 Revised end of period position

575. The March 2014 Access Arrangement Information provided estimated capital expenditure for the period until 30 June 2014 which is the end of the AA3 period. As that period has now been completed, AGA has updated its conforming capital expenditure for the AA3 period to incorporate the actual information now available.

576. The actual end of period position is $10.2 million less than the estimate as shown in Table 7–11 below.

Table 7–11: AA3 Conforming capital expenditure

Category of capital expenditure	AAI	Actual	Variance
Sustaining capital expenditure	22.2	16.5	- 5.7
Growth capital expenditure	35.1	35.9	0.9
Structures and equipment capital expenditure	20.7	15.5	- 5.2
IT capital expenditure	4.5	4.3	- 0.2
Total	**82.4**	**72.2**	**- 10.2**

577. The following sections outline the reasons for the variance.

578. **Sustaining capex** – the lower expenditure in sustaining capital expenditure reflected the need to undertake mains replacement work in Albany that utilised the same resources. This work was assessed as high priority at the time.

579. The new supply for Oakford and Forrestdale ($0.9 million) was deferred, due to delays in the timing of the subdivision development, and the High Pressure Signs Project ($0.3 million) was deferred as the competitive tender process took longer than expected.

580. **Growth capex** – expenditure was higher for growth capital expenditure due to the higher than expected greenfield connections. Mains expenditure was 14% higher (157 km versus 137 km) and expenditure on services was 9% higher (10,255 connections versus 9,377 connections).

581. **Structures and equipment capex** –. AGA's fleet ownership strategy was implemented during 2013 as this approach achieves the lowest sustainable cost of providing services over the longer term. The lower expenditure reflected the deferral of the Mandurah Depot and Warehouse upgrade ($1.8 million). There was also an underspend in fleet ($2.9 million) and associated operational equipment ($0.5 million), of which $1.5 million is carried forward to AA4.

582. **IT capex** – A relatively modest $0.2 million lower expenditure resulted from a schedule change for the GIS upgrade ($0.1 million) and some other minor variations.

7.2.7 Revised proposed opening capital base

583. AGA's proposed opening capital base, which considers each of the above changes, is show in Table 7–12

Table 7–12: AGA proposed opening capital base for AA4

Real $ million at 30 June 2014	Jan to June 2010	2010/2011	2011/2012	2012/2013	2013/2014
Opening Capital Base (AA3)	878.0	896.8	911.7	921.4	969.5
Plus: Capital Expenditure	31.1	41.5	38.7	79.5	72.1
Less: Depreciation	12.3	26.6	29.0	31.4	33.7
Closing Capital Base (AA3)	896.8	911.7	921.4	969.5	1,007.9
AGA Amended Revised Opening Capital Base for AA4 at 1 July 2014					1,007.9

8. Projected capital base

ERA required amendment 7

The value of conforming capital expenditure for 2014 to 2019 access arrangement period must be amended to reflect the values shown in Table 36 of this Draft Decision.

AGA Response: do not accept

Summary Only – AGA considers greenfield growth expenditure is conforming capital expenditure and should be included in the projected capital base. AGA does not agree with the ERA's assertion that the risk threshold for security of supply is too low and submits revised sustaining capital expenditure. AGA has revised its IT and Structures and Equipment forecast capital expenditure.

ERA required amendment 8

The projected capital base in the proposed access arrangement must be amended to reflect the values in Table 41 of this Draft Decision.

AGA Response: do not accept

Summary Only – AGA has not implemented the ERA's amendment as the ERA's forecast expenditure is not sufficient to ensure acceptable security of supply risk, not support current and future demand for gas services, or enable sufficiently functional and robust IT systems..

8.1 Summary of ERA position

584. The ERA has reviewed AGA's forecast capital expenditure amongst the following cost categories

Table 8–1: Total Capital Expenditure by category ($ million real at 30 June 2014)

Capital expenditure category	Revised AAI	ERA draft decision
Sustaining capital expenditure	311.3	213.9
Growth capital expenditure	228.5	24.0
Structures and equipment	38.4	35.7
IT capital expenditure	28.7	25.2
Overhead reductions	-	(10.6)
Labour escalation reductions	-	(1.8)
	-	-
Total	**606.9**	**286.4**

585. The ERA excludes $320.5 million of proposed capital expenditure from the AA4 projected capital base. The two biggest contributors to the reduction were the view that AGA takes an overly conservative approach to risk and the belief that the NPV assessment of growth investment was flawed resulting in unsubstantiated benefits from the investment.

8.1.1 Sustaining capital expenditure

586. The ERA excludes $97.4 million of proposed sustaining capital expenditure from the AA4 projected capital base.

Table 8–2: Network Sustaining Capital Expenditure ($ million real at 30 June 2014)

Sustaining capital expenditure	Jul-Dec 2014	2015	2016	2017	2018	2019	TOTAL
Revised AAI	17.7	42.0	51.5	64.1	63.3	72.7	311.3
ERA Draft Decision	17.7	42.0	39.4	40.5	39.4	34.9	213.9

587. The ERA has based its decision on two key considerations. The ERA considers that:

- The proposed security of supply risk threshold of 25,000 customers is not in line with good industry practice under rule 79(1)(a) of the NGR. The ERA has adopted EMCa's view that AGA's security of supply risk thresholds are not consistent with AS/NZS4645 and AS2885 or other gas distribution networks, and lead to over statement of expenditure requirements.
- AGA has not provided a cost benefit analysis for the security of supply projects to enable these projects to be considered conforming under rule 79 of the NGR.

588. Based on EMCa's recommendations the ERA is not satisfied that the following projects are justified under any ground in rule 79(2) of the NGR:

- Metallic mains replacement ($11.0 million)
- Interdependency projects ($47.3 million)
- Peel spur line ($20.9 million)
- Two Rocks spur line ($18.1 million)

8.1.2 Growth capital expenditure

589. The ERA excludes $204.5 million of proposed growth capital expenditure from the AA4 projected capital expenditure forecast.

Table 8–3: AGA Growth Capital Expenditure ($ million real at 30 June 2014)

Growth capital expenditure	Jul- Dec 2014	2015	2016	2017	2018	2019	Total
Revised AAI	18.7	39.2	51.8	42.6	41.5	34.7	228.5
ERA draft decision	3.4	6.9	7.6	2.0	2.1	2.0	24.0

590. The ERA has formed its determination on the basis of EMCa's assessment of AGA's NPV analysis of proposed growth expenditure. EMCa identified two assumptions within this analysis that it advises do not represent the best forecast or estimate possible, to meet the requirements of rule 74(2) of the NGR. This, EMCa has concluded, renders AGA's proposed justification under rule 79(2)(b) of the NGR invalid.[158]

591. EMCa considers the annual consumption of AGA's customer base used for NPV analysis should reflect the annual consumption of new customers rather than existing customers and therefore should be 3.5 gigajoules lower. EMCa also considers it is invalid to assume price rises based on recovering costs incurred by higher

[158] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 462.

capital expenditure, EMCa's view is that the NPV analysis should assume prices would increase only by the inflation rate.[159]

592. EMCa found that applying the above methodology renders AGA's NPV analysis negative and thereby fails the incremental revenue test.[160] The ERA accepts EMCa's assessment.

593. Further, the ERA uses EMCa's advice to disallow the following project-specific expenditure:

- Two Rocks ($27.2 million), Peel ($6.0 million) and Baldivis ($5.4 million) spur lines
- Capel to Busselton reinforcement ($5.2 million)
- Volume related demand capital expenditure and regulating facilities ($2.9 million)
- Greenfield customer initiated projects ($146.2 million)
- A percentage of reinforcement projects ($11.5 million)

594. EMCa submits AGA has not provided cost benefit analysis for the spur lines and reinforcement projects, or the volume related and regulating facilities projects. Therefore EMCa considers these projects do not meet the incremental revenue test. The ERA adopts EMCa's considerations.

595. The ERA's determination varies from EMCa's findings in relation to customer initiated greenfield projects. EMCa recommends proposed brownfield infill customer initiated projects can be justified under rule 79(2)(c)(iii) of the NGR (as the expenditure is necessary to comply with regulatory obligation), whereas greenfield customer initiated capital expenditure is not justified. The ERA agrees with EMCa's view in principle, however:

> *the Authority does not share EMCa's view that $19.8 million of service connections will be conforming capital expenditure as some mains and greenfield sites have already been installed.*
>
> *The Authority considers that ATCO has not provided any evidence of its proposed greenfield growth capital expenditure on greenfield customer initiated projects. ATCO has not provided any evidence that the large and relatively generic expansion initiative of greenfield customer initiated capital expenditure satisfies the incremental revenue test. Therefore, the Authority is not satisfied that $146.24 million is justified under rule 79(2)(b) of the NGR.*[161]

596. As a result the ERA excludes **all** customer-initiated greenfield investment from the projected capital base.

8.1.3 Structures and equipment

597. The ERA is satisfied $35.7 million of the proposed $38.4 million expenditure on structures and equipment is conforming capital expenditure.

Table 8–4: AGA Structure and Equipment Capital Expenditure ($ million real at 30 June 2014)

Structures and equipment	Jul – Dec 2014	2015	2016	2017	2018	2019	TOTAL
Revised AAI	3.7	16.7	3.5	3.5	5.5	5.5	38.5
ERA draft decision	3.8	16.2	2.3	3.5	5.1	4.8	35.7

159 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 464.

160 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 465.

161 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 471.

598. The excluded $2.7 million relates to:

- Deferring establishment of the Busselton depot to AA5, on the basis that AGA's growth projections are overstated ($1.2 million)[162]
- EMCa's recommendation that capital expenditure on fleet and plant and equipment should be reduced on the basis that growth projections are overstated ($0.8 million and $0.2 million respectively)[163]
- EMCa's consideration that the Osborne Park Blue Flame Kitchen project's link to safety is weak and should be removed from the expenditure forecast ($0.5 million)[164]

8.1.4 IT capital expenditure

599. The ERA is satisfied $25.1 million of the proposed $28.7 million expenditure on IT is conforming capital expenditure. The $3.5 million reduction relates to EMCa's view that the following expenditure does not comply with rule 79 of the NGR:

- Commercial operations: AGA-01, commercial services continuous improvements ($1.8 million)
- Network operations: AGA-02, GIS continuous improvements ($0.2 million)
- Business support improvements: AGA-11, business process standardisation, ($0.7 million)
- Business support upgrades: AGA-19, new technology business cases, ($0.1 million)
- IT hardware and equipment ($0.7 million)

Table 8–5: AGA IT Capital Expenditure ($ million real at 30 June 2014)

IT Capex	Jul-Dec 2014	2015	2016	2017	2018	2019	TOTAL
Revised AAI	5.1	6.6	5.8	4.4	3.7	3.1	28.7
ERA draft decision	4.8	6.2	5.3	3.9	2.9	2.1	25.2

600. The ERA excludes the expenditure due to the perceived speculative nature of some of the investment, the ability to reasonably defer some projects to AA5 and the absence of supporting documentation in the case of the IT hardware and equipment.

8.1.5 Overheads and labour escalation

601. The ERA does not consider that forecast overhead rate is efficient or in line with industry practice and does not accept it meets the requirements of rule 74 of the NGR. The ERA considers an overhead allocation of 15 per cent would be more in line with industry practice. As a result the ERA has reduced the relevant capital expenditure by $10.6 million on a pro rata basis for overhead allocation.

602. The ERA also rejects the proposed labour cost escalation on the basis of rule 74 of the NGR. The ERA has reduced the relevant capital expenditure by $1.8 million for labour cost escalation.

162 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 487.

163 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 491 and 492.

164 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 488.

8.2 AGA response

603. **AGA has not implemented required amendment 7 and 8**

604. AGA proposes an amended forecast capital expenditure of $592.2 million for the AA4 period, comprising:

- $291.8 million sustaining capital expenditure
- $233.9 million growth capital expenditure
- $40.2 million structures and equipment capital expenditure
- $26.3 million IT capital expenditure

605. This amended forecast capital expenditure is proposed on the assumption that the Final Decision contains a reasonable rate of return, which enables AGA to secure the necessary funding for the investment.

Table 8–6: Amended proposal for capital expenditure ($ million real at 30 June 2014)

Capital expenditure category	Revised AAI	ERA draft decision	Amended Proposal
Sustaining capex	311.3	213.9	291.8
Growth capex	228.5	24.0	233.9
Structures and equipment capex	38.4	35.7	40.2
IT capex	28.7	25.2	26.3
Overhead reductions		-10.6	
Labour escalation reduction		-1.8	
Total	**606.9**	**286.4**	**592.2**

606. AGA's rationale for the amended expenditure forecast and its response to matters raised in the Draft Decision is provided in the sections below.

8.2.1 Capital expenditure benchmarking

607. The Draft Decision imposes unreasonable reductions on AGA's capital expenditure for the AA4 period. This is demonstrated by an expert report from Acil Allen, commissioned by AGA, which provides capital cost benchmarking with 8 Australian Gas Distribution businesses.

608. The updated benchmarking information, provided by Acil Allen, in Appendix 6.1 demonstrates that AGA's capital expenditure continues to be at efficient levels relative to the sample.

Capex per customer

609. In their Gas Distribution Benchmark report, Acil Allen comments that AGA *consistently has among the lowest capex per customer, ranging from $59 in 2005-06 to $108 in 2013-14* and *over the period from 2005-06 to 2013-14, ATCO Gas' capex per customer ranged between:*

- *62 and 41 per cent below the sample average, reaching a maximum of 69 per cent below the average in 2011-12*
- *89 and 65 per cent below the highest cost distributor, reaching 83 per cent below in 2011-12.*[165]

[165] Appendix 6.1 Gas Distribution Benchmarking Partial Productivity Measures Acil Allen November 2014, page 25.

This is shown in Figure 8–1

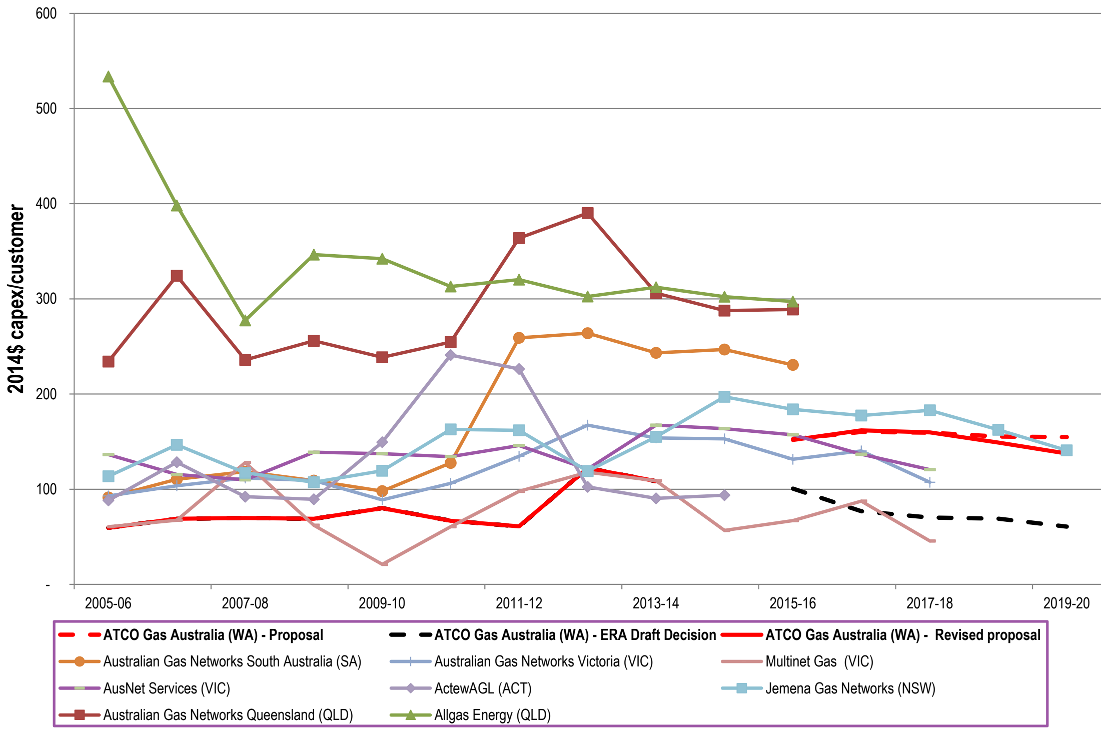

Figure 8–1: Capex per customer benchmark

610. The ERA's draft decision would take AGA's capex per customer to a level that is well below the 2013/14 average, at 67 per cent below the 2013/14 average by 2019. Under AGA's revised proposal, AGA's 2019 capex per customer would be 25 per cent below the 2013-14 average.[166]

Capex per km

611. Acil Allen further comments in their Gas Distribution Benchmark report that AGA *has had among the lowest capex per km of the nine gas distributors, ranging from $2,629 in 2005-06 to $5,399 in 2013-14 and ATCO Gas' capex per km has been relatively stable over the period before increasing in 2012-13, which according to ATCO Gas is due to necessary expenditure on safety performance improvements such as asset replacement and leak reduction*.[167]

The capex per kilometre benchmarking information provided by Acil Allen is shown in Figure 8–2

[166] Appendix 6.1 Gas Distribution Benchmarking Partial Productivity Measures Acil Allen November 2014, page 25, page 26.

[167] Appendix 6.1 Gas Distribution Benchmarking Partial Productivity Measures Acil Allen November 2014, page 25, page 24.

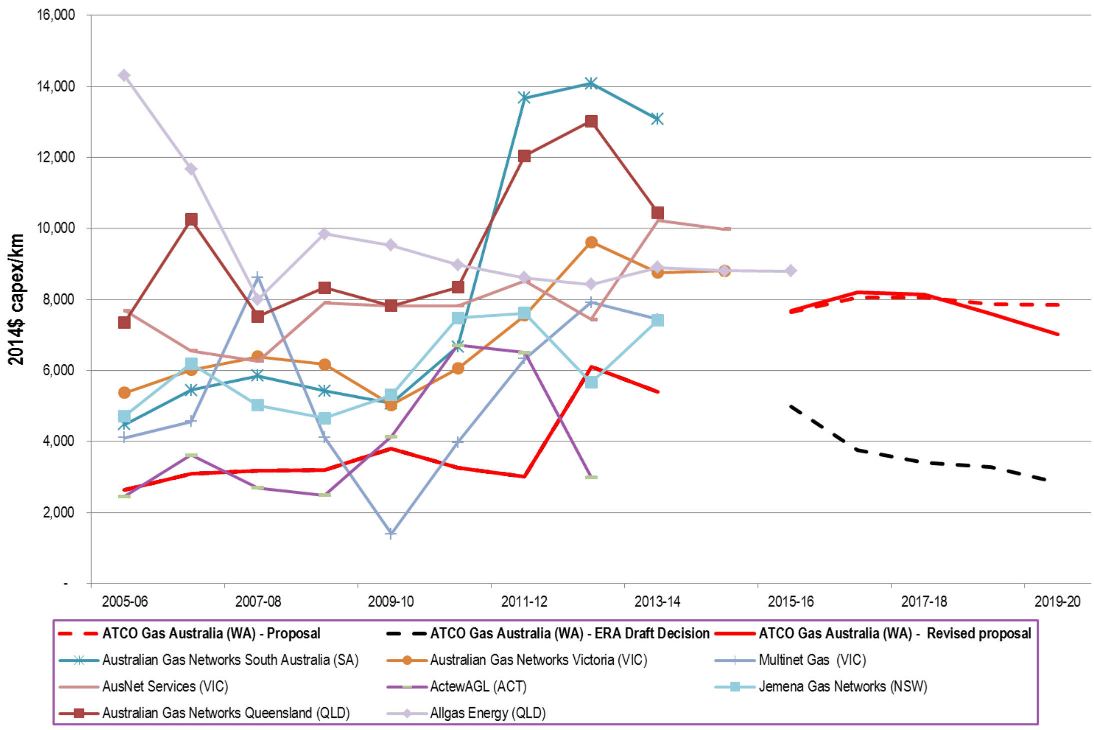

Figure 8–2: Capex per km benchmark

612. Figure 8–2 shows that the ERA's draft decision would take AGA's capex per km to a level that is well below the 2013/14 average, at 68 per cent below the 2013/14 average by 2019. Under AGA's revised proposal, AGA's 2019 capex per km would be 22 per cent below the 2013/14 average.

Capex efficiency

613. In Acil Allen's opinion, *These capex performance indicators suggest that ATCO Gas has efficient capital expenditure costs in relation to the sample of firms* and the *low level of ATCO Gas' normalised capex expenditures raises the question whether it has been at a high enough level to sustainably deliver required services over the long term*.

614. As shown, the ERA draft decision would reduce normalised capex costs to well below the current (2013/14) sample average level of unit capex costs and to a level that AGA considers to be unsustainable for the continued safe, reliable and efficient operation of the network.

615. Based on the historically low levels of capital expenditure compared to the benchmark firms, it would be reasonable to expect that AGA's forecast capex could approach levels higher than the sample average. This is not the case and the forecast capex over the AA4 period remains 22-25% below the 2013/14 sample average demonstrating the efficiency of the capital program which is required to deliver safe, reliable service to a growing customer base in Western Australia.

8.2.2 Sustaining capital expenditure

616. AGA accepts the ERA's recommendation to defer some expenditure on the unprotected metallic mains program to the AA5 period and submits a reduced amended proposal below. AGA has also reassessed proposed interdependency projects and submits that six of these projects can be deferred to later periods as a result of a review of the time period by which supply can be restored to customers supplied from these networks.

617. AGA does not accept the ERA's requirement to exclude the Two Rocks and Peel spur line projects from the projected capital base. AGA considers these projects are justified under the Safety Case and ASNZS4645 and are required to reduce the loss of supply risk level from its current rating of 'high'.

618. With regard to the ERA's view that AGA loss of supply risk threshold is too low, AGA submits evidence that demonstrates the 25,000 customer threshold is reasonable and consistent with good industry practice.

619. In addition to the ERA's amendments, AGA has removed the high pressure HP017 pipeline project ($3.2 million) from the projected capital base as on-site asset investigations have confirmed this project is no longer required.

620. These matters are discussed further in the following sections.

8.2.2.1 Metallic mains

621. EMCa considers the metallic mains project is efficient and in line with rule 71 of the NGR. However, EMCa believes AGA has increased the rate of replacement to meet a false deadline, and has recommended some of this program relating to unprotected metallic mains expenditure ($11.0 million) be deferred to the AA5 period.

622. AGA accepts EMCa's view that some expenditure may be deferred to later periods, and has reassessed the unprotected metallic mains project. Unprotected metallic mains are replaced as part of the broader metallic mains replacement program, which covers a bundle of asset types as shown in Table 8–7 below.

Table 8–7: Length of Mains for Metallic Mains Replacement Program: 2014 to 2019 km

Project Description	2H 2014	2015	2016	2017	2018	2019	Total [km]
Odd Size Steel	5	5	5	5	5	8	**33**
Unprotected Metallic Mains	5	21	22	22	28	38	**136**
Cast Iron	8	12	13	13	12		**58**
TOTAL [km]	**18**	**38**	**40**	**40**	**45**	**46**	**227**

623. In the March 2014 proposal, AGA outlined the implementation plan for the overall metallic mains replacement program, which is based on an optimised resource delivery plan to efficiently complete the program by 2019. All three metallic mains projects are delivered using the same resource base; therefore it is efficient to keep the resources engaged in delivering approximately the same annual volumes (km) over the period.

624. AGA has assessed the impact of reducing the asset replacement program in 2018 and 2019 and considers 11km of unprotected metallic mains can be deferred for replacement in AA5. The revised program is presented in Figure 8–3: Mains Replacement Program

625. Figure 8–3 and Table 8–9 below.

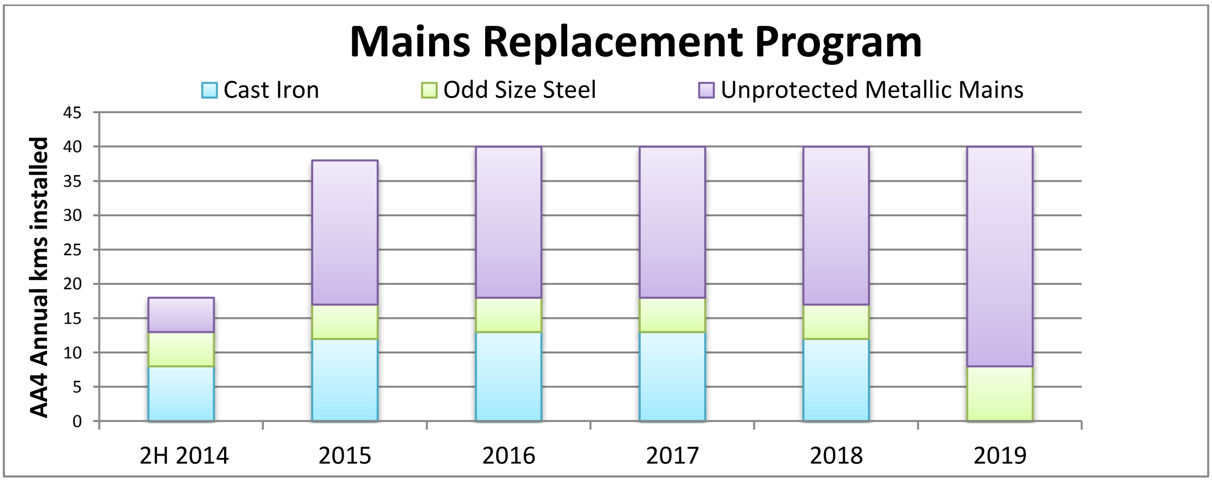

Figure 8–3: Mains Replacement Program

Table 8–8: Revised Length of Mains for Metallic Mains Replacement Program: 2014 to 2019 [km]

Project Description	2H 2014	2015	2016	2017	2018	2019	Total [km]
Odd Size Steel	5	5	5	5	5	8	**33**
Unprotected Metallic Mains	5	21	22	22	23	32	**125**
Cast Iron	8	12	13	13	12	-	**58**
TOTAL [km]	**18**	**38**	**40**	**40**	**40**	**40**	**216**

626. This reduction maintains a balanced and efficient utilisation of resources while maintaining the risk associated with these assets at a manageable level. The revised proposal defers $3.4 million of capital expenditure from AA4 to AA5. The revised costs associated with this program are presented in Table 8–9.

Table 8–9: Amended forecast expenditure on unprotected metallic mains ($ million real at 30 June 2014)

Unprotected metallic mains	2H 2014	2015	2016	2017	2018	2019	Total
Revised AAI	2.88	7.17	7.38	7.37	10.17	15.60	**50.57**
Amended proposal	3.67	7.35	7.35	7.35	8.22	13.20	**47.14**

8.2.2.2 Loss of supply risk threshold

627. The ERA determined it is not satisfied the following projects are justified under any grounds in rule 79 (2) of the NGR:

- Peel spur Line ($20.9 million)
- Interdependency projects ($47.3 million)
- Two Rocks spur line ($18.1 million)

628. Based on advice from EMCa, the ERA determined the security of supply related portions of these projects are designed to meet a security of supply risk threshold that does not accord with industry standards and that when applying the ALARP (as low as reasonable practicable) test, no cost benefit analysis has been conducted.

629. AGA does not accept EMCa's recommendations and considers the security of supply risk thresholds are consistent with good industry practice. Evidence to support AGA's view is provided in the following sections.

Catastrophic risk threshold for loss of supply

630. EMCa states:

> *ATCO has adopted a risk threshold for catastrophic events that appears to be lower than the threshold employed by other gas distribution networks. EMCa considers that the risk threshold that ATCO has adopted of 25,000 customers for loss of supply to be catastrophic is not prescribed in AS/NZS4645 and AS28855, nor mandated by EnergySafety, and is low by industry standards.*[168]

631. AGA does not agree with the EMCa assessment for the following reasons:

- AGA's loss of supply risk thresholds have been designed to meet the requirements prescribed in the standards
- AGA's loss of supply risk thresholds are consistent with industry peers
- Energy*Safety* has advised AGA that the loss of supply risk threshold of 25,000 customers does constitute a high risk and that action is required to reduce the risk as mandated by AS/NZS 4645 without any requirement to conduct a cost benefit analysis.[169]
- AGA has also tested its interpretation and application of the standards with Zincara, a technical expert in the field of gas distribution operation and management, who considers that ATCO's risk management practice is consistent with that of a prudent service provider acting efficiently in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services[170]

Designed to meet the requirements of Australian standards

632. The risk tolerance criteria for loss of supply were designed to meet the AS/NZ 4645.1 and AS2885.1 standards criteria of 'long term', 'prolonged' and 'short-term'. To provide greater certainty and prescription regarding the application of the thresholds, AGA adopts an approach that nominates a specific number of impacted customers that where supply was lost the event would result in a 'long term', 'prolonged' or 'short term' loss of supply.

633. Based on AGA's network configuration, geography and operational response capability, AGA has assessed that an event that interrupts supply to 25,000 customers is likely to result in customers being off supply for an average of 4 weeks (although some may be off supply for days while others may be off supply for months). This is consistent with the standard requirement of long term and therefore, consistent with the standard, a position that is endorsed by Energy*Safety*.

634. Zincara reviewed AGA's risk management approach including its risk matrix and considers that *ATCO's consequence and frequency tables are similar to that set out in AS/NZS4645.1 (Standard) and that ATCO's definitions in the table meet the guidelines as set out in the Standard. Similarly, the ATCO's risk matrix is also consistent with that of the Standard. In relation to the steps taken to assess and reduce the risk, Zincara considers that process is also consistent with Standard. Zincara therefore considers that ATCO's risk management approach is consistent with AS/NZS4645.1.*[171]

635. Table 8–10 compares AGA's Risk Model and the AS2885/AS/NZS4645 risk models.

[168] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 451.

[169] Confidential Appendix 8.1 Correspondence from Energy Safety November 2014.

[170] Appendix 6.3 Review of ATCO Gas Australia Capital and Operating Expenditure, Zincara, November 2014, Section 3.1.3.

[171] Appendix 6.3 Review of ATCO Gas Australia Capital and Operating Expenditure, Zincara, November 2014, Section 3.1.3.

Table 8–10: Comparison between the AGA's Risk Model and the AS2885/AS/NZS4645 risk models

AGA – AS/NZS4645 Risk Model Comparisons and where applicable AS2885 (2 pipelines only)						
	People1		Environmental Impact		Supply2	
	AS2885/AS4645	AGA Risk Model	AS2885/AS4645	AGA Risk Model	AS2885/AS4645	AGA Risk Model
Catastrophic	Multiple fatalities result	More than 2 fatalities	Effects widespread; viability of ecosystems or species affected; permanent major changes	Effects widespread; Viability of threatened ecosystems or species affected or permanent major changes	Long-term interruption of supply	Interruption of supply affecting > 25,000 customers
Major	Few fatalities; several people with life threatening injuries;	Up to 2 fatalities; Several people with life threatening or permanently disabling injuries	Major off-site impact; long term severe effects; rectification required	Major offsite impact; Long term (2yrs or more), severe effects; Rectification difficult; Major impact in an area of high conservation value of significance	Prolonged interruption; long term restriction of supply	Interruption or restriction of supply affecting >5,000 customers
Severe	Injuries or illness requiring hospital treatment	Injuries or illness requiring hospital treatment	Localized (<1 ha) and short-term (<2 yr) effects; easily rectified	Localised with short term effects (<2yrs); Easily rectified; Moderate impact upon cultural & heritage sites or rare/endangered flora/fauna; Chemical release contained with outside assistance	Short-term interruption; prolonged restriction of supply	Interruption or restriction of supply affecting >500 customers Prolonged interruption to critical customers*
Minor	Injuries requiring first aid treatment	Injuries or illness requiring first aid or medical treatment	Effect very localized (<0.1 ha) and very short-term (weeks), minimal rectification	Localised with very short term (weeks) effects; Easily rectified; Minor impact on rare/endangered flora/fauna; Onsite chemical	Short-term interruption; restriction of supply but shortfall met from other sources	Interruption or restriction of supply affecting >=100 customers Short-term interruption to critical

				release with is contained without outside assistance		customers*
Trivial	Minimal impact on health and safety	Minimal impact on health and safety	No effect; Minor on-site effects rectified rapidly with negligible residual effect	No effect or minor onsite effects that are rectified rapidly with a negligible, residual effect; Minor lead that does not lead to contamination	No impact; no restriction of gas distribution network/pipeline supply	Interruption or restriction of supply affecting <100 customers No impact to critical customers[3]
1 Human Injury or fatality. 2 Interruption to continuity of supply with economic impact. 3 Critical customers are hospitals and the Public Transport Authority.						

Consistent with industry practice

636. AGA has compared its loss of supply risk threshold to other gas distribution businesses and determined it is consistent with other networks. As previously mentioned, other businesses use alternative means of expressing the threshold such as customer days or customer weeks off supply. It should be noted therefore that AGA's 25,000 customer threshold is equivalent to 100,000 customer weeks off supply where each customer is off supply for 4 weeks on average.

637. Zincara reviewed AGA's security of supply risk thresholds and found that *Using a four week duration interruption to 25,000 customers will result in 100,000 customer weeks which is similar to that of Envestra. It is also similar to that of Multinet, which has defined a one month failure of gas supply as a catastrophic event* and that *As ATCO's definition of loss of supply is similar to that of Envestra (and Allgas) and Multinet, Zincara therefore considers that ATCO's definition of a catastrophic event for loss of supply is consistent with industry practice and as such consistent with a prudent service provider acting efficiently in accordance with accepted industry practice to achieve the lowest sustainable cost of delivering pipeline services*.[172]

638. Table 8–11 replicates the table in the EMCa report that compares AGA's thresholds with those currently adopted by other gas distribution operators in Australia and expresses AGA's thresholds in equivalent terms to the other businesses such as customer weeks and customer days off supply.

Table 8–11: Comparison between the AGA's Risk Model and industry peers

SUPPLY SEVERITY CLASSES – AS2885/AS4645 – AGA RISK MODEL – OTHER GAS DISTRIBUTION NETWORK OPERATOR COMPARISON						
	AS2885/AS4645	**AGA**	**Envestra**	**Allgas**	**Multinet**	**SP Ausnet**
Catastrophic	Long-term interruption of supply	Interruption of supply affecting > 25,000 customers **Equivalent**	Long term loss of supply to mass market >100,000 customer weeks	Long term loss of supply to mass market >100,000 customer weeks	Major disruption of multiple services capacity for greater than 1 month –	>200,000 customers or System Black or loss of supply to entire CBD

172 Appendix 6.3 Review of ATCO Gas Australia Capital and Operating Expenditure, Zincara, November 2014, Section 3.2.2.

		to: >100,000 customer weeks; Interruption to 25,000 customers for on average 1 month or greater			failure of gas supply	
Major	Prolonged interruption; long term restriction of supply	Interruption or restriction of supply affecting >5,000 customers **Equivalent to:** >35,000 customer days; Interruption to 5,000 customers for on average 1 week	Short term loss of service to >10,000 customer days	Short term loss of service to >10,000 customer days	Major disruption of multiple services capacity up 1 month – failure of gas supply	>100,000 customers

639. The supply risk thresholds also have regard to Perth's isolation and limited access to backup skilled resources from other gas distribution companies as would be available to the companies on the east coast from whom the industry benchmarks are derived.

640. AGA therefore considers that the risk threshold adopted is comparable to other gas network owners and operators in Australia and is therefore consistent with good industry practice.

Gas Distribution System Safety Case

641. AGA has designed its forecast network expenditure to enable it to comply with the Safety Case,[173] which was accepted by Energy*Safety* in 2011. The loss of supply thresholds are incorporated into the risk matrix contained in the Safety Case on the basis of the above interpretation and application of the standard adopted by AGA.

642. Since the release of the Draft Decision, AGA has discussed the findings of the EMCa report with Energy*Safety* and sought its expert opinion on the issues. Energy*Safety* advised AGA that the loss of 25,000 customers is a catastrophic event, hence constitutes a high risk and requires action to reduce the risk in accordance with AS/NZS 4645[174].

643. By excluding the security of supply related projects in AA4, the ERA would place AGA in a position of non-compliance with its principle governing standard AS/NZS 4645 and with its Safety Case. Prior to the Final Decision, AGA urges the ERA to seek advice from Energy*Safety* to ensure alignment with the safety

173 WAGN Gas Distribution System Safety Case, July 2011.

174 Energy*Safety*- draft decision submission (reinforcement projects) 26 November 2014 http://www.erawa.com.au/gas/gas-access/mid-west-and-south-west-gas-distribution-system/access-arrangements/proposed-access-arrangement-for-period-2014-2019

regulator. ATCO notes that the ERA and Energy*Safety* (**ESD**) entered into a memorandum of understanding dated 23 May 2006 which provides that the ERA may ask ESD to provide technical advice and support, including assisting the ERA in the assessment of asset management plans and the safety, reliability and quality of supply performance of electricity and gas network licence holders, and related advice[175]: AGA remains committed to delivering the Safety Case requirements and is optimistic that the ERA will support the proposed expenditure to address the network risk accordingly.

8.2.2.3 As low as reasonably practicable (ALARP) test

644. The ALARP test is incorporated under AS/NZ 4645.1. Under this standard, where a risk is identified as being high (consistent with AGA's risk management framework), AS/NZ 4645.1 mandates that AGA must implement a risk treatment action that reduces the risk to intermediate or lower without a requirement to conduct a cost benefit analysis.

645. While no formal cost benefits analysis is required or developed, any project AGA undertakes to address high risks is subject to its governance framework. EMCa has reviewed AGA's governance framework and states:

> 646. *…we consider the framework for procuring and managing the delivery of projects is generally sound and in keeping with what we would expect a prudent service provider acting efficiently and in accordance with good industry practice to employ.*[176]

647. The following chart presents the risk management procedure used by AGA as part of its risk management framework in determining that a risk can be considered ALARP.

[175] ERA website - http://www.erawa.com.au/library/MOUERAandDoCEP.pdf

[176] EMCa, Review of Technical Aspects of the Proposed Access Arrangement, June 2014, page 77.

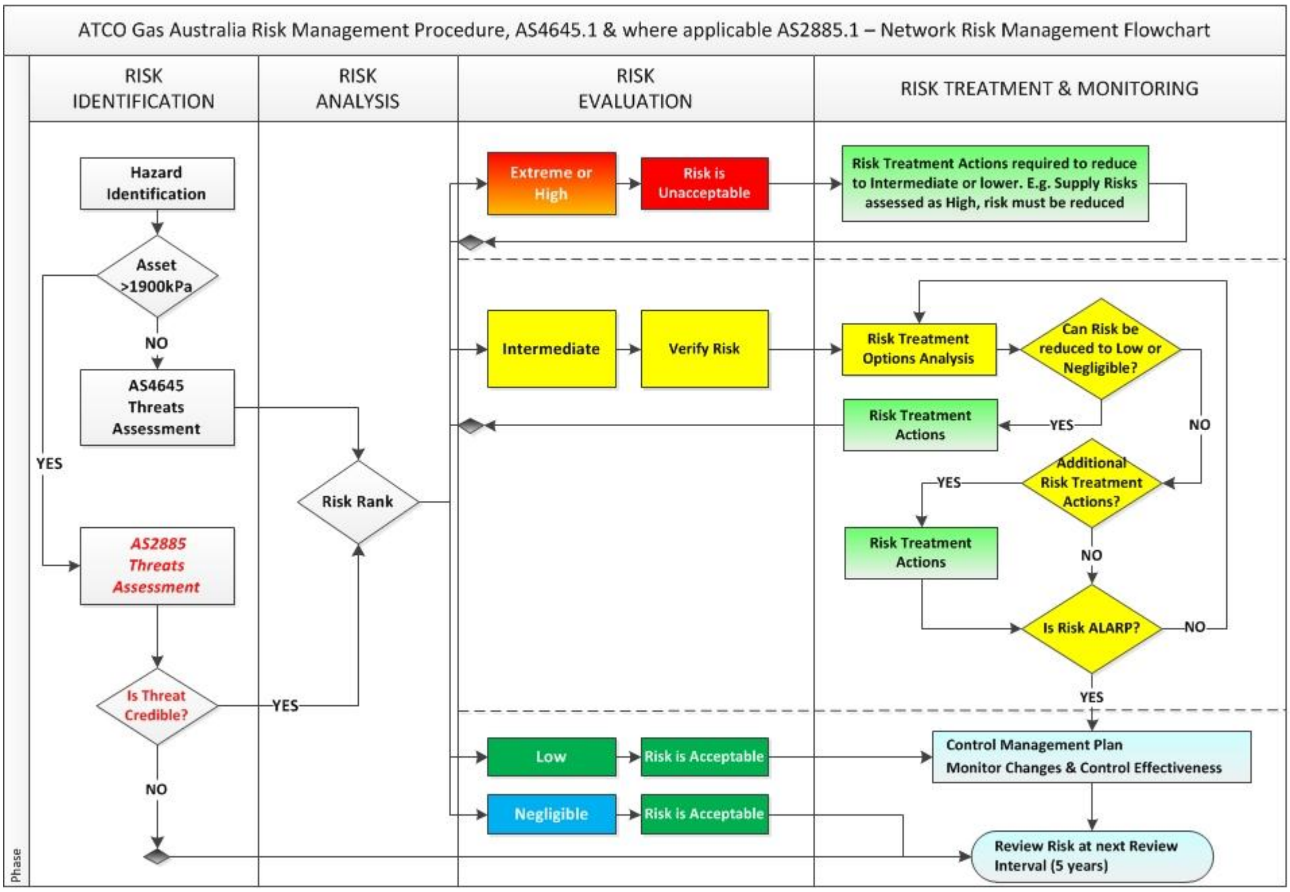

Figure 8–4: Risk management procedure

648. In the AAI, AGA has used the term 'ALARP' to describe the risk outcome for all projects with a residual risk of 'Intermediate' (where ALARP test has been applied) as well as' Low' and 'Negligible' (where the ALARP test is not required to be applied).

649. AGA acknowledges that the use of this term to refer to a situation where the risk level is 'Low' or 'Negligible' - and therefore does not require the ALARP test to be applied - is not consistent with the correct use of the term under AS/NZS 4645 which is a test that is only applied to risks that have been assessed as 'intermediate'. The outcomes in terms of required risk treatments and risk management action plans are not altered based on AGA's use of this terminology.

> *Zincara reviewed AGA's application of the ALARP test and found that ATCO risk management framework is consistent with the Australian Standards AS2885 and AS/NZS4645 (Standards). The framework requires that any event that is considered to have extreme or high risk needs to have specific action taken to reduce the risk. If after taking the action, the risk is deemed to be intermediate, further actions are required. However if these actions do not lower the risk to low, it may be required to consider extreme steps and in this case, a quantitative analysis needs to be carried out to determine if the cost grossly outweighs the benefits.*
>
> *Zincara considers that ATCO applies the above steps. However, ATCO has misrepresented the word ALARP in its Asset Management Plan and its Safety Case. ATCO has used ALARP to mean acceptable risk.*[177]

177 Appendix 6.3 Review of ATCO Gas Australia Capital and Operating Expenditure, Zincara, November 2014.

8.2.2.4 Two Rocks and Peel spur lines

650. The Two Rocks and Peel projects are required to reduce the risk associated with a loss of supply incident on the network. Currently the areas impacted by the proposed projects do not have secondary sources of supply and therefore the risk is assessed as high.

Two Rocks spur line

651. Currently there are 60,000 existing customers in the northern networks at risk of long term loss of supply if a catastrophic incident was to occur. The construction of a new Two Rocks spur line is required to reduce this high risk by introducing a secondary gas supply. Figure 8–5 shows the area that would be impacted by the loss of supply to 60,000 customers. It should be noted that this is a high growth area with an expected increase of 28,000 customers over the next 5 years bringing the total customers affected to 88,000.

652. Zincara reviewed the Two Rocks spur line and concluded that *ATCO's definition of a catastrophic event of the loss of supply to 25,000 customers is consistent with industry standard. This means the loss of supply in this situation is over twice to that defined as a catastrophic event. The Health and Safety Executive in the UK said the greater the risk the more should be spent in reducing it and the greater the bias on the side of safety*.[178] In this case, Zincara considers that the consequence of not carrying out the project is not grossly disproportional to the benefit.

[178] Appendix 6.3 Review of ATCO Gas Australia Capital and Operating Expenditure, Zincara.

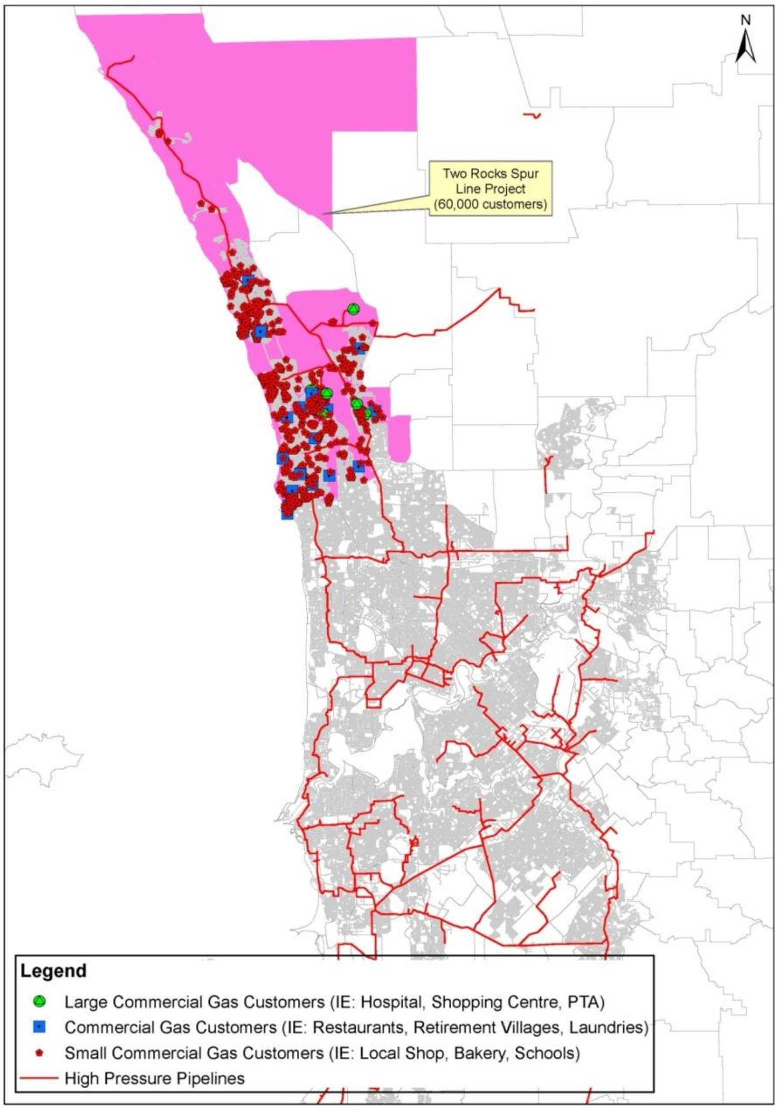

Figure 8–5: Area that would be impacted by the loss of supply – 60,000 customers

Peel spur line

654. The Peel spur line is required to address the loss of supply risk in the Peel region. This includes the loss of supply to over 34,000 customers in the Mandurah gas network. Figure 8–6 shows the area that would be impacted by the loss of supply to 34,000 customers.

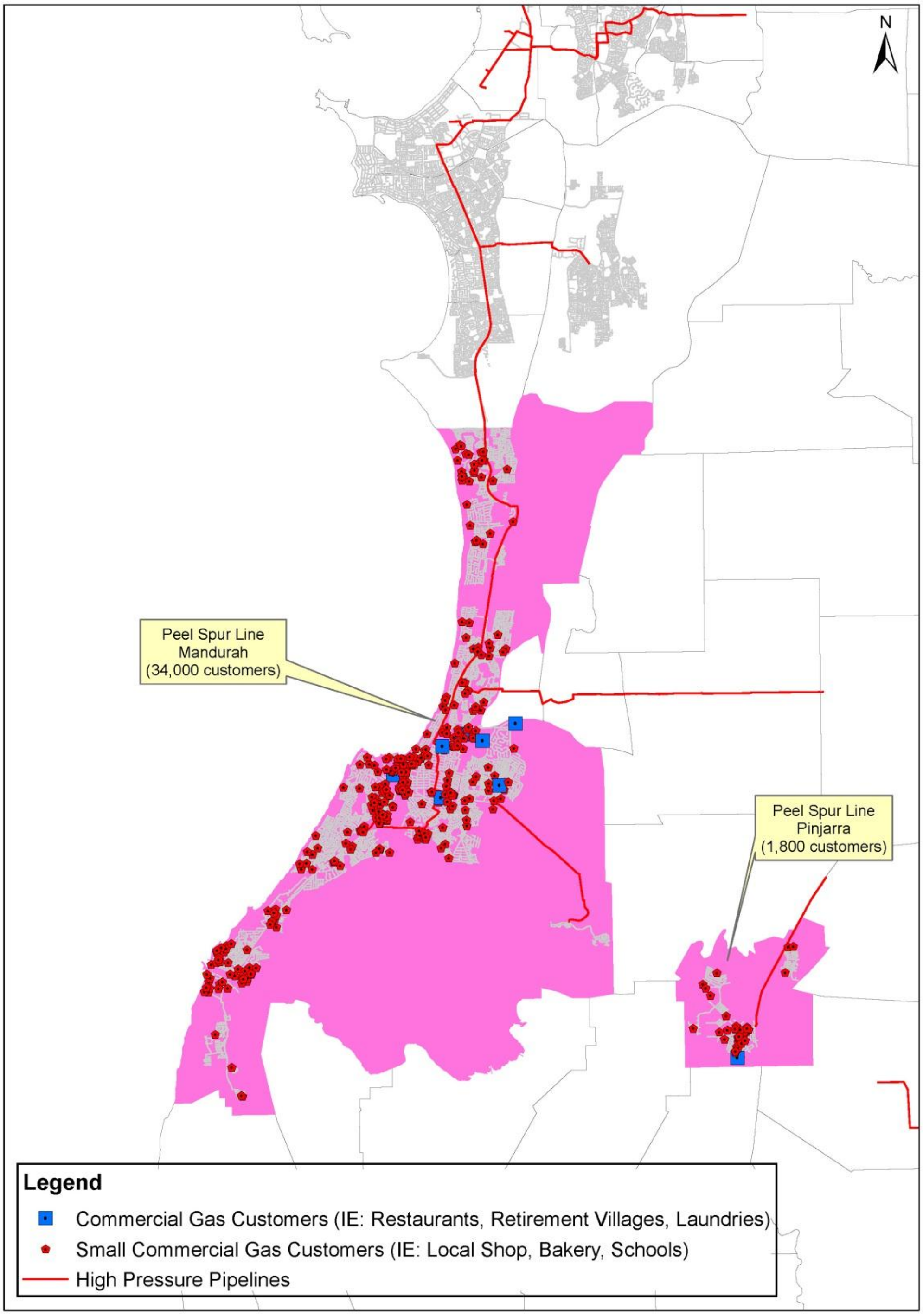

Figure 8–6: Area that would be impacted by the loss of supply – 34,000 customers

655. In designing the Two Rocks and Peel spur line projects to meet security of supply requirements, AGA has considered growth factors in the area and where required increased the scope of the security of supply projects to ensure future growth can be accommodated to avoid higher future costs of supporting future growth through an additional standalone project.

656. In the March 2014 submission, where a project was proposed to comply with rule 79(2)(d) of the NGR in terms of meeting both security of supply requirements and future growth objectives, the costs were allocated to the sustaining and growth investment categories on the basis of an NPV assessment. AGA conducted an NPV assessment of the project costs and future load and allocated the highest amount to growth investment while achieving a neutral NPV. AGA considers this conservative approach provides a higher threshold test when considering projects against rule 79(2) of the NGR. The balance of the forecast expenditure for these projects was included in the sustaining capital expenditure category to be assessed in accordance with rule 79(2)(c) of the NGR.

657. EMCa considers that in the absence of a cost benefit assessment of the proportion of costs allocated to sustaining capital expenditure, projects that meet both security of supply and future growth objectives should not be included under the sustaining capital expenditure category. ERA adopted this view in its rejection of the Two Rocks and Peel spur lines.

658. In relation to ATCO sharing the cost between demand for greenfields development and sustaining capex for these projects, Zincara *considers that this approach to be reasonable and practical. The alternative is to have separate pipelines for each requirement which is impractical and also the costs of separate pipelines would exceed that of sharing the costs between the two requirements as discussed in ATCO's draft response to the ERA. Zincara therefore considers the project to be consistent with NGR 79(2)(c)*.[179]

659. AGA disagrees with EMCa view and submits that where a project is initiated to achieve security of supply objectives, at least some of the costs of these projects should be categorised as sustaining capital expenditure and be assessed in accordance with rule 79(2)(c) of the NGR.

660. AGA considers that its approach to categorising expenditure on shared objective projects remains appropriate and complies with rule 79(2)(d) of the NGR. The stand-alone security of supply project assessments are provided in Confidential Appendix 8.2. These assessments demonstrate that the cost of undertaking two discrete projects to achieve the security of supply and growth objectives separately is greater than the combined projects costs proposed by AGA.

661. An alternative method of allocation might include adopting the stand alone security project costs as the costs to be allocated to sustaining capital expenditure and only allocate the incremental cost of a joint project to the growth project. This less conservative approach than the one adopted for the AAI would increase the NPV for the costs that would be allocated to growth investment.

662. Table 8–12: Two Rocks and Peel spur lines loss of supply consequences ($ million real at 30 June) provides a comparison of the project costs to be allocated between growth and sustaining expenditure based on AGA's method adopted in the AAI and the alternative method outlined above.

663. AGA has maintained its original allocation of costs across sustaining and growth for these projects, as per the AAI, with the allocation to growth reflecting the NPV neutral position of project costs and the balance included as sustaining capex.

Table 8–12: Two Rocks and Peel spur lines loss of supply consequences ($ million real at 30 June)

Project Name	Interruption of supply affecting >25,000 customers	Customer weeks off supply equivalent	Project costs	Current method		Alternative method		
				Growth	Sustaining	Growth	NPV	Sustaining
Two Rocks	60,000	563,000	$45.3	$27.2	$18.1	$5.4	$16.1	$39.9
Peel	34,000	186,000	$32.3	$11.4	$20.9	$0	$5.3	$32.3

179 Appendix 6.3 Review of ATCO Gas Australia Capital and Operating Expenditure, Zincara, November 2014, Section 5.2.2.2.

664. Regardless of the allocation of the costs of these projects to cost categories at least $40 million can be categorised as sustaining capital expenditure and complies with rule 79 (2) (c) of the NGR.

665. Furthermore, AGA has discussed the spur line projects with Energy*Safety* who agrees with the risk assessment and the action plans and projects to reduce the risk from high. Moreover, Energy*Safety* is of the opinion that should the expenditure not be included in the Final Decision and consequently AGA is not able to implement the action to reduce the risk, this would result in a non-compliance with AS4645, a breach of the Safety Case and likely action by Energy*Safety.*[180]

666. Therefore, as these projects are required to meet a regulatory requirement AGA considers these projects are also justified under rule 79(2) c (iii) of the NGR.

8.2.2.5 Interdependency projects

667. In accordance with AS/NZS4645 the network must be designed and constructed to ensure security of supply to customers. Using industry standard modelling software, a network interdependency study identified critical high pressure regulators and mains where the interruption to such assets would result in catastrophic loss of supply. The resultant interdependency projects provide an alternative source of gas to the network to ensure continuity of supply to customers in the event of interruption to these high pressure assets.

668. As part of its annual Asset Management Plan review AGA has revisited all proposed interdependency projects and the options to isolate the network in the event of interruption of supply. AGA has identified six interdependency projects that are no longer assessed as high risk. The reduction in risk has been assessed as a result of a review of the time period by which supply can be restored to customers supplied from these networks which has reduced to below ‘long term’. As a result the forecast capital expenditure on interdependency projects has been reduced from $47.3 million to $34.0 million.

669. Table 8–13 outlines the amended list of interdependency projects to be completed in AA4 period to reduce the high risk of loss of supply to the number of customers indicated.

Table 8–13: Revised interdependency projects ($ million real at 30 June 2014)

Project Name	Customers affected	Current risk	Revised AAI	Amended proposal
Hillarys	50,400	High	16.5	16.5
Canning Vale	42,000	High	9.4	9.6
Fremantle	28,000	High	0.8	0.9
Lathlain	40,000	High	6.8	7.0
Other	>25,000	Intermediate	13.8	-
Total			**47.3**	**34.0**

670. As the Risk has been assessed as High for the four remaining interdependency projects, a cost benefit analysis is not required to be conducted and EMCa’s and the ERA’s criticism in this regard is not justified.

671. Zincara has reviewed the revised Interdependency projects and concluded that *the threshold of 25,000 customers for catastrophic consequence is consistent with industry standard. As the interdependency projects are to address situations which have been classified as high risk, Zincara considers that the Interdependency projects are justified on the grounds that they reduce the risks to low. Zincara therefore considers the project to be consistent with rule 79(2)(c)*.[181]

[180] Confidential Appendix 8.1 Correspondence from Energy Safety November 2014.

[181] Appendix 6.3 Review of ATCO Gas Australia Capital and Operating Expenditure, Zincara, November 2014, Section 5.2.2.2.

672. A representation of the areas which would be impacted by the loss of supply to >25,000 customers in Hillary's, Canning Vale, Fremantle and Lathlain can be seen in Figure 8–7 (pink area in diagram)

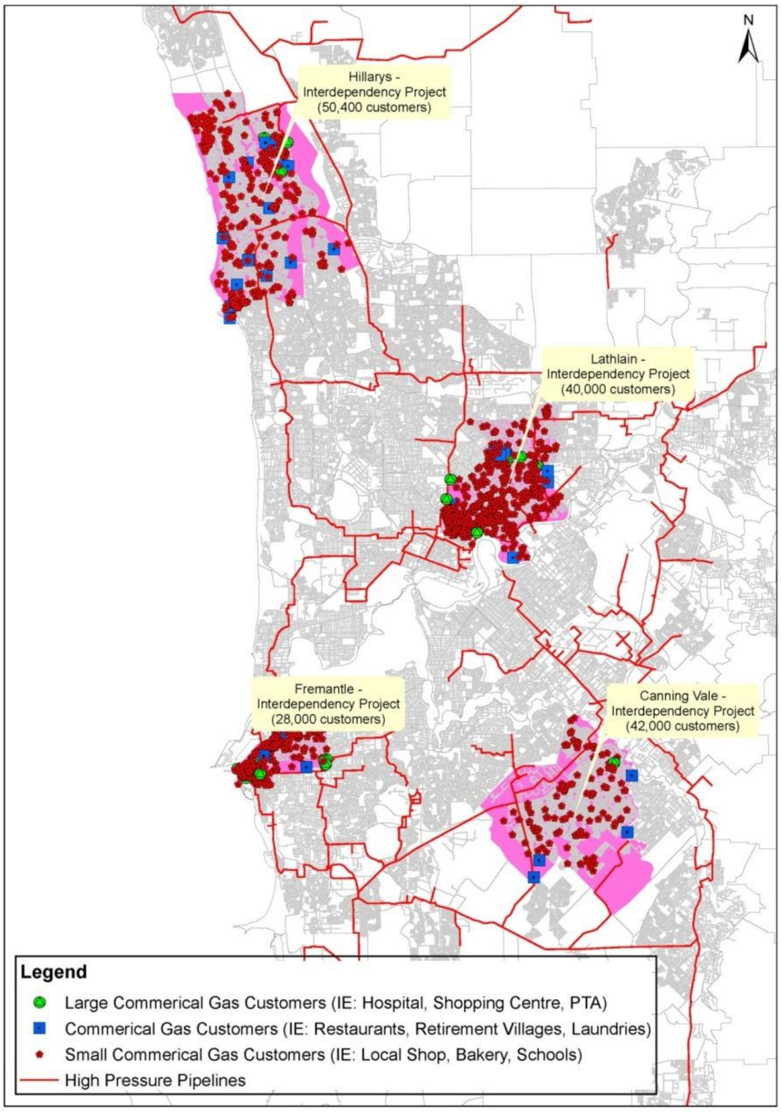

Figure 8–7: Areas that would be impacted by loss of supply – 160,400 customers

673. Further detail on the Interdependency Projects is included in Confidential Appendix 8.2.

8.2.2.6 Replacement project

674. The forecast asset replacement capital expenditure has reduced due to the removal of the high pressure pipeline HP017 in Bibra Lake. AGA undertook on-site technical investigations as part of the initiating and planning phase for the project. These investigations have confirmed that the hoop stress does not exceed 30% of Specified Minimum Yield Stress, and therefore meets operating specifications under AS4645.

675. The project and associated expenditure forecast ($3.2 million) have therefore been removed from the proposed sustaining capital expenditure.

676. A pipeline replacement project (odd size steel) has been postponed from the end of AA3 in to the beginning of AA4 due to conflicting project timeframes with Main Roads intersection upgrade adjacent to Fiona Stanley Hospital. The value of this section of the project is $0.4 million.

8.2.2.7 Summary of AGA amended forecast sustaining capital expenditure

677. AGA has amended its forecast capital expenditure as follows:

- Reduced the costs of the unprotected metallic mains replacement program by deferring 11km of mains replacement ($3.4 million) from AA4 to AA5
- Removed six interdependency projects ($13.3 million) that are no longer assessed as high risk
- Removed the high pressure HP017 pipeline project ($3.2 million)
- Increase of $0.4 million due to the deferral of the Pipeline 63 replacement from AA3 to AA4.

AGA considers that the revised forecast for sustaining capital expenditure including the Two Rocks and Peel Spur lines and the remaining interdependency projects satisfies rule 79 of the NGR.

678. Table 8–14 presents the amended forecast for sustaining capital expenditure.

Table 8–14: Amended proposal sustaining capital expenditure ($ million real at 30 June 2014)

Sustaining capital expenditure	July to Dec. 2014	2015	2016	2017	2018	2019	Total
Revised AAI	17.7	42.0	51.5	64.2	63.3	72.6	311.3
Amended proposal	15.0	37.9	51.1	64.6	61.1	62.1	291.8

8.2.3 Growth capital expenditure

679. The ERA excludes $204.5 million from the forecast growth capital expenditure for AA4. This equates to 90% of forecast growth capital expenditure. The ERA reached this conclusion on the basis of EMCa's view that AGA's NPV analysis is flawed resulting in the investment not passing the incremental revenue test and therefore not meeting rule 79 of the NGR.

680. The EMCa report raised concerns in regards to:

- The NPV analysis conducted by AGA and the underlying assumptions
- The scope and generic nature of the expenditure for greenfields customer initiated capital

AGA considers that EMCa has erred in its assessment of the NPV analysis undertaken and that all of the proposed growth capital expenditure meets rule 79 of the NGR.

As a privately owned business, AGA is required to secure funding for investment from banks (via the ATCO Group of companies). A lower price and no provision for finance costs for this investment would make any further connections non-commercial and constrained by an inability to secure funds. Should the ERA continue to rely on EMCa's assessment of the NPV analysis, and therefore disallow the proposed growth investment, AGA will not be in a position to provide any new connections in the AA4 period above those included in the final decision's capital expenditure forecast.

681. Energy*Safety* has also advised AGA that it is concerned that a large portion of the 90,000 homeowners that would otherwise connect to the natural gas network may instead choose bottled LPG as an alternative energy source in their homes.[182] Energy*Safety* believes that there are inherent safety concerns associated with the use of LPG bottles at the home, and that this community safety impact should be considered when

[182] Confidential Appendix 8.1 Correspondence from Energy Safety November 2014.

any economic assessment of greenfield growth expenditure is undertaken[183]. AGA urges the ERA to seek advice from Energy*Safety* in relation to community safety issues arising from a decision to disallow greenfields growth in the Final Decision.

682. EMCa's concerns about AGA's NPV analysis and greenfield growth investment are addressed in the following sections.

8.2.3.1 NPV Analysis

683. EMCa considers AGA should have detailed business cases for all of its growth projects during the regulatory period and that each individual project should demonstrate a positive NPV, including traditional supporting projects such as reinforcements and regulator sets.

684. AGA undertook an NPV assessment of its overall growth capital expenditure program to demonstrate compliance with rule 79 of the NGR as it did during the AA3 review process. It is standard practice for a regulated business to do this to demonstrate the economic value of the investment as provided for under rule 79(2)(a) of the NGR and the incremental revenue required under rule 79(2)(b) of the NGR. This approach accommodates situations where a business may not have sufficiently progressed, or have sufficient detail to assess each individual project. It also accounts for the likelihood that there may be some programs of work that on their own do not provide sufficient incremental revenue, but contribute to the services to be provided and the revenue to be received from the broader customer base, and in particular, growth in the customer base.

685. An additional consideration for AGA is the application of postage stamp pricing obligations. Even if AGA wished to price new growth investment sufficiently high to cover all costs the Regulations prevent AGA from doing so. This obligation is a relevant consideration in the assessment of proposed expenditure.

686. EMCa identified key concerns relating to the assumptions upon which AGA's NPV analysis was based, being:

- That the average consumption of new customers should be used rather than the average consumption of all customers
- That prices should be assumed to rise only by the inflation rate.

Average consumption of new customers

687. EMCa states:

> 688. *In the face of clear evidence that new customers are using considerably less gas than pre-existing customers, it is not, in our view, valid to assume the levels of additional consumption (and by extension additional revenue) that ATCO has used in its NPV analysis (i.e. the consumption estimate contravenes the principles in rule 74(2)).*[184]

689. EMCa's adjustment considered the annual consumption of new customers, which it states is 3.5 gigajoules per annum lower than AGA has assumed. Adopting the findings of EMCa, the ERA adopted 80 GJ for the annual average usage for new B2 customers and 12 GJ for new B3 customers.[185]

690. AGA accepts that the NPV analysis should reflect the average consumption of new customers rather than the average consumption of the existing customer base and NPV analysis has been updated to incorporate

183 Energy*Safety* Draft Decision submission (greenfields connections) 26 November 2014 http://www.erawa.com.au/gas/gas-access/mid-west-and-south-west-gas-distribution-system/access-arrangements/proposed-access-arrangement-for-period-2014-2019

184 EMCa, Review of Technical Aspects of the Proposed Access Arrangement, June 2014, paragraph 410.

185 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 119.

this. However, AGA does not agree with the annual average consumption estimates provided by EMCa and relied upon by the ERA in its Draft Decision.

691. AGA disagrees with the use of a flat rate of 12 GJ for the average consumption for new B3 customers across AA4 for the following reasons:

- The ERA has adopted EMCa's proposal to base the NPV analysis on the average use of customers connecting in 2011 and in 2012 during their first and second year of consumption. AGA considers this considerably underestimates the steady state consumption for new customers, which history has shown does not occur until the third year post connection (see Table 8-15 below). Core has observed that *the ERA approach relies on the observation of gas consumption in a first year of connection for a new customer, which is not representative of the average mature consumption for a new connection. Consumption is lower in the first year of a new connection than subsequent years*.[186]
- The ERA forecast relies on an assumption that average usage per customer for existing B2 and B3 customers will be constant as of 2014, which in Core's opinion, is not a basis for deriving the best forecast available under the circumstances relating to the AGDS. Use of a constant usage number is inconsistent with the trends in demand observed historically, and has not been justified by reference to specific analysis.[187]
- EMCa considered a 3.5GJ downward adjustment to average annual B3 consumption was required to reflect the lower levels of consumption by new customers to be connected during the regulatory period. While new customers on average do consume less than existing customers, a more appropriate reduction to average annual B3 consumption is 1.098 GJ to reflect the 6 star energy rating for new homes as shown in Table 6.10 of the Core Energy Gas Demand Forecast report.[188]

The estimates relied upon by the EMCa were also not weather adjusted. Winters in the last four years have been warmer than average.[189] Therefore, in the absence of weather adjusting the underlying data, the estimate is likely to underestimate forecast average consumption (also discussed in Chapter 4 – Demand Forecast) and therefore do not meet the requirements of rule 74(2) of the NGR.

Zincara reviewed ATCO's greenfields B3 consumption forecast and related NPV analysis and states that *it is Zincara's opinion that ATCO's AAI assumption to apply average consumption of network customers rather than forecast based on newer customer connections results in the forecast being overstated and as such does not satisfy rule 74.*

However, Zincara has also reviewed ATCO's draft response to ERA, whereby ATCO has accepted that the average consumption of new customers is the relevant consumption for assessing the NPV for growth investment and has developed updated modelling to assess consumption, connection numbers and incremental revenue enabling an improved accuracy for the forecast and the NPV analysis. On this basis Zincara believes that this approach and assumptions satisfy 79(1) and 74.[190]

AGA considers that the appropriate revised average consumption for new B3 customers is 13.58GJ for 2014, moving to 13.06GJ in 2019. This reflects the information adopted by Core Energy in its 2014 forecast demand report, as shown in Table 8–15 below and has been used as an underlying assumption for the revised NPV analysis referred to in Section 8.2.3.2.

186 Appendix 4.2 Expert Witness Report on the Authority's Adjusted Demand Forecast, Paul Taliangis, Core Energy Group opinion dated 25 November 2014, section 5.1.4.

187 Appendix 4.2 Expert Witness Report on the Authority's Adjusted Demand Forecast, Paul Taliangis, Core Energy Group opinion dated 25 November 2014, section 1.2.

188 Appendix 4.1 Gas Demand Forecast, Mid-West and South-West Distribution System Core Energy Group November 2014, page 51.

189 Appendix 4.1 Gas Demand Forecast, Mid-West and South-West Distribution System Core Energy Group November 2014, page 42, Table 6.3.

190 Appendix 6.3 Review of ATCO Gas Australia Capital and Operating Expenditure, Zincara, November 2014, Section 5.3.4.1.

Table 8–15: CORE Energy Forecasts[191]

	2014	2015	2016	2017	2018	2019
B3 – average consumption	14.67	14.45	14.32	14.25	14.21	14.16
B3 – adjustment for new connection	-1.10	-1.10	-1.10	-1.10	-1.10	-1.10
B3 – average new consumption	13.58	13.35	13.22	13.15	13.11	13.06

692. Core utilises extensive quantitative and qualitative analysis to support its forecast. Their use of a historical data series and regression analysis to derive a statistical trend, augmented by quantitative and qualitative analysis to derive estimates of future deviations from an observable historical trend, is widely accepted as a prudent and reasonable approach to developing demand forecasts.[192]

693. The Core Energy forecasts, which AGA has used as the basis for its revised NPV analysis, are broadly aligned to the average weather adjusted consumption levels AGA has experienced for new B3 customers, in their third year of connection which is approaching steady state consumption levels, as shown in Table 8–16 below.

694. Zincara's opinion confirms that Using the first year of connection does not allow for customers connecting at various times during the year. Even using the second year data is questionable as there may not be critical mass to wash the effect of connection timing. *Effectively the third year would give a more realistic figure*[193]

Table 8–16: Actual consumption by new B3 connections

Actual	**2009**	**2010**	**2011**	**2012**	**2013**
B3 customer connected in 2009	5.13	13.55	13.22	14.16	14.32
B3 customer connected in 2010		4.68	11.75	13.55	13.88
B3 customer connected in 2011			3.88	11.38	12.37
B3 customer connected in 2012				4.21	11.62
Weather adjusted	**2009**	**2010**	**2011**	**2012**	**2013**
B3 customer connected in 2009	5.11	13.45	13.62	14.33	14.59
B3 customer connected in 2010		4.65	12.10	13.72	14.13
B3 customer connected in 2011			4.00	11.51	12.60
B3 customer connected in 2012				4.26	11.84
Variance	**2009**	**2010**	**2011**	**2012**	**2013**
B3 customer connected in 2009	0.02	0.10	0.40	0.17	0.26
B3 customer connected in 2010		0.04	0.35	0.17	0.26
B3 customer connected in 2011			0.12	0.14	0.23
B3 customer connected in 2012				0.05	0.21

191 Appendix 4.1 Gas Demand Forecast, Mid-West and South-West Distribution System Core Energy Group November 2014, page 51.

192 Appendix 4.2 Expert Witness Report on the Authority's Adjusted Demand Forecast, Paul Taliangis, Core Energy Group opinion dated 25 November 2014, section 5.1.1.

193 Appendix 6.3 Zincara, Review of ATCO Gas Australia Capital and Operating Expenditure, November 2014, Section 5.3.4.1.

695. The figure below shows how the average consumption of new customers changes over time and compares the weather adjusted historical consumption with the proposed forecast average consumption for new customers under the ERA and AGA's methods.

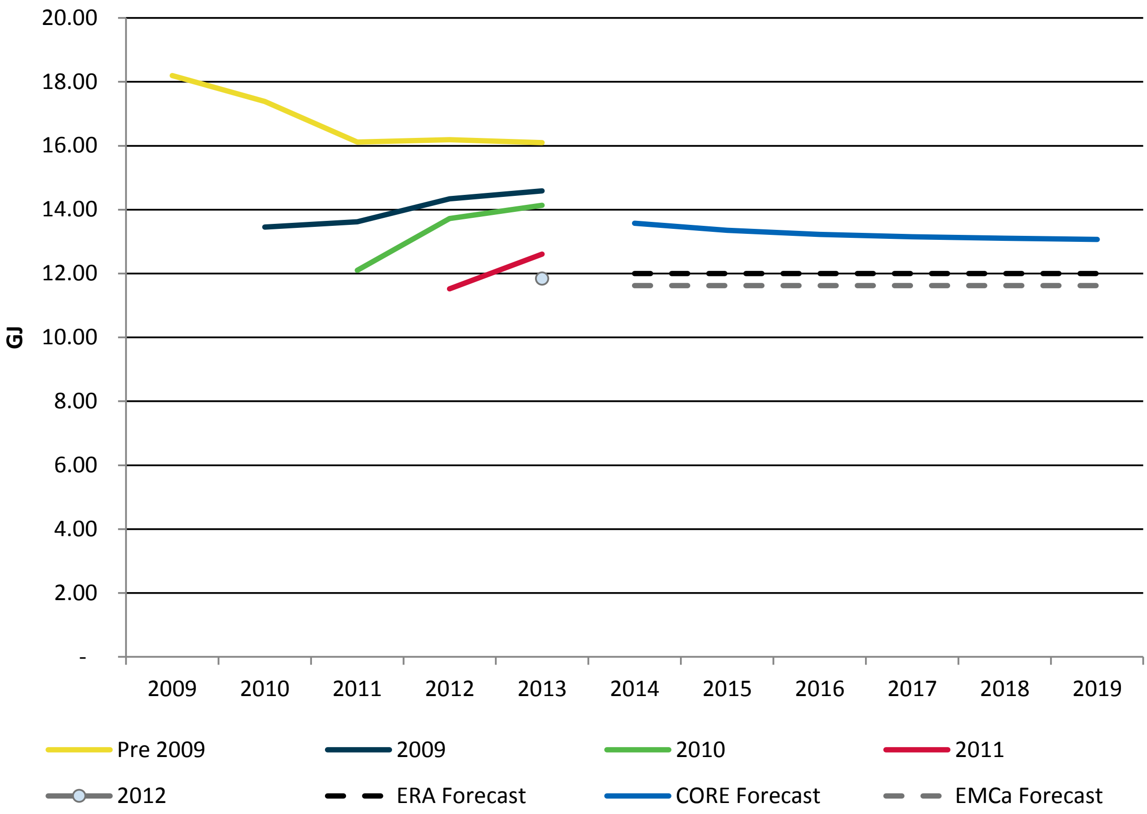

Figure 8–8: Weather adjusted average consumption for B3 customers

696. The ERA's estimate for the average consumption for B2 customers is 80GJ. This is broadly consistent with the historical average consumption of new B2 customers in the third year after connection as shown in Table 8–17 below.

Table 8–17: Average annual consumption for new B2 customers

Actual	2009	2010	2011	2012	2013
B2 customer connected in 2009	35.99	80.23	79.46	79.36	79.90
B2 customer connected in 2010		28.10	66.57	75.21	80.42
B2 customer connected in 2011			36.78	73.76	78.88
B2 customer connected in 2012				22.60	55.07
Weather adjusted	**2009**	**2010**	**2011**	**2012**	**2013**
B2 customer connected in 2009	35.85	79.62	81.85	80.33	81.39
B2 customer connected in 2010		27.89	68.56	76.13	81.91
B2 customer connected in 2011			37.88	74.67	80.34
B2 customer connected in 2012				22.88	56.08
Variance between actual and weather adjusted	**2009**	**2010**	**2011**	**2012**	**2013**
B2 customer connected in 2009	0.13	0.61	2.38	0.97	1.48
B2 customer connected in 2010		0.21	2.00	0.92	1.49

Actual	2009	2010	2011	2012	2013
B2 customer connected in 2011			1.10	0.90	1.46
B2 customer connected in 2012				0.28	1.02

697. In 2015, AGA is introducing the AL10 meter to reduce connections costs for end users and AGA, who previously would have been connected with an AL12 meter. The introduction of the AL10 meter will in effect reclassify almost 50% of new customers, who would previously have been considered B2 customers with low consumption (average 40GJ) to B3 customers.

698. This will reduce new B2 connections by an estimated 250 annually from 2015, which represents between 40% and 50% of new B2 connections.

699. These AL10 connections use significantly less gas than B2 connections. This means that the average use for the new B2 customers moving forward will increase, in line with the Core Energy forecast shown in Table 8–18. The average use for B3 customers will increase due to the reclassification, but the impact is negligible due to the volume of B3 customers.

Table 8–18: Average annual consumption for new B2 customers[194]

Average consumption	2014	2015	2016	2017	2018	2019
B2 – new connections	124GJ	119GJ	114GJ	111GJ	108GJ	106GJ

Appropriate prices to be used in the NPV analysis

700. AGA considers the price to be used in undertaking analysis under rule 79 of the NGR may differ depending on whether the analysis is to be undertaken under rule 79 (2)(a) or 79(2)(b) of the NGR. Rule 79(2)(a) of the NGR requires the overall economic value of the expenditure to be positive, whereas rule 79(2)(b) of the NGR requires the incremental revenue to be greater than the incremental cost.

701. The economic purpose of the NPV assessment applied, which considers whether incremental revenues exceed incremental costs, is to ascertain whether it is likely that the revenue that is expected from customers of the relevant services will exceed the capital costs of the project. Where this is the case it can be implied that customers value the service more than its costs.

702. In this context, the relevant question is whether it is more appropriate for the proposed capital expenditure to be included or excluded from the tariffs used for estimating incremental revenues.

703. If the relevant growth projects were to actually proceed the regulatory framework would provide that customers pay tariffs that include the associated capital costs. This is necessary in order to ensure that AGA can expect to earn a return on investment and so prices for customers include all the costs of supply and promotes efficient consumption.

704. In AGA's initial proposal, the tariff path increased each year. AGA maintains the view that it is appropriate when undertaking an assessment under rule 79(2)(b) of the NGR (the incremental revenue test) to adopt the prices that will actually apply during the period. However, when undertaking an economic value test under rule 79(2)(a) of the NGR the price adopted in an NPV analysis should reflect the value to the customer of the service. This could be sought by undertaking a willingness to pay study. For an economic value test, the price customers would be willing to pay is at least the price they are currently paying.

705. Under AGA's amended proposal, prices to customers will reduce over the regulatory period by on average 1.8 per cent in each year. AGA has undertaken NPV analysis using both current tariffs and amended

194 Appendix 4.1 Gas Demand Forecast, Mid-West and South-West Distribution System Core Energy Group November 2014, page 42 and 68.

proposed tariffs and undertaken sensitivity analysis on assumptions relating to average use and tariff reductions. In order to address EMCa's concerns regarding sensitivity of the NPV assessment, AGA has completed a sensitivity test of the overall growth program of work, which modelled new customer connections at the lower usage rate of 12GJ, as suggested by the ERA in its Draft Decision. All other things being equal, a positive NPV was achieved after 34 years, which AGA considers reasonable, and conforms to rule 79 (2)(b) of the NGR.

706. The results of the NPV analysis are presented in Table 8–19 below.

Table 8–19: NPV analysis

NPV analysis	NPV positive	NPV at end of 30 years	NPV at end of 40 years
Incremental revenue test (average use of B3 customer 13.25 GJ)	31 years	-$2.6m	$18.7m
Incremental revenue test (average use of B3 customer 12 GJ)	34 years	-$9.7m	$10.9m
Incremental revenue test (average use of B2 customer 20% lower)	32 years	-$4.6m	$16.6m
Incremental revenue test (average use of B2 12GJ and B3 customers 20% lower)	35 years	-$11.6m	$8.7m
Incremental revenue test (reduced decline in tariffs – higher tariffs than the amended proposal)	30 years	$2.7m	$26.0m

707. Although the ERA has not referred to the time period over which the NPV analysis is undertaken in its Draft Decision, EMCa considered a small positive NPV over a 30 year period is not sufficiently robust justification to support the inclusion of growth investment in the capital base. AGA considers it appropriate to consider economic value over the economic life of the primary assets utilised to achieve that value, and that 30 years is a conservative estimation for assets that can have an economic life of up to 80 years and on average 38 years. In any event, the alternative would be to not undertake investment that delivers benefits to customers.

708. Table 8–20 shows the economic life of assets, as identified in Table 78 of the March 2014 AAI. The growth capex is primarily an investment in medium pressure mains, regulators and meters and services, which have a useful life of 60, 40 and 25 years respectively.

Table 8–20: Useful life of assets

Regulated depreciation rates	
Asset	Useful Life
High pressure mains	80
PE high pressure mains	60
Medium Pressure mains	60
Medium low pressure mains	60
Low pressure mains	60
Gate stations	40
Regulators	40
Meter & Services	25
Equipment & vehicles	10
Building	40
IT Assets	5

709. For NPV assessments, AGA assumes all new services will be reference services at the reference tariff. Under the National Gas Access (WA) (local Provisions) Regulations 2009, AGA is unable to charge new reference service customers a different reference tariff to existing customers on the same reference tariff.

710. As can be seen from the analysis, a lower tariff delivers a lower NPV. To the extent that the tariff falls further than that proposed by AGA, the NPV will deteriorate. However, this does not mean that new customers would not be willing to connect at a higher tariff. For those customers, access to gas supply will no longer be available despite those customers placing a higher value on the service than the regulated reference tariff. This results in a loss of economic efficiency.

711. In these circumstances customers that value access to gas would have to pay the full cost of the connection through a surcharge or capital contribution. AGA notes however, that in this circumstance AGA receives no benefit from the new connection as the investment is not added to the capital base. Further, under the ERA's proposed treatment of tax on capital contributions, AGA would also need to recover the tax liability associated with the receipt of the revenue – whether it be through a capital contribution or surcharge. This further increases the costs to new customers. The result is not only new customers paying significantly more for gas (and likely more than they value it), but existing customers would also pay more over the longer term as any benefits of new connections are not available.

712. In the event that the ERA maintains its approach to growth investment in the Final Decision, there is no commercial benefit of AGA expanding the network and the provision of gas services will be constrained to existing customers and those customers that live within 20 metres of the network. Any future provision of service would only occur as a result of a new obligation to provide the service to an extended are or a direct government subsidy. This would seem to be a perverse (and inefficient) outcome and against AGA's objectives of growing the network to reduce prices to customers over the longer term. This outcome is also inconsistent with current government policy settings to reduce unnecessary regulations, encourage private investment, diversity in energy supply and reduce the $600 million per year currently paid by Western Australian's to electricity customers.

8.2.3.2 NPV of projects and programs

713. EMCa has stated that AGA's governance framework *is generally sound and in keeping with what we would expect a prudent service provider acting efficiently and in accordance with good industry practice to employ*[195]. All projects that are assessed individually progress through a project lifecycle which requires formal documentation, review and approval as it is assessed for progress from one stage in the project lifecycle to the next. The assessment of an NPV for individual projects takes place in the business case phase.

714. AGA's governance framework is reproduced below in Figure 8–9.

[195] EMCa, Review of Technical Aspects of the Proposed Access Arrangement, June 2014, paragraph 296.

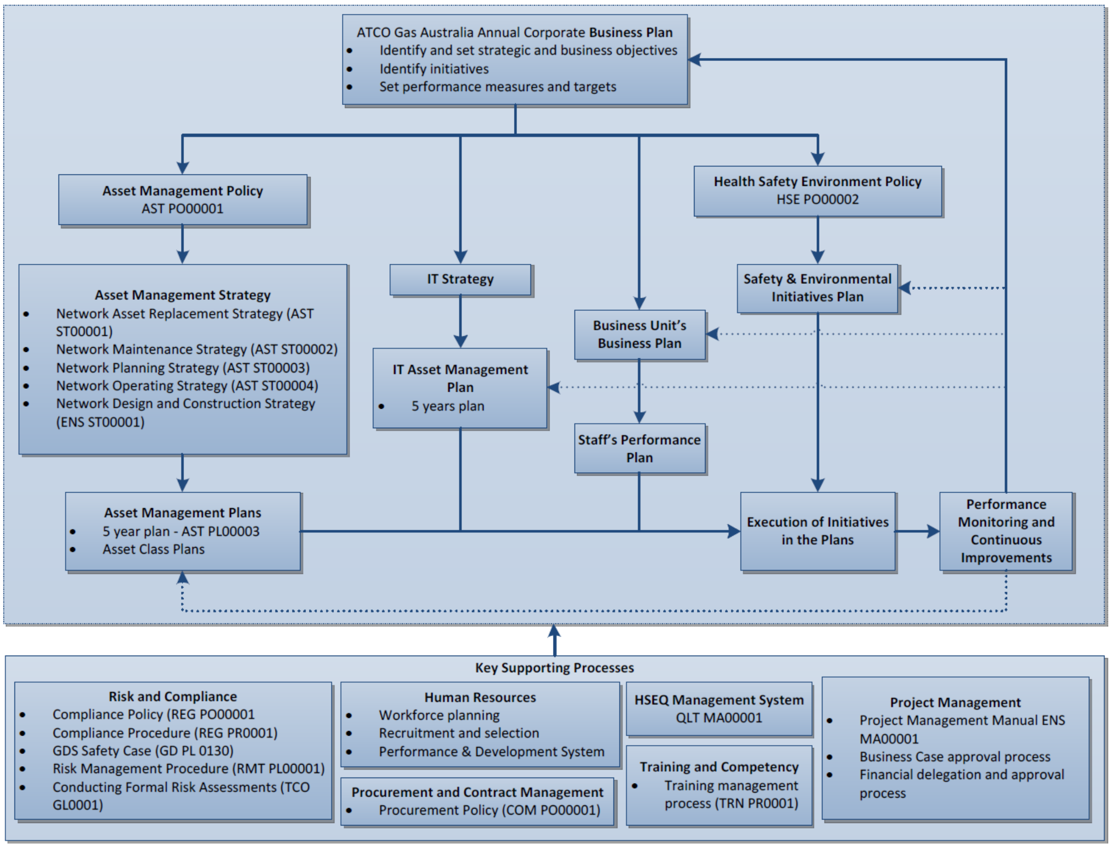

Figure 8–9: AGA Annual Corporate Business Plan

715. All individual projects discussed by the ERA are still in the initiation, planning and design phase as the planned execution of these projects (identified in Table 8–12: Two Rocks and Peel spur lines loss of supply consequences ($ million real at 30 June)Table 8–12) is not until 2016 through to 2019.

716. The governance framework requires that the projected projects align with the Asset Management Plan which includes an assessment of the demand scenarios, which might eventuate in an investment requirement. For significant projects, a feasibility study or project charter may also exist.

717. A full cost benefit analysis or NPV is only prepared once a project has progressed to the business case stage, where depending on the estimated cost of the project, either a CEAR (Capital Expenditure Approval Request) or a CEAR plus a fully detailed business case must be developed before any further investment consideration is made. As stated in the Project Management Manual (previously provided), *the purpose of developing the business case is to achieve financial approval to proceed with the project*.[196] In order for a project to proceed to the implementing phase, a business case must have been approved and/or a CEAR approved for the project.

718. AGA has completed a preliminary NPV analysis for the majority of the individual projects and programs of work identified by the ERA in its draft decision, namely greenfield development, the spur lines and the Capel to Busselton reinforcement. The capital expenditure required to deliver brownfields development has not been subject to an NPV analysis as AGA has an obligation to offer to connect customers that are within 20 metres of an existing gas main.

719. The forecast growth capital expenditure for these projects and programs along with the NPV outcomes are presented in Table 8–21

[196] ATCO Gas Australia's, Project Management Manual, section 5.2.20, page 41.

Table 8–21: Growth capital expenditure forecast ($ million real at 30 June 2014)

Growth capital expenditure	Jul to Dec 2014	2015	2016	2017	2018	2019	Growth Total	NPV
Greenfield customer initiated	14.3	28.2	27.0	25.7	24.2	24.4	143.8	49.3
Two Rocks spur line *	-	-	13.6	13.6	-	-	27.2	4.1
Peel spur line *	-	5.4	-	-	6.0	-	11.4	1.2
Baldivis spur line	-	-	-	-	5.4	-	5.4	2.6
Capel to Busselton reinforcement	-	-	-	-	-	5.3	5.3	0.5

720. *The allocation of these two projects to growth capital expenditure has not changed from the AAI submission and based on revised NPV parameters contained in this revised submission they are now returning a positive NPV on the AAI growth allocation. Refer to table 8-12 for standalone cost allocation method NPV analysis.

8.2.3.3 Greenfield customer initiated development

721. The ERA has said:

> 722. *ATCO has not provided any evidence that the large and relatively generic expansion initiative of greenfield customer initiated capital expenditure satisfies the incremental revenue test.*[197]

723. AGA submits that the proposed greenfield capital investment for the AA4 period is based on

- A sound forecast of connections and volume
- A competitive unit rate cost
- A targeted profile of locations and schedule

724. The greenfield program was arrived at on a reasonable basis and represented the best forecast possible in the circumstances, and is supported by the ECS independent expert report. AGA considers the greenfield program satisfies the incremental revenue test by returning a positive NPV of $49.3 million.

725. Zincara's report states *Zincara has also reviewed ATCO's approach and assumptions outlined in the draft response to ERA, specifically sections titled Greenfield development, Proposed greenfield's activity – locations and Timing and Amended NPV analysis for greenfields. In Zincara's opinion these form a reasonable basis for the forecasts and with a positive NPV, complies with rules 74, 79(1)(b) and 79(2)*.[198]

726. AGA has reviewed its greenfield investment proposal and adjusting its forecast in this revised proposal to reflect the revised customer connection forecast for the AA4 period (see Chapter 4 –Demand Forecast).

727. The following sections provide evidence to support the revised greenfield investment proposal and its inclusion in the AA4 projected capital base.

[197] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 471.

[198] Appendix 6.3 Zincara, Review of ATCO Gas Australia Capital and Operating Expenditure, November 2014, Section 5.3.4.1.

728. AGA's proposed greenfield investment in AA4 reflects the Department of Planning's *Directions 2031* plan, which identifies development of suburban infill areas as well as the continued expansion to more outlying areas of the greater Perth Metropolitan areas.[199]

729. Figure 8–10 shows the targeted areas, highlighted in red, for the greenfields activity in AA4.

[199] ATCO Gas Australia's Asset Management Plan, page 40.

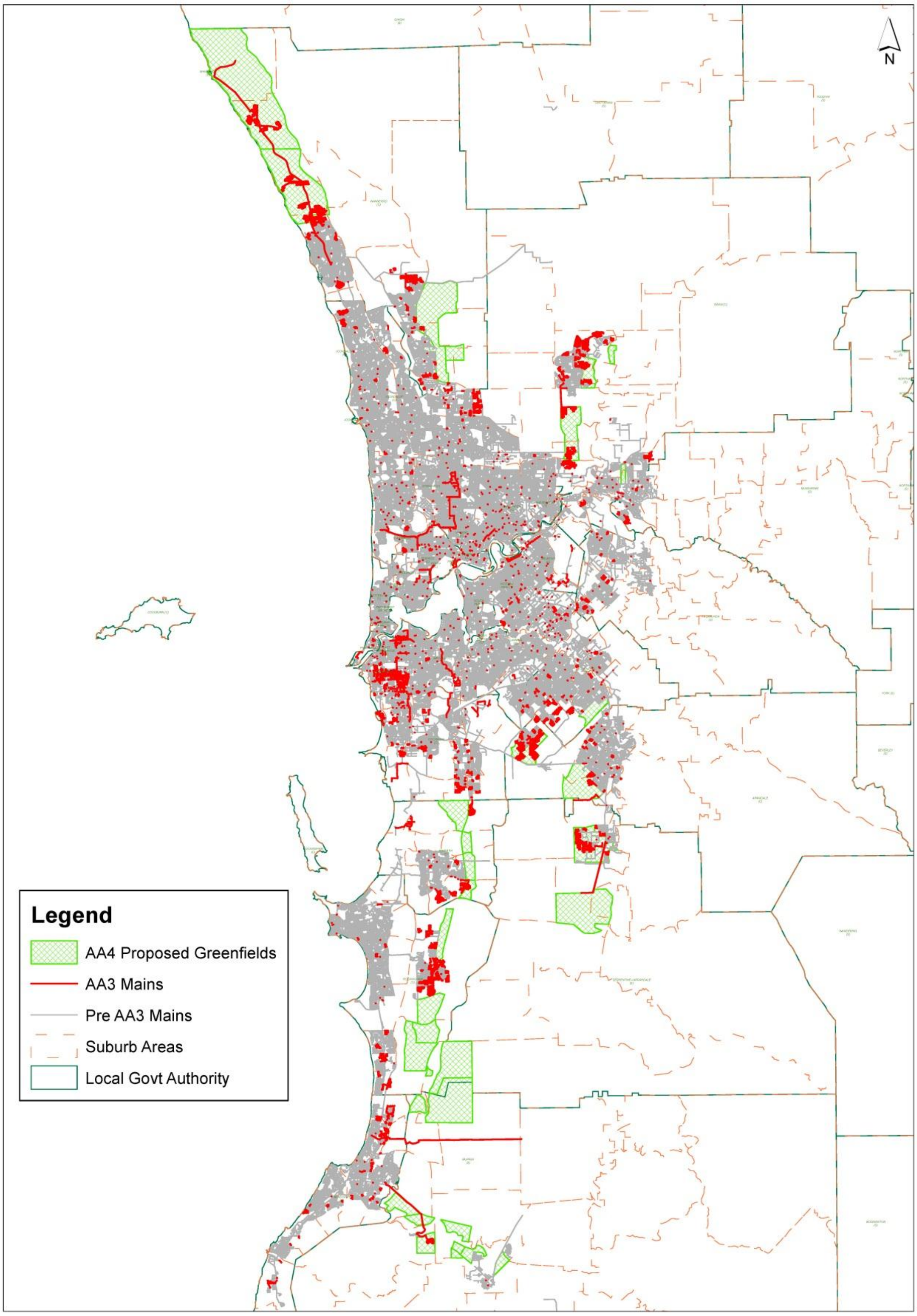

Figure 8–10: AA4 greenfield areas

730. The forecast expenditure associated with greenfields investment is based on the market tested unit rates secured by AGA for the next three years, following the recent competitive tender finalised in January 2014.

731. This process resulted in new contracting arrangements, incorporating key performance indicators and a performance incentive mechanism to enhance safety, productivity and encourage continuous improvement. A schedule of rates and services has been developed, which AGA uses to monitor service

quality and efficiency and ensure lowest sustainable cost of service. The tender process provided the opportunity to benchmark contracting companies in respect of their rates, their approach to safety and gas utility operations.

732. As noted in the EMCa report, *All purchasing decisions for capital expenditure are made in accordance with ATCO's Procurement Policy. The principles, processes, scope and required actions are all consistent with good industry practice.*[200]

733. Experience shows that the optimum time to construct assets to connect greenfields developments is when common trenches can be utilised due to significant lower cost per unit. Unit rates for open trench gas mains extensions are on average 59% lower than the equivalent gas main extension in any other scenario, with variances dependent upon the size of pipe in question. Further, new developments usually deliver higher connection rates. The higher connection rate results from homes being designed and built with natural gas appliances in mind.

734. Recently established (and near completion) suburbs that were reticulated as greenfields, such as Carramar, Butler and Aubin Grove, have penetration rates in excess of 85%. Experience shows that even targeted efforts to reticulate areas once developed are significantly less effective. Efforts by State Energy Commission of Western Australia to increase penetration in established locations such as Geraldton and Falcon achieved only approximately 35% penetration. Penetration rates have only increased in these suburbs where more recent greenfields developments have been established and reticulated, within their boundaries. The unit cost of connecting brownfield houses is also significantly higher, with higher installation mains costs and higher reinstatement costs.

200 EMCa, Review of Technical Aspects of the Proposed Access Arrangement, June 2014, paragraph 103.

When comparing the NPV impact of the proposed AA4 greenfield investment being constructed as a brownfields program instead, the NPV is negative $94.3 million on $199.2 million of investment (real). All NPV underlying assumptions reflect those detailed in the greenfield NPV analysis listed below, with the exception of the capital cost of a forecast pipe installation in an open versus closed trench, with associated reinstatement costs.

New connections

AGA has updated its greenfield expenditure proposal to reflect the new connection forecast updated by ECS, which incorporates the most recent housing industry forecast, current as at June 2014.[201] The revisions to the housing industry forecast are shown in Figure 8–11: HIA house starts

The HIA house start forecast and historical start rates (which is considered a lead indicator for demand for greenfield connection levels) shows that the forecast activity is aligned with historical actuals[202].

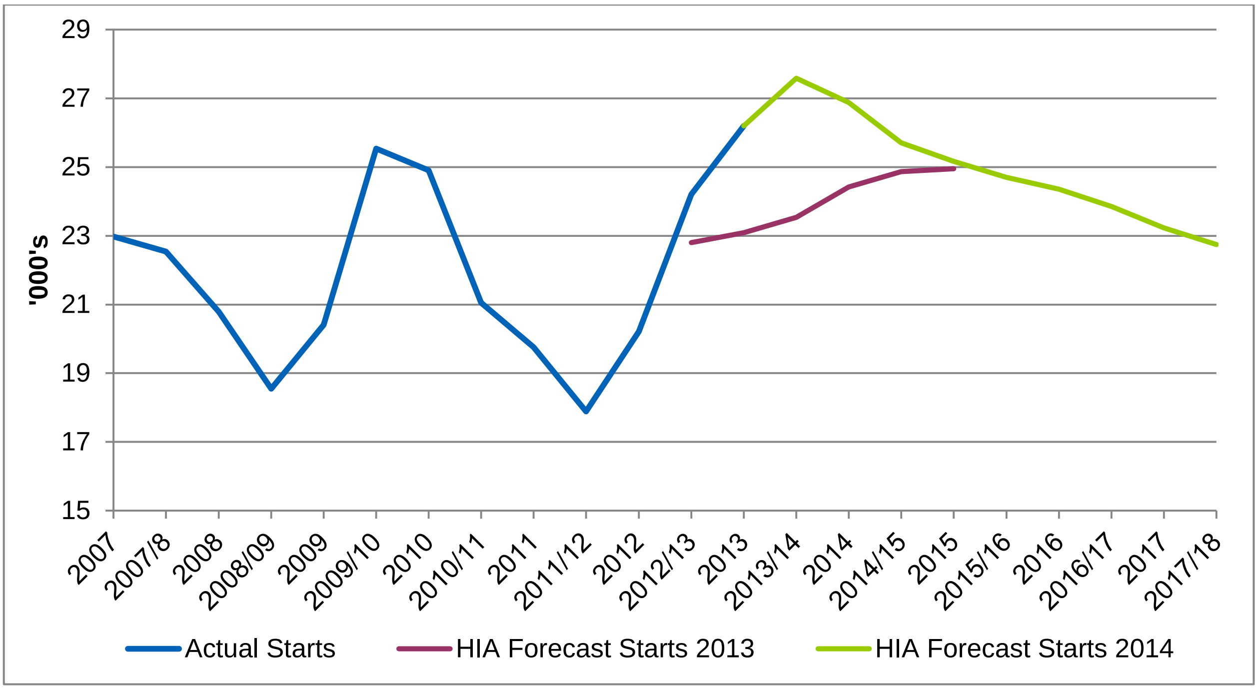

Figure 8–11: HIA house starts

735. AGA has also updated its greenfield connection forecast to reflect its amended business development and marketing expenditure. Revised business development and marketing activity focuses on brownfield development initiatives. As shown in Figure 8–12 below, the 5,583 additional greenfield connections initially forecast as a result of business development and marketing activities are no longer added to the greenfield connection forecast. For further information on the business development and marketing initiatives and campaigns and resulting connections, please refer Section 6.4.1.1.

201 ECS, ATCO Gas Australia Connections Forecast, June 2014.

202 HIA Economics Group Housing Forecasts – May 2013, HIA Economics Group Housing Forecasts – May 2014.

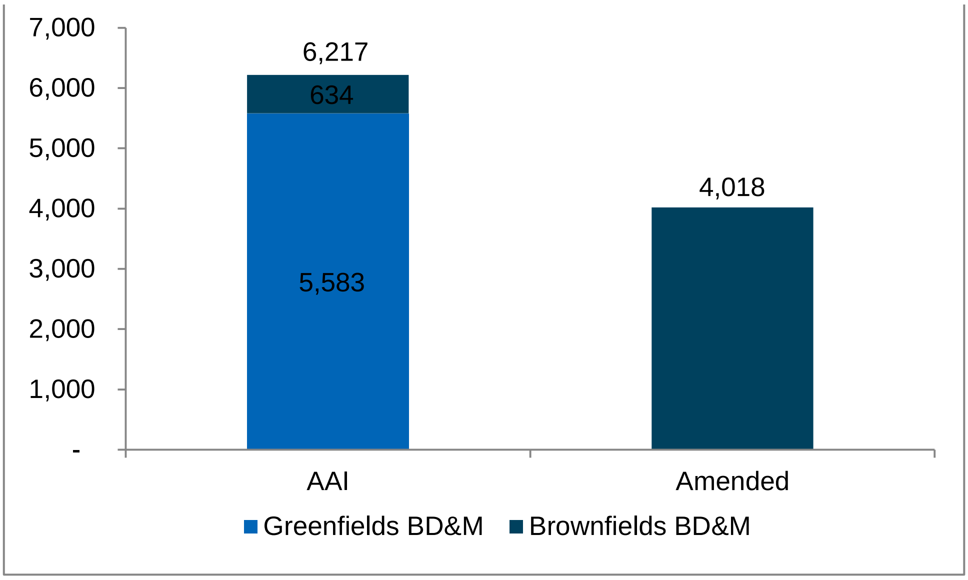

Figure 8–12: Previous and revised BD and marketing related new B3 connections, 2015 to 2019

736. AGA's amended AA4 connection forecast is shown in Figure 8–13.

737.

738.

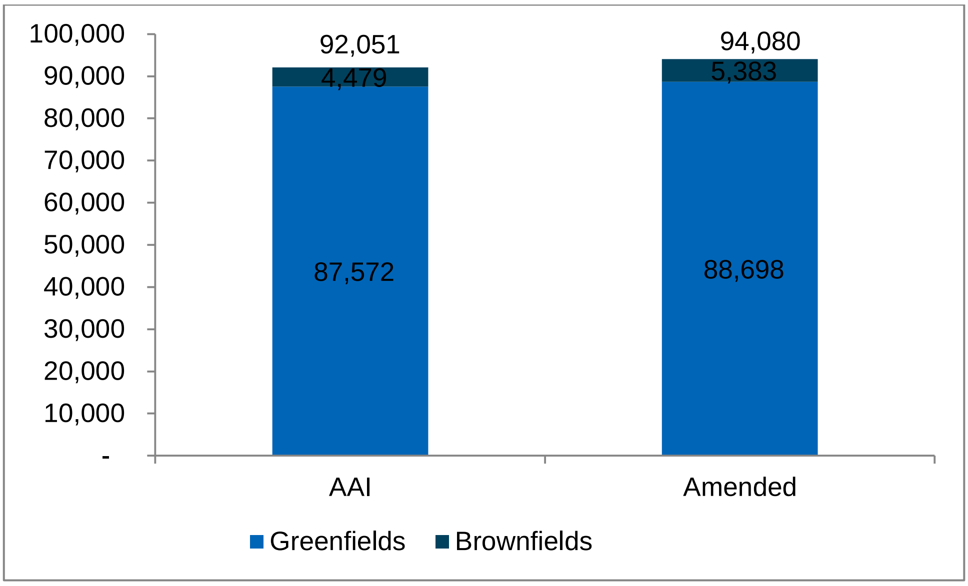

Figure 8–13: Previous and revised new AA4 B3 connections, 2015 to 2019

739. AGA has compared its forecast average annual greenfield connection rate for AA4 of 16,363 to the historical average annual greenfield connection rate over the last five years. As shown in Table 8–22, the average connection rate since 2009 is 17,491, this demonstrates AGA's greenfield connection forecast is reasonable.

Table 8–22: Actual B3 connections 2009-2014

Actual	2009	2010	2011	2012	2013	2014	Average
B3 connections	17,377	19,414	17,212	14,608	17,189	19,148	17,491
B3 greenfields	15,899	18,247	16,228	13,737	16,180	17,885	16,363

8.2.3.4 Demand related expenditure

740. The ERA has said that EMCa is not satisfied that the following proposed demand spur line projects ($38.6 million) meet the incremental revenue test in rule 79(2)(b) of the NGR:

- Two Rocks (60 per cent of cost or $27.2 million);
- Baldivis ($5.4 million); and
- Peel (22 per cent of costs or $6.0 million).

741. According to EMCa, the feasibility studies that ATCO provided for Two Rocks, Baldivis and Peel do not contain a cost benefit analysis. Moreover, the feasibility study for the Peel project contains insufficient information on the underlying assumptions.

742. Relying on EMCa's advice, the ERA is not satisfied that the following proposed reinforcement projects ($19.67 million) are justified under rule 79(2)(b) of the NGR:

- Capel to Busselton ($5.2 million)
- Other reinforcements ($11.5 million of ATCO's proposed $16.2 million)
- Volume related capital expenditure and regulating facilities ($2.9 million)

AGA submits that the proposed demand related capital investment for the Two Rocks and Peel spur line have been conservatively allocated based on a proportion that returns a neutral NPV. AGA has re-assessed the NPV of the demand capital expenditure based on the capital allocation to growth from a standalone method. This analysis returns a positive NPV of $16.1 million for the Two Rocks spur line and a positive NPV of $5.3 million for Peel spur line, therefore, the growth element of these projects satisfy rule 79(2)(b) of the NGR.

AGA submits that the reinforcement projects are required to provide sufficient network capacity to enable AGA to comply with its Licence obligation to offer to connect customers that are within 20 metres of an existing gas main. On this basis the forecast expenditure is required and conforms to rule 79(2)(c)(ii) and (iii) of the NGR.

743. Zincara has conducted a full review of the Two Rocks and Peel spur lines as detailed in the Sustaining Capital section above and has conducted a preliminary review of the remaining Demand related projects and commented *ATCO's draft response to the ERA provides a cohesive and reasoned justification for the demand projects. Whilst Zincara has only seen a draft response due to time constraints, Zincara considers the draft response has more robust justifications to comply with rule 79(1) and 79(2)*.[203]

Two Rocks and Peel spur lines

744. Two Rocks and Peel spur line projects have been assessed as both security of supply (within sustaining capex) and growth projects. Consistent with the AAI, the allocation of expenditure to the growth category has been based on the amount of expenditure that delivers a neutral NPV. AGA remains of the view that this is a conservative approach to categorising expenditure between sustaining and growth categories.

745. Nevertheless, AGA has re-assessed the NPV of the capital expenditure based on the capital allocation to growth based on the standalone method outlined in Table 8–12. This analysis returns a positive NPV of $16.1 million for the Two Rocks spur line and a positive NPV of $5.3 million for Peel spur line, therefore, the growth element of these projects satisfy rule 79(2)(b) of the NGR.

[203] Appendix 6.3 Review of ATCO Gas Australia Capital and Operating Expenditure, Zincara, November 2014, Section 7.

746. Zincara has reviewed these two spur lines and found that *In relation to ATCO sharing the cost between demand for greenfields development and sustaining capex for this project, Zincara considers that this approach to be reasonable and practical. The alternative is to have separate pipelines for each requirement which is impractical and also the costs of separate pipelines would exceed that of sharing the costs between the two requirements as discussed in ATCO's draft response to the ERA*.[204]

Baldivis spur line

747. The Baldivis South-Keralup region is located approximately 4 kilometres east of AGA's High Pressure network in Rockingham. The population of this region is forecast to increase to more than 63,000 as outlined by the Department of Planning in Directions 2031.

748. To facilitate timely and efficient expansion of the network, AGA proposes the construction of a high pressure steel pipeline in 2018 at a cost of $5.4 million, which will support the anticipated growth. The pipeline will provide the ability to grow the network efficiently.

749. The timing of the project will be coordinated such that it is constructed prior to the development of the area, when it is most cost effective, ensuring that common utility corridors can be used and that provisions and pipeline alignments are considered as the area develops.

750. An NPV of the total expenditure on this project is positive $2.6 million and therefore conforms to rule 79 2(b) of the NGR.

Capel to Busselton reinforcement

751. In the Draft Decision, the ERA states:

> *ATCO has sought to justify the Capel to Busselton project on integrity grounds. EMCa considers that the project description in the access arrangement information suggests that the project is required to maintain pressure to connect new customers, rather than existing customers. Therefore, EMCa's view is that this project should be assessed using the incremental revenue test in rule 79(2)(b) of the NGR, rather than the service integrity test under rule 79(2)(c)(ii). ATCO has not provided any feasibility study or cost benefit analysis for this project. Therefore EMCa is not satisfied that this project meets the incremental revenue test in rule 79(2)(b) of the NGR.*

752. AGA maintains this project should be assessed by the service integrity test under rule 79(2)(c)(ii) of the NGR and not assessed under the incremental revenue test under rule 79(2)(b) of the NGR because of AGA's obligation to connect customers within 20 metres of the network. This project does not yet require a feasibility study, per AGA's governance framework, as it is still in the initial planning and design stages.

753. This required reinforcement was identified through the annual hydraulic modelling of the gas network, which is part of the annual Asset Management Plan development process. The requirement was identified using standard SynerGEE software and the forecast of gas consumption over the five year period AA4. Currently, the Capel to Busselton pipeline supplies gas to 6,244 domestic customers and without the proposed high pressure reinforcement project the High Pressure Regulator in Busselton will not have sufficient pressure and capacity to support new brownfields connections and maintain gas supplies to the area. If this project were not to proceed, AGA will not be able to comply with its Licence obligation to offer to connect customers that are within 20 metres of an existing gas main.

754. The pipeline has been designed to accommodate forecast greenfield and brownfield demand due to the relatively small incremental additional cost this will require. The incremental cost, which is due to increasing the pipe diameter is $0.5 million (or 10% of total project value). The brownfield growth for Busselton is 3.9% per year, equivalent to 1,300 customers over 5 years.

[204] Appendix 6.3 Review of ATCO Gas Australia Capital and Operating Expenditure, Zincara, November 2014, Section 5.2.2.2.

755. The NPV of the total expenditure on this project is $0.2 million and therefore conforms with rule 79 2(b) of the NGR but in any case is required to enable AGA to meet its regulatory obligation to offer to connect any service that is on line of a gas main with up to 20 metres of service line and therefore conforms to rule 79 2(c) (iii) of the NGR.

Brownfields development

756. AGA proposed $10.1 million of brownfields investment in AA4.[205] The ERA has said that it is satisfied that $9.0 million for brownfield customer initiated capital expenditure is justified under NGR 79(2)(c)(iii)[206]. The Draft Decision provides no explanation of the variance between the proposed $10.1 million and the approved $9.0 million. In an email dated November 6, the ERA confirmed that it is …*satisfied that $10.09 million for brownfield customer initiated capital expenditure is justified under rule 79(2)(c)(iii) of the NGR not $9.02m as stated in paragraph 472*.

757. Since the AAI submission, there has been an increase in brownfields forecast due to the change in business development and marketing initiatives (increase of 3,580 connections) and the revised forecast from ECS (768). In addition to these increases, there was also an increase of 94 actual brownfield connections from July to December 2014.

Table 8–23: Movement in brownfields (B2 and B3) connections

Brownfields	July to Dec. 2014	2015	2016	2017	2018	2019	Total
Revised AAI	467	933	940	945	950	956	5,191
BD and Marketing impact		913	675	671	664	657	3,580
ECS forecast change impact		198	226	227	65	52	768
July to December actuals impact	94						94
Amended proposal	**561**	**2,044**	**1,841**	**1,843**	**1,679**	**1,665**	**9,633**

A percentage of reinforcement projects

758. In its Draft Decision, the ERA stated:

> *ATCO has identified weak pressure areas that require reinforcement to enable the connection of new customers. As a result ATCO has proposed $16.2 million for 21 reinforcement projects. The $16.2 million consists of $5.3 million for the Pinjarra reinforcement and $10.9 million for 20 smaller reinforcement projects that are detailed in Table 31 of ATCO's AMP. EMCa advised that there was insufficient justification of these reinforcement projects.*[207]

759. EMCa recommended applying a pro-rata adjustment to ATCO's proposed $16.2 million for these reinforcement projects to allocate them between greenfields and brownfield developments. EMCa recommended that 71 per cent ($11.5 million) of the costs of these proposed reinforcements are not justified under rule 79 of the NGR. This was based on the grounds that the reinforcements are not required to support the assumed growth in greenfield developments, as the capital expenditure for such greenfield developments does not meet rule 79 of the NGR.

[205] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 470.

[206] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 472.

[207] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 477.

760. EMCa's allocation of reinforcement expenditure across greenfields and brownfields was based on an incorrect underlying customer assumption, which showed a 71/29[208] split across the two categories. The ERA sought confirmation of the split between greenfields and brownfields as 94/6.[209]

761. Reinforcement projects are primarily driven by increased throughput due to brownfields growth levels experienced by customers in existing service areas and the network's inability to effectively meet this increasing demand. Both historical and forecast growth are considered when designing the solution to meet the required network demand.

762. Network expansion and the requirement to have sufficient capacity to supply gas during the peak period to existing customers is modelled using SynerGEE gas simulation software. SynerGEE is a well-accepted hydraulic simulation tool that can generate geographically accurate models of gas network flow. The models' accuracy is verified against actual pressures from pressure monitoring devices on the network.

763. AGA confirms that the areas identified for reinforcement are required to support predominantly support brownfields development, as shown in Table 8–24: Reinforcements by category Table 8–24 below.

Table 8–24: Reinforcements by category

Reinforcement project type	$ million real at 30 June 2014 Total AA4 Forecast	% of Investment
Greenfield customer initiated <$1M	1.8	8.0%
Brownfields customer initiated <$1M	6.0	26.8%
Brownfields customer initiated >$1M	14.6	65.2%
Total Reinforcement	**22.4**	**100.0%**

764. These reinforcement projects are scheduled across AA4 in order to ensure that the network can continue to operate above minimum allowable pressure levels and maintain gas supply to consumers' appliances for safe operation during forecast winter peak conditions while accommodating the forecast brownfield connections.

765. Without these projects, low pressure events could lead to loss of supply – intermittent in the immediate term moving to frequent in future years. Failure to construct these reinforcements will prevent AGA from connecting forecast brownfield growth in the areas concerned as they could not be accommodated without the reinforcements. Should this eventuate, AGA will not be able to comply with its Licence obligation to offer to connect customers that are within 20 metres of an existing gas main.

766. Greenfields reinforcement need is similar to that of brownfield, but represents just 8% of the total, as shown in Table 8–24 above.

Volume related demand capital expenditure and regulating facilities

767. EMCa advised that AGA's proposed growth capital expenditure on volume related capital expenditure and regulating facility projects does not meet the incremental revenue test in rule 79(2)(b) of the NGR because AGA has not provided a cost benefit analysis to demonstrate that its proposed growth capital expenditure is justified.

768. The upgrade of the capacity of existing medium pressure regulating facilities is considered a preferred option over mains construction as it is a more cost effective mechanism to maintain integrity of supplies during peak winter periods. All the medium pressure regulating facilities supply lower pressure networks and adding

208 EMCa, Review of Technical Aspects of the Proposed Access Arrangement, June 2014, Table 21, page 120.

209 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 470.

additional mains to elevate low operating pressure will only increase capacity for the short term (1 to 2 years) whereas replacing the regulator set will maintain pressures for 5 to 10 years. This will also enable AGA to comply with its regulatory obligation to offer to connect customers that are within 20 metres of an existing gas main within these areas. In addition to this, laying new mains is more costly compared to regulator set upgrade.

769. The geographical spread of Reinforcement, volume related demand capital expenditure and regulating facilities projects can be seen highlighted in light blue on Figure 8–14 and Figure 8–15, demonstrating the brownfields nature of the investment. Therefore the expenditure conforms to rule 79(2)(c)(iii) of the NGR.

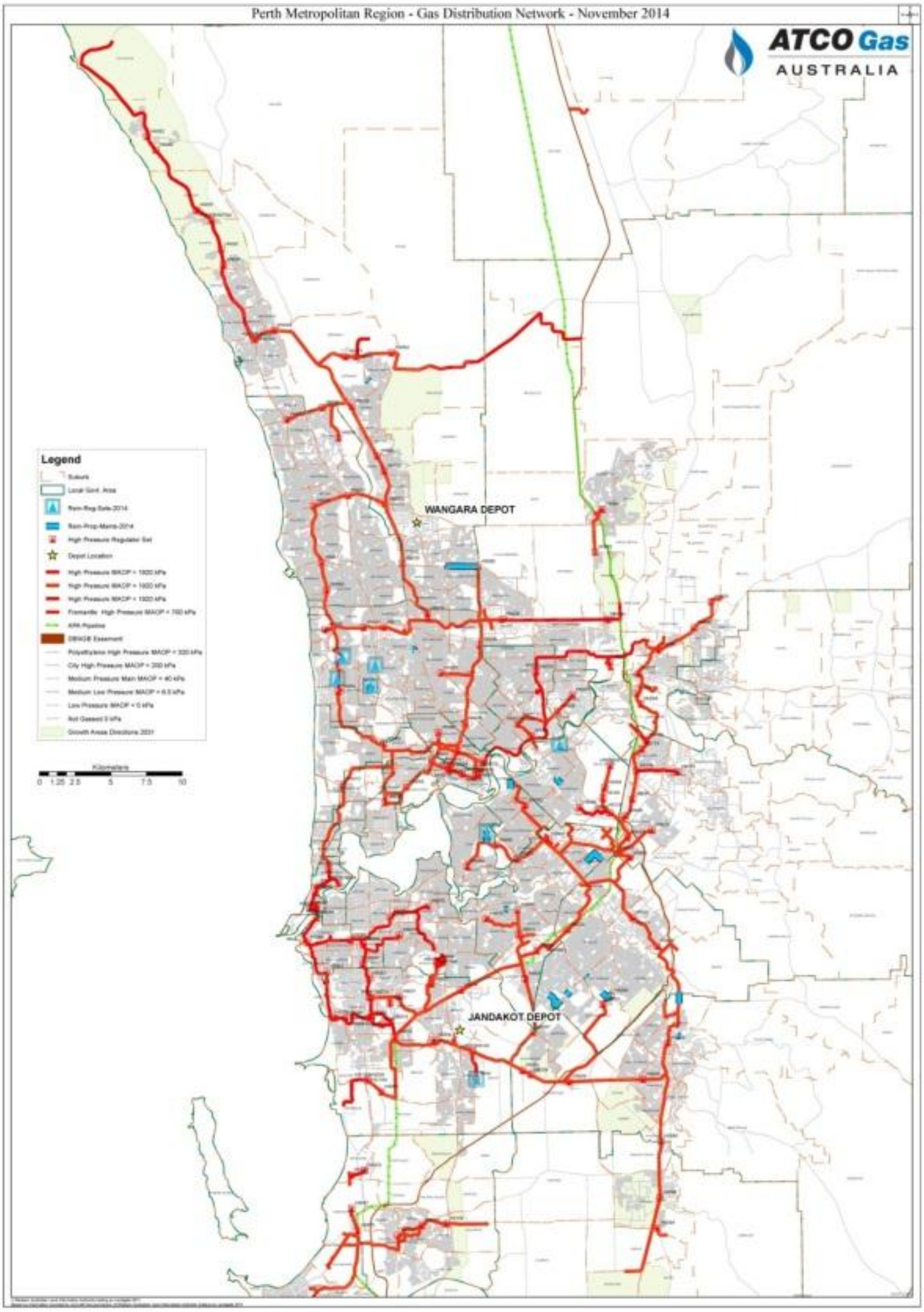

Figure 8–14: Proposed reinforcement projects, volume related demand and regulating facilities

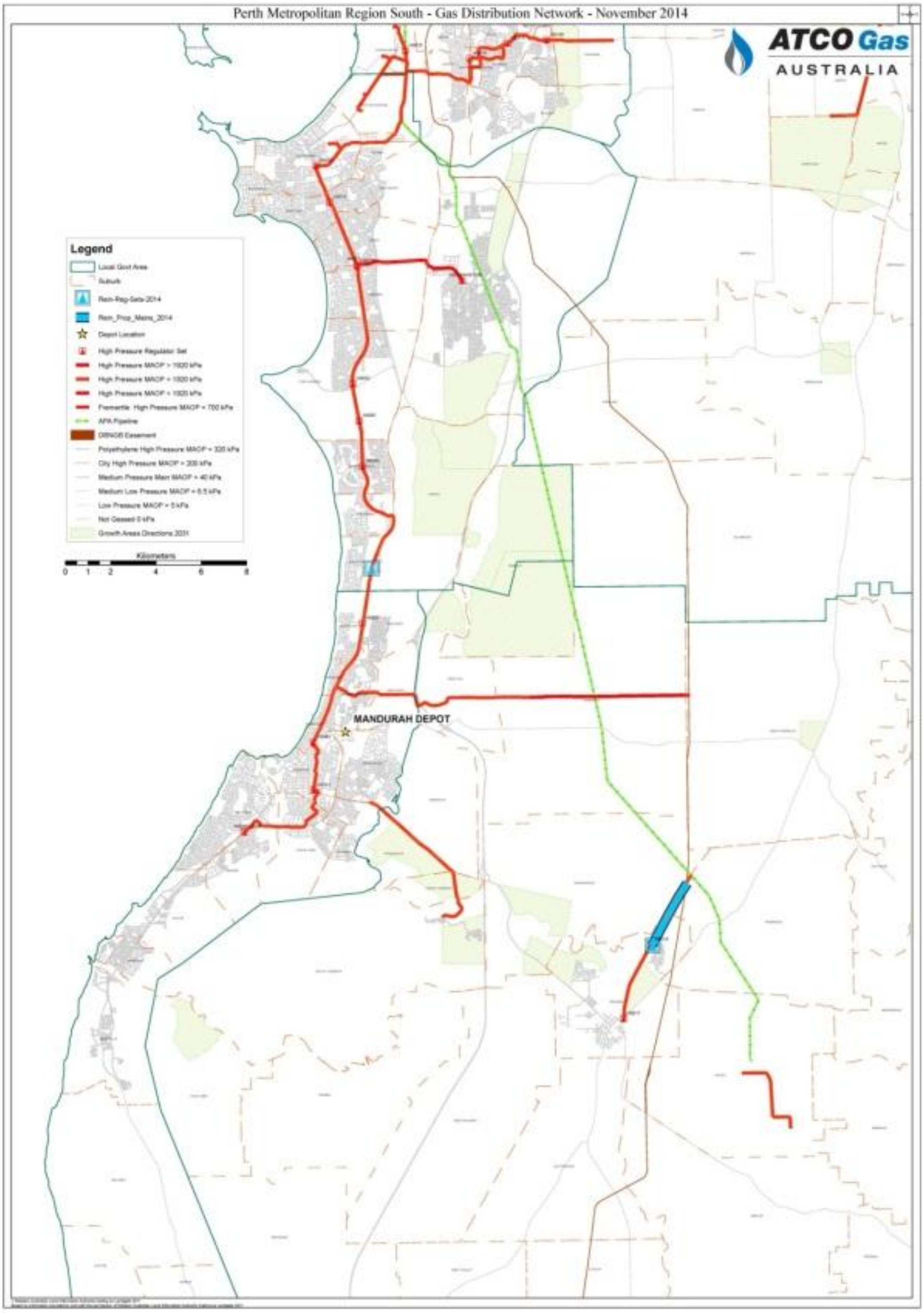

Figure 8–15: Proposed reinforcement projects, volume related demand and regulating facilities

8.2.3.5 AGA amended growth capital infrastructure

770. AGA's growth capital expenditure forecast has increased by $5.5 million, from $228.5 million in the March 2014 submission to $233.8 million. This increase in expenditure is primarily due to an increase in forecast brownfield activity in AA4, compared to AAI, which has a higher unit cost than greenfield developments.

Table 8–25: Proposed growth capital expenditure

$ million real at 30 June 2014	July to Dec. 2014	2015	2016	2017	2018	2019	Total
Greenfield customer initiated	14.3	28.2	27.0	25.7	24.2	24.4	143.8
Brownfields customer initiated	2.4	3.7	3.2	3.2	3.0	3.0	18.5
Two Rocks spur line	0.0	0.0	13.6	13.6	0.0	0.0	27.2
Peel spur line	0.0	5.4	0.0	0.0	6.0	0.0	11.4
Baldivis spur line	0.0	0.0	0.0	0.0	5.4	0.0	5.4
Capel to Busselton reinforcement	0.0	0.0	0.0	0.0	0.0	5.3	5.3
Elizabeth Quay	0.0	3.6	5.0	0.0	0.0	0.0	8.6
Reinforcements	0.6	1.0	5.7	1.1	2.0	1.1	11.5
Other	0.9	1.4	0.0	0.0	0.0	0.0	2.3
Capital Contributions	-0.2	0.0	0.0	0.0	0.0	0.0	-0.2
Amended proposal	**18.0**	**43.3**	**54.5**	**43.6**	**40.6**	**33.8**	**233.8**

8.2.4 Structures and Equipment

771. The ERA's decision to reduce proposed capital expenditure on structures and equipment was driven primarily by EMCa's view that network growth projections were overstated and therefore investment in depots could be deferred and equipment would not be required.

772. AGA does not agree with EMCA's assessment that growth is overstated as discussed earlier in Section 8.2.3. Further, the drivers of investment in structures and equipment include the impacts of traffic congestion and service level targets.

773. AGA has removed expenditure associated with the Blue Flame Kitchen safety initiative from the proposed expenditure on the Osborne Park depot and will reconsider the benefits of this project at a later date.

Table 8–26: Amended forecast structures and equipment capital expenditure ($ million real at 30 June 2014)

Category	July to Dec. 2014	2015	2016	2017	2018	2019	Total
Revised AAI	3.8	16.7	3.5	3.5	5.6	5.5	38.5
Osborne Park Blue Flamed Kitchen	-	-0.5	-	-	-	-	-0.5
Fleet, Plant and Equipment	0.9	-	-0.1	-0.1	-0.2	-0.2	0.3
Structures	0.8	1.3	-0.1	-0.1	-0.1	-0.1	1.7
Amended proposal	**5.5**	**17.5**	**3.3**	**3.3**	**5.3**	**5.2**	**40.0**

8.2.4.1 Busselton Depot

774. EMCa advises in its report that ATCO's strategy to locate people, plant and equipment close to major load centres to serve customers more efficiently and effectively is:

775. *…common industry practice and should help to achieve the various service level obligations enshrined in the Safety Case. Emergency response to broken mains/services within 1 hour is a key performance target. As to the specific locations of the depots, we agree with ATCO's rationale for trying to locate the depots in forecast demand growth areas and close to arterial roads.*[210]

776. Despite this, EMCa considers:

777. *…the primary driver for depot relocation or establishment for Bunbury and Busselton is network growth*[211] and that *ATCO's growth projections are overstated and the establishment of the Busselton depot can be prudently deferred to the fifth access arrangement period*.[212]

778. AGA does not agree it would be prudent to defer investment in the Busselton Depot until AA5. AGA has addressed the issues identified by the EMCa and the ERA in relation to forecast growth investment in section 8.2.3. AGA also considers population growth and traffic congestion in the region will result in AGA being unable to meet its obligations and KPIs to attend a site within 1 hour in the event of a Class 1 leak.

779. The City of Busselton has experienced average annual population growth of 4.1% each year for the past 20 years,[213] which has had a major impact on traffic congestion. Currently, Busselton is supported by the Bunbury Depot. Travel times between Bunbury CBD and Busselton CBD in traffic-free conditions is more than 53 minutes.[214] With a reported 8,000 vehicles travelling between Bunbury and Busselton daily[215], coupled with expected population growth, travel time will increase thereby impacting AGA's ability to safely respond to Class 1 leaks within 1 hour timeframe.

780. AGA therefore submits that $1.2 million related to the Busselton depot is required and conforms with rule 79(2)(c) of the NGR and is not contingent on greenfields growth in the region.

8.2.4.2 Fleet and plant & equipment

781. EMCa considers:

782. *…ATCO's demand forecasts are over stated and much of its growth-related expenditure is not required, we believe there will be less demand on ATCO's fleet*.[216]

783. EMCa reached the same conclusion when assessing the plant and equipment forecast for AA4.

784. AGA has addressed the issues raised by EMCa in relation to growth-related expenditure in section 8.2.3. The forecast fleet and plant & equipment expenditure of $14.9 million is required to ensure the business can manage the works maintenance program, respond to emergencies and undertake activities in compliance to the Safety Case and therefore conforms to rule 79(2)(c) of the NGR.

785. Plant and equipment has increased by $1.5 million. This expenditure relates to the deferred fleet from AA3 and testing of network fittings and improvements in operational tooling which have been identified during 2014 as part of supporting the Safety Case revision process. This includes such things as Modified Tapping Band replacement tool sets, calibration units, gas detectors and flow stop bypass hoses.

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210 EMCa, Review of Technical Aspects of the Proposed Access Arrangement, June 2014, paragraph 437.

211 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, paragraph 487.

212 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, paragraph 487.

213 South West Development commission Shire Statistics http://www.swdc.wa.gov.au/our-region/busselton.aspx.

214 This does not allow for areas outside of the CBDs, which may require a longer travel time.

215 Main Roads WA website: https://www.mainroads.wa.gov.au/AboutMainRoads/OurRoleRegions/SouthWest/RoadInfo/Pages/traf_count.aspx.

216 EMCa, Review of Technical Aspects of the Proposed Access Arrangement, June 2014, paragraph 443.

8.2.4.3 PPE non regulated and non reference services – allocation impact

786. A review of the portion of property plant and equipment directly relating to the Albany and Kalgoorlie unregulated networks has occurred.

787. The table below shows the proportion of property plant and equipment expenditure excluded.

Table 8–27: Impact of overhead allocation proposed change for PPE ($ million real at 30 June 2014)

Real $ million at 30 June 2014	July to Dec 2014	2015	2016	2017	2018	2019	Total
Amended proposal - old method	0.2	0.2	0.1	0.1	0.6	0.3	1.5
Amended proposal – change	0.2	0.2	0.1	0.1	0.3	0.2	1.1
Amended proposal – new method	0.4	0.3	0.2	0.2	0.8	0.5	2.4

8.2.4.4 Blue Flame Kitchen – Osborne Park

788. The ERA considers that *…the Osborne Park blue flame kitchen should be removed, consistent with the removal of the Jandakot blue flame kitchen in the third access arrangement as EMCa recommended that the project's link to safety is weak.*[217]

789. The intent of the Blue Flame Kitchen is to raise community awareness around how to use gas safely as well as promoting the benefits of natural gas.

790. AGA has accepted the removal of this expenditure and will re-assess the benefits of the Blue Flame Kitchen at Osborne Park at a later time consistent with a commitment to increase public awareness about the benefits of gas and gas safety.

8.2.5 IT capital expenditure

791. The ERA has determined that $3.5 million of AGA's proposed IT Capital expenditure is non-conforming under rule 79 of the NGR, broken down as follows:

Table 8–28: Draft decision IT capital expenditure adjustments ($ million real at 30 June 2014)

	2014 Jul to Dec	2015	2016	2017	2018	2019	AA4
Network operations						0.2	0.2
Commercial operations	0.3	0.2	0.4	0.3	0.3	0.3	1.8
Business support Improvements					0.3	0.4	0.7
Business support upgrades				0.0	0.0	0.0	0.0
IT Hardware and Software		0.2	0.2	0.1	0.1	0.1	0.7
Draft decision reduction	**0.3**	**0.4**	**0.6**	**0.4**	**0.7**	**1.0**	**3.4**

792. The ERA rejected the above IT capital expenditure based on the EMCa's findings that *…some elements in ATCO's proposed IT capital expenditure on network and commercial operations are speculative, and therefore not justified under rules 74 and 79 of the NGR*.[218]

[217] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, paragraph 488.

793. The ERA also accepted EMCa's recommendation that the business process standardisation project does not meet the requirements of rule 79(1)(a) of the NGR, and should be deferred to AA5. The ERA also agrees with EMCa's view that IT capital expenditure on business support upgrades, and hardware and software replacements is not justified under rule 79 of the NGR, as ATCO has not provided any information to support this expenditure[219].

794. The ERA accepted EMCa's view on the expenditure that was not justified under rule 79 of the NGR. However, the ERA made the adjustments to the reduced costs proposed by AGA under the new IT arrangements with WIPRO rather than the IT capital expenditure assessed by EMCa.

795. AGA has reviewed its IT capital expenditure forecast and proposes a reduction of $2.3 million rather than the ERA's $3.5 million. Table 8–29 summarises AGA's response to the ERA's required amendments to IT capital expenditure.

Table 8–29: Amended proposal for IT capital expenditure ($ million real at 30 June 2014)

$ million real at 30 June 2014	July to Dec. 2014	2015	2016	2017	2018	2019	Total
Revised AAI	5.1	6.6	5.8	4.4	3.7	3.1	28.7
Network Operations	-0.1	0.0	0.0	0.0	0.0	-0.3	-0.4
Commercial operations	-0.6	-0.1	-0.1	0.0	-0.1	-0.1	-1.0
Business support improvements	-0.2	0.0	0.0	0.0	-0.3	-0.4	-0.9
Business support upgrades	-0.1	0.0	0.0	0.0	0.0	0.0	-0.1
IT Hardware and Software	0.1	-0.1	-0.1	0.0	0.0	0.0	-0.1
Acquisition of AGA IT Infrastructure	0.3	0.0	0.0	0.0	0.0	0.0	0.3
Total additions / (reductions)	-0.5	-0.2	-0.2	-0.1	-0.5	-0.7	-2.2
Amended proposal	**4.0**	**6.2**	**5.4**	**4.3**	**2.8**	**1.6**	**24.3**

796. AGA's revised IT expenditure proposal is discussed in the following sections.

8.2.5.1 Movement in July to December 2014

797. In August 2014, AGA advised the ERA of the intention to acquire $3.0 million of assets from I-Tek. This transaction took place in August as anticipated. Within the acquired assets was a partially complete Work In Progress SAP project which has since been complete under AGA's ownership. The full project cost under AGA was an additional $0.2 million.

798. Across the other categories of expenditure, AGA's IT capital expenditure for the July to December period are underspent due to the impact of the transition phase between I-Tek and WIPRO.

218 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 508.

219 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 508.

8.2.5.2 Network operations

799. AGA included a proposed expenditure total of $2.0 million for its AGA-002 GIS Continuous improvement project, which EMCa considered was *…aligned with good industry practice…[and].would help ATCO provide accurate information to external parties at the lowest sustainable cost.*[220]

800. The proposed expenditure for this project included an allowance for unspecified future regulatory requirements. EMCa considered this component of the proposed project cost to be speculative and therefore not compliant with rule (74)(2) of the NGR. This allowance was adjusted from $0.4 million to $0.3 million as a result of the new IT agreement.

801. AGA's experience suggests this degree of regulatory change is likely to proceed. However, as it has not been codified at the point of this submission, AGA will remove this component from its forecasts and submit a cost pass through application as part of the annual tariff variation process when the regulatory change occurs.

8.2.5.3 Commercial operations

802. In the March 2014 AAI, AGA proposed expenditure of $1.8 million for its AGA-001 commercial operations continuous improvement project. EMCa maintained that because the new retailer was already operating in the market and there was no compelling link to any new requirements from REMCo, it was speculative to assume that there will be sufficient new retailers in the market in the AA4 period to warrant the expenditure proposed.

803. AGA has implemented this amendment in part. AGA has reduced its forecast expenditure for this project by $0.6 million associated with unspecified future regulatory requirements. Where new regulatory requirements occur AGA will seek to pass the costs through in the annual tariff variation process. However, the remaining $1.2 million reflects the forecast cost of a number of continuous improvement initiatives to support commercial services – in particular accuracy of metering and volume of information. The initiatives are not all related to the introduction of new retailers into the gas market. A detailed table of these initiatives are provided in Confidential Appendix 8.4. However, two particular issues are summarised below.

804. The retail market rules require that meter readings are provided as a reading of energy consumed. Automating the pressure correction factor (**PCF**) used to convert the volumetric reading from a gas meter to energy (using variables to represent environmental factors for atmospheric condition, network pressure dynamics and meter type dynamics) is required to improve the accuracy of billed consumption.

805. During AA3, AGA initiated its first review of the PCF and implemented a basic excel based system to manage its impact on the conversion for billing purposes and provide a more accurate meter reading to retailers. While this excel based system has been successful, it requires a significant amount of manual intervention, introducing the potential for error and/or inaccuracy. The AA4 forecasts include a staged approach to achieving automation to improve accuracy resulting from this initiative.

806. In addition to the automated PCF initiative, there are a number of additional initiatives directly related to the increased activity associated with a new retailer entry targeting the residential market. During AA3, retailers only chose to pursue customers in the industrial and commercial market segments, with a low volume of customer transfers (approx. 2-3 per month). This low level of customer transfers allowed the majority of issues with systems and processes to manage full retailer contestability (**FRC**) to be managed manually.

807. However, since Kleenheat Gas commenced pursuing residential customers in March 2013, the limitations of AGA's systems and processes developed for commencement of FRC in 2004, were exposed to mass market related issues and transactional volume stemming from retail competition.

[220] EMCa, Review of Technical Aspects of the Proposed Access Arrangement, June 2014, Table 23, p 130.

808. As confirmed by the REMCo monthly market activity reports, customer transfers in the 2013/2014 financial year averaged around 2,300/month with a peak of 4,500 (Kleenheat entry, and retailer marketing campaigns) and a low of 1,200 (summer season).

809. AGA expects this activity will intensify during AA4. The commencement of active retail competition in other Australian jurisdictions supports this view. Table 8–30 shows the recent experience in South Australia compared to Western Australia.

Table 8–30: South Australia and Western Australia customer transfer levels[221]

Year ending 30 June 2009	SA	WA
Total customers (MIRNS)	390,651	610,294
Active retailers (small use customers)	4	1
Total customer transfers	41,568	29
Churn rate	11%	0%
Year ending 30 June 2014	SA	WA
Total customers (MIRNS)	436,834	677,941
Active retailers (small use customers)	4	2
Total customer transfers	57,780	22,539
Churn rate	13%	3%

810. As a result, AGA anticipates further increases in:

- Customer transfer transactions - AGA systems need the capacity to accommodate further customer transfer transactions initiated by retailers and to minimise the potential for transaction volumes to cause system and process failures
- Billing issues – the volume of customer transfers may result in retailers not being billed correctly
- Customer disconnections and reconnections – the volume of customer transfers will also impact the volume of disconnections and reconnections that need to be done
- Metering data requests – as more retailers become active, AGA will need to comply with elevated levels of ad-hoc metering data requests that facilitate customer transfer
- Haulage pricing – retail competition has also increased in the commercial and industrial customer segment. AGA needs to be able to meet retailer ad-hoc demands for haulage pricing in this customer segment

8.2.5.4 Business support improvements and upgrades

811. EMCa considered the Business Process Standardisation project to be justifiable under rule 79(2)(a) of the NGR. However it raised concerns about ATCO's ability to *implement AGA-11 and AGA-18 in parallel… and the prudency in doing so given that the specific business process improvements to be embedded in the new system are driven in the main by the work from AGA-18.*[222] EMCa therefore proposed a deferral of the start date of this project until 2017, pushing some $0.1 million to AA5.

812. In the AAI, the forecast expenditure was for the cost of developing business cases for new technology solutions. These costs are capitalised when the project proceeds. Under the new arrangements, it is not expected these costs will be incurred and so AGA has accept its exclusion and has amended the forecast.

[221] AER, State of the Energy Market 2009, page 295 and 298.

[222] EMCa, Review of Technical Aspects of the Proposed Access Arrangement, June 2014, Table 25, page 133.

8.2.5.5 IT Hardware and Software

813. In relation to the proposed IT Hardware and Software proposed capital expenditure, EMCa stated:

> *ATCO has provided no information to support this expenditure ($0.76m) and it is not clear to us what the drivers are for it or how it can be justified under rule 79(2). In the absence of any supporting information, we are of the view that this expenditure does not comply with rule 79(2) and, by extension, cannot be considered conforming capex[223].*

814. In the AAI, this forecast expenditure represented the purchase of desktop computers, laptops, peripheral devices, and mobile phones that would be required for employees over the AA4 period.

815. AGA has implemented the amendment to remove the hardware and software that is incorporated into the arrangements with WIPRO. However, AGA remains responsible for the provision and replacement of mobile phones for its employees. AGA currently holds 233 mobile phones. AGA forecasts a replacement cost of approximately $0.3 million over the AA4 period. AGA has therefore revised its expenditure to reflect only mobile phones.

8.2.5.6 IT non regulated and non reference services – allocation impact

816. All IT CAPEX projects for the period January 2010 to December 2019 were reviewed to determine an appropriate proportion of expenditure to exclude for non regulated and non reference services, as discussed in Section 8.2.7.

817. The result of the analysis is shown in Table 8–31: Impact of overhead allocation proposed change for IT ($ million real at 30 June 2014) below.

Table 8–31: Impact of overhead allocation proposed change for IT ($ million real at 30 June 2014)

Real $ million at 30 June 2014	July to Dec 2014	2015	2016	2017	2018	2019	Total
Amended proposal - old method	0.1	0.1	0.1	0.1	0.1	0.0	0.5
Amended proposal – change	0.0	0.1	0.1	0.0	0.0	0.0	0.2
Amended proposal – new method	**0.1**	**0.2**	**0.2**	**0.1**	**0.1**	**0.0**	**0.7**

8.2.6 Capitalisation of overheads

818. The ERA requires a reduction to the percentage of overhead allocated to the sustaining and growth capital projects. AGA proposes on average 19.6% for overheads. The ERA considers 15% allocation is more in line with industry practice. Table 8–32 shows the impact if the 15% allocation was applied.

Table 8–32: Impact of overhead allocation proposed change ($ million real at 30 June 2014)

Category	Revised AAI	ERA Draft Decision	Variance
Sustaining and growth capex	539.8	237.9	-301.9
Total overhead costs to be allocated	105.8	35.7	-70.1
% of sustaining and growth capex	19.6%	15.0%	

819. The ERA does not consider the overhead expenditure to be efficient or in line with industry practice, stating that:

[223] EMCa Review of Technical Aspects of the Proposed Access Arrangement, June 2014, paragraph 466.

820. *The AER has approved the following overhead allocations not including IT and SCADA in recent decisions (SP Ausnet 15 per cent, Envestra Victoria 13 per cent and Multinet Victoria 5 per cent).*[224] *The Authority further asserts that ATCO has not provided any explanation or evidence for the proposed increase in overheads...[and that it]…does not accept that ATCO's proposed overhead costs meet the requirements of rule 74 of the NGR.*[225]

821. AGA's overhead costs represent undistributed costs which are not directly charged to discrete capital projects. It is not a measure of efficiency.

822. As PB advised in a 2011 report for Envestra:

823. *One of the inherent difficulties in analysing overheads is the definition and allocation of overheads, as each business takes a different approach to overhead classification and allocation. For example, one business may capture the time of network planning engineers and allocate the time directly to projects as a direct cost, while another business will allocate the total network planning cost to overhead and then reallocate that cost to capital projects via an overhead allocation process*[226].

824. In determining the appropriate level of overheads that are efficient or in line with industry practice the ERA must consider the costs themselves that are being allocated to capital expenditure and the basis upon which the allocation occurs. The resulting percentage of total capex is merely an output of this process.

825. There is no reason to adjust the allocated percentage unless the underlying costs are inefficient or the allocation methodology is unreasonable. AGA submits that neither is the case. The ERA has assessed the operating and capital expenditure forecasts. The allocation of overheads is an output of applying the method to forecast costs. Further, the Acil Allen benchmark report demonstrates that AGA's operating and capital expenditure are the lowest of its peers on a per km and per customer basis. [227] This is also true for operating and capital expenditure.

826. A change in the allocation percentage simply results in a transfer of these costs to the operating expenditure category. The allocation method has been consistent over AA3 and will continue in to AA4. Any change to the current allocation method would require a restatement of the capital and operating expenditure forecast for AA4.

A reasonable allocation method

827. AGA's core activities are managed based on cost centres which are aligned to specific activities and/or locations. Each person that works for AGA is allocated to a cost centre where all costs associated with the delivery of their activities and tasks are captured. This is done to facilitate the transparency of data for management, reporting and budgeting/forecasting purposes.

828. While resources are allocated to an individual cost centre within AGA, their core responsibilities may be linked to the provision of services for the operating or capital program of work. Each cost centre is assessed for the activities that individuals and teams within them contribute to the operating and capital program of work. Based on this assessment, a portion of the cost centre's operating expenditure is allocated to sustaining and growth capital projects. The allocation of these costs to capital projects results in them being capitalised. This is what is referred to as 'overhead allocation'.

829. The 'overhead' allocation is based on the costs associated with provision of key services, including:

- Asset management

[224] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 521.

[225] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 520.

[226] Confidential Appendix 8.3 Level of Overheads, Report for Envestra, Parsons Brinkerhoff March 2011.

[227] Appendix 6.1 Gas Distribution Benchmarking Partial Productivity Measures Acil Allen November 2014, page 25.

- Environmental advice
- Gas distribution officers
- Planning
- Project management and administration
- Operational supervisor advice
- Technical compliance

830. These overhead costs are made up of a number of expenditure categories, but predominantly salaries and labour, as shown in Table 8–33.

Table 8–33: Break down of expense type for overhead allocation

Expense Type	% of total
Salaries and Labour	81
Motor vehicle expenses	5
Property expenses	3
Communication expenses	2
All other	9
Total	**100%**

831. AGA's resources do not all complete timesheets to directly allocate hours to individual projects or programs. The overhead allocation method is used to allocate the time and costs required to deliver the capital program of works to the assets constructed.

832. A number of cost centres across AGA indirectly support capital projects work. These operating costs would be reduced if the capital projects did not take place, particularly headcount. Allocating costs to the capital program is based on a number of considerations including but not limited to:

- The number of percentage of employees time in each cost centre dedicated to capital construction projects
- The provision of network demand forecasting, network pressure system modelling, faults analysis and asset performance criteria and replacement required to plan capital construction
- The provision of engineering, project management and specialist technical support required for detailed asset designs
- Time dedicated to dealing with new connections
- Time dedicated to the scheduling of capital construction works

Cost centres which provide services to sustaining and growth capital projects are shown in Table 8–34 below, along with the percentage of costs which is allocated to capital, and what portion of the overall overheads they represent.

Table 8–34: Cost centre functions, allocation to capital and their % of total overhead

Cost Centre Description	Core functions	% of costs allocated	% of total overhead
Construction	construction of new pipelines; installation of new customer connections	100%	9.3%
Gas Projects	major projects relating to asset maintenance and growth	100%	15.0%
Engineering Services	engineering, project management and specialist technical support	85%	20.0%
Asset Services	network demand forecasting, network pressure system modelling, faults analysis and asset performance criteria and replacement	75%	9.0%
Call Centre	24 hour faults and emergencies response, management of dial before you dig, plans and supports scheduling	50%	3.0%
Management	senior members of the operational business who oversee and manage the operations and individual cost centres; allocated in line with allocation of individual business areas	50%	7.5%
Planning	Planning	50%	2.0%
Jandakot Depot	running facilities and fleet which service both capital and maintenance works.	40%	3.5%
Regional	due to physical remoteness from the Construction and Capital Projects team, all capital investment is delivered by the regional teams in partnership with subcontractors.	40%	4.0%
HSE	supporting the safe operation of the network	40%	3.0%
Stores	management of inventory	30%	0.5%
Facilities Maintenance	testing and application of corrosion prevention to the pipeline	30%	0.2%
Systems Monitoring	monitoring and testing of pipeline pressures.	30%	2.0%
CP HP Location & Pipeline Patrol	pipeline maintenance as opposed to pressure reduction stations and other elements of the network.	30%	0.2%
Technical Compliance	Ensures pipeline operates within legislated boundaries and meets all relevant safety standards	25%	6.0%
HR	based on portion of resource pool dedicated to capital	25%	3.5%
Business Development	demand forecasting and NPV assessment of all investment	25%	5.0%
Commercial Services	billing and reporting/monitoring of data to the retailers and market	10%	1.0%
Other	All other	varied	5.3%
Total			**100.0%**

833. With more than 80% of the total allocated costs made up of salaries and labour costs, the increase in overhead is largely due to the increased headcount required to support the capital program.

834. If AGA were to directly charge these activities, which are fully or predominantly (75% or more) allocated to the capital program of work, the overhead allocation would reduce by an annual average of $8.7M from 2015 to 2019, and the percentage of overhead would move to an annual average of 9%. However, as these costs would be directly charged to capital projects the capital expenditure would not decrease.

In line with industry practice

835. EMCa proposed overhead allocation for AA4 and suggested that 15 per cent would be more appropriate and in line with industry practice. As discussed above the overhead allocation method is not a measure of efficiency, any change to the percentage allocated to capital expenditure would have to be reflected in the operating expenditure forecast.

836. AGA’s expenditure is prudent and efficient. Its current allocation method is appropriate and is reviewed periodically to ensure the accurate and current overhead allocation. As the capital program moves (increases or decreases), the relative impact and percentage of total expenditure will in turn increase or decrease for the variable components of the cost.

837. The $35.7 million in the Draft Decision is not sufficient to pay the personnel costs for the direct labour, which is allocated as opposed to directly attributed through timesheets. In the event the ERA’s recommended adjustment be accepted and applied to the management of core cost centre activities within AGA, the business would have to request a corresponding increase ($70.1 million) in operating costs.

8.2.7 Allocation of PPE and IT to non regulated and non reference services

838. In paragraph 359 of its draft decision the ERA required AGA to review how indirect capital expenditure should be apportioned between the regulated network and reference services and the non-regulated network and non-reference services.

839. AGA has reviewed that indirect capital expenditure consisting of property plant and equipment expenditure and IT capital expenditure for the period January 2010 to December 2019 as required by paragraph 359.

8.2.7.1 Property plant and equipment

840. Property plant and equipment directly relating to the Albany and Kalgoorlie unregulated networks is separately identifiable and has been excluded from the regulated asset base.

841. The cost centres providing both reference and non reference services were identified. The proportion of costs relating to non reference services was calculated. That calculated proportion of property plant and equipment expenditure was excluded from the regulated asset base. A further proportion of overhead cost centres that support the management of non reference services and unregulated services property plant and equipment expenditure was also excluded, in line with the proportion of OPEX expenditure that was excluded with the CAM.

842. The impact of this adjustment is discussed in Section 8.2.4.3 above.

8.2.7.2 IT

843. All IT capital projects for the period January 2010 to December 2019 were reviewed to determine an appropriate proportion of expenditure to allocate to non regulated and non reference services. Costs were allocated according to the number of users or IT devices related to performing services in the unregulated networks or non reference services. The number of delivery points relating to regulated relative to non regulated networks was also used where appropriate.

844. The impact of this adjustment is discussed in Section 8.2.6 above.

8.2.8 Labour escalation

845. In its Draft Decision, the ERA removed $1.8 million of forecast capital expenditure relating to labour escalation on the basis of rule 74 of the NGR. The ERA has determined labour escalation for the AA4 period should be CPI only and not the CPI +2% proposed by AGA.

846. AGA has not reduced the capital expenditure forecast as it does not accept the ERA's labour escalation rate. AGA considers the rate should be CPI +2% and submits evidence in response to required amendment 5 to support this in Section 6.2.1.

8.2.9 Equity raising costs

847. In its draft decision, the ERA accepts that the efficient costs of raising equity constitute part of the forward looking costs of providing covered services. However, the ERA did not accept the cashflow modelling assumptions which underpinned AGA's proposal. The assumptions were based on those that the AER has approved in its most recent regulatory decisions. The ERA has instead required AGA adopts the methodology stipulated in the Rate of Return Guidelines.

848. AGA will implement the modelling of equity raising costs in line with the ERA's Rate of Return Guidelines. However, the methodology described in the ERA in the Draft Decision is not the same as in the Rate of Return Guidelines. The costs associated with dividend reinvestment plan requirement costs are zero as the costs of raising equity through this means is a simple 'tick the box' process. However, the ERA's Rate of Return Guidelines and revenue model incorporates a cost assumption of 1%. The Explanatory Statement for the Rate of Return Guidelines references the considerable analysis undertaken by the AER on this matter:[228]

849. The AER has undertaken its own research of the costs of DRPs among domestic energy network businesses. The AER observed that where reported, costs as a portion of equity raised had a median of 0.75 per cent and a mean of 1 per cent. On the basis of all the information considered including ACG report [zero cost] and Carlton's anecdotal evidence [1.25 per cent], the AER considers that a conservative estimate of 1 percent is appropriate. The AER considers that this figure is the appropriate unit cost to be applied to the amount of equity assumed to be raised through a DRP.[229]

850. Consistent with the AER's analysis and the ERA's Rate of Return Guideline AGA does not accept that dividend reinvestment plan costs are a simple 'tick the box' exercise and therefore incur no costs.

851. AGA accepts capitalising equity raising costs in its RAB using the method proposed by the ERA. However AGA does not accept the ERA's cashflow modelling assumptions as presented in the Draft Decision. Instead, AGA will estimate equity raising costs based on those in the Rate of Return Guidelines:[230]

- *Retained earnings of 30 per cent of after-tax profits will be available to increase equity at zero cost*
- *Dividends will be assumed to be paid at the benchmark payout ratio of 70 per cent of after-tax profits, consistent with the payout ratio used in the estimation of gamma*
- *25 per cent of dividends paid out will be treated as being reinvested through dividend reinvestment plans, with an equity raising cost allowance of 1 per cent*
- *Any further required equity is raised at the Seasoned Equity Offering cost of 3 per cent*

[228] ERA, Explanatory Statement for the Rate of Return Guidelines; Meeting the requirements of the National Gas Rules, 16 December 2013, paragraph 904.

[229] Australian Energy Regulator 2009, Australian Capital Territory Distribution Determination 2009-10 to 2013-14, www.aer.gov.au, page 258.

[230] ERA, Rate of Return Guidelines; Meeting the Requirements of the National Gas Rules, December 2013, paragraph 150.

852. Given AGA's forecast cost of service for the next access arrangement period, the forecast value of equity raising cost is immaterial. Therefore, AGA has not included any equity raising costs in this proposal, but this may change if either the forecast cost of service or equity raising cost assumptions change between this response to the Draft Decision and the ERA's Final Decision.

9. Rate of return

ERA required amendment 9

The Authority requires that ATCO revise its rate of return to be 5.94 per cent.

The Authority requires that ATCO insert a fixed principle in its access arrangement that will bind it to apply an adjustment to the debt risk premium set for the fifth access arrangement period – in present value revenue neutral terms – which will account for the difference between the debt risk premium set at the start of the fourth access arrangement, and the actual annual update outcomes for the debt risk premium that applied in each of the second to fifth years of the fourth access arrangement period.

AGA Response: do not accept

Summary only – AGA has not implemented the ERA's amendment as it results in a rate of return that is too low and is not compliant with the NGO, NGR or RPPs. AGA's proposed rate of return departs from the ERA's Rate of Return Guidelines and the Draft Decision. AGA submits an overall rate of return of 7.64%. This includes a cost of debt of 5.73% and cost of equity of 10.51%.

9.1 Summary of ERA Decision

853. The ERA rejects AGA's approach with regard to the rate of return, largely because AGA has not followed the approach set out in the ERA's Rate of Return Guidelines.

854. In relation to the cost of equity, the ERA:

- Applies the methodology for estimating the cost of equity set out in its Rate of return Guidelines
- In doing so continues to hold the view that only the Sharpe Lintner CAPM (**SL CAPM**) is relevant for the purposes of estimating the cost of equity
- Rejects AGA's evidence and proposal to estimate the cost of equity having regard to a range of relevant models

855. In respect of the estimate of the parameters for input into the SL CAPM:

- Estimates the risk free rate using the yield on Commonwealth Government Securities (**CGS**) with a 5 year term to maturity to match the regulatory period and rejects AGA's proposal to use a 10 year term
- Changes its approach to the estimate of the market risk premium (**MRP**) set out in its Rate of Return Guidelines. In order to select a point estimate from its MRP range of 5% to 7.5%, the ERA has introduced a new method whereby it takes four forward looking indicator variables and compares their current value against the history of that variable. The ERA then infers where the current MRP estimate lies in relation to its historical range and, after weighting the four estimates, arrives at an MRP of 5.5%
- Continues to estimate the equity beta based on a very small sample of domestic firms and excluding foreign data, giving rise to an estimate for the equity beta of 0.7

856. In relation to the cost of debt, the ERA has significantly changed its approach to estimating the cost of debt so that it differs from its Rate of Return Guidelines. The ERA:

- Continues to estimate the cost of debt as the sum of the risk free rate, relevant debt risk premium (**DRP**) and relevant debt raising costs
- Continues to estimate the risk free rate from CGS with the same term as the regulatory period, that is 5 years

- Modifies its approach for estimating the DRP to now be based on a term of 10 years, which is estimated using a bond yield approach that includes international bonds issued by domestic entities
- Continues to apply the annual update for the DRP
- Changes its approach to adjusting revenue for the annual update, by applying the four updated cost of debt estimates – to occur for years 2 to 5 of AA4 – at the start of the next regulatory period through a present value neutral adjustment to the AA5 revenue

857. The application of the 5 step method outlined in the ERA's Rate of Return Guidelines for the estimation of the return on equity and modifications to the return on debt as outlined above results in a rate of return of 5.94%.[231]

9.2 AGA response

858. AGA does not accept the ERA's required amendment to adopt a rate of return of 5.94%. AGA's proposed rate of return departs from the ERA's Rate of Return Guidelines and the ERA's Draft Decision. As set out in more detail in this chapter and the accompanying expert reports, the ERA's approach does not comply with the requirements set out in the National Gas Rules (**NGR**) and does not achieve the allowed rate of return objective (**ARORO**) because:

- In relation to the return on equity, the approach in the ERA's Draft Decision continues to apply a single model, the SL CAPM, and ignores other relevant models, methods, data and other evidence. Consequently the ERA's cost of equity estimate is not the best estimate. Further, in applying its single model the ERA commits significant error when estimating the parameters for input into the SL CAPM. The Draft Decision also fails to consider whether the resulting return on equity is consistent with the ARORO, NGR or the revenue and pricing principles (**RPP**)
- In relation to the return on debt, the approach in the Draft Decision does not represent an efficient debt management strategy that would be implementable by a benchmark efficient firm with a similar degree of risk to that of AGA. For this reason alone it cannot meet the ARORO and does not give rise to the best estimate of the cost of debt. The ERA's approach also fails to give appropriate consideration to the independent and robust data estimates published by the Reserve Bank of Australia

859. In response to the Draft Decision AGA has revised its estimate of the nominal post tax weighted average cost of capital to:

- Update the various parameters to account for movements in the market conditions since the March 2014 submission
- Update the weighting methodology used to estimate the return on equity by applying a weighted average to the output of four relevant models for estimating the cost of equity, resulting in an estimate 10.51%[232]
- Modify the approach for measuring the cost of debt in response to the Draft Decision and proposes a cost of debt estimate based on a hybrid methodology.[233] The hybrid methodology uses the trailing average of the 10 year cost of debt, impact of the swap portfolio and the trailing average 10 year swap rate estimated from the Reserve Bank of Australia's *Aggregate Measures of Australian Corporate Bond Spreads and Yields* publication. This debt margin combined with an allowance for debt raising and hedging costs results in a cost of debt estimate of 5.73%

[231] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 553.

[232] Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014.

[233] Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014.

860. AGA's revised nominal post-tax rate of return estimate is 7.64%. This estimate has been arrived at having regard to all available and relevant data, estimation methods, financial models and evidence. It therefore reflects the best estimate available based on all relevant evidence. AGA's expert evidence shows that its proposed rate of return complies with the NGR, specifically the ARORO, the national gas objective (**NGO**) and the RRP.

861. Simply put, the ERA's estimate of the rate of return is too low to promote efficient investment. The return on equity is significantly below that allowed for other gas distribution businesses in Australia – by more than 2% - as well as below that available to AGA in its other regulated utility businesses within the ATCO Group. The resulting inability to attract capital in any capital market not only puts the levels of service at risk, it would result in a constant challenge to maintain compliance with its Gas Distribution License or regulatory obligations, and reduce the likelihood that services would be provided to future customers at all. It is difficult to imagine what circumstances would exist that would result in an investor choosing to invest in AGA to receive a return that is more than 2% lower than that available in any other Australian gas distribution business.

862. The return on debt is not sufficient to cover the costs of an efficient debt management strategy. Under the ERA's approach, not only is a benchmark efficient entity unable to implement the debt management strategy, it will be subject to retrospective application of the ERA's 'perfect' hindsight view of efficient cost. The ERA recognises the benchmark efficient entity cannot mitigate the risk of this hindsight approach but nevertheless justifies it on the basis that it is appropriate to impose additional risk on the benchmark efficient entity consistent to that which would apply to an entity in a competitive market – despite providing no compensation for the additional imposed risk.

863. AGA would be left in the situation similar to that of investors during the global financial crisis significant losses on paper that are only realised when those shares are sold. It would appear the only information the ERA would accept to demonstrate the impact of its determined rate of return would be if AGA sold the business at less than the RAB. This would seem an extreme measure for any business to take and surely not the outcomes that the NGL, NGR or the ERA contemplate.

864. The following discussion and analysis, together with the expert reports relied upon, demonstrate that AGA's revised rate of return estimate is commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to AGA as required by rule 87(2) of the NGR.

9.2.1 National Gas Rules requirements

865. The overarching requirements of the NGO and the RPP set out in the National Gas Law (**NGL**) are integral to the determination of the rate of return. The rate of return framework has been designed to give primacy to achieving these objectives. As set out above, in setting the rate of return the ERA has failed to achieve the NGO and the RPP and does not comply with rule 87 of the NGR.

866. The NGO as set out in the **NGL** is to:

> *promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas.*

867. The RPP provide guidance on how the NGO is to be achieved. The most relevant principles to the rate of return are set out below.

868. *(2) A service provider should be provided with a reasonable opportunity to recover at least the efficient costs the service provider incurs in—*

869. *(a) providing reference services; and*

870. *(b) complying with a regulatory obligation or requirement or making a regulatory payment.*

871. *(3) A service provider should be provided with effective incentives in order to promote economic efficiency with respect to reference services the service provider provides. The economic efficiency that should be promoted includes—*

872. *(a) efficient investment in, or in connection with, a pipeline with which the service provider provides reference services; and*

873. *(b) the efficient provision of pipeline services; and*

874. *(c) the efficient use of the pipeline.*

875. *(5) A reference tariff should allow for a return commensurate with the regulatory and commercial risks involved in providing the reference service to which that tariff relates.*

876. Rule 87 of the NGR governs determination of the rate of return to be used in setting the total revenue and reference tariffs for regulated gas network service providers. Rule 87 of the NGR provides for the following:

877. ***Rate of return***

878. *(1) Subject to rule 82(3), the return on the projected capital base for each regulatory year of the access arrangement period is to be calculated by applying a rate of return that is determined in accordance with this rule 87 (the allowed rate of return).*

879. *(2) The allowed rate of return is to be determined such that it achieves the allowed rate of return objective.*

880. *(3) The allowed rate of return objective is that the rate of return for a service provider is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the service provider in respect of the provision of reference services (the allowed rate of return objective).*

881. *(4) Subject to subrule (2), the allowed rate of return for a regulatory year is to be:*

882. *(a) a weighted average of the return on equity for the access arrangement period in which that regulatory year occurs (as estimated under subrule (6)) and the return on debt for that regulatory year (as estimated under subrule (8)); and*

883. *(b) determined on a nominal vanilla basis that is consistent with the estimate of the value of imputation credits referred to in rule 87A.*

884. *(5) In determining the allowed rate of return, regard must be had to:*

885. *(a) relevant estimation methods, financial models, market data and other evidence;*

886. *(b) the desirability of using an approach that leads to the consistent application of any estimates of financial parameters that are relevant to the estimates of, and that are common to, the return on equity and the return on debt; and*

887. *(c) any interrelationships between estimates of financial parameters that are relevant to the estimates of the return on equity and the return on debt.*

888. *Return on equity*

889. *(6) The return on equity for an access arrangement period is to be estimated such that it contributes to the achievement of the allowed rate of return objective.*

890. *(7) In estimating the return on equity under subrule (6), regard must be had to the prevailing conditions in the market for equity funds.*

891. *Return on debt*

892. (8) *The return on debt for a regulatory year is to be estimated such that it contributes to the achievement of the allowed rate of return objective.*

893. (9) *The return on debt may be estimated using a methodology which results in either:*

894. (a) *the return on debt for each regulatory year in the access arrangement period being the same; or*

895. (b) *the return on debt (and consequently the allowed rate of return) being, or potentially being, different for different regulatory years in the access arrangement period.*

896. (10) *Subject to subrule (8), the methodology adopted to estimate the return on debt may, without limitation, be designed to result in the return on debt reflecting:*

897. (a) *the return that would be required by debt investors in a benchmark efficient entity if it raised debt at the time or shortly before the time when the ERA's decision on the access arrangement for that access arrangement period is made;*

898. (b) *the average return that would have been required by debt investors in a benchmark efficient entity if it raised debt over an historical period prior to the commencement of a regulatory year in the access arrangement period; or*

899. (c) *some combination of the returns referred to in subrules (a) and (b).*

900. (11) *In estimating the return on debt under subrule (8), regard must be had to the following factors:*

901. (a) *the desirability of minimising any difference between the return on debt and the return on debt of a benchmark efficient entity referred to in the allowed rate of return objective;*

902. (b) *the interrelationship between the return on equity and the return on debt;*

903. (c) *the incentives that the return on debt may provide in relation to capital expenditure over the access arrangement period, including as to the timing of any capital expenditure; and*

904. (d) *any impacts (including in relation to the costs of servicing debt across access arrangement periods) on a benchmark efficient entity referred to in the allowed rate of return objective that could arise as a result of changing the methodology that is used to estimate the return on debt from one access arrangement period to the next.*

905. (12) *If the return on debt is to be estimated using a methodology of the type referred to in subrule (9)(b) then a resulting change to the service provider's total revenue must be effected through the automatic application of a formula that is specified in the decision on the access arrangement for that access arrangement period.*

906. Rate of Return Guidelines

907. Pursuant to rule 87(18) the *rate of return guidelines* are not mandatory but, if the ERA makes a *decision* in relation to the rate of return (including in an access arrangement draft *decision* or an access arrangement final *decision*) that is not in accordance with them, the ERA must state, in its reasons for the *decision*, the reasons for departing from the guidelines.

9.2.2 Overall issues with the ERA’s approach in the Draft Decision

908. AGA submits that the ERA’s overall rate of return does not meet the requirements of rule 87 of the NGR and does not give rise to a rate of return that achieves the ARORO, the NGO or the RPP. The ERA’s Draft Decision delivers a rate of return that:

- Is too low to provide incentives for efficient investment

- Is significantly lower than that earned historically by the Mid-West and South-West Gas Distribution System and lower than that earned by its peers
- Is inconsistent in the treatment of data, analysis and thresholds for justifying the departure from the ERA's Rate of Return Guidelines
- Results in increased volatility for customers and investors

909. In relation to the cost of equity the ERA's Draft Decision does not consider all relevant methods, models, data and other evidence and instead relies solely on the SL CAPM. In applying its chosen model, the ERA does not use the best estimates of the relevant parameters and in some cases has arrived at unreasonable estimates. Finally, the ERA does not provide effective consideration of the resulting return on equity against the ARORO, the NGO or the RPP.

910. However, the ERA sees fit to depart from its Guidelines in respect of the cost of debt. The ERA's new approach to the cost of debt:

- Does not estimate the cost of a debt financing strategy that could actually be implemented by a benchmark efficient entity
- Does not provide any adequate justification as to why the RBA data should be disregarded
- Unlike AGA's proposed approach using RBA data, it is not replicable, independent or transparent
- Modifies the term of the DRP**,** but the risk free rate component of the cost of debt remains with a term of 5 years. This raises an issue of inconsistency and does not provide the business with an opportunity to recover efficient costs which is the ERA's stated intention
- Introduces a new concept in estimating the DRP referred to as the 'guiderails'. These guiderails appear to have no statistical foundation and are designed to unnecessarily constrain the DRP estimate. The effect is to deny the benchmark efficient entity the opportunity to fully recover its efficient costs in times of market uncertainty
- Modifies the annual update set out in the Guidelines, introduces additional revenue risk and does not convey appropriate efficiency or pricing signals to customers

9.2.3 Return on Equity

911. In the Draft Decision the ERA says it has conducted an indicative assessment, as at 9 September 2014, of the return on equity for AGA. The ERA claims this assessment is consistent with delivering an outcome that meets the approach set out in the ERA's Rate of Return Guidelines and hence the allowed rate of return objective, as well as the NGL and NGR more broadly.[234]

912. AGA notes that *delivering an outcome that meets the approach set out in the rate of return guidelines* is not a test under the NGR. The relevant test is to determine a rate of return such that it achieves the ARORO.[235] This should be the ERA's main consideration. The ERA's 5 step process for estimating the cost of equity in its Rate of Return Guidelines and its application of that process in the Draft Decision is in error because:

- It excludes relevant estimation methods and models
- The estimates of parameters used to populate the SL CAPM are not the best estimates
- The process results in relevant information and evidence having no effective influence on the estimate
- The estimate is not considered against the ARORO

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[234] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 661.

[235] Rule 87(2) of the NGR

9.2.3.1 Averaging period for market based parameters

913. In its Draft Decision the ERA has not accepted AGA's adoption of a 20 day averaging period for market based parameters. The ERA will instead adopt the averaging period of 40 days as set out in its Rate of Return Guidelines.[236] However, for the purpose of the Draft Decision the ERA encountered some practical issues which meant that it was not able to implement the 40 day averaging period and instead measured relevant parameters over a 7 day period.[237]

914. AGA maintains that the adoption of a 20 day period or the 40 day period is immaterial to the outcome of the approach. However, the practical implementation of a 40 day averaging period is complex and costly process for a business to undertake. Under the previous arrangements, regulated businesses were required to undertake a 20 day averaging period. By increasing the averaging period to 40 days, the amount of time over which financiers are required to be available to transact is doubled. As a result, the benchmark efficient entity will incur additional costs from financial institutions and the market. It is possible the ERA encountered similar difficulties in arriving at its parameter estimates for the Draft Decision.

915. For these reasons AGA continues to propose the adoption of a 20 day averaging period for market based parameters. For the purpose of calculating the return on equity in the response to the Draft Decision, AGA has adopted a 20 business day averaging period to 9 September 2014. As accepted by the ERA in its Draft Decision, the averaging period will be agreed upon and re-set closer to the Final Decision.

9.2.3.2 ERA Step 1- Identify relevant material and its role in the estimate

916. Despite evidence submitted to the contrary in the two SFG Reports relied upon by AGA,[238] the ERA finds that the SL CAPM is the only relevant model for estimating the required return on equity. The ERA has not adequately addressed the issues raised by AGA in relation to the multi model approach.

917. The ERA considers its approach in the Guidelines with regard to the determination of relevance and finds that the SL CAPM is the only relevant model consistent with the intent of the Australian Energy Market Commission's (**AEMC**) rule changes. The ERA sites the AEMC's Final Position Paper:

> *The regulator must actively turn its mind to the factors listed, but it is up to the regulator to determine how the factors should influence its decision. It may indeed consider all of them and decide none should influence its decision. It is not intended that the regulator's decision is solely dependent on how it applies any or all of those factors.*[239]
>
> *Achieving the NEO, the NGO, and the RPP requires the best possible estimate of the benchmark efficient financing costs. The Commission stated that this can only be achieved when the estimation process is of the highest possible quality. The draft rule determination stated that this meant that a range of estimation methods, financial models, market data and other evidence must be considered. At the same time, the regulator requires discretion to give appropriate weight to all the evidence and analytical techniques considered.*[240]

918. However, the ERA's position is that no other models or methods are relevant for the purposes of rule 87(5)(a) of the NGR and that incorporating returns from other models would detract from the ability of the

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236 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 653.

237 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 654.

238 SFG 2014, Estimating the required return on equity, Report for ATCO Gas Australia and SFG 2013, Regression-based estimates of risk parameters for the benchmark firm.

239 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 667.

240 AEMC Rule Determination, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012, 29 November 2012, page 43.

ERA to meet the ARORO.[241] The ERA has not given regard to other models and the returns they produce and then decided they do not influence their estimate. Rather, the ERA has no regard to the returns produced by other models. The ERA's finding that only the SL CAPM is relevant contradicts the AEMC's conclusion that no one method can be relied upon in isolation to estimate an allowed return on capital that best reflects the benchmark efficient financing costs. The AEMC also noted the application and interpretation of the previous rule 87 of the NGR (including the use of the SL CAPM alone to determine the cost of equity)

> *…presupposes the ability of a single model, by itself, to achieve all that is required by the objective. The Commission is of the view that any relevant evidence on estimation methods, including that from a range of financial models, should be considered to determine whether the overall rate of return objective is satisfied.*[242]

919. The SFG reports establish that in addition to the SL CAPM, equally relevant models for consideration in estimating the cost of equity are the Black CAPM, the Fama-French model (**FFM**) and the Dividend Growth model (**DGM**).[243] For these reasons the ERA has failed to have regard to the relevant models and methods identified by SFG, contrary to rule 87(5)(a) of the NGR.

920. SFG's expert opinion[244] is that the ERA's rejection of all models other than the SL CAPM is based on a number of errors as follows:

- It is an error of logic to decide that all industry dividend discount models are irrelevant based on the outcomes of the (very different) ERA model
- The ERA has erred in its conclusion that the SFG dividend discount model leads to an upward bias in the estimate of the required return on equity – the AER's Guideline makes it clear that the ERA has interpreted this point backwards
- It is an error to reject the FFM on the basis of its empirical motivation.[245] Logically, it makes no sense to maintain sole reliance on the SL CAPM due to the fact alternative models were originally developed for the purpose of improving the very poor empirical performance of the CAPM
- No reasonable person could give weight to the ERA study of the FFM over the published study of Brailsford, Gaunt and O'Brien, which concludes that *the three-factor model is found to be consistently superior to the CAPM*[246] in the Australian market.
- It is an error to disregard the Black CAPM on theoretical or empirical grounds. It is based on the same theory as the SL CAPM but with less restrictive assumptions, and its performance is consistently documented as being superior to the SL CAPM – so much so that it is known as 'the empirical CAPM' in US regulation cases.[247]

Estimates of the Return on the Market

921. The ERA considers that AGA presented only limited new information in relation to the relevant estimation methods, financial models, market data and other evidence which had not previously been considered in the

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241 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 663.

242 AEMC Rule Determination, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012, 29 November 2012, page 48.

243 SFG 2014, Estimating the required return on equity, Report for ATCO Gas Australia and SFG 2013, Regression-based estimates of risk parameters for the benchmark firm.

244 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014.

245 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 292.

246 Brailsford, Gaunt and O'Brien, Size and book-to-market factors in Australia, Journal of Management, 2012, p. 279.

247 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 296.

Rate of Return Guidelines process. The only element of the AGA proposal considered by the ERA to be new is the estimation of the required return on the market.

922. The ERA raised concerns that estimates of the return on the market are used to inform both the MRP estimate and the overall required return on equity. The ERA believes including this estimate in the return on equity brings the return for the benchmark efficient entity closer to the return on the market. As previously submitted by AGA and set out in the SFG Report,[248] the required return on the market is relevant information as all asset pricing models begin with an estimate of the required return on the market and then make adjustments for the extent to which the firm in question is considered to be different from the average firm. Further, it allows both theories relating to the relationship between the MRP and risk free rate to be taken into account.

923. The ERA also considers that it accounts for most of the information used to derive the return on the market in its estimate of the MRP. As demonstrated in section 0 and the SFG Report[249] the ERA has not appropriately accounted for all of the relevant information (being the Wright, Ibbotson, and DGM) for estimating the MRP.

924. With regard to the independent expert valuation report from Grant Samuel, which was submitted by AGA, the ERA considers that independent analyst reports are useful as cross checks but do not directly compare to the ERA's five year estimate of the required return on equity. Therefore the ERA only considers this information in the cross check step of its process. AGA has previously submitted evidence addressing the relevance of independent expert reports.[250] This evidence included a review of independent expert reports since 2008 and noted that none of them adopt a required return that is as low as proposed by the ERA. This information is not considered explicitly in the Draft Decision.

9.2.3.3 ERA Step 2 - Identify parameter values

925. Step 2 of the ERA approach for estimating the return on equity involves the estimation of ranges for each parameter based on relevant material, determining a point estimate within these ranges that takes into account relevant material, and adjusting for differences in risk if deemed necessary. As the SL CAPM is the only model the ERA considers to be relevant for the estimation of AGA's return on equity, the risk free rate, MRP and equity beta are the only parameters considered for estimation.

926. As previously submitted, AGA has significant concerns in relation to the ERA's estimation of these parameters. The ERA's sole reliance on the SL CAPM raises the bar on the required quality and accuracy of parameter inputs. These issues were extensively covered in AGA's March 2014 submission and accompanying expert reports. For the purposes of responding to the Draft Decision, AGA has relied on this previously submitted information and supplemented this where necessary with additional expert reports attached to this submission.

Risk free rate

927. In its consideration of the risk free rate component of the SL CAPM, the ERA states that its view on this matter, including the support for aligning the term of the risk free rate with the regulatory period, were set out in detail in the Rate of Return Guidelines.[251] Based on this previous analysis, the ERA has rejected AGA's proposed 10 year term for the risk free rate.

928. The ERA has maintained its position that the risk free rate should be estimated using the yield on CGS with a five year term to maturity. In the Draft Decision, the ERA adds to its previous reasoning for the term of the risk free rate and states that use of a 5 year term for the return on equity more appropriately reflects the

248 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 296.

249 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 296.

250 SFG 2014, Estimating the required return on equity, Report for ATCO Gas Australia.

251 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 628.

relevant investment horizon for the regulated business rather than a period which approximates the longer term to perpetuity (such as a period of 10 years or more).[252] This view is based on the assumption that as the value of the regulatory asset base, the risk free rate, and the equity premium are set at the start of each regulatory period there is relative certainty with regard to the related earnings cash flow over the regulatory period.[253]

929. The key errors in the ERA's approach setting the term of the risk-free rate to 5 years are:[254]

- The ERA's estimate is significantly different to that estimated commercially. Commercial practice is to estimate the risk-free rate using the yield on 10-year government bonds. In the current market conditions, the ERA's regulatory estimate of the risk-free rate (based on 5-year government bonds) is a material 0.63% below the commercial estimate[255]
- The ERA has erred in its interpretation of the NPV=0 principle. By insisting the NPV=0 principle requires the use of a 5-year risk-free rate, the ERA must either consider that:
  - Its conclusion does not require that the market value of the regulated asset at the end of the regulated period is known with certainty from the beginning of the regulatory period; or
  - The end-of-period market value of the regulated asset actually is known with certainty from the beginning of the regulatory period

  Neither of these assumptions are supportable.
- The ERA uses two different estimates of the risk-free rate in the two places the parameter appears in the CAPM equation (re = rf + B(rm-pf). The ERA adopts a MRP relative to the yield on a 10 year government bond in the second part of the equation and a 5 year term in the first part of the equation. This runs counter to the Tribunal's *GasNet* decision.[256]

Commercial practice

930. AGA agrees with the ERA that the term of the return on equity should correspond to the period over which cash flows are expected in relation to the invested assets.[257] However, the cash flows in relation to AGA's invested assets are expected to continue over an average life of approximately 38 years, or as long as 80 years for some investments made over the AA4 period.

931. AGA also agrees with the ERA in relation to the time horizons used by equity analysts. It is common practice for equity analysts to use 10 year rates as a proxy for the long term when evaluating cash flows. As noted by SFG, this is because the ten year bond market is the deepest bond market available in Australia and is a widely used and recognised benchmark.[258] In markets such as the USA where there are deeper markets for longer term bonds it is common practise for analysts to use a term of 30 years.[259]

[252] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 632.

[253] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 631.

[254] Appendix 9.1 SFG, The required return on equity: Response to ATCO Gas Draft Decision, November 2014, paragraph 264.

[255] Appendix 9.1 SFG, The required return on equity: Response to ATCO Gas Draft Decision, November 2014, paragraph 264.

[256] ACT, Application by GasNet Australia (operations) Pty Ltd, [2003] ACompT 6, Para. 46, emphasis added.

[257] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 630.

[258] Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 186.

[259] Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 186.

932. The ERA infers that the regulatory period has greater influence on equity investor's value of an asset rather than the life of the asset over which the cash flows will be provided. As noted by SFG,[260] a survey by Incenta examined the commercial practice for setting the risk free rate. In the survey, analysts were asked specifically about the term of the risk free rate in a CAPM valuation of regulated infrastructure assets with a five year regulatory cycle. All of those surveyed indicated that despite the five year regulatory term it was appropriate to use a 10 year rate for the purposes of CAPM valuation.[261]

933. The ERA suggests that the observed commercial practice of analysts and investors is not relevant to their regulatory task.[262] This is because the ERA does not see its task as seeking to replicate the commercial return that would be required by investors when investing in an asset with a similar degree of risk to the asset that is being regulated. Instead, the ERA sees its role as only estimating the prevailing conditions that apply for the regulatory period.[263] This position is in conflict with the ARORO, which states that the task at hand is to provide service providers with a return on capital that reflects efficient financing costs, allowing the service provider to attract the necessary investment capital to maintain a reliable energy supply while minimising the cost to customers.

934. It is accepted standard commercial practice for investors to assess the required return in accordance with the long term risk free rate. Yet the ERA maintains it will set the allowed rate of return based on (generally lower) shorter term risk free rates. This shows there is a clear misalignment between the behaviour of investors and the ERA. This misalignment creates a risk that the allowed return on regulated assets will be set below the rate that investors expect to receive on comparable assets in a commercial setting.[264] Setting the allowed return below the investors' required return will limit investment and result in allocative inefficiency.[265]

935. Figure 9–1 below demonstrates that the ERA's term of the risk free rate is significantly below that measured by other Australian regulators, accepted Australian commercial practice and accepted US commercial practice.

260 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 188.

261 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 188.

262 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 643.

263 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 643.

264 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 198.

265 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 201.

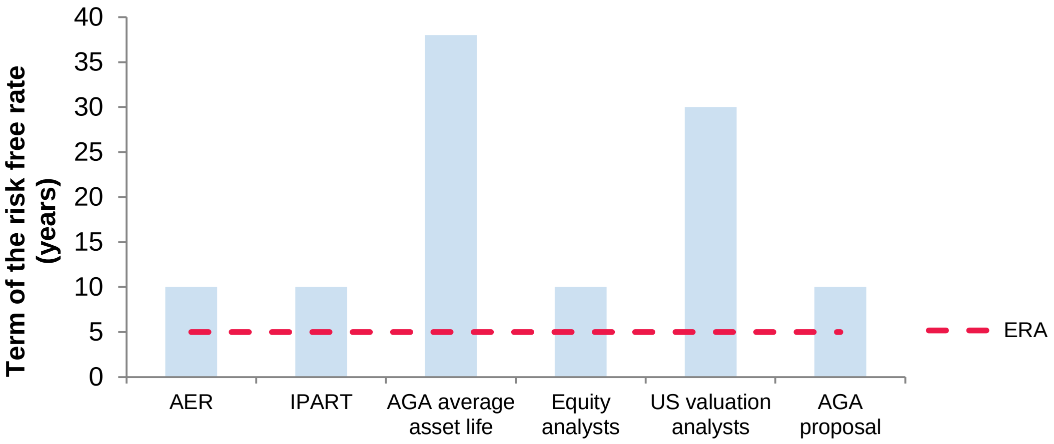

Figure 9–1: Comparison of the term of the risk free rate

NPV = 0

936. The ERA maintains that aligning the term of the risk free rate to the regulatory period achieves the NPV=0 principle. That is, by aligning the term of the risk free rate to the term of the regulatory period the net present value of expected cash flows is equal to the asset value.[266] AGA agrees it is appropriate to estimate prices such that the present value of expected cash flows is equal to the asset value. However, it is not necessary for the term of the risk free rate to equal the term of the regulatory period to achieve the NPV=0 principle. Correctly interpreted, the NPV=0 principle says that the term of the risk free rate should be appropriate for the cash flows that are being considered by investors.[267]

937. A further issue with the ERA's analysis is the assumption that the end of period market value of the assets in question is certain.[268] If this was the case, and the market value of the regulated asset was known with certainty from the outset, investors would be able to value the asset with reference to the cash flows over the regulatory period. There would be no need to consider any cash flows beyond the regulatory period if the end-of-period market value of the asset was known with certainty. However, in practice this is not the case. The end of period market value of assets is not know with certainty, as actual market conditions over the regulatory period are unknown.[269] Therefore, due to the risk associated with the market value at the end of the regulatory period, the cost of capital should reflect expectations for all future cash flows over the life of the asset. SFG considers this issue extensively in Appendix 9.1.

Inconsistency

938. The adoption of a five year term for the risk free rate also results in a consistency issue with the MRP. While the ERA states that its estimate of the MRP is consistent with a five year term, it is in fact estimated relative to the yield on 10 year bonds.[270] That is, the ERA has used a 10 year yield to estimate the risk free rate in one part of the CAPM formula (the MRP), and the 5 year yield to estimate the risk free rate in another part of the same CAPM formula. This issue has arisen because the historical market returns and dividend discount

266 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 207.

267 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 209.

268 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 631.

269 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 211.

270 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 232.

models used by the ERA to estimate the MRP were estimated by other regulators and consultants who set the term of the risk free rate to 10 years.[271] Further, a long term history of 5 year government bond yields is not available.[272] Therefore the ERA has created internal inconsistency in its chosen return on equity model by adopting both a ten and five year term for the risk free rate. The issue of consistency has been dealt with previously by the Australia Competition Tribunal (**ACT**) in the *GasNet* Decision. In its decision the ACT stated that the mathematical logic of the CAPM formula

> *…requires a consistent use of the value of rf in both parts of the CAPM equation where it occurs so that the choice was either a five year bond or ten year bond rate in both situations*[273]

939. The ACT went on to conclude that

> *In truth and reality, the use of different values for a risk free rate in the working out of a Rate of Return by the CAPM formula is neither true to the formula nor a conventional use of the CAPM.*[274]

940. A further issue of consistency arises due to the ERA's application of a 5 year term for equity holders and a ten year term for debt holders. As these are the same investors buying different types of securities (debt or equity) in the same firm it does not follow that the investments would be evaluated over different time horizons.

941. In relation to the term of the risk free rate for the cost of debt, the ERA has justified the use of a 5 year risk free rate with reference to the use of interest rate swaps:

> *The application of a 5 year risk free rate and an allowance for costs associated with interest rate swap contracts replicates the efficient financing costs of a benchmark efficient entity operating in a competitive market. The benchmark efficient entity may manage refinance risk by issuing longer term debt, but may hedge the underlying base rate by entering into 5 year swaps.*[275]

942. AGA is not aware of any reason as to why the term of the risk free rate would need to be consistent with the term of interest rate swaps. Unlike the cost of equity, an estimate of the risk free rate is not an input into the cost of debt estimate. Therefore, for the purpose of estimating the cost of debt for the benchmark efficient entity it is not necessary to define a risk free rate. To the extent that there is any implied risk free rate that is 'consistent' with a given debt management strategy it is intuitive that the risk free rate will have a term that is the same as the term of the debt at issuance.[276] If, as acknowledged by the ERA, the benchmark efficient entity issues staggered 10 year debt, the term of the risk free rate that underpins the associated cost of debt will also have a term of 10 years.[277]

Best estimate

943. AGA proposes that where the risk free rate is required as an input into the return on equity, CGS with a yield to maturity of ten years should be used. This approach is consistent with that previously submitted and with the accepted practice of market practitioners, and the expectations of investors. As discussed by SFG, the adoption of a 10 year term is also consistent with the practice of a number of Australian regulators.[278] Based

271 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 231.

272 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 232.

273 ACT, Application by GasNet Australia (operations) Pty Ltd, [2003] ACompT 6, paragraph 46.

274 ACT, Application by GasNet Australia (operations) Pty Ltd, [2003] ACompT 6, paragraph 46.

275 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 650.

276 Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014, section 6.

277 Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014, section 6.

278 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 253-255.

on this evidence and the expert evidence from SFG regarding the misapplication by the ERA of the NPV=0 principle, AGA submits the risk free rate estimate should be 3.58%, using the 20 day averaging period to 9 September 2014.

Market risk premium

944. The ERA departs from the approach outlined in its Rate of Return Guideline for the estimation of the MRP. In summary, the errors in the ERA's approach to estimating the MRP are:

- The ERA has incorrectly and illogically used indicator variables relative to their *historical ranges* to select a point estimate from within its current range for MRP. This approach has no logical basis to it. The appropriate way to have regard to indicator variables is set out by Independent Pricing and Regulatory Tribunal (**IPART**)[279]
- The ERA's estimate of the MRP includes the assumed value of imputation credits. Since its Guideline, the ERA has materially increased its assumed value of imputation credits but has neglected to revise its MRP estimates in accordance with its new estimate for gamma
- In relation to the Ibbotson historical returns approach, the ERA has failed to use the most recently available data and has failed to correct the available data for known inaccuracies
- In relation to the Wright historical returns approach, the ERA states that the approach should be used, but never calculates an estimate for it
- The dividend discount approach produces an estimate of the required return on the market, from which the risk-free rate is subtracted. By contrast, the ERA has interpreted the dividend discount approach as though it produces a direct estimate of MRP, which is independent of the risk-free rate. This is a clear error that results in the ERA adopting a dividend discount estimate of MRP that is inconsistent with the evidence on which the ERA relies.
- In relation to use of independent expert reports, the ERA has erroneously compared its own *with-imputation* estimate of MRP with an independent expert *ex-imputation* estimate of MRP. The ERA also erroneously compares its own estimate of *future* MRP allowances with independent expert estimates of the *current* MRP. These comparisons lead the ERA to conclude that its own estimate of MRP is consistent with the independent expert estimate when it is clearly not.[280]

945. Figure 9–2 below demonstrates that the ERA's estimate of the MRP is significantly below that estimated by relevant models and other Australian regulators.

[279] Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 108-111.

[280] Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, Section 3.

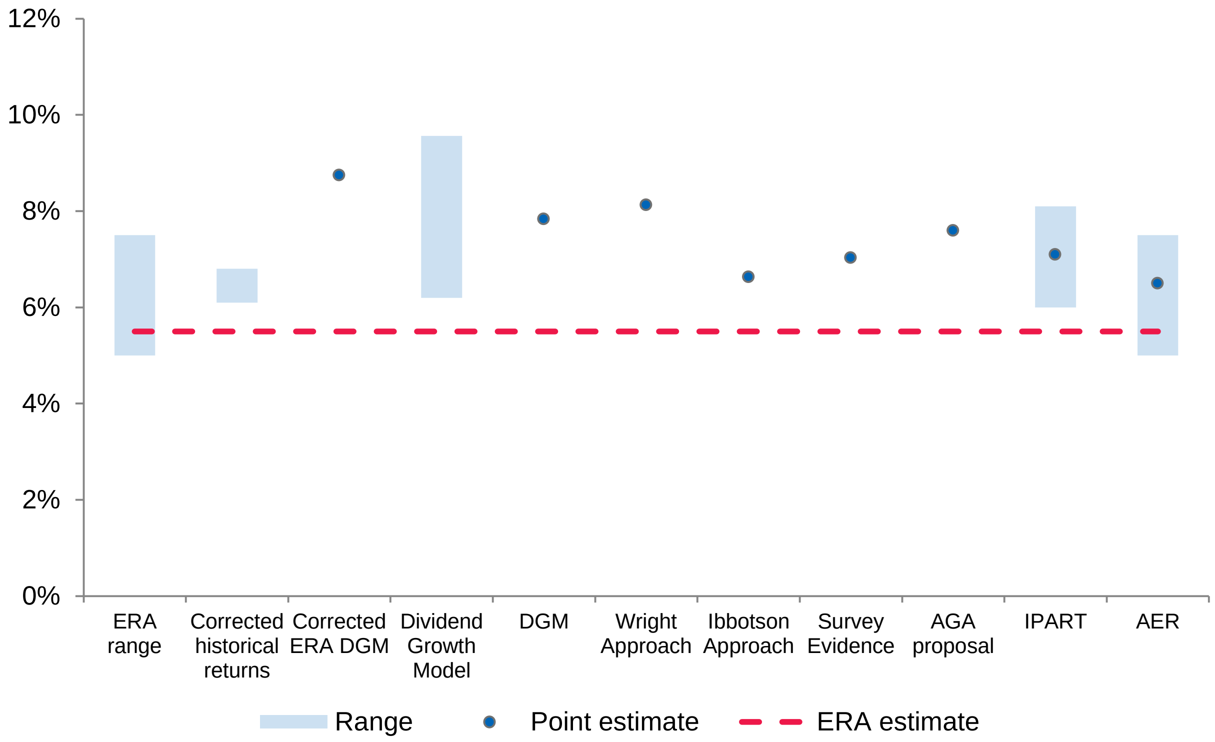

Figure 9–2: Comparison of MRP

Indicator variables

946. Consistent with the Guidelines, the ERA has maintained the range of 5%-7.5%, derived from the historical mean and DGM estimates, as the estimate of the current forward looking MRP. However, in order to select a point within this range the ERA has introduced four forward looking indicators.[281]

- Australian Stock Exchange (**ASX**) 200 volatility index
- Dividend yields on the All Ordinaries
- Interest rate swap spreads on 5 year bonds
- Default spreads

947. The current value of each of these variables is compared against the history of that variable over the length of the historical period available. The ERA then determines where the current value lies in relation to the historical range, which is then used to infer where the current MRP estimate would lie in relation to its historical range. This produces four estimates of the MRP, which are assigned weights to account for quality and relevance of each of the forward indicators.[282] The resulting estimate of 5.5% is then adopted as the MRP.

948. The use of the four forward indicator variables to select a point from within the 5% to 7.5% range was not detailed in the Guidelines.

949. AGA submits that the ERA has made a logical error by comparing each indicator variable to its historical mean with its own range for the current forward-looking MRP. Any consideration of indicator variables

[281] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 726.

[282] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 730.

relative to their history can only be used to inform the estimate of the MRP relative to its history. As demonstrated by SFG,[283] the leading indicators approach can be used to infer information about the MRP over the same historical period. That is, when the indicator variable is low relative to some historical period, it would be expected that the MRP would be correspondingly low relative to its values over the same historical period.[284] The ERA's approach uses one subset of evidence to determine that the current MRP lies between 5% and 7.5%. It then compares another subset of evidence (the four forward looking variables) to their historical ranges. Such a method may determine that the current MRP is below/above some historical point in time. However, it does not provide any evidence to determine which point in the ERA's estimate of the current range should be selected.

Historical Data

950. The ERA states that AGA's consultant, SFG, contends that *long run (or unconditional) estimates such as historic averages should not be used in forming a range for the MRP.*[285] AGA agrees that historical excess return estimates are relevant data that should be considered when estimating the MRP. However, historical returns should only be used to provide information about the MRP over average market conditions that applied over the relevant sample period. Sole reliance on historical data will only produce an estimate that is commensurate with the prevailing market conditions if the prevailing conditions are consistent with the long run average conditions.[286]

951. In response to issues previously submitted by AGA, the ERA clarifies that the 5%-7.5% range for the MRP does not represent a *statistical range based on the observations of a single data series.*[287] Instead the ERA considered a wide range of estimates including those based on the DGM and historical averages. The ERA states that:

> *…multiple estimates of each based on various sets of data (as opposed to a single set) were considered appropriate to establish a range for the MRP. The statistical range around each of the various estimates was not used in establishing the range of 5 per cent to 7.5 per cent. The resulting range spanned the outcomes of the estimates the Authority considered.*[288]

952. As noted by SFG, on this basis the range of estimates for the MRP from historical data would be 6.1% to 6.8%.[289] This range is achieved once the data the ERA relies on is updated and corrected for the following:

- The ERA's most recent estimate is three years out of date. The historical return estimates relied on by the ERA use sample periods that end in 2008, 2010 and 2011.[290]
- The estimates depend on the assumptions relating to gamma. In the Draft Decision the ERA has made significant revisions to its approach for estimating gamma, the MRP estimates should be updated to reflect this change.[291]

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283 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 101-107.

284 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 103.

285 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 703.

286 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 122.

287 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 702.

288 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 702.

289 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 120.

290 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 115.

291 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 115.

- As previously submitted, there are inaccuracies in the Brailsford estimates that should be corrected.[292]

Wright and Ibbotson Approaches

953. The ERA accepts AGA's previously submitted evidence that both the Wright and Ibbotson methods of processing historical data provide relevant evidence for the estimation of the MRP.[293] However, AGA does not agree that the ERA's current approach for determining the MRP is appropriately informed by the Wright or Ibbotson estimates.

954. The ERA does not present an estimate of the Ibbotson or Wright approach in the Draft Decision. Instead the ERA suggests that as it has established a range for the MRP encompassing both historical and DGM estimates it has *accounted for the alternative views relating to the stationarity of the MRP.*[294] The ERA also suggests that the DGM estimate is a substitute for the Wright approach estimate[295]. This is not the case as the Wright approach is a method for processing historical data, whereas the DGM estimate is based on current stock prices and forecast dividends.[296] The Wright approach and DGM also produce significantly different estimates. As both the Ibbotson and Wright approaches are relevant to the estimation of the MRP, the ERA should use both approaches to process the historical return data.

Dividend Growth model analysis

955. For the purpose of establishing the MRP range, the ERA considered 11 different estimates and based on a median of these observations established the top of the MRP range as 7.5%. It did not rely on its own DGM estimate to inform the range.[297] AGA submits that the ERA's interpretation of some of the estimates in the sample results in a downward bias in the MRP estimate. These issues relate to the ERA not using the most contemporaneous data and incorrectly interpreting that all DGM estimates have been presented as being with-imputation.[298] Correctly interpreted, the ERA's sample results in an estimate of the required return on the market of at least 11.70% and an estimate of the MRP of at least 8.75%.[299]

Best estimate

956. AGA maintains its previously submitted position[300] that the ERA's estimate of the MRP is not the best estimate, as the primary range of 5%-7.5% has been incorrectly established. Evidence relating to the downward bias in the historical mean estimate[301] and a recent DGM study by IPART[302] indicates that the approach set out in the ERA's Rate of Return Guidelines is not the best estimate of the MRP. Further, there is no justification for utilising the current position of forward looking indicators in relation to their historical performance for choosing the point estimate.

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[292] Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 115.

[293] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 674.

[294] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 715.

[295] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 714.

[296] Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 129.

[297] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 722.

[298] Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 143.

[299] Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 144.

[300] ATCO Gas Australia, Access Arrangement Information 1 July 2014 – 31 December 2019 (AA4), March 2014.

[301] SFG 2014, Estimating the required return on equity, Report for ATCO Gas Australia, paragraph 399-401.

[302] SFG 2014, Estimating the required return on equity, Report for ATCO Gas Australia, paragraph 403.

957. The ERA's approach will not result in an estimate of the return on equity that is commensurate with the efficient financing costs of a benchmark efficient entity and does not give rise to a rate of return that achieves the ARORO, the NGO or the RPP because:

- As a result of the errors identified by SFG, it is not the best estimate of the MRP
- The ERA fails to have regard to all relevant models, data and evidence in estimating the MRP

958. AGA proposes to use all relevant information to estimate the required return on the average firm that is consistent with the prevailing conditions in the market. This material is considered relevant as all asset pricing models begin with an estimate of the required return on the market and then make adjustments for the extent to which the firm in question is considered to be different from the average firm. Further, it allows both theories relating to the relationship between the MRP and risk free rate to be taken into account.

959. AGA's proposal is dealt with in further detail below and in the SFG reports. In summary, SFG's opinion is that the best possible estimate of the MRP is obtained by correcting the errors in the ERA approach set out above and estimating the required return on equity for the market considering the following four approaches:

- DGM estimate of the contemporaneous required return on the market of 11.42%
- Wright approach estimate of the required return on the market of 11.71%
- Ibbotson approach estimate of the required return on the market of 10.21%
- Survey evidence from independent valuation experts resulting in a with-imputation estimate of 10.61%[303]

960. AGA recognises that all these approaches have their own strengths and weaknesses.[304] Therefore, in order to arrive at an average market estimate, AGA proposes to apply the following weights to the return on the market estimates:

- Historical return (Ibbotson) 20%
- Historical return (Wright approach) 20%
- Dividend discount model 50%
- Independent expert valuation reports 10%

961. This method produces an estimate of 11.19%[305] for the required return on the market which implicitly incorporates an estimate of 7.61% for the MRP.

Equity Beta

962. The ERA has applied the same method for estimating the equity beta parameter as outlined in its Rate of Return Guidelines. This approach involves three key steps. First a range of 0.5-0.7 is established from a range of empirical studies. In particular, the ERA has relied on an updated empirical study based on the methodology outlined by Henry.[306] In the second step, a point estimate of 0.7 is adopted from the nominated range based on an assessment of the downward bias in equity beta estimates with values less than one. The third step involves cross checks of this point estimate, however, the draft decision does not present any relevant cross checks for the equity beta until Step 4 of the process. Therefore the estimate of 0.7 is adopted.

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303 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph171-176.

304 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 172-173.

305 SFG 2014, Estimating the required return on equity, Report for ATCO Gas Australia, paragraph 430.

306 Henry 2009 Estimation beta, Advice submitted to the Australian Competition and Consumer Commission.

963. The result of partitioning this evidence into three separate steps effectively prevents it from being properly considered in the context of its relative strengths and weaknesses[307] and restricts the ability of any other evidence to influence the range established by the ERA's empirical studies. In the Draft Decision, the ERA has determined that the systematic risk of AGA has fallen by 12.5% over the last five years (from 0.8 to 0.7). Accordingly, the equity risk premium available to AGA's shareholders will be reduced by 12.5%. These are highly material changes, yet the ERA has not explained what has led to AGA becoming materially less risky over the past few years. AGA's business operations have not changed, its financial and operating leverage has not changed, and its credit rating has not changed. The ERA appears to have reduced the equity beta estimate based purely on its statistical analysis.

964. The ERA did not consider any of the evidence previously submitted by AGA or its consultant SFG warranted a revision to the process or data set used to estimate equity beta.

965. The ERA's Draft Decision in respect of equity beta is subject to the following key errors:

- The ERA incorrectly takes the view that the very small set of domestic comparators is able, by itself, to produce a reliable estimate of equity beta
- The ERA fails to have regard to international comparators, which is relevant to the estimation of equity beta[308]

Consequently the ERA's estimate of equity beta is inaccurate, unreasonable and is not the best estimate

966. The following discussion addresses the issues raised by the ERA in relation to this evidence and demonstrates that the ERA's approach does not consider all relevant information.

Methodological issues

967. The ERA considers a range of statistical techniques to inform the overall observed range of equity beta.[309] The ERA notes that the upper point of 0.7 is consistent with the upper end of the range determined by bootstrap analysis.[310] The lower bound of 0.5 is the midpoint of the 0.3 to 0.72 range[311] and is consistent with the equally-weighted portfolio average estimate, the average value-weighted portfolio estimate and the average of the individual firm estimate.[312] The ERA's range does not represent a statistical confidence interval and does not represent the minimum or maximum point estimates of the bootstrap analysis. Rather, as demonstrated by SFG,[313] it appears that the ERA's range represents the point estimate from domestic comparators and one end of the 95% confidence interval from the ERA's bootstrap analysis. It is not clear how to interpret a range that combines a point estimate at one end with a statistical upper bound at the other.[314] Further, Table 40, Appendix 25 of the ERA's Rate of Return Guidelines reports an average

307 SFG 2014, Estimating the required return on equity, Report for ATCO Gas Australia, paragraph 359-362.

308 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, Section 2.

309 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 745.

310 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 746.

311 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 747.

312 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 747.

313 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 33.

314 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 34.

bootstrap confidence interval of 0.307 to 0.760. That is, the upper bound from the ERA's own analysis of its domestic comparators is closer to 0.8 than 0.7.[315]

968. The ERA rejects SFG's criticism regarding the sensitivity of individual equity beta estimates to the methodological choices of regression technique and sampling period.[316] It appears the ERA has misinterpreted this point. As previously submitted, the ERA's equity beta estimates vary across methodological choices and overtime. Further, the ERA's beta estimates comprise an implausible variation in the systematic risk of the firms sampled. As the variation in the ERA's beta estimates do not plausibly reflect the variation in the true systematic risk of comparator firms, it is unlikely that the ERA's estimates would reliably reflect the level of systematic risk in the comparator firms.[317]

969. AGA also submitted evidence demonstrating that the ERA's equity beta estimates varied materially depending on which day of the week or month was used. The ERA rejected this evidence based on the analysis in its Rate of Return Guidelines.[318] AGA maintains the view that the wide variation in mean beta estimates caused by changing the date of the week or month used to define the return interval is evidence of instability. That is, the beta estimates vary widely across methodological choices and over time.[319] The ERA notes that its use of Friday to Friday return is consistent with that suggested by Henry and commonplace throughout academic literature.[320] However, as noted by SFG, there is no conceptual or statistical reason to prefer one day of the week to any other and there is no uniform standard day of the week that is generally used in academic literature.[321] This issue is compounded by the fact the ERA's sample is so small that variation in beta estimates as we move from day to day does not cancel out. In a larger sample this variation would tend to cancel out.[322]

Use of international comparators

970. It was previously submitted that many of the issues associated with the ERA's estimate of equity beta could be overcome if the sample was increased to include international data. Based on the analysis in the Rate of Return Guidelines, the ERA disagrees with the use of international data to inform the required equity beta.[323] The rejection of international data was based on the consideration that while the inclusion of this data would improve the size of the sample, this would be outweighed by distortions due to differences between the benchmark efficient entity and international firms.

971. AGA acknowledges there is a trade-off between comparability and statistical reliability. In the case of estimating the equity beta it is important to consider the reliability of the beta estimate from the proposed sample against the comparability of the firms that might be included.[324] The ERA has recently considered this trade-off in its Rate of Return Guidelines for the Freight and Urban Railway Networks. Due to the lack of comparators in the domestic market, the ERA uses foreign comparators for the purposes of estimating the

315 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 34.

316 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 748.

317 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 39.

318 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 752.

319 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 36.

320 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 752.

321 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 50.

322 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 47.

323 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 753.

324 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 57.

equity beta. The ERA notes that some parameters are likely to be more independent of jurisdiction than other parameters. The ERA site gearing, credit rating and equity beta are likely to be more independent of jurisdiction than other parameters more closely linked to country conditions.[325] It is not clear how the ERA can determine that the presence of only 6 comparators for the rail networks cannot produce reliable estimate of equity beta and therefore international data is required to produce a robust estimate. However, the ERA concludes that for the purpose of estimating equity beta for AGA, the four currently listed comparators do produce reliable estimates for beta.

972. Further, the ERA has been inconsistent in its consideration of the relevance of international data for different parameters. The ERA considers it is appropriate to consider international data for the cross check of regulatory precedent of the return on equity and have included international bonds in the sample from which the DRP estimate is derived. Yet the ERA is still of the opinion that international comparators are not relevant to the estimation of equity beta. It is not clear to AGA how the ERA has arrived at the conclusion that international data can be relevant for some parameters but not for others.

973. As demonstrated by SFG, international data is richer, more stable and more reliable than those available in the domestic market.[326]

Best estimate

974. AGA maintains its previously submitted position that the ERA's exclusive reliance on a small sample of Australian listed firms creates a high level of instability over time. Therefore the ERA's approach will not result in a best estimate of the equity beta, nor one which produces a rate of return commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk to AGA.

975. AGA proposes that where the equity beta is required as an input, an estimate of 0.82 be applied. This proposal is addressed further in the SFG report,[327] but in summary this estimate was derived from a sample including 9 Australian and 56 US listed stocks. This estimate overcomes the reliability issues caused by the ERA's small sample size. The Australian-listed firms are consistent with those relied upon by the ERA while the US-listed firms have been selected after careful analysis for industry classifications, the proportion of assets regulated and liquidity. As information from an Australian-listed firm will be more relevant than information from a U.S.-listed firm, Australian observations have received twice the weight of those from the US.[328]

976. AGA submits its estimate of 0.82 for the equity beta is a better estimate than provided for in the ERA's Draft decision as:

- It overcomes the statistical issues associated with small samples
- It is a reliable estimate of the equity beta
- It is consistent with estimates adopted in previous regulatory decisions
- It takes into account all relevant data

9.2.3.4 ERA Step 3 - Estimate return on equity

977. This step involves populating the SL CAPM with the relevant parameter values. As the ERA has relied on a single model the resulting return on equity will be determined as a product of changes to parameter values,

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325 ERA 2014, Review of the method for estimating the weighted average cost of capital for the freight and urban railway networks – Draft Determination, paragraph 132.

326 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 71-72.

327 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 75-78.

328 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 78.

rather than consideration of estimates from other models. As a result, the ERA's estimate for the return on equity of 6.80% only reflects the parameter values identified and this result has not been assessed against the ARORO. This mechanical approach to the estimate of the cost of equity was the reason for the AEMC rule changes to rule 87 of the NGR and the insertion of the requirement in rule 87(5)(a) of the NGR to have regard to all relevant models, methods, data and evidence in order to arrive at the best estimate.

978. As discussed throughout this chapter and established by the SFG Reports,[329] AGA does not agree with the ERA's assessment that other cost of equity models are not relevant for consideration in estimating the return on equity consistent with the ARORO and rule 87 of the NGR.

9.2.3.5 ERA - Step 4 conduct Cross Checks

979. This step involves the consideration of other relevant material as a form of checking the parameter estimates and overall return on equity. While the Rate of Return Guidelines states this step also involves consideration of whether the return on equity estimate achieves the ARORO, such a test is not explicitly considered in the Draft Decision. As previously submitted, the cross checks outlined in the Rate of Return Guideline do not appear to have any impact on the overall return on equity estimate.

980. The material set out by the ERA, which it has considered for the purposes of estimating the return on equity for the Draft Decision, has only been used to confirm the estimates of individual parameters rather than the estimate of the return on equity. These cross checks have no material effect on the estimate of the allowed return on equity. AGA's specific concerns relating to these cross checks is detailed in the following discussion.

MRP Cross check

981. The ERA has referenced several other information sources in its consideration of the point estimate of the MRP. This information has been used by the ERA to determine whether an upwards or downwards revision to the point estimate is required.[330] The material considered relevant for cross checking the MRP estimate includes:

- Views of valuation experts and surveys
- Decisions of other regulators

982. For the purpose of performing these cross checks, the ERA is of the opinion that it is appropriate to estimate long term average figures for the MRP and return on equity. This is because the ERA's 5 year forward looking MRP and return on equity are not directly comparable to the ten year estimates used by investment analysts and other regulators. Therefore, the ERA:

> *… considers it appropriate that all 10 year/perpetual investment horizon type estimates of the return on equity can only be compared to the longer term average of the Authority's 5 year forward looking return on equity estimates using its proposed methodology.*[331]

983. The ERA has estimated that the average of the forward looking five year return on equity over the period 1993-2014 is 10.9%.[332]

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329 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014 and SFG 2014, Estimating the required return on equity, Report for ATCO Gas Australia.

330 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 766.

331 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 774.

332 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 775.

984. The ERA considers that the Grant Samuel expert valuation report, submitted by AGA, is consistent with the ERA's longer term average of the forward looking return on equity. This is because the ERA's long run average of the 5 year return on equity of 10.9% is within the Grant Samuel range of 10.7% to 15.2%. AGA submits the ERA's assertion that its estimate of the required return on the market passes the 'views of valuation experts' cross check is incorrect. This is due to several factors including:

- Inconsistency between the Grant Samuel and ERA estimates. Grant Samuel presents an estimate of the return that investors would reasonably require from a contemporaneous equity investment in a gas distribution business such as Envestra. This estimate should be compared with the ERA's estimate of the *current* required return on equity, not the return on equity that the ERA might estimate at some time in the future[333]
- Even if it was expected that the ERA *would* eventually revert to using a 10.9% estimate for the required return on the market, its *current* estimate for the next five years is 8.45%. Therefore, the long term estimate would be a weighted-average of its current estimate and its expected future estimates over a period of transition back to its long-term estimate of 10.9%. The current estimate would receive more weight because it applies to near-term cash flows. Thus, the weighted-average estimate would fall below the Grant Samuel range[334]
- Even if this was the correct basis of comparison, the fact that 96% of the Grant Samuel range is above the ERA's long-run estimate would be a relevant consideration when determining whether or not the ERA estimate is corroborated by Grant Samuel[335]

Adjustment for imputation credits

985. Another issue with the ERA's comparison to the Grant Samuel estimate is due to the inclusion of the value of imputation credits. The ERA's estimate includes the assumed value of imputation credits while the Grant Samuel estimate has excluded the value of imputation credits. Therefore, the ERA and Grant Samuel estimates are not comparable. If the ERA estimate was converted to the same basis as the Grant Samuel estimate the required return excluding imputation credits estimated by the ERA would be 6.96%. This estimate falls well outside the Grant Samuel range of 10.7% to 15.2%.

986. The ERA considers that if Grant Samuel did account for the impact of imputation credits then it would need to adjust its observed return on the market estimate down.[336] The ERA's position on this adjustment is in stark contrast to that of other Australian regulators.[337] Further, as the Grant Samuel estimate does not incorporate the value of imputation credits it is not clear how this estimate could be adjusted downwards to remove the impact of imputation credits.[338] The application of the imputation credit adjustment is also an issue in the ERA's consideration of the Ernst and Young (**EY**) survey. Again the ERA incorrectly states that as the EY estimates do not assign a value for imputation credits the resulting estimates would have to be adjusted downwards.[339] In line with the correct practice, adjusting for the value of imputation credits would be expected to increase the estimate.

333 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 152.

334 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 152.

335 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 152.

336 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 786.

337 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 164-165.

338 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 162.

339 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 787.

Estimates from other regulators

987. In its consideration of the views of other regulators the ERA compares the return on the market estimate (and its components) to that from the AER, IPART and the Alberta Utilities Commission. The AER and IPART prepare their estimates on a 10 year basis and assign more weight to the Wright approach. Despite having a much lower estimate to that of the AER and IPART, the ERA considers its current indicators are a reasonable approach for assessing the return on equity. When making comparisons to international regulators, such as the Alberta Utilities Commission, the ERA erroneously compares its longer term estimate of the 5 year return on equity. For the reasons discussed previously, it is inappropriate for the ERA to use this longer term estimate when undertaking its cross-check as it does not represent the ERA's estimate of the current return on equity required by investors.

988. In summary, the ERA has made significant errors in the cross check step of their process. Not only does this step have limited influence/impact on individual parameters but the ERA has misinterpreted and incorrectly applied adjustments to information it considers relevant for the purpose of cross checks. Therefore the parameter estimates do not take into account all relevant material and do not represent the best estimates.

989. Figure 9–3 below demonstrates that the ERA's estimate of the return on the market is materially below that produced by relevant models and adopted by other Australian regulators.

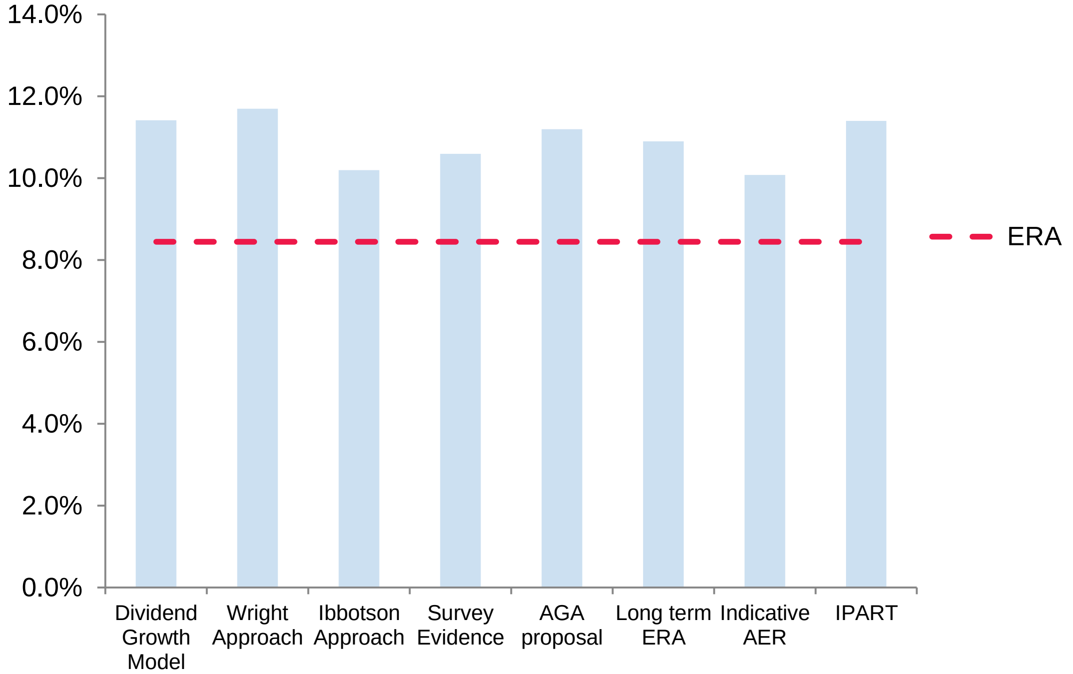

Figure 9–3: Comparison of return on the market estimates

9.2.3.6 ERA - Step 5 Determine the return on equity

990. The ERA states that having taken into account all relevant information, an expected return on equity of 6.80% is appropriate as an estimate for the forward looking five year return on equity.[340] The ERA considers its estimate is:

> *…commensurate with a similar degree of risk as that which applies to the Service Provider in respect of the provision of Reference Services prevailing at this time. On this basis the Authority*

340 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 817.

considers that the estimate meets the allowed rate of return objective and the requirements of the NGR and NGL more broadly.[341]

991. As set out in this submission and supported by the SFG expert evidence, the ERA's methodology fails to have regard to numerous relevant models and information and accordingly does not give rise to the best estimate of the rate of return commensurate with the risk of a benchmark entity. To accept that it would achieve the ARORO requires accepting the proposition that other estimates from models, market valuations and regulators are irrelevant or wrong. Consideration of the information presented by AGA and SFG, clearly demonstrates that the ERA has omitted relevant evidence and utilised parameter estimates that result in a required return on equity that:

992. • Fails to have regard to and is not commensurate with estimates from other models and approaches

993. • Does not apply the best estimate of the parameters relevant to the SL CAPM

994. • Is not a best estimate of the cost of equity

995. • Is not commensurate with the prevailing cost of equity

996. • Is not commensurate with benchmark efficient financing costs

997. Consequently, the ERA approach in the Draft Decision does not produce a cost of equity estimate that meets the ARORO, the NGO or the RPP.

9.2.3.7 AGA's return on equity proposal

998. Consistent with the position previously submitted, AGA has considered all relevant estimation methods, models, market data and evidence when estimating the required return on equity. AGA sought expert advice to ensure all relevant evidence was identified, tested and properly considered in undertaking this task. This advice included an assessment of the ERA's Draft Decision against the requirements of the NGR, NGO and RPPs. AGA's estimate of the required return on equity of 10.51% is consistent with the ARORO and meets the requirements of rule 87 of the NGR, the NGO and RPP.

999. AGA proposes the cost of equity be estimated after consideration of four separate cost of equity estimates, which rely upon different equations and empirical support. This approach considers all relevant estimation methods, financial models and market data in a single step, ensuring all evidence is considered in the context of its own strengths and weaknesses. This approach also has the effect of eliminating restrictions on the ability of evidence to influence the return on equity estimate.

1000. Discussion of each technique and consideration of each estimate's role in determining the return on equity is set out in the attached expert report by SFG. The models and their associated estimates used by AGA to determine the required return on equity for the benchmark firm are:

- The SL CAPM – 9.80%
- Black CAPM – 10.41%
- The Fama-French model – 10.64%
- The DGM – 10.76%

[341] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 818.

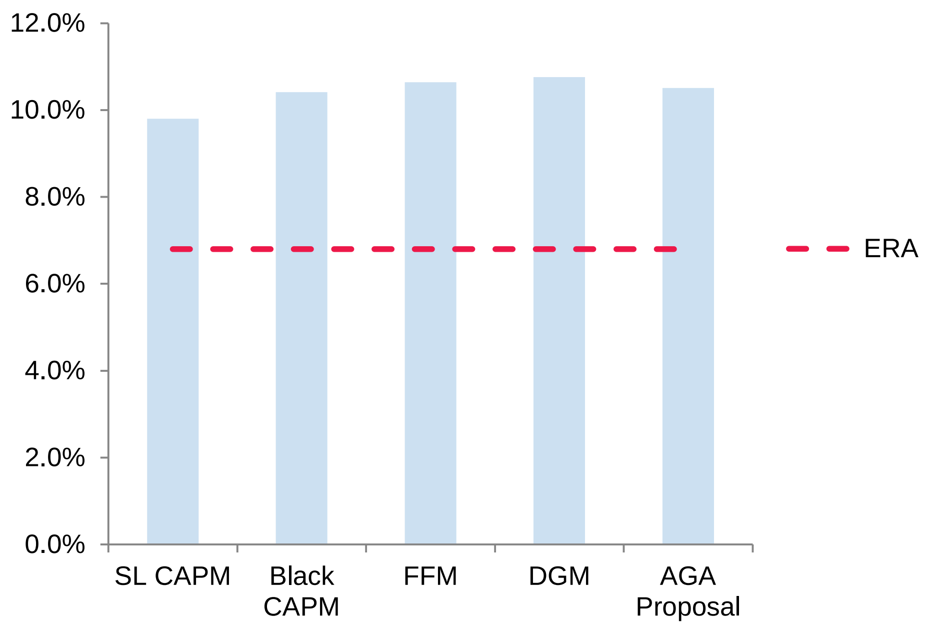

Figure 9–4: Return on equity comparison

9.2.3.8 SL CAPM

1001. AGA agrees with the ERA that the SL CAPM is relevant and should be considered in the estimation of the rate of return. SL CAPM like other models has strengths and weaknesses and is affected by estimates of input parameters. As previously submitted by AGA, the SL CAPM is acknowledged to have poor empirical performance; inability to reflect changes in market conditions; and failure to achieve rates of return that would be consistent with the outcomes of efficient, effectively competitive markets.[342] These weaknesses can be addressed, at least in part, by incorporating appropriate and correctly estimated parameter inputs. For the reasons set out above and in the SFG report,[343] the ERA's parameter estimates in the SL CAPM are incorrect and unreasonable. AGA has incorporated the following parameter estimates into the SL CAPM:

- Risk free rate of 3.58% derived from the yield on CGS with a term to maturity of 10 years
- Estimate of the required return on the market of 11.19% as estimated through the weighted average approach
- Equity beta estimate of 0.82[344] based on a range of regression analyses applied to a large sample of domestic and international comparators. This estimate overcomes statistical issues associated with small samples and is consistent with past regulatory practice

1002. AGA estimates the return on equity from the SL CAPM properly applied to be 9.80%.[345]

9.2.3.9 Black CAPM

1003. The Black CAPM is used extensively in US regulation cases precisely because of its superior empirical performance relative to the SL CAPM. In US regulation cases, the Black CAPM is known as the 'empirical

342 SFG 2014, Estimating the required return on equity, Report for ATCO Gas Australia, paragraph 114-121.

343 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014.

344 SFG 2013, Regression-based estimates of risk parameters for the benchmark firm.

345 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 329-330.

CAPM' because it is a version of the CAPM that has more reliable empirical performance. There is also a large academic literature that attests to the superior empirical performance of the Black CAPM.[346]

1004. Relative to the SL CAPM, the Black CAPM requires the estimation of one additional parameter, the zero beta premium. At the time of AGA's previous submission to the ERA, no precise estimates were available for the zero-beta premium for the Australian market. There was, however, a study by NERA (2013) which showed that for the Australian market there was no statistically significant relationship between beta (as estimated by Australian regulators) and subsequent returns. This implies a flat CAPM line whereby all firms have the same expected return as the market regardless of their beta estimates.[347]

1005. In its Draft Decision the ERA disregards the NERA study on the basis that it is not sufficiently reliable. Since AGA's March 2014 submission, SFG has further developed an estimate of the zero beta premium, which addresses issues raised by the AER and the ERA in its Guidelines.[348] The SFG[349] Report provides an estimate of the zero-beta premium of 3.34%, which is within the reasonable range set out in the AER's Guideline materials.[350] This estimate is also consistent with the estimates that have been reported for US data which led to the original development of the Black CAPM.

1006. The SFG estimate of the zero beta premium and the estimate of the return on equity arising from the Black CAPM are set out in the SFG Report.[351] For the reasons set out in the SFG reports, the Black CAPM is a relevant model for the purposes of estimating the required return on equity.

1007. AGA estimates the return on equity from the Black CAPM to be 10.41%.[352]

9.2.3.10 Fama French

1008. AGA considers the FFM is relevant and should be considered in setting the return on equity, as it is theoretically sound and is commonly used by market practitioners as well as in academic research.

1009. As demonstrated by SFG,[353] the FFM generally satisfies the criteria outlined in the ERA Guidelines at least as well as the SL CAPM. Specifically, the FFM is fit for purpose; driven by economic principles; supportive of robust, transparent and replicable analysis; as well as supportive of specific regulatory aims.[354] Therefore the FFM is clearly relevant to the estimation of the return on equity and should be taken into account in the estimation, which SFG has done and AGA relies on.

1010. AGA has based its estimate from the FFM on the SFG 2014[355] study, which sets out the most recent estimates of beta and the size and book-to-market premiums using Australian and US-listed observations. As a result, AGA's FFM estimate encompasses the most recent and relevant market information. In order to arrive at an estimate the FFM has been populated with the following parameters:

- Market beta of 0.77

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346 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 296.

347 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 298.

348 Appendix 9.3 Cost of Equity in the Black Capital Asset Pricing Model, Stephen Gray, SFG Consulting May 2014.

349 Appendix 9.3 Cost of Equity in the Black Capital Asset Pricing Model, Stephen Gray, SFG Consulting May 2014.

350 AER Rate of Return Guideline, Explanatory Statement, Appendix C, p. 71.

351 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 295-302, 331-332 and the appendices to the SFG report.

352 SFG 2014, Estimating the required return on equity, Report for ATCO Gas Australia, paragraph 319.

353 SFG 2014, Estimating the required return on equity, Report for ATCO Gas Australia, paragraph 74-113.

354 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 282-294.

355 Appendix 9.4 The Fama-French model, Stephen Gray, SFG Consulting May 2014.

- Ex-imputation MRP of 6.53%
- Risk premium in relation to the size factor of -0.19%
- Risk premium in relation to the book-to-market of 1.15%
- Risk free rate and required return on the market as specified in the SL CAPM model

1011. This results in an estimate of the required return on equity of 10.64%[356]

9.2.3.11 Dividend growth model

1012. The foundation of the DGM is that share prices represent the present value of expected dividends. Therefore, the DGM estimate represents the discount rate that sets the present value of all expected future cash flows to equity holders equal to the share price. As identified by SFG, the DGM approach has a sound basis and is extensively used in practice, including for the purpose of determining regulatory rates of return.[357] As such, AGA considers industry DGM estimates are relevant in the estimation of the return on equity.

1013. The DGM analysis relied upon by AGA takes information provided by equity analysts such as earnings forecasts, dividend forecasts, and price targets and derives estimates of the cost of equity using all available data in a systematic manner. In AGA's view, cost of equity estimates derived from forecasts of earnings, dividends and share prices constitute relevant information and should therefore be given consideration under the NGR.

1014. In its Guidelines the ERA elected not to give consideration to DGM estimates of the cost of equity on the basis that the inputs into the model are subjective, the model is not based on a strong theoretical foundation and that, 'without further development' it has shortcomings with regard to being fit for purpose. While the ERA has dismissed DGM estimation as a relevant model for estimating the cost of equity for the overall market or benchmark firm, it considers it is relevant to inform the range from which the MRP is estimated, for the application of providing this input to the SL CAPM. This position was maintained in the Draft Decision. It is unclear how a model could be considered relevant for the estimation of a range for a particular parameter of the SL CAPM but it is not considered relevant for measuring the cost of equity for the overall market or a benchmark firm.

1015. AGA submits the approach it employs for DGM estimation addresses the limitations highlighted in both the ERA and AER Guidelines.[358] In order to estimate the return on equity using the DGM, AGA has relied on the 2014 SFG study[359] which applies the DGM approach to a broad market index and also to a set of comparable firms.

1016. For the reasons set out in the SFG Reports, DGM estimates are relevant information for the purposes of estimating the required return on equity. The DGM estimate of the required return of the benchmark comparable firm is 10.76%.[360]

9.2.3.12 Return on equity estimate

1017. The return on equity proposed by AGA is based on a weighted average of the four estimates discussed above being:

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356 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 335-339.

357 SFG 2014, Estimating the required return on equity, Report for ATCO Gas Australia, paragraph 122-139.

358 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 281.

359 Appendix 9.5 Alternative versions of the dividend discount model and the implied cost of equity, Stephen Gray, SFG Consulting May 2014.

360 Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 340.

- The SL CAPM – 9.80%
- Black CAPM – 10.41%
- The Fama-French model – 10.64%
- The DGM – 10.76%

1018. Consistent with the views of SFG,[361] AGA proposes the following weightings in recognition that all the models considered have varying levels of strengths and weakness:

- 25% weight is applied to the dividend discount model and a total of 75% weight is applied to the three asset-pricing models
- Of the 75% weight that is applied to asset-pricing models, we apply half to the FFM and half to the CAPM
- A total of 37.5% weight is applied to the CAPM models. The two forms of the CAPM differ only in terms of the intercept that is used (since the same values of beta and the required return on the market are used for both models)

1019. SFG's opinion is that this weighting reflects the best available estimate of the required return on equity for a benchmark efficient entity and best reflects the prevailing conditions in the market for equity funds.[362] SFG also note that the final estimate of the required return on equity for a benchmark efficient entity is relatively insensitive to the choice of weights.[363]

1020. Applying these weights to the return on equity estimates from multiple models results in an overall return on equity of 10.51%. The NGR requires the cost of equity be estimated having regard to all relevant information. The proposal put forward by AGA incorporates all relevant information into the cost of equity estimate in an objective and transparent manner.

9.2.3.13 Materially preferable to correct errors

1021. The SFG report identifies a number of errors in the ERA Draft Decision relating to the cost of equity. The errors are summarised in paragraph 349 of the SFG Report. SFG has considered the ERA's Draft Decision against the achievement of the NGO and the RPP. In SFG's view:

- As a result of the errors in the ERAs Draft Decision, the current estimate of the cost of equity is not the best possible estimate and does not meet the ARORO. Consequently the ERA's allowed return will not achieve the NGO or the RPP[364]
- Correction of the ERA's errors identified by SFG would lead to a materially preferable estimate of the allowed return on equity that is more consistent with the ARORO, NGO and RPP[365]

[361] Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 342.

[362] Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 344.

[363] Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 343.

[364] Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 365.

[365] Appendix 9.1 The required return on equity: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 370.

9.2.4 Cost of debt

1022. It has been the practice of Australian regulators to express the cost of debt as the sum of the risk free rate and debt margin, where the debt margin represents the compensation above the risk free rate that investors require for credit, maturity and market risk.

1023. AGA submits that as the cost of debt estimate can be observed directly, it is not necessary to estimate the risk free rate component of debt.[366] There is no requirement in the NGR for the cost of debt to be estimated in this way. Therefore AGA proposes to base its estimate of the cost of debt on the DRP combined with a swap contract overlay (the hybrid approach). Consistent with the ERA's Draft Decision, AGA has also incorporated a margin to account for administrative and hedging costs.

1024. The ERA's Draft Decision and AGA's approach are consistent as to what amounts to efficient debt management strategies. However, unlike AGA, the ERA proposes estimation methodologies which are inconsistent with these strategies.[367] While it is agreed that efficient debt management strategies include 10 year staggered debt, the ERA nevertheless seeks to calculate the cost of that debt using annual updates of the DRP. This is a non-sequitur because a 10 year staggered debt portfolio by definition cannot be rolled-over annually. Secondly, as set out below, the ERA and AGA differ significantly as to the basis for calculating the debt risk premium (**DRP**).

9.2.4.1 ERA Draft Decision approach

1025. The ERA's draft decision departs significantly from the cost of debt methodology outlined in its Rate of Return Guidelines. Some of the ERA's changes, such as the adoption of a 10 year term of debt issuance assumption, are consistent with that previously submitted by AGA. Other modifications, such as the structure of the DRP, proposed 'switching' between mutually exclusive debt management strategies and delayed annual update mechanism results in the ERA's revised methodology failing to represent a reasonable or best estimate of an efficient debt management strategy.[368]

1026. Consistent with the approach outlined in its Rate of Return Guidelines, the ERA's draft decision compensates for the cost of debt each year based on the sum of the risk free rate, DRP, debt raising and hedging costs.[369]

1027. The risk free rate is to be set with reference to the yields on 5 year CGS. The ERA maintains that the 5 year term is consistent with the present value principle and with investor's horizon with regard to the regulated assets, given the 5-year regulatory period.[370] This is despite the fact the ERA now accepts that the term of debt at issuance is 10 years.[371] As a result the ERA estimates the DRP over a 10 year term.

1028. The ERA has also modified its bond yield approach for estimating the DRP to increase the sample size and estimate their own spread to swap curves. The ERA has extended its sample to include Australian bonds denominated in key foreign currencies. The ERA uses curve fitting techniques to estimate the DRP at tenors beyond five years and arrives at its 10 year 'spread to swap'. The ERA then converts this 'spread to swap' estimate into the regulated DRP using its newly developed 'term spread approach'.

366 Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014, section 6.1.

367 Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014.

368 Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014.

369 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 819.

370 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 824.

371 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 832.

1029. The ERA maintains that an annual update of the DRP is an important efficiency consideration, given the inability of firms to hedge this component of the cost of debt.[372] However, the ERA has modified its approach by introducing 'guiderails' and delaying the effect of each annual update of the DRP until the next access arrangement period.

1030. The approach outlined by the ERA does not result in an estimate of a return on debt that achieves the ARORO or complies with the NGR.[373] This is because it:

- Is not consistent with an implementable efficient debt management strategy
- Is based on a debt management strategy that cannot be replicated and consequently does not provide an estimate of the benchmark efficient entity's cost of debt at all
- Unnecessarily constrains the estimate of the DRP and restricts the ability of the benchmark efficient firm to recover the efficient cost of debt
- Introduces additional requirements for an annual update that has no other effect than to increase the risk faced by the business with no additional compensation
- Is not based on the best available data, this results in an estimate that does not provide an opportunity to recover the full efficient costs of debt
- Does not provide the best estimate of the benchmark efficient entity's efficient cost of debt.

1031. For these reasons AGA does not consider the ERA's approach in the Draft Decision reflects the requirements of rule 87 of the NGR, nor does it contribute to the achievement of the NGO or RPP.[374] Accordingly AGA's proposal departs from the Draft Decision in estimating the cost of debt.

9.2.4.2 Replicable debt management strategies

1032. As previously submitted by AGA[375], in order to satisfy rule 87(3) of the NGR, the cost of debt must be estimated based on the cost of implementing a well-defined debt management strategy that is efficient and consistent with a policy that a benchmark efficient entity with a similar degree of risk to AGA would undertake. As a matter of logic, the cost of debt estimated must reflect a debt management strategy that can actually be implemented. Otherwise, it could not be efficient.[376]

1033. As demonstrated by CEG[377], there is agreement between AGA and the ERA's consultant, Lally, regarding the implementable debt management strategies available to the benchmark efficient entity. Both parties agree that a benchmark efficient debt management strategy involves the staggered issuance of 10 year debt.

1034. With this in mind Lally states:

> *… only two possible debt strategies for a business are viable, and each has a matching regulatory policy such that the combination satisfies the NPV = 0 principle. The first involves borrowing long-term and staggering the borrowing to ensure that only a small proportion of the debt would mature in any one year; this reduces refinancing risk to a minimal level. The matching regulatory policy would be for the allowed cost of debt to be set in accordance with the trailing average cost (for a term matching that for benchmark firms). The second debt strategy*

[372] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 897.

[373] Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014.

[374] Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014.

[375] Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014.

[376] Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014.

[377] Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014, paragraph 2.

> *additionally involves the use of interest rate swap contracts (relating to the risk-free rate component of the cost of debt). The matching regulatory policy would be for the allowed risk free rate within the cost of debt to be set in accordance with the rate prevailing at the beginning of the regulatory cycle (for a term equal to the cycle) whilst the DRP would be set in accordance with the trailing average (for a term matching the borrowing term for benchmark firms).*[378]

1035. That is, there are two identified options for a replicable benchmark efficient strategy:[379]

- Staggered issuance of 10 year debt with no swap contract overlay, otherwise known as a trailing average
- Staggered issuance of 10 year debt with a swap contract overlay, otherwise known as the hybrid approach

1036. The ERA's recognition that businesses issue staggered debt and reset base interest costs at the beginning of each regulatory period for the length of the five year regulatory period in principle aligns with the hybrid approach.[380] The ERA's approach calculates the cost of debt based on the following:

- The 5 year CGS yield at the beginning of the regulatory period; plus
- The cost of issuing 10 year debt for each regulatory year; less
- The 10 year CGS yield for each regulatory year; plus
- For each year whichever is the lower of:
  - 10 to 5 year CGS 'term spread' (i.e. 10 year CGS yield less 5 year CGS yield); or
  - 10 to 5 year swap costs (which it provisionally puts at 16bp based on QCA precedent)

1037. This approach departs materially from the cost of debt associated with the identified replicable debt management approaches.[381] This is because the ERA's approach:

- Uses the prevailing DRP estimated at the beginning of the regulatory year rather than a historical average DRP. This is then annually updated for the entire debt portfolio
- Uses CGS yields rather than the swap rates that a benchmark efficient entity would use to engage in the relevant hedging strategy
- Estimates the 'efficient' compensation based on which ever approach achieves the lowest value. This assumes that businesses can easily change between two mutually exclusive debt management strategies

1038. For the reasons set out in this submission and the CEG expert report,[382] in order to meet the ARORO, the NGO and the RPP it is necessary to estimate the cost of debt that is consistent with the efficient financing costs of the benchmark efficient entity with a similar degree of risk to AGA. It is impossible to achieve this under the ERA's method as it is impossible to replicate the ERA's method in the real world.

9.2.4.3 Term of debt

1039. The ERA maintains that the present value principle is a key consideration when estimating the rate of return. For the purposes of estimating the term of the cost of debt components the ERA states that it must equal the

[378] Lally, The Cost of Debt, October 2014, pp.10-11

[379] Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014, paragraph 46.

[380] Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014, paragraph 51.

[381] Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014.

[382] Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014.

term of the regulatory period.[383] However, the ERA notes that the present value principle will only hold if there are financial instruments available in the market that firms can use to hedge the risk free rate and DRP. In line with the advice from their consultant, Lally, the ERA concedes that there are no such hedging instruments available for the DRP.

1040. The ERA and AGA are now in agreement that the DRP should be estimated based on the average term at issuance. As previously submitted by AGA,[384] the evidence in the ERA's Rate of Return Guidelines supported a term at issuance of 10 years. The ERA has now adopted the 10 year term for its estimate of the DRP. However, the ERA still use a term of five years to estimate the risk free rate.

1041. AGA submits that there is no need to estimate the risk free rate for the cost of debt when implementing the trailing average or hybrid debt management strategy. As discussed by CEG,[385] unlike the return on equity the risk free rate is not an input into the cost of debt estimate. As the cost of debt can be estimated directly it is not necessary to estimate the risk free rate for debt. That is, as businesses do not issue or trade in CGS as part of their efficient debt management strategy they will not influence the cost of debt estimate. It has previously been a matter of regulatory practice, but it is unnecessary to define a term of the risk free rate for the purpose of estimating the cost of debt.[386]

1042. As noted by CEG,[387] a risk free rate could be implied by separating out the cost of debt into the DRP and risk free rate components by mechanically subtracting the risk free rate from the overall cost of debt. Imposing the risk free rate on the cost of debt calculation in this way means that the level of the risk free rate will not affect the cost of debt estimate. This is because a higher/lower risk free rate is perfectly offset by a lower/higher DRP.[388] Therefore attempting to estimate a risk free rate is not a productive exercise in the circumstances. However, if the risk free rate is to be imposed in this manner then its term should be consistent with the term of the debt issuance. In the case of the ERA, if a business efficiently issues staggered 10 year debt, the term of the risk free rate that underpins the associated cost of debt will also has a term of 10 years.[389]

9.2.4.4 Debt management strategy

1043. In order to estimate the DRP, the ERA has developed a debt management strategy that it states is consistent with the advice received from its consultant, Lally. The ERA used Figure 9–5 below to illustrate the construction of its chosen debt management strategy.

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383 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 648.

384 ATCO Gas Australia, Access Arrangement Information 1 July 2014 – 31 December 2019 (AA4), March 2014.

385 Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014, Section 6.

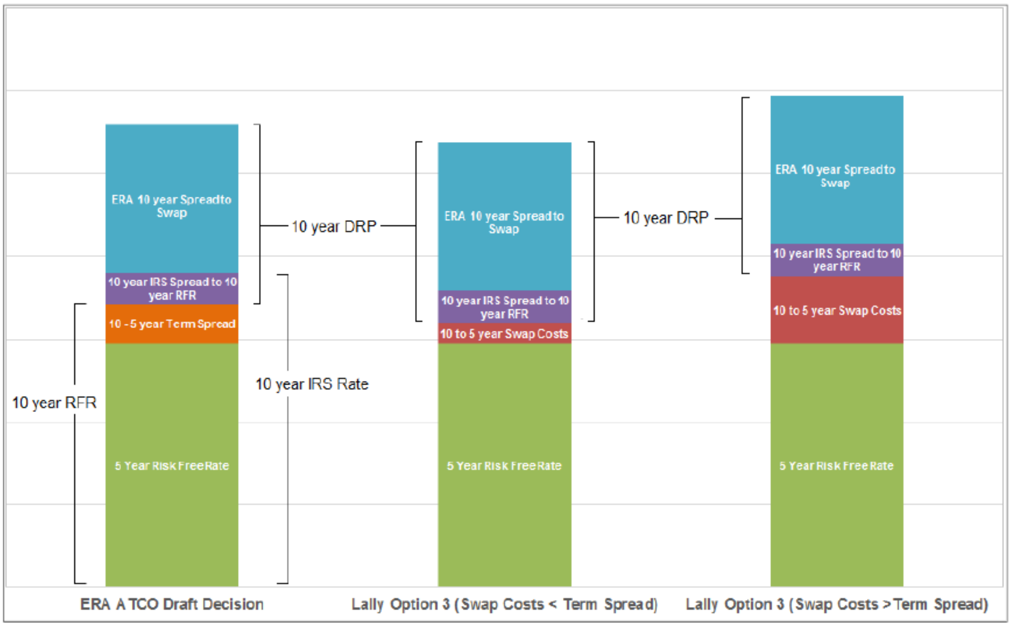
386 Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014, Section 6.

387 Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014, Section 6.

388 Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014, Section 6.

389 Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014, Section 6.

Figure 31 Decomposition of the Cost of Debt under the 'Term Spread' and 'Swaps' Approaches to determining the Regulated Debt Risk Premium



Source: Economic Regulation Authority

Figure 9–5: ERA decomposition of the cost of debt under the term spread and swaps approach

1044. The ERA will calculate the cost of debt by estimating:

- The 5 year CGS yield at the beginning of the regulatory period; plus
- The cost of issuing 10 year debt for each regulatory year; less
- The 10 year CGS yield for each regulatory year; plus
- For each year whichever is the lower of:
  - 10-5 year CGS 'term spread'; or
  - 10 to 5 year swap costs.

1045. It appears the approach outlined by the ERA in the Draft Decision recognises that businesses issue staggered debt and reset base interest costs at the beginning of each regulatory period for the duration of the five year regulatory period. Such an approach, in principle, aligns with the practice of staggered issuance of 10 year debt with a swap contract overlay, otherwise known as the hybrid approach.

1046. However, as demonstrated by CEG,[390] the ERA has failed to estimate the costs associated with the efficient debt management strategy. This is because the ERA, while assuming that a benchmark efficient strategy is to enter into swaps, does not compensate for these swap costs in the cost of debt. This is because the ERA has substituted yields on CGS for swap rates. The ERA does not explain or provide any evidence as to why this departure from the efficient debt management strategy is necessary or how it could reflect an estimate of the costs of the benchmark efficient entity with a similar degree of risk to AGA. The substitution of CGS yields in the place of swap rates will lead to significant under or over estimation of costs.[391]

[390] Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014, Section 6.

[391] Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014, paragraph 183.

1047. Further, the ERA's approach suggests that the benchmark efficient entity is able to easily move between a 10-5 year CGS term spread or 10-5 year swap cost strategy and as such, the ERA will adopt the lowest cost option. AGA submits that by proposing this comparison and the choice of the lowest cost option, the ERA incorrectly assumes that the benchmark efficient entity can be in a position to implement two mutually exclusive debt management strategies at the same time.[392] Consequently, the ERA's approach does not represent a replicable debt management strategy and would underestimate the actual cost of debt over time.[393]

1048. Therefore, the cost of debt estimated by the ERA cannot reflect the costs associated with an efficient debt management strategy.

9.2.5 Estimating the debt risk premium

1049. The acceptance by the ERA, that the appropriate term for the estimate of the debt risk premium was ten years, required the ERA to modify the approach for estimating the DRP identified in the Rate of Return Guidelines. In order to estimate the DRP, the ERA considered the use of two data sets being either the ERA's extended bond yield approach or the RBA estimates of credit spread estimates.

1050. AGA submits that the latter data set should be used. As previously submitted by AGA,[394] the methodology behind the RBA's estimates is transparent, well documented and repeatable. The RBA data is robust, relevant and the best source of data to use for estimating the cost of debt.

1051. The ERA states it has evaluated the estimates developed by the RBA and has concerns that they are not the best means to deliver the allowed rate of return objective.[395] The ERA's issues with the RBA estimate can be summarised as follows:

- The effective tenor of the RBA's 10 year target is only 8.6 years and is therefore not consistent with the 10 year term of the DRP
- The RBA's data is only available for the A and BBB credit rating bands. This limits the set of estimates available to the ERA and may not be consistent with the requirements of the NGR or ARORO
- The RBA only reports month end estimates, which is not ideal as Australian regulatory practice is to adopt a 20-40 day averaging period so as to avoid significant fluctuations on any given day

1052. Based on these matters, the ERA has dismissed the RBA data and adopted its own extended bond yield approach estimate, which incorporates Australian bonds denominated in foreign currency and various curve fitting techniques. The ERA estimates the spread to swap of each bond in its sample and then undergoes a curve fitting process to determine yield curves for the benchmark sample. The three curve fitting techniques used by the ERA include the Gaussian kernel; Nelson-Siegel, and Nelson-Siegel-Svensson. In order to arrive at a single estimate of the DRP, the ERA calculates a simple average of the three curve fitting techniques.

1053. For the reasons set out by CEG,[396] AGA submits that the ERA's extended bond yield methodology will not result in a reliable estimate of the prevailing efficient cost of debt for a benchmark efficient entity. This is because the approach is not a transparent or replicable process. Further, the Bloomberg sources from which the yield on interest rate swaps and spreads to swaps data is sampled has not been specified. Due to this lack of transparency it has been impossible for CEG to replicate the ERA's DRP estimate. As demonstrated

392 Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014, paragraph 168.

393 Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014, paragraph 169.

394 ATCO Gas Australia, Access Arrangement Information 1 July 2014 – 31 December 2019 (AA4), March 2014.

395 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 849

396 Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014, Section 5.

by CEG,[397] the ERA may have made a series of errors in calculating its estimate of the debt risk premium. These errors may include:[398]

- Failing to convert foreign currency issue amounts into Australian dollars to weight bonds when applying the Gaussian kernel methodology
- Failing to exclude duplicate bonds from the extended bond yield sample
- Implementing a simplified version of a cross-currency swap that does not apply the conversion factor
- Including bonds that have a country of risk *or* a country of domicile as Australia when it claims that only bonds with country of risk as Australia have been included

1054. In response to the criticism relating to the RBA's effective tenor of 8.6 years, AGA notes that the ERA's own Gaussian kernel methodology has an effective tenor of only 8.4 years.[399] AGA submits that the ERA's criticism of the RBA's Gaussian kernel estimates apply equally to their estimates.[400] Further, as set out in CEG's March 2014 report, the use of the above tenor period produces a conservative cost of debt having regard to the underlying assumption of a 10 year term hedged debt portfolio.

1055. The ERA's concern that the RBA's DRP is limited to only BBB and A credit rating bands equally applies to its own estimate. This is because the ERA's own estimate relies upon bonds drawn from the BBB-/BBB/BBB+ range which is equivalent to the rating band used by the RBA's BBB DRP estimates.[401] Finally, the ERA notes that the RBA's monthly reporting of DRPs is less than ideal. AGA submit that this concern could be resolved by interpolating between the month end values that straddle any averaging period should this be required. However, as noted by CEG, there is no implementable debt management strategy that would require an estimate of either of these variables over a period shorter than 10 years.[402]

1056. AGA has considered the concerns raised by the ERA in relation to the RBA's credit spread estimates. As demonstrated by CEG[403] the issues raised by the ERA as grounds to reject the RBA estimates also apply to the ERA's preferred extended bond yield approach. Further, the ERA's extended bond yield approach suffers from errors, is not transparent and cannot be replicated.

1057. AGA submits that the ERA's reasons for rejecting the RBA estimates are unfounded and do not establish that the ERA approach is preferable for meeting the requirements of the NGR, NGO or RPPs.

1058. CEG establishes that the RBA data is robust, reliable and results in the best available estimate of the cost of debt.[404]

9.2.5.1 Annual update of the debt risk premium

1059. The ERA has maintained the position outlined in its Rate of Return Guidelines that an annual update of the DRP is necessary to promote economic efficiency by regularly updating the cost of debt to reflect the cost of newly issued debt. As demonstrated by CEG[405] there are several reasons why the ERA's annual update of the DRP fails to reflect a feasible debt financing strategy that could be implemented by the benchmark efficient entity. These issues can be summarised into two key areas:

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397 Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014, paragraph 228.

398 Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014, paragraph 228.

399 Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014, paragraph 222.

400 Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014, paragraph 223.

401 Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014, paragraph 223.

402 Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014, paragraph 224.

403 Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014, paragraph 221-225.

404 Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014, paragraph 213.

405 Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014, Section 4.2.

- ERA's annual update of the DRP is calculated for the entire debt portfolio
- ERA's annual update addresses volatility by only updating the DRP once every five years

1060. Each of these issues is considered in turn below.

9.2.5.2 Annual update of the DRP for the entire debt portfolio

1061. For the purpose of the Draft Decision, the ERA engaged Lally to consider the merits of annual updating compared to no annual update in the context of the present value principle. Lally finds that:

> *both approaches fail to satisfy the NPV=0 principle. The annual DRP updating would involve more effort and would send superior signals to firms contemplating capex. The effort involved in annual updating relative to resetting only at the beginning of the cycle would seem to be less important than the superior capex signal. Consequently annual updating would seem to be superior.*[406]

1062. AGA has previously submitted that the annual update of the DRP does not reflect an efficient benchmark efficient strategy.[407] It has been established that both AGA and the ERA's consultant Lally, agree that a benchmark efficient debt management strategy involves the staggered issuance of 10 year debt. The DRP paid by a business is fixed for the term of that debt. As such, where 10 year staggered debt is used the update to the DRP should reflect the changes that result from the rollover of newly issued debt. The ERA's approach reflects the changes in costs that would result from reissuing the entire debt portfolio each year. Therefore, updating the prevailing DRP annually does not reflect the costs incurred by the benchmark efficient entity at all.

1063. The ERA has erred in its assertion that resetting the DRP each year mimics the conditions found in competitive markets. As detailed by CEG[408] many, if not most, non-regulated infrastructure investments are undertaken in the presence of long term contracts that deliver a similar level of compensation to that based on a trailing average cost of debt. The prices and revenues will not vary based on annual variations in the level of interest rates. Further, where an investment proceeds without a long-term contract, market forces will not create a scenario where revenues fluctuate one for one with prevailing interest rates.[409]

1064. The ERA's consultant Lally, claims that resetting the DRP each year will send superior signals to firms contemplating capex is also incorrect. Lally proposes that annually resetting the DRP based on the prevailing estimate promotes efficient investment decisions and that this justifies a departure from compensation based on the efficient financing costs of the benchmark efficient entity.

1065. As demonstrated by CEG, due to the design of the regulatory framework, the investment incentives will not be influenced by the regulatory allowance for the cost of debt at the time an investment decision is undertaken.[410] Instead, incentives for investment will depend on the expected regulatory allowance in future regulatory periods as this is when the actual expenditure will enter the RAB and the cost of debt allowance is applied.[411] Annually resetting the DRP will not influence marginal investment decisions of regulated businesses. Further, Lally's advice to the ERA contradicts other recent reports written for the AER, which state that a weighted trailing average approach would provide the correct incentives to promote the efficient investment in capex.[412]

406 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 901.

407 ATCO Gas Australia, Access Arrangement Information 1 July 2014 – 31 December 2019 (AA4), March 2014.

408 Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014, paragraph 95.

409 Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014, paragraph 95.

410 Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014. 129.

411 Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014, paragraph 129.

412 Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014, section 4.2.2.3.

1066. Lally also states that annually resetting the DRP based on the prevailing DRP will result in only a trivial departure from the costs that a benchmark efficient entity would incur over the life of its invested assets. AGA notes that Lally has not provided any empirical justification of this assertion. In its analysis, CEG[413] demonstrate that Lally's claims are incorrect as there is a material difference between the allowed DRP and the actual DRP paid, based on the trailing average DRP.[414] However, even if Lally's claim of triviality was correct there is no valid reason to depart from compensating for efficient costs.[415]

Updating the DRP once every five years

1067. In response to submissions from network users expressing concern at the resulting network tariff volatility resulting from the annual update, the ERA has resolved to only update the DRP once every 5 years. To ensure the *regulated firms costs of debt is aligned closely with that faced by other firms in the economy,*[416] the ERA will preserve the intent of the annual update and track the annual movements of the DRP. A corresponding present value revenue neutral adjustment will be applied to the DRP at the start of the next access arrangement. This adjustment will account for the difference between the DRP set at the start of AA4 and the actual annual outcomes that occurred during the AA4 period. The ERA also proposes to constrain the annual DRP estimate to ensure that it falls within the range of 100 to 300 basis points. The ERA states that the application of guiderails will ensure that the DRP is not influenced by unusually low or high prevailing conditions, such as that which occurred in the global financial crisis.

1068. Effectively, the ERA plans to carry forward the difference in revenues that would have been passed through network tariffs had an annual update of the DRP been implemented. This means that customers and the network business must lend/deposit revenue to the other party in one regulatory period to be paid back in the next regulatory period. There is no guarantee that the same customers who receive the benefit of lower prices in the first regulatory period will be the same customers that pay it back in the following period.[417] Postponing the update of the DRP to the end of the access arrangement period simply shifts price volatility from within an access arrangement period to between access arrangements.

1069. The ERA states that its annual update is required so that the changes in debt costs are passed through to create a stronger incentive for investments. However, the ERA then applies 'guiderails' to constrain the pass through, undermining its own stated intention. The ERA has introduced the guiderails approach with no supporting analysis and results in an outcome that is contrary to the ERA's stated intention. AGA does not propose to implement this component of the ERA's approach as even if the correct change in costs were to be passed through the annual update, the guiderails approach reduces the likelihood that the business can recover its efficient costs. Thus, the guiderails do not allow the benchmark efficient entity to recover the true costs associated with the efficient debt management strategy.

1070. For these reasons and those set out in the expert report of CEG,[418] AGA submits that the ERA's annual update of the DRP does not represent an efficient practice that a benchmark efficient firm would or could undertake. The ERA's approach to the annual update imposes additional risks on the benchmark efficient entity without providing sufficient compensation. Further, the ERA's carryover update would impose an inefficient practice upon network service providers and would fail to deliver any additional efficiency.

9.2.6 AGA approach to estimating cost of debt

1071. The ARORO states that the allowed rate of return must be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as the relevant service provider. To achieve this the cost of debt must be:

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413 Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014, section 4.2.3.

414 Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014, section 4.2.3.

415 Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014, section 4.2.3.

416 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 902.

417 Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014, paragraph 201.

418 Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014.

- Estimated by reference to a well-defined efficient and replicable debt management strategy
- Efficient in the sense that it is based on a prudent debt management strategy that minimises the expected cost of financing
- Estimated based on the best available data
- Estimated having regard to a similar degree of risk the service provider is exposed to

1072. It follows that the allowed return on debt must be commensurate with the efficient financing costs of servicing a debt financing strategy that is efficient in the above circumstances.

1073. Consistent with the approach set out in the initial submission, AGA submits the appropriate cost of raising debt should be determined by:

- Establishing the efficient debt financing strategy that would be employed by an efficient benchmark entity in the circumstances of the business that is being regulated
- Setting the allowed rate of return on debt to be commensurate with the efficient costs of servicing that efficient debt financing strategy

1074. As noted by CEG there may be multiple debt management strategies that are replicable by the benchmark efficient entity.[419] As discussed previously, the ERA and AGA agree that the benchmark efficient debt management strategy of a regulated business involves the staggered issuance of 10 year debt. The ERA and AGA are also in agreement that it is:

- Possible for a business to use interest rate swaps to hedge the base rate of debt exposure on staggered debt portfolio to the length of the regulatory period
- Impossible for a business to hedge against the DRP that a business pays on its staggered debt portfolio

1075. In CEG's review of efficient financing practises it is found that there are two approaches that would meet the requirements of a replicable debt management strategy.[420] These are:

- Staggered issuance of 10 year debt with no swap contract overlay
- Staggered issuance of 10 year debt with a swap contract overlay

1076. CEG notes that the approach outlined by the ERA in the Draft Decision is designed to reset base interest costs at the beginning of each regulatory period for the length of the five year regulatory period.[421] Such an approach in principle aligns with the practice of staggered issuance of 10 year debt with a swap contract overlay. Following this debt strategy would give rise to a cost of debt that reflects:

- The 'on the day' 5 year base rate of interest determined by the level of five year swap rates at the beginning of the regulatory period
- The trailing average DRP measured over 10 years of staggered issuance determined by the difference between the 10 year cost of debt in each year of the trailing average less the 10 year swap rate

1077. This debt management strategy is referred to as the hybrid approach. The hybrid approach recognises that the benchmark efficient entity has issued staggered debt over time but given the application of an 'on the day' approach under the old NGR, it should also be assumed to have fixed interest rates up until the end of each regulatory period. Given these assumptions CEG[422] considers that the hybrid debt management

419 Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014, paragraph 50.

420 Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014, paragraph 46.

421 Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014, paragraph 48.

422 Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014, paragraph 55.

strategy would be the efficient response of a benchmark efficient entity. CEG's opinion is that the barrier to AGA entering into such swaps would be low, that is, it could enter into those swaps having regard to the size of its RAB.[423]

1078. CEG notes that adoption of a particular debt management strategy does not guarantee that this same strategy will be maintained into the future. It may be the case the benchmark efficient entity will transition to an approach such as the trailing average.[424] However, as benchmark efficient entities cannot simply switch between benchmark debt management strategies from one year to the next it would be necessary to plan this transition and the associated debt costs over time.

1079. AGA submits that it was the intent of the ERA in its Draft Decision to emulate a debt management strategy based on a staggered issuance of 10 year debt with a swap overlay. However, as outlined above and in the CEG[425] report the ERA has made significant errors in estimating the cost of debt to reflect the implementation of this debt management strategy. AGA has addressed these errors in the design of its hybrid approach.

1080. Under the hybrid approach the benchmark efficient entity will enter into swap contracts in order to:

- Fix the base interest rate in the current regulatory period based on the swap rates that prevailed at the beginning of the current regulatory period
- Have its base interest rate exposure purely floating at the end of that regulatory period
- Facilitate the ability to repeat the process for the next regulatory period

1081. This strategy once entered into cannot be instantaneously unwound. In order to use swap rates to fix interest rates for a regulatory period, a business must have arranged its debt management over the previous 10 years to ensure that all of the base rate of interest will be floating rate exposure at the beginning of the regulatory period.[426]

9.2.6.1 Methodology to estimate the cost of debt

1082. As previously submitted,[427] AGA maintains that the best estimate of the cost of debt is one based on the RBA's Australian Corporate Credit Spreads for BBB rated 10 year Australian corporate debt. As demonstrated by CEG, the RBA fair value curve is the best third party source that can be relied on to estimate the cost of 10 year BBB debt over the historical 10 year period to October 2014[428] and provides the best estimate of the cost of debt.

1083. Consistent with the hybrid debt management strategy and using the RBA's BBB rate 10 year corporate debt data set, the cost of debt estimate is 5.58% for October 2014.[429] This estimate reflects the annualised 5 year swap rate for October 2014 derived from the RBA (3.19%), plus the trailing average 10 year annualised spread to swap calculated between January 2005 and October 2014 (2.39%). This spread to swap is calculated at 10 years using extrapolation based on the best fit slope of the spread to swap curve extended forwards from the 10 year target maturity observation. This is the best estimate of the cost of debt which meets the ARORO, the NGO and the RPP. AGA proposes to update the estimate at an agreed date closer to the Final Decision.

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423 Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014, paragraph 69-75.

424 Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014.

425 Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014.

426 Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014, paragraph 61.

427 ATCO Gas Australia, Access Arrangement Information 1 July 2014 – 31 December 2019 (AA4), March 2014.

428 Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014, paragraph 215.

429 Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014, paragraph 69.

9.2.6.2 Debt issuance and hedging costs

1084. In the Draft Decision the ERA accepts AGA's debt issuance and hedging cost proposal.

1085. Consistent with the Draft Decision, AGA will incorporate an allowance of 0.125% for debt raising costs and a hedging allowance of 0.025% into the cost of debt estimate. This allowance acknowledges the difficulty in hedging the exposure to movements of the risk free rate and is consistent with the Guidelines.

9.2.6.3 Resulting cost of debt

1086. Based on the benchmark credit rating, cost of debt (5.58%), debt issuance (0.125%) and hedging costs (0.025%) set out above, the cost of debt which best meets the ARORO, RPP and NGO is 5.73%. This allowance will be updated prior to the ERA's final decision to reflect the time period agreed with the ERA.

1087. AGA's cost of debt estimate complies with rule 87 of the NGR, gives rise to the best estimate of the cost of debt which meets the ARORO, the NGO and the RPP. AGA's adoption of the RBA's ten year BBB Australian corporate debt estimate reflects the costs likely to be incurred by a benchmark efficient financing strategy. The RBA's method is transparent, periodically updated and provided by a reputable and independent agency.

9.2.6.4 Fixed principle

1088. The ERA required AGA to introduce a fixed principle to ensure that the difference between the annual update of the DRP and the regulatory DRP applying during AA4 will be carried forward and applied in AA5. AGA agrees that a fixed principle is required to ensure the pass through of changes in debt costs in AA4. However, AGA's proposal differs from that required by the ERA due to the different approaches for estimating the DRP. AGA's revised fixed principle is described in Chapter 16 Fixed principles. As detailed in the Annexure B of the access arrangement, AGA proposes to update the trailing average component of the DRP annually through a cost pass through variation. The mechanics of the cost pass through are described in clause 3 of Annexure B of the access arrangement.

9.2.6.5 Materially preferable to correct errors

1089. The CEG report identifies the errors in the ERA's approach to estimating the cost of debt. CEG has considered the ERA's approach to estimating the cost of debt against the achievement of the NGO and the RPP and expresses the opinion that:

- Meeting the ARORO requires the cost of debt allowance to reflect the costs associated with a well-defined debt management strategy that a benchmark efficient entity could be expected to undertake[430]
- Promoting the ARORO in this way is necessary to also promote the NGO and lead to outcomes consistent with the RPP[431]
- The ERA has not proposed to set the cost of debt based on a well-defined debt management strategy. Instead, it has proposed a methodology that is not replicable for a number of reasons. The result is that the cost of debt allowance provided by the ERA has the potential to significantly depart from any estimate of the cost of debt finance that a benchmark efficient entity would incur[432]
- Correcting this error would materially improve the achievement of the ARORO and, consequently, the NGO and the RPP

[430] Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014, section 2.2.

[431] Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014, 2.2.

[432] Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014, paragraph 317.

- On this basis, CEG consider that correcting this error (by compensating based on a well-defined debt management strategy that a benchmark efficient entity could reasonably be assumed to undertake) would materially promote the NGO[433]

9.2.7 AGA proposed rate of return

1090. AGA submits that a return on equity of 10.51% and a cost of debt of 5.73% generate a rate of return of 7.64% which complies with the NGR, the ARORO, the NGR and the RPP.

[433] Appendix 9.2 Cost of debt consistent with the NGR and NGL, Tom Hird, CEG Consulting November 2014, paragraph 318.

10. Gamma

ERA required amendment 10

ATCO is required to adopt a gamma of 0.5.

AGA Response: do not accept.

Summary only – AGA has not implemented the ERA's amendment because the ERA has estimated the wrong thing and the supporting analysis does not provide the best estimate**.**

10.1 Summary of ERA Decision

1091. The ERA has departed from its Rate of Return Guideline in relation to the definition and estimation of gamma. In arriving at its estimate of gamma the ERA has taken into consideration information from dividend drop off studies, equity ownership, taxation statistics and the conceptual goal posts.

1092. The ERA's gamma estimate of 0.5 is based on the product of a payout ratio of 0.7 and an utilisation rate of 0.7. The ERA has rounded up its gamma estimate from 0.49 to 0.5 *in acknowledgement that the estimate is based on a fairly wide range and subject to imprecision*.[434]

10.2 AGA response

AGA has not implemented required amendment 10

1093. The estimate of gamma is a product of the distribution rate and theta. AGA and the ERA agree that a 0.7 distribution rate is the best estimate available but AGA does not agree that the estimate for theta of 0.7 as adopted by the ERA in the Draft Decision is the best estimate possible in the circumstances.

1094. Regardless of the estimate used, there is no reason to round the estimate of gamma. The ERA has multiplied its estimate of the distribution rate (0.7) and its estimate of theta (0.7) to get 0.5. There is no basis for such rounding and no reason why a two decimal place estimate could not be used (without accepting its correctness). Other parameters estimated by the ERA are also subject to wide ranges and imprecision (such as the MRP, equity beta, debt risk premium) but no such rounding is applied. The rounding of the gamma estimate is without foundation and arbitrary.

10.2.1 NGR requirements

1095. The requirements for the costs of corporate income tax are outlined in rule 87A of the NGR as follows:

1096. (1) The estimated cost of corporate income tax of a service provider for each regulatory year of an *access arrangement period* (ETCt) is to be estimated in accordance with the following formula:

1097. ETCt = (ETIt ×rt) (1–γ)

1098. Where

1099. ETIt is an estimate of the taxable income for that regulatory year that would be earned by a benchmark efficient entity as a result of the provision of reference services if such an entity, rather than the service provider, operated the business of the service provider;

[434] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 970.

1100. rt is the expected statutory income tax rate for that regulatory year as determined by the AER; and

1101. γ is the value of imputation credits.

1102. Rule 74 of the NGR also requires that the estimate must be:

- arrived at on a reasonable basis; and
- represent the best estimate possible in the circumstances

10.2.2 Distribution rate

1103. The ERA arrives at an estimate of 0.7 for the distribution rate, which is the same distribution rate estimate submitted by AGA. In arriving at its estimate of the distribution rate the ERA has had regard to a 2013 study by Lally[435] for the Queensland Competition Authority (**QCA**) which suggested a distribution rate of 0.84 for listed firms. For the reasons set out in the SFG Gamma report, Lally's study does not provide a robust estimate of the distribution rate. This is due to the fact that Lally has estimated distributed credits as a proportion of created credits. This ratio is not consistent with the definition in the regulatory framework or the standard specifications of the AER's post tax revenue model,[436] which requires the measurement of distribution credits as a proportion of corporate tax paid.

1104. The ERA also raises concerns with the reliability of the Australian Tax Office (**ATO**) data, which is commonly used to determine the distribution rate. The ERA is concerned that estimates *are not entirely consistent and the potential biases due to reporting omissions.*[437] As demonstrated by SFG,[438] the issues raised by the ERA do not materially affect the estimate of the distribution rate.

10.2.3 Theta

1105. The ERA has significantly changed its approach for estimating theta from that outlined in its Rate of Return Guidelines. One of the most significant changes is that the ERA now estimate a redemption rate rather than a value measure of gamma, defining theta as the proportion of imputation credits distributed that are redeemed.[439]

10.2.3.1 Definition of theta

1106. In its Guideline, the ERA defined theta as the value of distributed credits and estimated the value of distributed credits. In the Draft Decision, the ERA has estimated the proportion of distributed credits that investors are able to redeem. This change has made the approach to estimating theta set out in the ERA's Rate of Return Guidelines (of estimating the value of theta through dividend drop off studies) of no guidance at all. The reason given by the ERA for the departure from the approach in the Guideline is new evidence presented in two Lally reports of late 2013.[440]

435 Lally 2013, Estimating Gamma, Report for the QCA, 25 November.

436 Appendix 10.1 Estimating gamma: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 50-58.

437 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 946.

438 Appendix 10.1 Estimating gamma: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 59-61.

439 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014,Appendix 8 paragraph 11.

440 ERA Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, Appendix 8, paragraph 20.

1107. The ERA's reliance on the evidence presented by Lally is subject to the following errors further explained in SFG:[441]

- The ERA has misinterpreted the advice provided in the Lally (2013) report to the AER. The ERA interprets that report as supporting its conceptual definition of theta and its use of the equity ownership approach and tax statistic redemption rates to estimate theta. However, as set out in detail in the SFG Gamma report Lally (2013 AER) provides no such support.
- Irrespective of what might be contained in the Lally (2013) report to the AER, on its proper construction the regulatory task pursuant to Rule 87A requires theta to be estimated as the value of distributed credits.

1108. The ERA's revised definition of gamma and theta is not consistent with the definition in the NGR. Rule 87A of the NGR states that gamma is the value of imputation credits. The ERA now interprets the 'value' component of rule 87A of the NGR as a 'numerical value' representing the degree to which imputation credits are utilised rather than a measurable market value.[442]

1109. This revised definition of value is inconsistent with the findings of the AEMC and is contrary to economic and regulatory principles. During the last round of rule changes made by the AEMC[443] in 2012, the definition of gamma was revised from a utilisation measure to a value measure. The AEMC's change to the definition of gamma reflected the actual practice of regulators at the time, which was to measure the value of imputation credits.

1110. The interpretation of 'value' in rule 87A of the NGR has implications for the estimation of theta. Redemption rates provide an indication of the number of credits that are redeemed but do not provide an indication of the value of those credits to the investor. Importantly, redemption rates are not a measure of value as they ignore the costs incurred by investors to obtain and redeem imputation credits. As set out in the SFG Gamma Report, the Australian Competition Tribunal[444] (**ACT**) ruled redemption rates cannot be used to estimate the value of imputation credits. The ACT found that redemption rates can provide no more than an upper bound check on estimates of the value of imputation credits derived from the analysis of market values.[445]

1111. The ERA has relied on a theoretical study by Lally[446] to support its changed approach away from a measure of value to a measure of redemption rate. Based on this study, the ERA describes theta as a complex weighted average over all investors holding risky assets, where the weights involve each investor's investment in risky assets and their risk aversion.[447] The ERA's reliance on this study is flawed as the theoretical model used to measure the weighted average over all investors only applies in two special cases; that of perfect segmentation and perfect integration of equity markets. Neither of these special cases corresponds to the ERA's definition of the domestic capital market, which it is examining for the purposes of estimating theta. The ERA's domestic capital market considers foreign investors to the extent that they invest in Australian equity. That is, the ERA is considering only a limited amount of integration. Therefore the ERA's measure is inconsistent with the theoretical study set out by Lally.

1112. AGA submits that, for the reasons summarised here and the evidence of SFG in the Gamma Report, there is no theoretical basis for the ERA's proposed use of redemption rates to estimate the value of theta.

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441 Appendix 10.1 Estimating gamma: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014.

442 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 942.

443 Appendix 10.1 Estimating gamma: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 107.

444 Application by Energex Limited (No. 2)[2010] ACompT 7 (13 October 2013).

445 Application by Energex Limited (No. 2)[2010] ACompT 7 (13 October 2013).

446 Lally 2013, Estimating Gamma, Report for the AER, 25 November.

447 Lally 2013, Estimating Gamma, Report for the AER, 25 November.

10.2.3.2 Measuring redemption rates

1113. In order to measure the use of redemption rates the ERA considers a range of estimates derived from a number of studies and models that were not considered relevant in the Rate of Return Guidelines. The ERA considers these additional studies to be 'new' information. However, AGA notes that this information was available and considered by the AER during its 2013 Draft Rate of Return Guidelines[448] which was occurring at the same time as the ERA was developing its Guideline.

1114. In reference to the additional studies to arrive at the final estimate of theta, the ERA awards each of the studies a particular weight ranging from 'low´ to 'most' weight. The studies and their weighting are as follows:

- Dividend drop off studies suggest an estimate in the range of 0.3-0.7 is given low weight
- Equity ownership suggests an estimate of theta of 0.7 is given the most weight
- Taxation statistics suggest an estimate of theta within the range of 0.4-0.8 is given low weight
- Conceptual goal posts suggest an estimate of theta within the range of 0.6-1 is given some weight

1115. The ERA states that the above weightings reflect the robustness of the estimates.[449] However, the ERA provides very little explanation or reasons for the weightings it has adopted or how the weights have been assigned to the particular study. There is also no description of how the qualitative weightings have been combined with the ranges and estimates to produce an overall estimate of theta of 0.7.

Dividend drop off studies

1116. The ERA considers that dividend drop off studies should only be afforded a low weight when measuring theta. This is because the ERA considers that dividend drop off studies do not correctly estimate the required utilisation rate under the Officer framework.[450] That is, dividend drop off studies do not provide an estimate of the utilisation rate across the entire market over the entire year. Further, these studies may be subject to significant econometric challenges.

1117. It is unclear to AGA how to reconcile the ERA's new interpretation of value with the inclusion of dividend drop off studies in their evaluation of theta. The ERA makes it clear that its new interpretation of the value of imputation credits is to measure redemption rates rather than market value. This distinction means dividend drop off studies, which measure the market value of imputation credits, should be excluded from the ERA's analysis. Nevertheless, the ERA's reasoning for placing low weight on these studies is not stated and the merits of the SFG studies previously submitted by AGA are ignored.

1118. The ERA continues to rely on two dividend drop off studies, SFG (2011 and 2013) and ERA (2013), which were outlined in the Rate of Return Guidelines. As previously submitted by AGA[451], the ERA's study does not produce the best estimate of theta due to the ERA's disproportionate weighting of the SFG studies in favour of its own estimate. There is no evidence to suggest the ERA study is to be preferred to that of SFG. As demonstrated by SFG:[452]

- The SFG approach has been subjected to intense scrutiny by both the AER and ACT. The ERA's study has not been subject to the same level of third party examination.

[448] Appendix 10.1 Estimating gamma: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, section 4.

[449] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 969.

[450] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, Appendix 8, paragraph 88.

[451] ATCO Gas Australia, Access Arrangement Information, 1 July 2014-31 December 2019 (AA4), March 2014. Section 10.11 and Estimating Gamma for ATCO Gas Australia, SFG, March 2014.

[452] Appendix 10.1 Estimating gamma: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 211.

- The SFG study utilises the standard, ACT and AER agreed approach of correcting prices for market movements over the ex-dividend day.
- The SFG theta estimates have been shown to be stable and reliable.

1119. SFG[453] has re-examined the ERA's approach and confirms that the mid-point estimate from within its range of 0.35 to 0.55 is not the best estimate given the available information. This is due to the fact that:

- The ERA's own estimates are below 0.45 and a significant proportion of those estimates are below 0.35.
- The ERA's study supports the SFG estimate once the standard ex-day market correction has been correctly applied.
- The SFG (2013) estimates indicates that, if anything, the 0.35 estimate is towards the upper end of the reasonable range.

1120. The ERA has also raised several econometric issues in relation to dividend drop off studies. As demonstrated by SFG[454] these issues are not material and are not sufficient to limit the uses of dividend drop off studies. Perhaps the most significant econometric issue raised by the ERA relates to an adjustment involving dividing the estimated coefficient of the franking credit by the estimated coefficient of the cash dividend.[455] The ERA considers that applying the Lally adjustment may bring the estimate of theta derived from dividend drop off studies closer to its true value. SFG[456] demonstrates that:

- The adjustment is inappropriate given the correct interpretation of 'value.'
- The adjustment produces perverse outcomes.
- The adjustment would have to apply throughout the WACC parameter estimation process.

Equity ownership

1121. The ERA gives significant consideration to the equity ownership approach. This approach is described as providing an appropriate estimate of the redemption rate as the majority of domestic investors will be eligible to redeem imputation credits (implied utilisation rate of 1) while foreign investors will not be eligible (with an implied utilisation ratio of 0). The ERA states that the proportion of domestic ownership of capital investments therefore provides *a simple and transparent estimate of the utilisation rate.*[457] The ERA notes that the current estimate of domestic investors' equity ownership share is 0.7 for listed and unlisted equity.[458] This estimate is ultimately given the heaviest weighting in the ERA's estimation of theta.

1122. The estimate relied on by the ERA for equity ownership is not the most contemporary and is subject to data quality and reliability issues. As noted by SFG,[459] the 2007 data relied upon by the ERA produces estimates of foreign ownership that are materially lower than previous and subsequent estimates. The ERA does not

453 Appendix 10.1 Estimating gamma: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 212.

454 Appendix 10.1 Estimating gamma: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, section 8.

455 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 954.

456 Appendix 10.1 Estimating gamma: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 181-186.

457 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 962.

458 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 963.

459 Appendix 10.1 Estimating gamma: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 261.

provide any evidence as to why this 2007 estimate should be preferred to updated estimate of 0.46, which indicates a materially lower proportion of domestic equity ownership.[460]

1123. Issues relating to the reliability of the data suggest that the aggregate Australian Bureau Statistics (**ABS**) equity ownership estimate is inappropriate and should not be relied upon. As demonstrated by SFG[461] the ABS data relied upon by the ERA suffers from issues associated with the inclusion of equity in government owned corporations, general government and the Reserve Bank. This causes a systematic downward bias in the estimate of foreign ownership. The authors of this dataset, the ABS, also has concerns regarding the robustness of the data and has warned that it suffers from data problems and inaccuracies.[462]

1124. AGA submits that for the reasons outlined above, the equity ownership approach should not be used to measure theta as it will not contribute to the best estimate of gamma given the information available.

Taxation statistics

1125. The ERA agrees with the AER that taxation statistics should be considered in the estimation of theta. However, the ERA only considers these estimates to a limited extent based on concerns regarding data quality and consistency.[463]

1126. Further, as noted by SFG[464] the tax statistic approach is designed to measure redemption rates. That is, tax statistics do not measure the value of distributed credits and as such they do not provide relevant evidence for estimating theta.

1127. The ERA acknowledged the shortcomings of taxation statistics in the Rate of Return Guidelines.[465] The core issue with taxation statistics is that they do not accurately represent the full costs incurred by investors in obtaining and redeeming franking credits. The ACT considered the application of taxation statistics for the estimation of theta itself. The Tribunal found that tax statistics should not be used to produce an estimate of theta[466]. It was found that a more appropriate use of this data was to produce an upper bound that can be used as a cross-check of the reasonableness of an estimate produced by some other method.

1128. Given these well-accepted issues with taxation statistics, AGA submits that they should not be used to measure theta as their inclusion will result in an estimate of gamma that does not reflect the best estimate given the information available.

Conceptual goal posts

1129. The final model considered by the ERA for the estimation of theta is the conceptual goal post approach developed by Lally. The ERA describes this approach as recognising that the estimate of the rate of return required by investors in the domestic market should lie between the bounds of an estimate related to a completely segmented domestic financial market and a market fully integrated with the global market.[467]

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460 Appendix 10.1 Estimating gamma: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 263.

461 Appendix 10.1 Estimating gamma: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 263.

462 Appendix 10.1 Estimating gamma: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 264.

463 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 965.

464 Estimating gamma: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 162-169.

465 ERA 2013, Explanatory Statement for the Rate of Return Guidelines, paragraph 932.

466 Application by Energex Limited (Gamma) (no 5) [2011].

467 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 966.

1130. The ERA conceptual goal posts arrive at a range of 0.6 -1 for theta. AGA considers that the ERA has incorrectly interpreted the results from the conceptual goal posts approach[468] and has arrived at a conclusion that is at odds with interpretations of Lally, the AER and the QCA. These parties conclude that the test suggests theta must be one or close to one.[469] Further, as demonstrated by SFG,[470] the conceptual goal posts test does not establish a reasonable range for the utilisation rate and should not be afforded any weight because:

- The is no evidence of any entity adopting an estimate of the utilisation rate that falls within the range established by the Lally test.
- The test relies on estimates of CAPM parameters as they would be in perfectly segmented and integrated worlds. Estimating these parameters in the real world is a complex and contentious task and would be impossible in the theoretical worlds examined by Lally.
- The test relies on the assumption that the MRP in every country is equal to the same multiple of historical stock market variance. The ERA has rejected such methods of estimation for the MRP in the AGA Draft Decision.
- One version of the Lally test relied on the assumption that government bonds have the same yield whether or not foreign investors are allowed to buy them, which is an unsupportable assumption.
- The second version of the Lally test is based on the assumption that the market for government bonds is completely integrated, while at the same time the market for all other assets is completely segmented. This is also an unsupportable assumption.

1131. For these reasons and the reasons set out in the SFG report[471], the ERA's new approach to estimate theta incorrectly estimates redemption rates rather than the value of imputation credits to investors. The ERA's approach is illogical and unreasonable and cannot give rise to the best estimate of the value of imputation credits.

10.2.4 AGA's imputation credits proposal

1132. Rule 87A requires the estimate of gamma, being the 'value' of imputation credits. AGA maintains that the most appropriate and robust method to measure the value to the investor of distributed imputation credits is through dividend drop off estimates. As previously submitted,[472] the most robust and stable estimates of theta produced are produced from the SFG studies.[473] The approach used by SFG has been subject to a large degree of scrutiny from both the AER and has been endorsed by the ACT. The SFG approach is superior to other similar studies as it employs the standard approach of correcting prices for market movements over the ex-dividend day.[474] The theta estimates produced by the SFG dividend drop off studies have been shown to be stable and reliable in the face of stability and robustness tests and no subsequent studies or information have been shown to perform better than the SFG studies.

1133. The ERA's estimate of the value of imputation credits:

468 Appendix 10.1 Estimating gamma: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, section 9.

469 Appendix 10.1 Estimating gamma: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, paragraph 219-221.

470 Appendix 10.1 Estimating gamma: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014, section 9.

471 Appendix 10.1 Estimating gamma: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014.

472 ATCO Gas Australia, Access Arrangement Information, 1 July 2014-31 December 2019 (AA4), March 2014. Section 10.11 and Estimating Gamma for ATCO Gas Australia, SFG, March 2014.

473 SFG, Estimating Gamma for ATCO Gas Australia, March 2014.

474 SFG, Estimating Gamma for ATCO Gas Australia, March 2014.

a) Is based on an incorrect interpretation of the “value” of imputation credits to be estimated pursuant to Rule 87A and therefore measures the wrong thing.

b) Uses a methodology for estimating theta which measures the wrong thing using data which is not fit for purpose and consequently does not provide the best estimate of theta.

c) Involves an arbitrary rounding of the estimate from 0.49 to 0.50 which has no justification and is incorrect and unreasonable.

1134. For these reasons and the reasons set out in the SFG Gamma report,[475] the best estimate of theta is derived from the SFG dividend drop off studies, giving rise to an estimate of 0.35.

1135. Accordingly AGA submits that the value of imputation credits that best meets the requirements of the NGR is 0.25. This estimate is derived from a distribution rate of 0.7 and a value of theta of 0.35.[476]

[475] Appendix 10.1 Estimating gamma: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014.

[476] Appendix 10.1 Estimating gamma: Response to ATCO Gas Australia Draft Decision, Stephen Gray, SFG Consulting November 2014.

11. Depreciation

ERA required amendment 11

The Authority requires that ATCO amend section 9.1 of its access arrangement as follows

The Authority requires that ATCO adopt the current cost accounting approach to depreciation, based on the indexed value of the calculated real depreciation and amend section 9 (Depreciation) to ensure that it is consistent with the current cost accounting approach.

The Authority requires that ATCO amend section 9.1 of its access arrangement as follows:

(a) For the calculation of the nominal (indexed) Opening Capital Base for the WAGN AGA GDS for the Next Access Arrangement Period, depreciation over the Current Access Arrangement Period is to be calculated in accordance with the real straight line depreciation method – where the real opening capital base in any year is divided by the remaining asset life – and then converted to nominal terms by applying indexation to the calculated real annual depreciation, and is to be the sum of:

(i) indexed real depreciation on the Opening Capital Base over the Current Access Arrangement Period;

(ii) indexed real depreciation of the forecast Capital Expenditure for the Current Access Arrangement Period (being the amount of forecast Capital Expenditure used for the purpose of determining Haulage Tariffs for the Current Access Arrangement Period); and

(iii) indexed real depreciation of any unanticipated Regulatory Capital Expenditure for the Current Access Arrangement Period (being depreciation calculated in accordance with Clause 3 of Annexure B of this Access Arrangement).

(b) For the calculation of the Opening Capital Base for the WAGN AGA GDS for the Next Access Arrangement Period, each of:

(i) the nominal (indexed) Opening Capital Base (end of period) for the Current Access Arrangement Period adjusted for any difference between estimated and actual nominal (indexed) Capital Expenditure included in that Opening Capital Base. This adjustment must also remove any benefit or penalty associated with any difference between the estimated and actual capital expenditure;

(ii) nominal (indexed) Conforming Capital Expenditure made, or to be made, during the Current Access Arrangement Period;

(iii) any nominal (indexed) amounts added to the Capital Base under rule 82, rule 84, and rule 86 of the National Gas Rules;

(iv) nominal (indexed) depreciation over the Current Access Arrangement Period (calculated in accordance with paragraph 9.1(a));

(v) nominal (indexed) value of redundant assets identified during the course of the Current Access Arrangement Period; and

(vi) the nominal (indexed) value of Pipeline Assets disposed of during the Current Access Arrangement Period;

all indexed consistent with the rate of inflation as measured by the CPI All Groups, Weighted Average of Eight Capital Cities as at 31 December of each regulatory year.

The Authority requires that ATCO change the asset life for vehicles to ten years or provide justification to the Authority that the reduction to 5 years is consistent with rule 89 of the NGR.

AGA Response: do not accept

Summary Only – AGA remains of the view that the correct approach to avoid a double count of inflation is to not index the capital base. The ERA's required amendment requires the continuation of indexing the capital base. AGA has not implemented this amendment because the AGA's proposed depreciation schedule results in tariffs varying over time in a way that promotes efficient growth in the market for reference services. The ERA's approach does not.

11.1 Summary of ERA decision

1136. The ERA requires AGA to calculate depreciation using the Current Cost Accounting (**CCA**) approach. The ERA's approach is to apply a straight line method of depreciation to the indexed value of the asset base. This results in a depreciation amount $104.54 million (nominal) greater than the amount proposed by AGA.

1137. The ERA considers the Historical Cost Accounting (**HCA**) approach to depreciation (applying the straight line method to the non-indexed asset base), and equally the transition to this approach, is not consistent with the criteria in rule 89(1) of the NGR because[477]:

- Prices under the HCA approach are likely to diverge to a greater extent from Long-Run Marginal Cost (**LRMC**) than under the CCA approach
- It would lead to unnecessary price shock in the near term and potentially in the longer term as significant assets are replaced giving rise to relatively higher prices and potentially inefficient investment in the pipeline and by upstream and downstream users
- It discourages efficient management of the pipeline assets and user's assets as pipeline assets near the end of their useful lives as lower prices will result in inefficient over-use of the pipeline assets and distort incentives for investment, in particular the steeper recovery profile means all future capital will be recovered more quickly

1138. The ERA's analysis is based over the long term horizon and is not limited to the AA4 period.

1139. These three matters are discussed in sections 11.2.1, 11.2.2 and 11.2.3 below.

1140. Further, the ERA's reasons for not adopting HCA are that it is inconsistent with rule 89(1) (a) of the NGR; that HCA is not consistent with the NGL; and that it is not compliant with the RPPs (under the NGL, as it increases the risk of under or over utilisation of the pipeline at particular points in time. The ERA also considers the HCA approach leads to subsidisation from current to future users.[478]

1141. The ERA also requires that AGA justifies why the asset life for vehicles should be 5 years.

1142. Table 11–1 presents the ERA's calculation of depreciation for AA4 compared to AGA's proposal.

Table 11–1: Depreciation calculation

Real $ million at June 2014	Jul to Dec 2014	2015	2016	2017	2018	2019	Total Forecast AA4
Revised AAI Depreciation	4.8	15.0	19.2	22.8	25.9	28.6	116.2
ERA Draft Decision Depreciation	14.89	35.05	37.82	40.00	42.36	44.78	214.90

477 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1038.

478 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1041.

11.2 AGA response

1143. **AGA has not implemented required amendment 11**

1144. As outlined in its response to required amendment 2, AGA submits that where the ERA has indexed the asset base, the only building block that can be adjusted to remove the double count of inflation is the depreciation building block. AGA submits that the ERA's approach of making an inflationary adjustment to total revenue does not comply with rule 76 of the NGR, as the rule sets out a complete listing of the revenue building blocks and does not provide for a new or further building block to be added.

1145. As outlined in its March 2014 submission, AGA submits that the double count of inflation only arises as a result of applying indexation to the capital base[479]. The correct way to avoid this anomaly is to not index the capital base. The NGR does not require the capital base to be indexed. The potential for the capital base to be indexed for inflation is acknowledged in rule 89(1)(d) of the NGR. However, this rule contemplates but does not *require* indexation of the capital base for inflation, noting it can occur where the accounting method approved by the regulator permits.

1146. AGA considers the only correct way to remove a double counting of inflation is to remove it in the calculation of the depreciation building block. This is because the NGR require a nominal rate of return to be applied (so the double count cannot be removed from the return on capital because the effect of doing so would be that the return would be real) and no other building blocks are allowed.

1147. Removing the double count from the depreciation calculation is allowed as long as the depreciation schedule is compliant with rule 89 of the NGR, which outlines the criteria for the depreciation schedule and circumstances where deferral of depreciation may occur. If transparency is desired, the removal of inflation from the depreciation building block can be expressly acknowledged and shown, but it remains the case that the NGR recognise that removal of inflation can only be from depreciation.

1148. AGA recognises that a change from an approach where the capital base is indexed to one where it is no longer indexed can result in higher short-term prices for customers. In its March 2014 submission AGA proposed a transitional approach to reduce the price impact on customers. AGA resubmits this transition whereby the AER's PTRM method (which removes the double count associated with indexation from the depreciation building block) applies during AA4 is not indexed. However, absent these higher short-term prices, the transition is not required, and the correct approach is not to index the capital base.

11.2.1 Prices under the HCA approach are likely to diverge to a greater extent from long run marginal cost (LRMC)

1149. The ERA considers the future revenue and trend LRMC analysis by NERA is flawed and does not support AGA's submission. The NERA conclusions were:

- The depreciation schedule that best promotes efficient growth in the market will be HCA as it minimises the extent of departure from the purported LRMC trend[480]
- That HCA will be more 'flat' than CCA, leaving less of a gap between the depreciation charge and a declining LRMC over the longer term.[481]

1150. To ensure clarity regarding the point of difference between the methods referred to as HCA and CCA, AGA will refer to the HCA method as the non-indexed method of depreciation (as proposed for AA6 after a period

479 A view supported by Greg Houston in his report Evaluation of ERA's Draft Decision on ATCO's Depreciation Allowance, HoustonKemp, November 2014, p.4. (Appendix 11.1).

480 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1014.

481 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1014.

of transition), and the CCA method as the indexed method. For further clarity and consistency with the ERA's analysis relating to depreciation, the indexed method includes the deduction of the double count for inflation.

1151. The ERA has found the price trend under the indexed and non-indexed approach (Figure 36 of the Draft Decision) is declining due to lower capital expenditure assumptions[482]. The ERA regards the long term estimates as necessarily indicative, and states that the LRMC of AGA's services will not decline strongly into the future and that it is entirely feasible, given the relatively mature nature of gas pipeline technology, that LRMC could remain flat[483]. Earlier, the ERA identifies that the LRMC could also be slightly increasing[484].

1152. Nevertheless, the ERA concludes there is no strong evidence that the gap between unit prices and LRMC is likely to be reduced by shifting to a non-indexed approach to depreciation, and given that LRMC is likely to be flat at most or slightly declining over time, the indexed approach to depreciation provides a superior approach in terms of signalling efficient use over time[485].

1153. The ERA supports NERA's view that the depreciation schedule that best promotes efficient growth in the market will minimise the extent of departure from the purported LRMC trend. The point of difference appears to be the divergence of the approaches with the estimated LRMC trend.

1154. AGA maintains that the non-indexed approach will, over the longer term, be less divergent from LRMC than an indexed approach. Greg Houston of HoustonKemp (formerly of NERA) has undertaken further analysis to estimate the extent of the divergence (Appendix 11.1). The analysis shows that over the period that reflects the life of AGA's assets, the departure of the unit price per GJ over time (constant prices) from LRMC is minimised when an unindexed asset base with straight line depreciation is applied from 2014 to 2080, as compared with an indexed capital base with indexed straight line depreciation.[486] In other words, the non-indexed approach minimises the gap between the change in unit price per GJ and the indicative LRMC trend, in constant prices.[487]Having regard to the above, AGA considers that the non-indexed approach best promotes efficient growth in the market for reference services.

1155. The ERA's approach falls in to error from the commencement of the AA4 period onwards. It is only by reason of the transitional arrangements proposed by AGA that the error only changes the revenue allowance during the AA4 period marginally[488]. Thereafter, the error produces material differences.[489] AGA's approach safeguards against and corrects that error from the commencement of the AA4 period and permits the selection of the depreciation method (non-indexation) to meet the requirements of rule 89(1)(a) of the NGR (thus best promoting efficient growth in the market for reference services) from the outset of AA4 onwards.

11.2.2 Unnecessary price shock and inefficient investment

1156. The ERA considers that the magnitude of the revenue increase in the short to medium term resulting from the change to a non-indexed approach is significant even if smoothed over a number of years, and

[482] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1022.

[483] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1028.

[484] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1027.

[485] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1029.

[486] See figures 10 and 11 of the HoustonKemp report, *Evaluation of ERA's Draft Decision on ATCO's Depreciation Allowance,* November 2014. The analysis giving rise to this conclusion is set out in section 5 of the report (p15-24) Appendix 11.1.

[487] See figures 11 of the HoustonKemp report, *Evaluation of ERA's Draft Decision on ATCO's Depreciation Allowance,* November 2014. The analysis giving rise to this conclusion is set out in section 5 of the report (p15-27) Appendix 11.1.

[488] See figure 12 of the HoustonKemp report, *Evaluation of ERA's Draft Decision on ATCO's Depreciation Allowance,* November 2014. The analysis giving rise to this conclusion is set out in section 5 of the report (p15-27) Appendix 11.1.

[489] As shown in figures 13 and 14 of the HoustonKemp report, *Evaluation of ERA's Draft Decision on ATCO's Depreciation Allowance,* November 2014. The analysis giving rise to this conclusion is set out in section 5 of the report (p15-27) Appendix 11.1.

references AGA's proposed revenue impacts of 1.5% per year from AGA's proposal[490]. The ERA indicates that the price shock in the near term and longer term price shock due to inefficient investment is not consistent with promoting efficient growth in the market.

1157. Under AGA's amended access arrangement revisions, prices to customers will decline in real terms over AA4. Further, under the transition to a non-indexed approach, the contribution of the depreciation amount to the price path in the future will also decline. Under the indexed approach, prices will fall more during AA4 but the contribution of depreciation to future prices will increase – putting upward pressure on the price path[491].

1158. HoustonKemp have modelled the average prices (expressed in revenue per GJ) under AGA's transitional approach and under the indexed asset base with indexed straight line depreciation as proposed by the ERA. Both give rise to broadly similar prices for the period 2014-2024, as is the intention of the transitional approach.[492]

1159. On the one hand the ERA relies on relatively lower prices as pipelines assets near the end of their lives.[493] On the other hand, the ERA appears to consider the lower price impacts in the later years would not be realised because the ERA believes AGA would inefficiently invest in replacing assets before the end of their assumed lives[494] (because the incentive to do so is greater under the non-indexed approach than the indexed approach). This inefficient investment would not be accepted by the ERA as meeting the efficient capital expenditure criteria, would not be added to the capital base and would not result in a significant increase in prices. Further, the concerns expressed by the ERA in relation to the potential for inefficient investment arising from long term distortions caused by inefficiently low prices as particular assets come to be replaced have no foundation, either in principle or in fact. As outlined by HoustonKemp the most appropriate long term incentives for both pipeline owners and users will be created when the gap between best estimates of longer prices and long term LRMC is minimised[495].

1160. The incentive for a business to invest in inefficient replacement of assets relates to the expectation that a reasonable return will be earned over the life of the asset. For this to hold, the investment would have to be added to the capital base and attract a reasonable return. Under both indexation and non-indexation, the criteria to be met before the investment is added to the capital base are the same, the return to be applied to the capital would be the same and the return over the life of the asset would be the same.

1161. Further, under the NGR, inefficient investment cannot be added to the capital base. It follows that; inefficient investment will not lead to higher allowed revenue or result in price impacts in the future.

1162. It would appear that the ERA's decision to index the asset base is driven by the ERA's determination to achieve large short term price reductions at the expense of price increases (or lower price reductions) in the longer term. This reasoning is also consistent with the view taken by the ERA in choosing the method of tax depreciation.

1163. For tax depreciation, the ERA selects an accelerated method of depreciation, whereas in regulatory depreciation it prefers a deferral of depreciation. The effect of these two decisions together gives rise to a sharper decline in prices in the short term rather than a flatter price profile over the long term.

[490] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1030.

[491] See figure 9, of the HoustonKemp report, *Evaluation of ERA's Draft Decision on ATCO's Depreciation Allowance,* November 2014. The analysis giving rise to this conclusion is set out in section 5 of the report (p15-27) Appendix 11.1.

[492] See section 5.4 of the HoustonKemp report, *Evaluation of ERA's Draft Decision on ATCO's Depreciation Allowance,* November 2014, figure 12, (p25) Appendix 11.1.

493 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraphs 1034 and 1035.

[494] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraphs 1036.

[495] See section 5.5 of the HoustonKemp report, *Evaluation of ERA's Draft Decision on ATCO's Depreciation Allowance,* November 2014, p27, Appendix 11.1.

1164. Moreover, the shape of the price path is a result of the choice to smooth the revenue profile over the regulatory period (recognising that the NPV of revenue remains the same). The ERA has sought to achieve a sharp reduction between AA3 and AA4 followed by a flat tariff path during AA4. AGA's proposed price path is one that results in less volatility to customers between periods with a slight decline over the period.

11.2.3 HCA discourages efficient management of the pipeline assets

1165. Prices will only drive inefficient use if the price is inefficient. It is commonly accepted that an efficient tariff structure is a two part tariff consisting of a fixed component and a variable component. The NERA and HoustonKemp reports and the ERA all consider that a price trend would be considered efficient where it was most closely aligned with the trend in LRMC. The ERA found that under both indexation and non-indexation, the long term price trend is declining and that the LRMC trend is indeterminate, but feasibly flat or slightly declining over time.

1166. Assuming the tariff structure is efficient, non-indexation will only result in inefficient use of the assets or distort incentives for investment where the long term price trend is rising. Therefore, the recovery of capital more quickly under a non-indexed approach will only be inefficient if the price trend is rising over the longer term. The ERA has found that the price trend is not rising over the longer term.

1167. AGA submits that its proposal to no longer index the capital base for inflation in the future promotes efficient growth in the market for reference services and the transition approach alleviates price shocks whilst still providing for the efficiency benefits associated with an unindexed capital base to be realised.[496]

11.2.4 Asset lives for vehicles

1168. AGA has adopted an asset life for vehicles of five years consistent with expected use of the vehicles, the assumptions adopted in the business case supporting the change to owning rather than leasing fleet, the asset lives adopted for statutory accounting purposes and accepted business practice.

11.2.5 Summary of AGA's amended proposal for depreciation for the AA4 period

1169. Table 11–2 presents AGA's amended proposed depreciation for the AA4 period.

Table 11–2: AGA amended proposal depreciation

Real $ million at June 2014	Jul to Dec 2014	2015	2016	2017	2018	2019	Total Forecast AA4
Amended proposed depreciation	4.8	14.8	19.3	22.8	26.0	28.8	116.5

496 Support for the approach is found in section 5.4 of the HoustonKemp report, *Evaluation of ERA's Draft Decision on ATCO's Depreciation Allowance,* November 2014, p. 26-27 (Appendix 11.1).

12. Taxation

ERA required amendment 12

The Authority requires that ATCO update the calculation of the estimated cost of income tax as per Table 59.

The Authority also requires that ATCO revise the TAB as per Table 60, to implement the following:

d) Exclude capital contributions from the calculation.

e) Exclude commercial meters from the calculation.

f) Base taxable income on smoothed tariff revenue.

g) Use the nominal (indexed) opening RAB derived using the current cost accounting depreciation method for determining the debt service costs used in the taxation calculations.

The Authority requires that ATCO:

h) Update asset lives for the TAB as per Table 58.

i) Update the rolled forward TAB to ensure that it includes commissioned assets only.

j) Apply the diminishing value method to calculate tax depreciation for capital expenditure over the fourth access arrangement period.

k) Update the cost of debt risk margin and nominal risk free margin for the calculation of debt servicing costs.

AGA Response: do not accept

***Summary only* –** AGA has implemented the ERA's amendments relating to tax except for the treatment of capital contribution and commercial meter sets, as well as the adoption of a diminishing value approach to tax depreciation. AGA does considers that the receipt of revenue from capital contributions, usage fees and commercial meter sets results from the provision of reference services and the prime cost method of tax depreciation would be adopted by an efficient benchmark entity**.**

12.1 Summary of ERA decision

1170. The ERA accepts capital contributions may lead to a tax liability and therefore that AGA has a right to recover the tax liability. However, the ERA has excluded capital contributions from the tax asset base because it considers:

- *tax costs associated with capital contributions may not necessarily be associated with efficient costs - capital contributions are not included in the RAB, and thus are not evaluated in terms of rule 79 of the NGR that sets out the criteria for conforming capital expenditure as that incurred by a prudent service provider acting efficiently, and justified on economic, safety or regulatory grounds.*
- *to allow tax costs that are not associated with efficient costs to be charged to all customers would be inconsistent with the NGO and rule 87A of the NGR;*
- *it is unlikely that existing customers gain any benefit from contributed or gifted assets;*
- *the service provider does have a tax liability associated with a contribution, but given the objective of economic efficiency and the associated principle of 'user pays', this should be recovered from the contributor – to do otherwise would lead to a subsidy from the existing customer base to the contributing entity and the user of the asset;*

- *the service provider and the contributor are best placed to work out the commercial terms of the tax implications of any contribution, taking into account their business interests and tax positions.*[497]

1171. The ERA also requires commercial meters to be removed from the initial tax asset base, citing the 'user pays' principle.

1172. The ERA requires AGA to amend the tax asset lives for buildings, equipment and vehicles and full retail contestability to be 40, 10 and 4 years respectively.

1173. The ERA has updated the tax depreciation calculation to maintain a one year lag between the outlay of capital expenditure and the commissioning of the relevant asset. Further, the ERA applies the diminishing value method to calculate tax depreciation on the basis a benchmark efficient entity would choose this method to minimise its tax liability.

1174. The ERA has also specified required amendments to debt servicing costs to reflect its Draft Decision on the opening RAB, cost of debt risk margin and nominal risk free rate.

1175. As a result of the ERA's required amendments for each building block including the tax building block, AGA will have no tax liability for the period 2015 to 2019. A summary of the ERA's forecast tax liability is provided in Table 12–1.

Table 12–1: ERA decision forecast tax liability

Real $ million at June 2014	July to Dec 2014	2015	2016	2017	2018	2019	Total
Estimated Cost of Corporate Income Tax	8.04	0.0	0.0	0.0	0.0	0.0	8.04
Value of Imputation Credits	(4.02)	0.0	0.0	0.0	0.0	0.0	(4.02)
Estimated Cost of Corporate Income Tax Net of Imputation Credits	**4.02**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**4.02**

12.2 AGA response

AGA has not implemented required amendment 12.

1176. AGA accepts the revised asset lives, the ERA's calculation to maintain a one year lag between the outlay of capital expenditure and the commissioning of the relevant asset, and the method for the calculation of debt servicing costs.

1177. AGA does not accept the removal of capital contributions and commercial meter sets from the tax asset base or the adoption of diminishing value tax depreciation for the AA4 period. In addition, AGA has identified user specific charges that form part of the A1, A2 and B1 Reference Service Tariffs were not included in the ERA's calculation of the tax liability. This has been rectified in the revised tax building block submitted by AGA. The reasons for AGA's revised proposal are provided in the sections below. A summary of the amended tax liability calculation is provided in the Table 12–2.

[497] ERA, Draft Decision on Proposed Revision to the Access Arrangement for the Mid-West and South-West Gas Distribution System, paragraph 1078.

Table 12–2: AGA amended proposal forecast tax liability

$ million real at 30 June 2014	July to Dec 2014	2015	2016	2017	2018	2019	Total
Estimated Cost of Corporate Income Tax	9.1	11.2	9.5	8.6	7.6	5.2	51.2
Value of Imputation Credits	-2.3	-2.8	-2.4	-2.1	-1.9	-1.3	-12.8
Estimated Cost of Corporate Income Tax Net of Imputation Credits	**6.8**	**8.4**	**7.1**	**6.4**	**5.7**	**3.9**	**38.4**

12.2.1 Capital contributions

1178. AGA submits that the ERA is required to include capital contributions and commercial meter sets in the tax asset base. The key component of the estimated cost of corporate income tax in rule 87A of the NGR, is ETIt which is defined as:

> *"an estimate of the taxable income for that regulatory year that would be earned by a benchmark efficient entity as a result of the provision of reference services if such an entity, rather than the service provider, operated the business of the service provider;"*

1179. As part of operating a business of providing reference services an efficient entity must undertake activities (such as new connections) which will require capital contributions from users. That is such consumer contributions inevitably arise from the fact that reference services are being provided. AGA cannot refuse to establish new connections unless there is an impediment to doing so relating to safety, lack of capacity or impact other user of the network. Therefore such contributions arise as a result of the provision of reference services and must be included as part of ETIt. This is not, AGA submits, a matter in which the ERA has discretion. Rule 87A of the NGR sets out the legal test which must be applied in accordance with the terms of the rule. There is no discretion to exclude income which falls within the scope of the definition.

1180. Even if this were not the case and there is an element of discretion in the application of the provision, AGA submits that the NGO requires that discretion is to be exercised so as to include capital contributions and meter sets in the tax asset base. Essentially this is because the customer base generally benefits from such contributions as costs per customer are lowered by the addition of now customers to the network. Therefore the long term interests of customers as to price, security and reliability of supply are promoted. Equally those interests are jeopardised by placing too great a cost on parties seeking connections. The assumption that a party seeking a connection should pay all costs, including tax costs, assumes that there is no benefit to other customers from the connection. Indeed as there are benefits to other customers as explained above, then it is contrary to economic efficiency and equity for the costs to be imposed solely on the party seeking the connection rather than not spread across the customer base. AGA notes that the ERA's analysis of this issue does not consider the customer base and whether that customer base will be better off or not, in terms of the NGO, if capital contributions are included in the tax asset base rather than being charged to individual customers. In part this is because the ERA's analysis assumes incorrectly that existing customers receive no benefit from capital contributions.

1181. These matters are considered further below.

1182. Though capital contributions and commercial meters are not included in the RAB, AGA considers these costs are efficient when tested against the requirements of rule 79 of the NGR Evidence to demonstrate this is provided in section 12.2.2 below.

1183. Rule 87A (1) of the NGR requires that the cost of corporate income tax is estimated based on the taxable income of the entity for that regulatory year, which would be earned by a benchmark efficient entity as a result of the provision of reference services. Capital contributions arise as a result of providing reference services. The capital contribution amount is the difference between the total efficient costs associated with the customer connection, and that which would be recovered by the tariff revenue as a result of the customer's consumption. The way rules 79 and 82 of the NGR work together is that the whole expenditure is assessed against rule 79(1)(a) then, if part of that expenditure is not justified under rule 79(1)(b) of the NGR, that part becomes a capital contribution. Therefore, the capital contribution amount represents a sub set of the efficient cost and satisfies rule 79(1)(a) of the NGR.

1184. The ERA recognises that the receipt of a capital contribution leads to a tax liability. AGA cannot recover the tax liability arising from past contribution from particular customers. Customers that paid past contributions are now provided with and continue to have access to reference services at reference tariffs. Therefore, if the past capital contributions are excluded from the calculation of the tax liability, AGA is not provided with an opportunity to recover its efficient costs.

1185. The ERA considers the contributor of the capital cost of the asset should pay for the tax liability rather than all users because it does not believe all users are likely to benefit from the contribution. AGA submits all customers benefit from past capital contributions as outlined in section 12.2.3 below.

12.2.2 Satisfaction of rule 79 of the NGR

1186. Capital contributions are calculated by determining the amount required to ensure that the net present value (**NPV**) of the expenditure to connect the customer is zero after a period of 25 years. The entire expenditure required to connect the customer is assessed against rule 79(1)(a) of the NGR and then the amount required to be paid by the customer is assessed against rule 79(2) of the NGR. Therefore, the capital contribution amount satisfies rule 79 of the NGR.

1187. The above procedure and relevant objectives, requirements and assumptions relating to capital contributions are included in AGA's Capital Contribution Policy and Capital Contribution Procedure provided at Appendix 12.1 and 12.2 of this document.

1188. Further, the capital contribution is the NPV of the difference between the cost of the connection and the revenue received. Therefore the revenue paid by the customer through haulage tariffs and the capital contribution is the total cost of connection, which will always be more than the avoidable cost of connection. Therefore, no subsidy is paid by existing customers to the new customer. (Confidential Appendix 12.3 Capital Contributions).

12.2.3 Benefits to customers

1189. The revenue and load associated with the customers that have paid a tax contribution is included when calculating reference tariffs and the benefits associated with this are greater than the tax liability recovered. Capital contributions arise from three sources:

- cluster connections (B3 Reference Service customers paying the B3 Reference Tariff)
- meter upgrades
- net connection costs from small commercial customers (B2 Reference Service customers paying B2 Reference Tariffs).

1190. The following analysis presents the net benefits to all customers from the payment of capital contributions by the reference service customers paying reference tariffs[498]

[498] Confidential Appendix 12.3.

Table 12–3: Benefit to customers from capital contributions

Capital contributions paid as a result of	Economic life adopted for NPV analysis	NPV for each customer contribution	Time before all other customers benefit
Cluster connections	25 year life of connection assets	$756	13 years
Small commercial meter upgrades	25 year life of meter assets	$2,111	4 years
Small business customer connections	25 year life of connection assets	$5,793	6 years

1191. It is difficult to estimate how charging the user the tax liability would impact the likelihood of a new customer choosing not to connect. However, even if one additional customer chooses not to connect as the result of the charge being greater than it is willing to pay, existing customers forgo the benefit. This would be inconsistent with the efficient use and utilisation of the gas network.

1192. No other Australian gas distribution businesses adopt the ‘user pays’ approach to recovering the tax liability, so it is not possible to observe the impact on connection rates. The AER’s PTRM revenue approach incorporates the tax liability in the calculation of the tax building block. The ERA’s user pays approach is only applied to electricity and water utilities, which are essential services, while gas is not.

1193. AGA’s policy for calculating the amount of capital contribution adopts a number of assumptions about the load, the connection rate for new subdivisions, and the number of years over which the load will exist. Where the actual load is greater than the assumptions, all other customers will benefit through a reduction in tariffs.

1194. For new residential developments AGA assumes a connection rate of 75%[499], which is the average residential connection rate in Western Australia. However, the connection rate for new developments has been much higher, leading to higher load than forecast. The higher load benefits existing customers as they have contributed no costs for connecting the additional customers but their prices have been maintained at a lower level as a result. Table 12–4 shows the connection rates achieved in subdivisions over the last 25 years.

[499] Confidential AGA Penetration Rate report November 2014.

Table 12–4: Connection rate in new residential development areas

Suburb	Connection Rate	Decade Established
Tapping	96%	1990s
Kinross	94%	1990s
Atwell	94%	1990s
Winthrop	94%	1980s
Ridgewood	93%	1990s
Withers	93%	1980s
Usher	93%	1980s
Secret Harbour	91%	1980s
Connolly	91%	1980s
Currambine	91%	1990s
Carramar	88%	1990s
Butler	87%	2000s
Aubin Grove	86%	2000s

Source: Confidential AGA Penetration Rate report November 2014[500]

1195. Table 12–5 presents the estimated benefit to existing customers of new connections in residential development areas since the network has been subject to economic regulation (from 2000) as a result of the actual connection rate being higher than that forecast when calculating a capital contribution. The forecast average consumption per connection is assumed to be 13.6 GJ.

Table 12–5: Benefit calculated from higher than forecast connection rates in new residential development areas[501]

Residential development area	Forecast connection rate	Forecast load	Actual connection rate	Load at actual connection rate	Load benefit to other customers	Revenue benefit to other customers
Butler	75%	56,108 GJ	87%	65,102 GJ	8,995 GJ	$142,585
Aubin Grove	75%	27,982 GJ	86%	24,510 GJ	3,472 GJ	$55,043

1196. For commercial and industrial customers, the capital contribution calculation assumes the customer will use 80% of the nominated load over a 20 year period. This assumption is based on historic evidence that customers rarely disconnect within 20 years. Therefore, where these customer loads are greater than the forecast load and the customer remains connected for more than 20 years, all other customers receive the benefit. It is very rare for customers to disconnect within 20 years. AGA's disconnection rate is less than 0.04%.

1197. Once customers are connected, AGA cannot distinguish the additional load, or the additional time (compared to forecast) for the purposes of determining reference tariffs, and apportion the benefit to particular users. Therefore, the benefits are passed through to all customers in full, through lower prices than if the connecting customers had not connected.

500 Confidential AGA Penetration Rate report November 2014.

501 Confidential Appendix 12.3.

1198. A further example of benefits to existing customers from customers that connect and pay a capital contribution is the benefit from large A1 customers. The connection of the Fiona Stanley and QEII Charles Gairdner hospitals during AA3, will provide net benefits to all other customer of more than $2.5 million after 7 years.[502]

12.2.4 Commercial meter sets and user specific charges

1199. AGA does not include commercial meter sets in its regulated capital base because it receives revenue through user specific charges under reference tariffs for A1, A2 and B1 Reference Services. The costs incurred to install commercial meter sets are based on the required labour and materials to construct, install and commission the meter sets. These costs are based on an established supply chain, following AGS's procurement policy and an experienced technical installation team seeing the meters through from construction to efficiently and in time to meet customer's needs. Therefore, these costs are efficient and properly included in the tax asset base for the purpose of calculating the tax liability.

1200. In its March 2014 access arrangement information, AGA inadvertently excluded the revenue received through user specific charges from the calculation of tax liability. This revenue relates to the provision of reference services and so is properly included in the estimate of taxable income under rule 87A of the NGR.

1201. Table 12–6 presents the revenue from user specific charges to be included in the calculation of the tax liability.

Table 12–6: User specific charges

$ million real at 30 June 2014	July to Dec 2014	2015	2016	2017	2018	2019	Total
User specific charges	1.5	2.5	2.3	2.1	1.9	1.7	12.1

12.2.5 Adoption of diminishing value depreciation

1202. AGA agrees with the ERA that a benchmark efficient entity would choose to minimise its tax liability. However, AGA disagrees that this can only be achieved by choosing a diminishing value method for tax depreciation.

1203. AGA considers a benchmark efficient entity may minimise its tax liability by adopting either the diminishing value or prime cost methods. This is permitted by section 40-65 of the *Income Tax Assessment Act 1997* (**ITAA**) in providing the choice and recognised by the AER in considering the matter for other benchmark efficient entities.[503]

1204. AGA submits a benchmark efficient entity in AGA's position would not adopt the diminishing value method. This is because:[504]

- **AGA has already chosen the prime cost method** – sections 40-65 and 40-130 of the ITAA 97 outlines that a taxpayer has a choice of two methods to work out the decline in value of a depreciating asset, which is the diminishing value method or prime cost method and that this choice must be made on the date the taxpayer lodges the income tax return for the income year to which the choice is made. The taxpayer cannot change it. AGA chose the prime cost method in the pre-tax regime when AGA was subject to strong incentives to minimise its tax liability. Those were the actions of a prudent and benchmark efficient entity and remain so in the future

502 Confidetnial Appendix 12.3.

503 The AER acknowledged in its decision for SPAusNet that the Australian tax law allows both methods to be used and accepted a change to prime cost method. (see Appendix 12. 4 Ernst and Young :Review of regulated tax asset base for regulated revenue purposes with addendum to the report by Vaughan Linfield 21 November 2014).

504 See Appendix 12.4 for supporting advice on the application and requirements of the Australian tax law.

- **The diminishing value method results in an undeducted amount remaining until the asset is disposed of** – AGA is not able to dispose of the majority of its assets. Therefore, it would not be able to recover its efficient asset costs contrary to the NGR and RPP. A benchmark efficient entity in AGA's position would not choose such an outcome and it follows it would not choose to adopt the diminishing value method.
- **The diminishing value method defers the recovery of tax costs to future regulatory periods** – AGA has identified no market characteristics that would suggest future customers should bear a higher proportion of tax costs than current customers.
- **AGA cannot apply a different method to future assets in the nature of improvements or alterations** – section 40-130 of the ITAA 7 does not allow a taxpayer to change the method for assets to which it has already applied a particular method. The diminishing value method could only apply to new assets identified to not be improvements or alterations to existing assets or else AGA would not be able to recover its efficient asset costs. This would be contrary to the NGR and RPP.
- **The diminishing value method results in an un-deducted amount remaining until the asset is disposed of** – AGA is not able to dispose of the majority of its assets. Therefore, it would not be able to recover its efficient asset costs contrary to the NGR and RPP. A benchmark efficient entity in AGA's position would not choose such an outcome and it follows it would not choose to adopt diminishing value.

Table 12–7 summarises the closing tax asset base in AGA's amended proposal.

Table 12–7: AGA amended proposed tax asset base

$ million nominal	July to Dec 2014	2015	2016	2017	2018	2019
Opening Tax Asset Base	497.4	518.0	577.5	643.6	711.8	775.2
AGA's Forecast Capital Expenditure	44.8	110.8	123.9	128.4	125.4	120.9
AGA's Forecast Depreciation	24.2	51.3	57.7	60.3	62.0	67.5
AGA's Amended Proposal Closing Tax Asset Base	**518.0**	**577.5**	**643.6**	**711.8**	**775.2**	**828.6**

13. Return on working capital

ERA required amendment 13

The value of return on working capital for the fourth access arrangement must be amended to reflect the values shown in Table 63 of this Draft Decision

AGA Response: accept with modifications

Summary only - AGA has not implemented the ERA's amendment in relation to working capital because the ERA requires the removal of an 'inflationary gain' which is not relevant to working capital.

13.1 Summary of ERA decision

1205. The ERA approves inclusion of working capital as an efficient cost. The ERA also accepts use of the working capital cycle model to estimate the working capital requirement and has agreed with the underlying assumption proposed by AGA. However, as a result of various required amendments, the ERA requires the working capital amount to be amended to reflect its required amendments to tariff revenue, forecast expenditure and rate of return. The ERA also adjusts the working capital calculation to account for what it calls 'inflationary gain'.[505]

1206. Table 13–1 presents the working capital allowance in its decision.

Table 13–1: ERA decision return on working capital (nominal) for AA4

Nominal $ million	July to Dec 2014	2015	2016	2017	2018	2019
Tariff revenue	**96.95**	**133.67**	**139.64**	**144.96**	**150.21**	**155.64**
Expenses						
Forecast Capital Expenditure	32.26	64.46	66.16	67.77	70.48	72.43
Forecast Operating Expenditure	28.37	70.24	55.56	52.16	52.62	47.41
Total Expenses	60.63	134.70	121.72	119.93	123.10	119.84
Working Capital Requirement						
Receivables (18 days)	9.48	6.59	6.87	7.15	7.41	7.68
Payables (15 days)	-4.94	-5.54	-4.99	-4.93	-5.06	-4.92
Inventory (0.89 of capital expenditure)	0.25	0.63	0.49	0.46	0.47	0.42
Working Capital Requirement	4.79	1.68	2.37	2.68	2.82	3.17
Return on Working Capital at WACC = 5.94%	0.14	0.10	0.14	0.16	0.17	0.19
Inflationary gain	-0.05	-0.04	-0.06	-0.06	-0.07	-0.07
Return on Working Capital	**0.09**	**0.06**	**0.09**	**0.10**	**0.10**	**0.11**

505 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1134.

13.2 AGA response

AGA has implemented required amendment 13 with modifications

1207. The ERA makes an adjustment to remove a double count of inflation that results from using nominal dollars multiplied by the nominal weighted average cost of capital.[506] The ERA explains that nominal dollars and the nominal weighted average cost of capital both factor in the presence of inflation and states:

1208. *Without making an adjustment to remove the double counting of inflation in both figures, ATCO's return on working capital amount would be overstated and incorrect.*[507]

1209. As highlighted by the ERA, inflationary gain occurs when a nominal rate of return is applied to an indexed asset base. The inflationary adjustment eliminates double counting of inflation that results from using an asset value indexed for inflation and a nominal rate of return that also includes compensation for inflation.

1210. However, the working capital calculation proposed by AGA does not use data from an indexed capital base. AGA's proposal does not index the capital base going forward therefore it is not appropriate to adjust its working capital amount.

1211. Further, AGA is concerned the ERA has made an error in its return on working capital calculations in the tariff model. It appears the ERA's inflationary gain for working capital has been back solved and as a result, the net present value of the real and nominal returns on working capital do not reconcile. The return on working capital component calculated by the ERA delivers a lower return than that required to cover the efficient costs of a benchmark efficient entity. AGA's modelling approach resolves this issue.

1212. The ERA considers AGA has adopted a reasonable methodology in producing its forecast return on working capital.[508] AGA will maintain its working capital assumptions as set out in the initial proposal:

- Inventory as a percentage of capex 0.89%
- Accounts payable creditor days 15
- Accounts receivable 18 days

1213. Table 13–2 shows the proposed value of working capital for the AA4 period. The amounts in the table are consistent with AGA's revised tariff revenue, expenditure and rate of return proposal. The working capital allowance reflects efficient cash flow management practices.

506 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1134.

507 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, footnote 559.

508 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1134.

Table 13–2: AGA amended return on working capital requirement (nominal) for AA4

Nominal $ million	July to Dec 2014	2015	2016	2017	2018	2019
Tariff Revenue	**95.6**	**188.3**	**197.0**	**204.5**	**212.0**	**218.8**
Expenses						
Forecast Capital Expenditure	43.7	108.8	121.8	126.2	123.2	118.6
Forecast Operating Expenditure	32.6	74.8	77.7	81.2	85.5	90.2
Total Expenses	76.3	183.7	199.6	207.4	208.7	208.8
Working Capital Requirement						
Receivables (18 days)	4.7	9.3	9.7	10.1	10.5	10.8
Payables (15 days)	-3.1	-7.5	-8.2	-8.5	-8.6	-8.6
Inventory (0.89 of capital expenditure)	0.4	1.0	1.1	1.1	1.1	1.1
Working Capital Requirement	2.0	2.7	2.6	2.7	3.0	3.3
Return on Working Capital at WACC = 7.64%	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**

14. Tariffs

14.1 Allocation of total revenue between reference services and other services

ERA required amendment 14

The value of tariff revenues to be allocated for the calculation of haulage tariffs for the fourth access arrangement period must be amended to reflect Table 67 of this Draft Decision.

AGA Response: accept with modifications

Summary Only – AGA has implemented the methodology applied by the ERA but not the total revenue.

14.1.1 Summary of ERA decision

1214. The ERA determined the total revenue to be recovered from reference haulage service tariffs by subtracting the NPV of ancillary service revenue and the NPV of prudent discount revenue from the NPV of total revenue derived through the building block methodology. In addition, the ERA adjusted the ancillary service revenues and therefore the charges for ancillary services.

1215. The ERA adjusted tariffs in 2015 and kept them constant in real terms from 2015 to 2019 such that the present value of the total revenue is identical to the new cost of service. For the B3 standing charge, the ERA has applied a separate adjustment to increase it gradually from 2015 to the avoidable cost recovery level in 2019.

14.1.2 AGA response

AGA has not implemented required amendment 14

1216. AGA accepts the methodology applied by the ERA but not the revenue calculation. AGA's response in relation to the revenue calculation is presented in Chapter 3 of this document.

14.2 Haulage tariffs

ERA required amendment 15

The Authority requires that ATCO update its calculation of the B3 standing charge, in addition to all haulage tariff price paths, as per Table 72 of this Draft Decision.

The Authority also requires that ATCO provide the Authority with updated avoidable costs and standalone costs by tariff class in response to this Draft Decision.

AGA Response: accept with modifications

Summary Only – AGA has implemented the approach adopted by the ERA to B3 standing charges but not the amount of the standing charge.

14.2.1 Summary of ERA decision

1217. The ERA accepts AGA's proposal to increase the standing charge for B3 customers to cover the avoidable capital costs of connection. However, the ERA requires the increase be phased in over the AA4 period to reduce the price impacts to small use customers using less than 2 GJ of gas per year.

1218. The ERA updated GDS haulage tariffs based on updated total revenue and implemented the following price paths:

- For A1, A2, B1 and B2 tariff classes:
  - Decrease haulage tariffs by the full extent of the revenue adjustment in 2015
  - Fix haulage tariffs in real terms from 2015 to 2019
- For B3 tariff classes
  - Increase standing charge gradually until 2019
  - Decrease usage charges to the full extent of the revenue adjustment in 2015
  - Decrease usage charges in real terms from 2015 to 2019

14.2.2 AGA response

AGA has implemented required amendment 15 in part, with some modifications

14.2.2.1 B3 standing charge

1219. AGA accepts the ERA's approach to phase in increases to standing charges for B3 customers over the AA4 period. However, it does not accept the calculated charges. AGA has recalculated the charges based on the revenue calculation outlined in this response to the Draft Decision.

1220. The standing charge in each year of the access arrangement period is provided in Table 14–1.

Table 14–1: B3 Reference Tariffs

Charging parameter ($ real at 30 June 2014)	2015	2016	2017	2018	2019
Standing charge	83.04	95.30	106.92	117.91	128.30

14.2.2.2 Tariff path

1221. AGA accepts the ERA's approach to the price structure and variations to the components of the price structure over the AA4 period. However, AGA does not accept the tariff path required by the ERA. AGA considers a smooth tariff path provides a better balance for customers and AGA for the following reasons:

- Cash flow – it results in a better match between the building block costs and revenue
- Price shock – it reduces the price shock to customers between regulatory periods
- Incentives maintained for new retailers – retail margins are reduced over time rather than all in one year, providing a more consistent incentive for new retailer entry and price competition
- Reduces the significant impact on the business of the reduced revenue – this will better enable AGA to manage its financial position and financing

1223. Figure 14–1 illustrates the total revenue in each year of the AA4 period compared with the tariff revenue to be received over the period. The price path proposed by AGA results in less revenue being received compared to the building block total revenue in the final years of the period. This is preferred to the ERA's proposed price path which would result in a significant drop in revenue in 2015 compared to 2014 as shown in Figure 14–2.

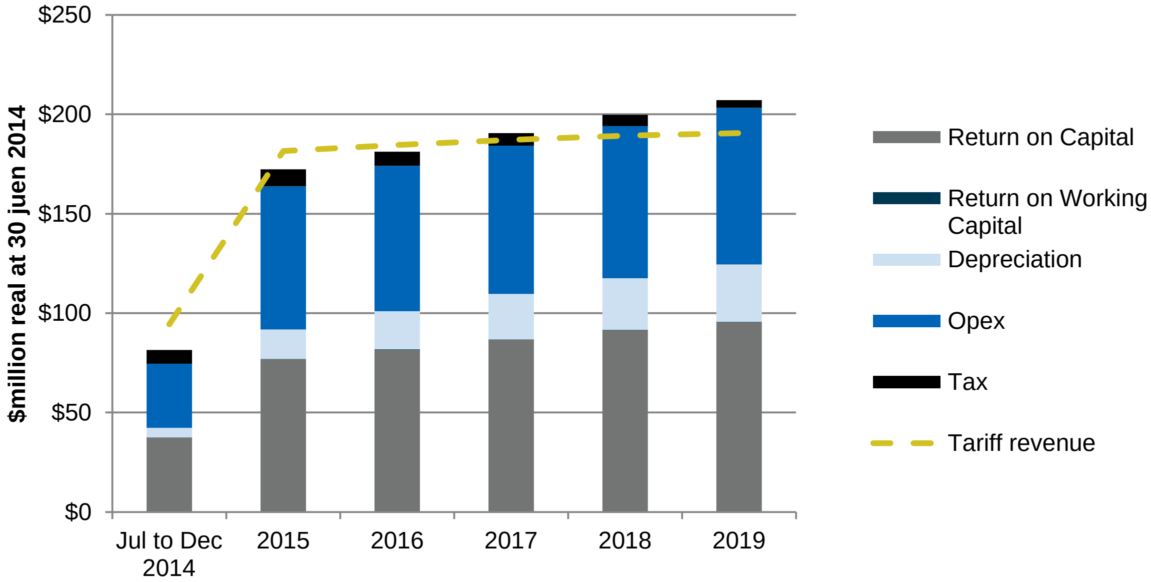

Figure 14–1: Revenue building blocks and tariff revenue (including reference ancillary service and prudent discounted revenue)

1224. Figure 14–2 below presents a comparison of total revenue received from 2010 to 2014 compared with the ERA's draft decision and AGA's amended proposal for AA4.

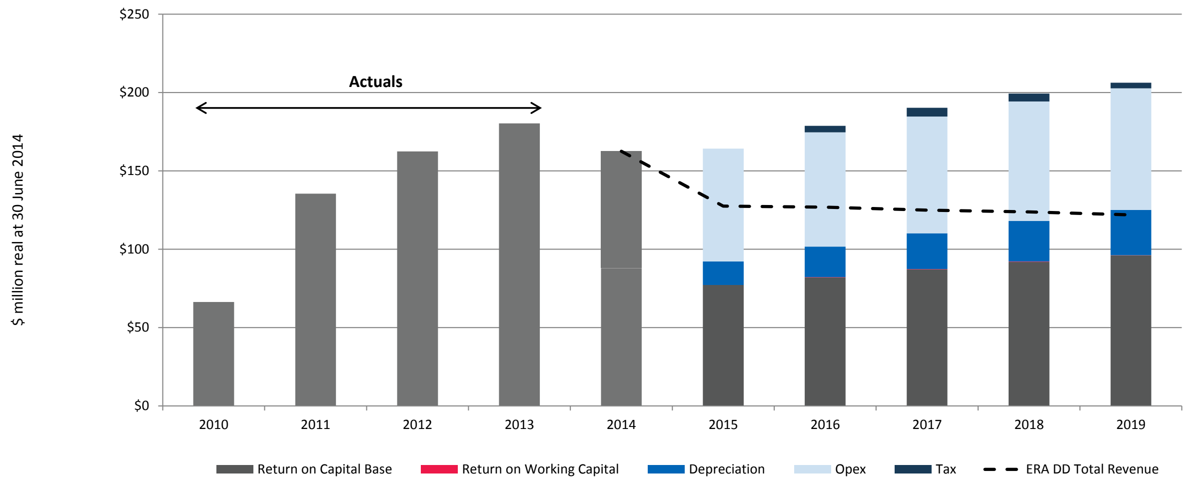

Figure 14–2: Total revenue

1225. As a result of the amendments to AGA's proposal, the average annual tariff change to all customers is a reduction of 1.8% per year and a reduction of 1.1% per year for residential customers. The table below presents the change to the average annual price over the AA4 period.

Table 14–2: Price Path (% annual change in average price, forecast CPI of 2.5%)

Reference Tariff	2015	2016	2017	2018	2019	Average annual % change
A1	-3.1%	0.5%	-2.4%	-3.3%	-3.4%	-2.4%
A2	-1.5%	-1.2%	-2.3%	-2.4%	-2.9%	-2.1%
B1	-4.0%	-1.2%	-1.6%	-1.7%	-1.7%	-2.1%
B2	-1.8%	1.0%	0.2%	-0.1%	-0.0%	-0.1%
B3	-4.6%	0.7%	-0.2%	-0.5%	-0.8%	-1.1%
All customers	-3.9%	-2.0%	-0.6%	-1.0%	-1.4%	-1.8%

1227. Table 14–3 presents the reference tariffs for each reference service under AGA's amended revised access arrangement.

Table 14–3: Reference tariffs by Reference service

Charging parameter ($ real at 30 June 2014)	Units	July to December 2015	2016	2017	2018	2019
Reference tariff A1						
Standing charge	**$/year**	**45,334.62**	**44,515.40**	**43,710.98**	**42,921.10**	**42,145.49**
Demand charge						
First 10 km	$/GJ km	191.07	187.62	184.23	180.90	177.63
Distance > 10 km	$/GJ km	100.57	98.75	96.97	95.21	93.49
Usage charge						
First 10 km	$/GJ km	0.04054	0.03980	0.03909	0.03838	0.03769
Distance > 10 km	$/GJ km	0.02025	0.01989	0.01953	0.01917	0.01883
Reference tariff A2						
Standing charge	**$/Year**	**25,099.65**	**24,646.09**	**24,200.72**	**23,763.40**	**23,333.98**
First 10 TJ	$/GJ	2.42	2.38	2.34	2.30	2.25
Volume > 10 TJ	$/GJ	1.30	1.28	1.25	1.23	1.21
Reference tariff B1						
Standing charge	**$/Year**	**1,264.39**	**1,241.54**	**1,219.10**	**1,197.07**	**1,175.44**
First 5 TJ	$/GJ	4.83	4.74	4.66	4.57	4.49
Volume > 5 TJ	$/GJ	4.14	4.07	3.99	3.92	3.85
Reference tariff B2						
Standing charge	**$/Year**	**325.30**	**327.61**	**329.62**	**331.33**	**332.77**
First 100 GJ	$/GJ	8.03	7.86	7.69	7.52	7.36
Volume > 100 GJ	$/GJ	4.78	4.68	4.58	4.48	4.38
Reference tariff B3						
Standing charge	**$/Year**	**83.04**	**95.30**	**106.92**	**117.91**	**128.30**
First 2 GJ[1]	$/GJ	-	-	-	-	-
Volume > 2 <10 GJ[2]	$/GJ	14.77	13.32	11.88	10.43	8.98
Volume > 10 GJ	$/GJ	6.37	5.75	5.13	4.50	3.88

1228. Notes: (1) Rounded from 1.825 GJ, (2) Rounded from 9.855 GJ

1229. AGA also points out that where the ERA imposes significant reduction in prices compared to those incurred in 2014, AGA will maintain significant losses as a result of the reduction in revenue. AGA has continued operating its business under the same business model, policies and approaches used in AA3 and as proposed for AA4. Where the ERA disagrees with the approach, policies or efficiency of costs incurred, and these decisions are applied retrospectively; AGA has no ability to respond to the decision or avoid losses. This will be the case for the period up until the ERA releases its Final Decision (expected in March 2015) and for a transition period beyond the decision as the business absorbs the decision and implements the changed operating model and reduced costs.

1230. For example, AGA connects approximately 19,000 customers per year. Under the ERA's draft decision, the number of new connections will fall to around 2000 customers per year. AGA has already connected 17,000 customers in 2014 and has incurred the costs associated with these connections. To reduce the number of connections to 2000 customers a year, AGA will have to change many of its policies, reduce its work force significantly (90% of the workforce are involved in growth investment), and manage the communication and fallout associated with customers who will no longer be offered AGA's services. Undertaking these tasks will take some time.

1231. To the extent that any of the costs incurred by AGA in 2014 are above those approved by the ERA, losses will not be avoided. However, where these costs relate to the workforce, including in corporate support and marketing and business development, strategies will be required to reduce the workforce. This is likely to result in an increase in costs in the short term as redundancies are paid and contracts are paid out.

1232. AGA accepts that this situation has resulted from the delay due to the change in rule 87 of the NGR. Nevertheless, AGA does not consider it is consistent with the NGO for AGA to bear the costs associated with the delay. Therefore, AGA's full costs in 2014 must be recognised in the Final Decision. AGA will submit its independently reviewed regulatory financial statements to the ERA in February 2015, which will provide the costs actually incurred during 2014 for incorporation into the ERA's Final Decision.

14.2.2.3 Stand alone and avoidable cost

1233. The expected revenue is determined by calculating the revenue to be generated by the forecast number of customers paying the AA4 reference tariff using the forecast consumption amounts.

1234. The avoidable cost is calculated by identifying the avoidable cost of providing services to each reference tariff class of customers. These costs were identified based on a review of those costs in each cost centre that would not be incurred if that class of customer was no longer provided with the reference service.

1235. Avoidable operating costs include employee costs, unaccounted for gas and the return on and of avoidable capital costs.

1236. The standalone costs are determined based on subtracting the avoidable operating costs for each tariff class from the total operating cost forecast for AA4, plus the return on and of the capital base required to provide each service.

1237. The following table presents the expected revenue by tariff class compared with the stand alone and avoidable cost of providing the haulage reference service.

Table 14–4: Stand alone and avoidable costs by reference tariff class

$m real at 30 June 2014	A1	A2	B1	B2	B3
Expected revenue	39.8	31.3	47.0	51.4	704.0
Stand alone cost	394.0	501.6	607.6	624.2	799.8
Avoidable cost	5.9	2.7	6.8	6.3	81.4
Compliance with Rule 94 (3)	Yes	Yes	Yes	Yes	Yes

14.3 Haulage tariff variation mechanism

ERA required amendment 16

The Authority requires that ATCO remove references to revenue yield in Annexure A, and remove clause 2 and clause 3 (B) and update all the formulas in Annexure B of the Access Arrangement to reflect the following:

To maintain the current tariff variation mechanism for B2 and B3 customers for the fourth access arrangement period as in the approved current access arrangement;

To exclude cost pass-throughs for regulatory costs (clause 3.1 (iii) (B) of Annexure B); and

The Authority also requires that ATCO reword clause 3.1 (iii) (A) in Annexure B as follows:

“Conforming Capital Expenditure or Conforming Operating Expenditure as a direct result of a Change in Law or Tax Change.”

The Authority requires that ATCO reword clause 3.1 (iv) in Annexure B as follows:

“ATCO Gas Australia incurs Conforming Capital Expenditure or Conforming Operating Expenditure as a direct result of any Law that imposes a fee or Tax on greenhouse gas emissions or concentrations; and for avoidance of doubt, this expenditure includes only direct capital or direct operating expenditure associated with preparation for, compliance with the Laws which implement, and the participation in, the Emissions Trading Scheme; and liability only for direct capital or direct operating expenditure transferred to ATCO Gas Australia from another entity as a direct result of accordance with the Emissions Trading Scheme.”

The Authority requires the removal of clause 3.1(v) in Annexure B.

The Authority requires that ATCO reword clause 3.2 in Annexure B as follows: “If a Cost Pass Through Event occurs, ATCO Gas Australia must notify the ERA of the Cost Pass Through Event, and may vary one or more Haulage Tariffs to recover only direct Conforming Operating Expenditure and depreciation of and return on direct Conforming Capital Expenditure incurred or forecast to be incurred by ATCO Gas Australia (or on ATCO Gas Australia’s behalf) as a direct result of the Cost Pass Through Event, provided that these costs have not already been recovered by ATCO Gas Australia.

A consequential amendment is required to clause 4.2. The Authority requires ATCO to amend the wording of clause 4.2 to read:

"ATCO Gas Australia will use its best endeavours to give the ERA a variation report at least 40 Business Days before the date on which the Haulage Tariff is to be varied as a result of a Cost Pass Through Event, and that report shall contain the following information:

(a) a statement of reasons for the variation of the Haulage Tariff as a result of the Cost Pass Through Event;..."

AGA Response: accept with modifications

Summary Only – AGA has implemented most of these required amendments. However, it has not accepted the removal of reference to the revenue yield and has incorporated an explicit cost pass through for licence fees, and the required amendment to adopt the term ‘best endeavours’ has been rejected.

14.3.1 Summary of ERA decision

1238. The ERA requires AGA to remove references to revenue yield in its price control formula for B2 and B3 customers and instead applies the tariff variation mechanism from the current access arrangement period. The ERA rejects revenue yield per connection point on the following basis:

- *The tariff variation formula does not further allocate the tariff variation to the standing or variable component of the tariff, leaving that for ATCO to determine*
- *ATCO has not outlined a procedure by which it would supply evidence for revenue variance calculations*

- *ATCO has not provided a sufficiently broken down demand forecast, by tariff class and usage bracket, which would enable the Authority to verify its revenue yield per customer calculations.*[509]

1239. The ERA also suggests that because demand forecasts have been higher than actual demand for the second and third access arrangement, there is the potential for significant volume risk. The ERA believes the proposed revenue yield per delivery point transfers volume risk from AGA to future users in the form of higher forward-looking tariffs where demand is overestimated. The ERA also considers: *ATCO Gas Australia has not provided sufficient information to satisfy the Authority that ATCO's updated demand forecasting methodology addresses the problems that gave rise to the historical inaccuracy in GDS demand forecasts*.[510]

1240. AGA disagrees with the ERA's assessment of the revenue yield variation mechanisms and considers the mechanism should be applied to B2 and B3 tariffs during the AA4 period. Evidence to support AGA's proposal and to address the ERA's reasons for rejecting the mechanism is provided in the following sections.

14.3.2 AGA response

1241. AGA has implemented required amendment 16 in part, with some modifications

14.3.2.1 Revenue yield

1242. AGA has not implemented this required amendment. Each of the reasons for the ERA required amendment are addressed in the following sections.

Revenue Allocation to the standing or variable component of tariff

1243. The ERA requires an amendment to fix the standing charge for residential customers in each year of the period. AGA accepts this amendment. Therefore, any variation to be applied as a result of the revenue yield will occur through the variable charge.

Procedure for supplying evidence for revenue variation calculations

1244. AGA does not consider there are additional administrative costs associated with the revenue yield approach compared to the current arrangements. The process for applying the revenue yield is readily incorporated in to the annual tariff processes that existed during the AA3 period.

1245. AGA submits annual regulatory financial statements, which are reviewed by professional auditors. These accounts will be prepared, reviewed and submitted each year to the ERA during the AA4 period. The accounts contain the information required to verify any adjustments under a tariff variation proposal, including a breakdown of actual consumption by tariff class and usage level. These accounts can be compared to the forecast provided in the tariff model submitted with this revised proposal (and previously with the March 2014 submission). The ERA ultimately decides whether to accept these verified accounts or not.

Breakdown of demand forecast by tariff class and usage bracket

1246. The tariff model submitted to the ERA in March 2014 provides the forecast demand by tariff class and usage bracket. This is also included in the tariff model accompanying this response.

[509] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, October 2014, paragraph 1217.

[510] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, October 2014, paragraph 1211.

Transfer of volume risk

1247. AGA proposes a revenue yield to address the factors affecting consumption per customer that it is unable to mitigate. Previously, AGA has borne the risk associated with weather. AGA has also identified the emergence of a relatively new risk associated with a decline in the average use for each residential customer. The revenue yield approach is proposed to mitigate this emerging risk. Although, it may reduce the costs borne by AGA in the event average consumption declines more than forecast, it also reduces the costs to customers in the event average consumption is greater than forecast. To the extent the forecast can be expected to properly factor in the observed decline, and it is expected that the variation in actual demand compared to forecast will not be biased in one direction; there is no transfer of risk. To the extent that these conditions are not met, the reference tariff variation mechanism is designed contrary to rule 92(2) of the NGR, in that forecast revenue will not recover costs. This also applies to satisfying the NGO and RPP.

1248. The demand forecasts proposed by AGA have been developed to incorporate the observed decline in average consumption per customer. The demand forecast used by the ERA has not. AGA does not agree with the ERA's view that AGA has not provided sufficient information on how past forecasting inaccuracy has been addressed. In contrast to the last two access arrangement periods, AGA has:

- Sought expert advice from the CORE Energy[511] to develop forecasts that properly account for historical trends and future expected drivers of demand
- Adopted a forecast methodology that considers all the drivers for residential demand (as outlined in Appendix 4 and 5 of the AAI submitted in March 2014) rather than solely temperature
- Adopted a forecast methodology that has been used by the AEMO and other gas distribution businesses and is supported by the AER
- Outlined the forecast methodology in the AAI and provided the expert reports from ECS and CORE Energy
- Provided updated demand forecasts in this revised proposal which ensure that the latest information has been incorporated (see response to required amendment 3)

1249. The decline in average consumption per customer in the AA3 period is attributed to:

- Weather conditions, with three years of the AA3 period significantly warmer than the 10 year average
- The effect of significant retail gas price increases on gas usage
- Further penetration of reverse cycle air-conditioning as a heating alternative, which has been driven by subsidised electricity prices and the advent of subsidised solar photo voltaic cells
- Improved energy efficiency levels in appliances and changes to the building code for new home construction to improve energy efficiency.

1250. The Core Energy forecasting methodology incorporates effective degree day weather nominalisation. The forecast changes in retail prices have been incorporated (and the demand forecasts updated in this response to the ERA's Draft Decision include the expected impact of the removal of carbon tax). The penetration of air-conditioning is incorporated as are the continued expectations of improvements in energy efficiency of appliances and homes. The methodology and issues addressed are outlined in the CORE Energy Report (Appendix 4.3). The Core Energy forecasts, adopted by AGA, meet the requirements of rule 74 of the NGR.

1251. In contrast the ERA's forecast methodology adopts the current average consumption per customer and assumes that level of consumption will continue (for B2 and B3 customers). However, the current average consumption per customer has not been weather adjusted and does not take in to account other factors that may have contributed to the decline in the average demand in the AA3 period. As pointed out in the expert

[511] Appendix 4.1 Gas Demand Forecast, Mid-West and South-West Distribution System Core Energy Group November 2014.

report from CORE Energy, this approach, if adopted in prior periods, would have resulted in a continued overstatement of demand. If uncorrected, AGA would not be able to recover the allowed revenue through reference tariffs contrary to rule 92(2) of the NGR, the NGO and the NGR. The ERA estimate does not satisfy the requirements of rule 74 of the NGR.

1252. The ERA has also noted that the revenue yield per delivery point is not consistent with efficient risk allocation as it passes on a historical forecasting risk to customers in the form of possible higher tariffs.

1253. This statement by the ERA is incorrect. The historical forecasting risk has been borne by AGA – not customers. AGA has consistently earned less ($50 million each period) than the amount allowed under the access arrangement. This under recovery is not being recovered from customers.

1254. AGA has proposed marketing and business development activities designed to increase consumption per customer and the number of new connections. Under a revenue yield approach customers are better off in the short term where consumption grows as this will result in price decreases in subsequent years of the period. Where connection numbers grow customers will also be better off in subsequent regulatory periods.

1255. In any event, how risks might have been borne in the past is irrelevant – there is no recovery or claw back mechanism in the building blocks. Similarly, forecasting errors in the past are not relevant to the future. The only relevant issue is whether the forecast of demand for AA4 is unbiased so that neither AGA nor customers are taking on risk that would be inconsistent with rule 92(2) of the NGR. Only the Core Energy forecast achieves this.

Impact on customers of variations between forecast and actual demand

1256. Under the price variation in the current period, and that required by the ERA in AA4, if there is a downward bias in forecast demand (that is the forecast consumption is higher than forecast), AGA is likely to recover more revenue than that needed to cover its efficient costs. This will result in customers paying more than they need to. However, under the revenue yield, the prices to customers would reduce as a result of consumption being higher to maintain the revenue yield per connection without putting at risk the likelihood of AGA recovering its efficient costs.

1257. Where there is an overestimation bias in the forecast as is shown in the ERA's demand forecast (Appendix 4.3), AGA will be unable to recover its efficient cost of providing services and further expenditure on the provision of services will be at risk as AGA attempts to avoid losses. This could result in customers receiving lower levels of service, less timely connections or no connection at all due to it being uneconomic to provide the service. This outcome is also inconsistent with the RPPs and the NGO as AGA is denied an opportunity to recover its efficient costs from the outset arising from the bias in the forecast. Prices to customers would increase in this circumstance under the revenue yield, however, AGA would not recover more than its efficient costs and service levels and service accessibility will not be at risk.

1258. AGA does not consider the variation that might be expected under a revenue yield would result in price shocks to small customers for the following reasons:

- Sensitivity analysis suggests that forecast consumption would have to reduce by 8% to give rise to an impact on customers of more than $10.
- Any variation would need to be first passed on by the retailers
- There is an equal expectation that any price impact would be an increase or a decrease
- The ERA has required the standing charge to residential customers to be 'fixed' during the period so that any revenue yield variation would be passed through in usage charges so the impact on a customer using very little gas will be minimal

Forecast bias

1259. The ERA indicates the adoption of a revenue yield results in a lack of incentive to forecast accurately and therefore, this is inconsistent with the NGO. AGA desires an accurate forecast so that the revenue yield adjustments are minimal. The effective degree day (**EDD**) methodology increases forecast accuracy, providing stable and predictable revenues. However, under a price cap AGA has an incentive to under forecast demand (to increase the likelihood of over recovering more than the allowed revenue), while history shows the ERA has a tendency to over forecast demand.

1260. Given that customers and AGA are indifferent to whether the forecast is biased (as the expectation of prices delivering the allowed revenue is the same regardless of an over or under forecast), a revenue yield approach is more likely to deliver an unbiased forecast. It is a forecast being more likely to result in an under recovery or over recovery of allowed revenue that would be inconsistent with the NGO, not a forecast that may be less accurate but likely to be less accurate in both directions. In any event, the AGA forecast is more accurate than the ERA's as discussed above. Therefore, AGA disagrees with the ERA's assessment that the revenue yield approach gives rise to an incentive that is inconsistent with the NGO.

1261. Under the revenue yield approach, because AGA is kept whole regardless of whether there is a bias in the forecast consumption, it has no incentive to underestimate demand. Indeed, neither the ERA nor AGA has any incentive in relation to consumption forecasts.

The need for efficient tariff structures

1262. It is accepted that an efficient tariff structure incorporates a fixed and variable component. The fixed component should reflect the fixed costs of service, and the variable component should reflect the variable costs of services. AGA's cost of service are nearly entirely fixed. There are few costs that vary with the provision of additional haulage services. However, only around 30% of revenue is recovered through fixed charges. Therefore a more efficient tariff structure would be achieved if the fixed component (the standing charge) recovered a greater proportion of revenue. In addition, AGA's fixed charge does not even recover the avoidable costs of a new connection.

1263. The ERA accepts AGA's proposal to ensure that the fixed standing charge for B3 customers should at least recover the avoidable capital costs of connection. This is a necessary requirement for an efficient tariff structure. Nevertheless, the ERA has determined that the price impact to small use customers is not tolerable under the *National Gas Access (WA) (Local Provisions) Regulations 2009*, and so the necessary condition for efficient tariff structure is to be phased in over the regulatory period. The impact on existing small customers could be addressed if AGA charges all new customers a higher standing charge. This would also provide more efficient pricing signals to new customers. However, as a result of the postage stamp pricing provisions under the same regulations, AGA is unable to charge new customers a different tariff to existing charges. AGA has accepted the ERA's required amendment to phase in the increase to the standing charge.

1264. Therefore, as a result of the *National Gas Access (WA) (Local Provisions) Regulations 2009* the opportunities to improve the efficient tariff structure and the need for an efficient tariff structure are the same for the AA3 tariff variation mechanism and the revenue yield mechanism.

Adoption of AA3 Price control formula

1265. In AA3, the tariff control formula included a specific amount for 'regulatory costs'. AGA considers that the pass through of a specific GL cost account is inconsistent with the approach to all other operating cost amounts. AGA considers that the only costs that should result in a tariff variation are licence fees or those associated with a change in regulation or obligation. AGA is proposing to maintain the clauses relating to the pass through of regulatory costs and regulatory change as existed during AA3. However, more specific information is provided regarding the licence fees incurred.

Satisfaction of rule 97(3) of the NGR

1266. AGA remains of view that the revenue yield approach satisfies rule 97(3) of the NGR. Tariffs under the revenue yield approach will:

- Continue to adopt a fixed and variable component consistent with efficient tariff structures

- The administrative costs of applying the mechanism will not differ to the current arrangements as the information required to implement the annual tariff variation is available in the annual regulatory financial statements and financial template submitted to the ERA
- The application of the revenue yield approach to residential customers and not to small business or industrial customers is due to the emergence of a relatively new risk associated with a decline in the average use for each residential customer. This is driven by increasingly energy efficient appliances and dwellings which is not as apparent for small business and industrial customers
- The price control arrangements in AA3 resulted in customers bearing the risk for variations in regulatory costs controlled by AGA which reduces the incentives for AGA to manage its efficient costs

14.3.3 Change of law events

1267. The ERA was not satisfied that the proposed change by AGA to include indirect costs relating to cost pass through events was properly explained and introduces ambiguity. Further, the ERA considered that the cost pass through for regulatory costs provided for only increased regulatory cost pass throughs and it was difficult for the ERA to reconcile variations between forecast and actual costs incurred. **AGA accepts the amendments to clause 3.1(iii) and 3.1(iv) in Annexure B.**

1268. The ERA has recognised that AGA incurs license fees from a number of agencies and has included a forecast for these fees in operating costs. **AGA has included specific information to facilitate the cost pass through for variations in the licence fees** incurred compared to those forecast in each year. It is proposed that the definitions that existed in AA3 be retained for regulatory change and regulatory costs. Under this mechanism, AGA has the opportunity to recover its efficient costs, an opportunity denied to it under the ERA's approach.

14.3.4 Exclude UAFG cost pass through

1269. The ERA considers that as a result of AGA engaging in a competitive tender for the cost of gas for the term of AA4, it is unnecessary to retain the clause providing for a pass through of a change in the price of UAFG. **AGA accepts the amendment to clause 3.1(v) in Annexure B**.

14.3.5 Include best endeavours

1270. Rule 94(3) requires that the expected revenue of each tariff class lie on or between an upper bound representing the standalone cost of providing the reference service and a lower bound representing the avoidable cost of not providing the reference service. AGA has amended these calculations according to the costs in this response to the ERA's draft decision. Additionally as required by ERA amendment 17, AGA has provided information regarding the compliance with expected ancillary service revenue with rule 94(3).

1271. The ERA has provided no explanation as to why it requires the inclusion of 'best endeavours'. **AGA does not accept amendment to clause 4.2** as it considers it is important to be consistent with the Template Haulage Contract which uses 'reasonable endeavours'. In addition, AGA will include a definition of reasonable endeavours to include operational, commercial and economic interests to ensure that these can be taken in to account.

14.4 Ancillary Service Tariffs

ERA required amendment 17

The Authority requires that ATCO adjust the ancillary service volumes and tariffs as per Table 75 of this Draft Decision.

The Authority requires ATCO to confirm that ancillary services are provided by external resources, and if these services are provided using internal resources, further justification on the efficiency of these costs.

The Authority requires that ATCO justify whether the ancillary service revenue to be recovered for each customer lies between an upper bound (the stand alone cost of providing the reference service to the customer) and a lower bound (the avoidable cost of not providing the reference service to the customer) as per rule 94(3) of the NGR.

AGA Response: do not accept

Summary Only - AGA has not adjusted the volumes to reflect the ERA's Table 75. However, the volumes have been adjusted to reflect the updated customer forecasts as discussed in response to required amendment 3. Ancillary services are provided by a mix of internal and external resources, though 95% of deregistrations, disconnects and reconnects are conducted by contractors. The avoidable cost of the service to each customer is the material cost, which is much lower proportion of the cost.

14.4.1 Summary of ERA decision

1272. The ERA requires the ancillary service volumes and tariffs as per table 75. There are no changes to tariffs, however volumes for applying a meter lock and removing a meter lock have been adjusted for the ERA's forecast growth in B3 customers.

1273. The ERA requires confirmation that the ancillary services are provided by external resources. Where the services are provided by internal resources, further justification for the efficiency of these costs is required. The ERA also requires the tariffs be demonstrated to be between stand alone and avoidable costs.

14.4.2 AGA response

1274. **AGA has not implemented required amendment 17**

1275. AGA has not adjusted the volumes to reflect the ERA's Table 75. However, the volumes have been adjusted to reflect the updated customer forecasts as discussed in response to required amendment 3.

1276. Ancillary services are provided by a mix of internal and external resources. All meter lock and unlock services are undertaken by contractors on a fixed price basis. AGA provides the padlocks and valve locking devices, which are incorporated into the tariffs.

1277. The majority (95%) of the deregistration requests, disconnection services and reconnection services are undertaken by contractors, mainly on a tendered price basis with materials included in the price. There are no overheads included in the service tariffs due to the proportion of services provided by external contractors.

1278. The avoidable cost of the service to each customer is the material cost, which is a much lower proportion of the cost. The stand alone cost would be much greater as a result of the direct costs of associated corporate support, IT and licence fees. As a minimum the stand alone costs would be 19.3% higher if the proposed overhead allocation rate were applied to the tariff for each customer.

1279. The ancillary service tariffs proposed for AA4 reflect the lower costs achieved during AA3 as a result of efficient work practices and competitively tendered contract rates.

14.4.2.1 Stand alone and avoidable costs of ancillary services

1280. Avoidable costs have been calculated for the reference ancillary services deregistration, disconnection and reconnection based on the materials, subcontractor and reinstatement costs as recorded in the variable volume maintenance cost forecast. Avoidable costs for meter lock costs are based on the per activity costs of installing or removing a meter lock by a subcontractor.

1281. Standalone costs for reference ancillary services include an allocation of the existing team administering these and other services plus and estimated IT systems cost necessary for transferring information to and from retailers as well as managing the activities.

1282. The following table presents the expected revenue by tariff class compared with the stand alone and avoidable cost of providing the ancillary reference service.

Table 14–5: Stand alone and avoidable cost of ancillary reference services

$ million real at 30 June 2014	Expected Revenue	Stand alone cost	Avoidable cost	Complies with Rule 94(3)
Apply meter lock	0.5	4.5	0.5	Yes
Remove meter lock	0.2	4.2	0.2	Yes
Deregistration	1.1	4.7	0.8	Yes
Disconnection	0.4	4.3	0.3	Yes
Reconnection	0.5	4.5	0.5	Yes

14.5 Ancillary service tariff variation mechanism

ERA required amendment 18

The Authority requires that ATCO amend Annexure C of the Access Arrangement to reflect the Authority's decision that the ancillary service tariff variation be varied based on the Consumer Price Index – Weighted Average for Eight Capital Cities.

AGA Response: accept

14.5.1 Summary of ERA decision

1283. The ERA requires the ancillary service tariff variation be varied based on the CPI weighted for eight capital cities.

14.5.2 AGA response

1284. AGA has implemented required amendment 18

15. Other access arrangement provisions

15.1 Application procedure

ERA required amendment 19

Clauses 5.5(a)(vi), 5.5(a)(x), 5.5(a)(xi) and 5.5(b) of the proposed revised access arrangement should be deleted.

AGA Response: accept with modifications

Summary Only – AGA accepts the ERA's proposed amendments to clause 5.5 in the access arrangement.

15.1.1 Summary of ERA decision

1285. The ERA considers clause 5.5(b) of the access arrangement should be deleted as it *grants broad powers to the service provider to introduce additional preconditions*.[512]

1286. The ERA also considers clauses 5.5(a)(vi), 5.5(a)(x), 5.5(a)(xi) of the access arrangement should be deleted as they appear to restate clauses that are very similar in the template haulage contract. The ERA considers there are risks because the clauses in the access arrangement and the template haulage contract are not worded identically.[513]

15.1.2 AGA response

AGA has implemented required amendment 19

1287. AGA has deleted clauses 5.5(a)(vi), 5.5(a)(x), 5.5(a)(xi) and included correlating clauses in the template haulage contract.

1288. AGA has retained the proposed clause 14 in the template haulage contract and included equivalent provisions to clauses 5.5(a)(vi), 5.5(a)(x), 5.5(a)(xi) as conditions precedent in clause 1 and as continuing obligations. These are dealt with in the response to required amendment 23.

1289. AGA has deleted clause 5.5(b) from the access arrangement as required. The clause was not intended to grant broad powers to the service provider to introduce additional conditions; therefore AGA agrees to remove the clause to avoid confusion.

[512] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1251.

[513] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1246.

15.2 Capacity trading requirements

ERA required amendment 20

Clause 6.1 of the access arrangement should be amended as follows:

> 6.1 Capacity Trading Requirements to be specified in the Service Agreement
>
> A User's right to transfer its contracted capacity to another person will be set out in the User's Service Agreement with ATCO Gas Australia. The terms and conditions for the transfer of contracted capacity for Haulage Services are set out in clause 14 of the Template Haulage Contract. In accordance with the Template Haulage Contract, a user will have qualified rights to transfer some or all of its contracted capacity for Haulage Services to one or more third parties.

Clauses 6.2 to 6.4 of the access arrangement should be deleted.

AGA Response: accept with modifications

Summary Only – AGA accepts the ERA's required amendments and has modified clauses in the Template haulage contract.

15.2.1 Summary of ERA decision

1290. The ERA highlights inconsistencies between related clauses in the access arrangement and the Template Haulage Contract. It considers *that the overlap on these matters in section 6 of the access arrangement and clause 14 of the proposed revised template haulage contract complicates the task of interpretation.*[514]

1291. The ERA also considers that the requirement for an access arrangement to set out capacity trading requirements *can be met by the inclusion of the detailed capacity trading requirements in either, rather than in both, section 6 of the access arrangement or clause 14 of the template haulage contract*.[515]

1292. And that:

> *the template haulage contract is the better instrument in which to set out the detail of the capacity trading requirements that will apply to reference services under the access arrangement*[516]

1293. The ERA therefore proposes clause 6.1 of the access arrangement should be amended and clauses 6.2 to 6.4 should be deleted and the relevant provisions retained in the template haulage contract.

15.2.2 AGA response

AGA has implemented required amendment 20, with some modifications

1294. AGA agrees there should not be inconsistency between the access arrangement and the template haulage contract. For the reasons outlined in its response to required amendment 19 above, AGA agrees clauses 6.2 to 6.4 should be deleted from the access arrangement and the corresponding provisions reflected in clause 14 of the template haulage contract. This will ensure consistency and make interpretation less complicated.

[514] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1258.

[515] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1259.

[516] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1259.

1295. AGA has made the proposed amendments to clause 6.1 and deleted clauses 6.2 to 6.4 of the access arrangement.

15.3 Extension and expansion requirements

ERA required amendment 21

Include definitions in the access arrangement on what constitutes a low pressure, medium pressure and high pressure pipeline in the access arrangement.

Amend section 7.2 Extensions of medium and low pressure pipelines to include high pressure pipelines not captured by the High Pressure Pipeline Extension definition.

Amend the definition of a High Pressure Pipeline Extension as follows: “means for the purpose of the Template Haulage Contract and for section 7 of the Access Arrangement an extension to <Service Provider> Covered Pipeline with a direct connection to a transmission pipeline that provides reticulated gas to a new development <u>or an existing development not serviced with reticulated gas or an extension to <Service Provider> Covered Pipeline with a Maximum Allowable Operating Pressure of greater than 1,000kPa and greater than 25km in length.</u>

AGA Response: accept with modifications

Summary Only – AGA proposes modifications to sections 7.1 and 7.2 and the definition of a High Pressure Pipeline to clarify the distinction between pipeline extensions and expansions treated as part of the covered pipeline.

15.3.1 Summary of ERA decision

1296. The ERA requires an amendment to include a definition on what constitutes a low pressure, medium pressure and high pressure pipeline to distinguish between extensions that are captured by clause 7.1 and those that automatically form part of the covered system.

1297. The ERA also suggests a threshold of for determining which section of the access arrangement (7.1 or 7.2) a high pressure pipeline falls into. The ERA has determined *any high pressure pipeline extensions greater than 1,000kPa and over 25km in length should also be captured by section 7.1 of the proposed Access Arrangement*.[517]

15.3.2 AGA response

1298. AGA has implemented required amendment 21 in part, with some modifications

1299. AGA agrees greater clarity is required on which high pressure pipelines are covered by clause 7.1, however, an alternative threshold is proposed. AGA considers only pipelines with a maximum allowable operating pressure greater than 1,920 kPa will be covered by clause 7.1.The threshold of 1,920 kPa is proposed as it is the threshold for the distribution system in AGA’s Distribution Licence.

1300. “Extensions” and “Expansions” are defined terms and the references to those terms in clause 7 have also been updated to reflect this.

1301. Clause 7 outlines a procedure for the ERA’s approval where AGA proposes that a High Pressure Pipeline Extension should form part of the covered pipeline and be covered by the access arrangement. The only extension type that requires the ERA’s approval is a High Pressure Pipeline Extension.

[517] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1279.

1302. All other high pressure, medium and low pressure pipelines automatically form part of the covered pipeline under amended clause 7.2(a) so there is no need to define these. In any event, there are different definitions of the high, medium and low pressure in the Distribution Licence performance reporting handbook, the Safety Case and the AMP – depending on the purpose and the characteristics of the network.

The proposed amendments to the access arrangement are presented below:

7.1 Extensions of High Pressure Pipelines

(a) If ATCO Gas Australia proposes a High Pressure Pipeline Extension of the covered pipeline it must apply in writing to the ERA for a decision on whether the proposed Extension will be taken to form part of the covered pipeline and will be covered by this Access Arrangement. The application must describe the Extension and set out why the extension is necessary.

(b) The application referred to in (a) above must be made before the proposed High Pressure Pipeline Extension comes into service.

(c) After considering ATCO Gas Australia's application and undertaking such consultation as the ERA considers appropriate the ERA will inform ATCO Gas Australia of its decision. Taking into account any consultation the ERA considers appropriate the Authority will use its reasonable endeavours to provide ATCO Gas Australia with written notice of its decision within 90 Business Days of ATCO Gas Australia's application.

1303. (d) The ERA's decision referred to in (c) above may be made on such reasonable terms as determined by the ERA and will have the effect stated in the decision.

1304. (e) An Extension under this paragraph 7.1 will not affect reference tariffs during a current Access Arrangement Period.

1305. **7.2 Other extensions**

l) Other than High Pressure Pipeline Extensions as referred to in clause 7.1, any extension of the Covered Pipeline designed to operate at a maximum allowable operating pressure of 1,920 kPa or less will be treated as part of the Covered Pipeline, and will accordingly be covered by this Access Arrangement.

m) No later than 20 Business Days following the expiration of the Financial Year, ATCO Gas Australia must notify the ERA of all pipeline Extensions as referred to in clause 7.2(a) during that year, including all extensions commenced, in progress or completed.

n) The notice must describe each Extension and set out why the Extension was necessary.

o) An Extension under this paragraph 7.2 will not affect reference tariffs during a current Access Arrangement Period.

1306. **Dictionary**

1307. **High Pressure Pipeline Extension** means for the purposes of the Access Arrangement –

a) an extension to **<Service Provider>** Covered Pipeline with a direct connection to a transmission pipeline that provides reticulated gas to a new development or an existing development not serviced with reticulated gas; or

b) an extension to <Service Provider> Covered Pipeline with a Maximum Allowable Operating Pressure of greater than 1,920kPa.

16. Fixed principles

ERA required amendment 22

The Authority requires that ATCO remove Fixed Principle 11.1 (a) and 11.1 (c).

The Authority requires that ATCO remove Fixed Principle 11.2(a).

The Authority requires that ATCO delete Fixed Principles 11.3 and 11.4 from the revised access arrangement for the fourth access arrangement period.

The Authority requires that the access arrangement include an additional fixed principle as follows: "Differences between the published update of the debt risk premium, for years 2 to 5 of the fourth access arrangement, and the regulatory debt risk premium applying from July 2014 to December 2019 (the fourth access arrangement period), will be used to adjust the estimated debt risk premia applying during the years of the fifth access arrangement period. The resulting adjustment must ensure that any net revenue differences between the total approved revenue for the fourth access arrangement period, and the total revenue for the fourth access arrangement period that would have arisen with the application of the published annual updates, are accounted for in the total approved revenue for the fifth access arrangement period, in present value neutral terms."

ATCO Gas Australia Response: do not accept

Summary Only – AGA has implemented the ERA's requirement to remove fixed principles 11.1(a) and 11.1(c). AGA also implemented the introduction of a new fixed principle to account for variations in the debt risk premium but proposes alternative drafting. AGA has not implemented the requirement to remove fixed principles 11.3 and 11.4. This is because AGA maintains the HCA method should be used to calculate depreciation and the revenue yield price control for B2 and B3 customers should apply for the AA4 period.

16.1 Summary of ERA decision

1308. The ERA accepts AGA's proposal to extend the fixed principles relating to straight-line depreciation and higher heating value costs (fixed principles 11.1(b) and 11.1(d)) as they remain relevant and provide stability to the consumer across regulatory periods. However, the ERA considers the fixed principles 11.1(a) and 11.1(c), which relate to the 60:40 capital structure and Full Retail Contestability (**FRC**) costs respectively, are no longer relevant.

1309. The ERA considers principle 11.1(a) is not relevant because the Rate of Return Guidelines address financing structure and debt/equity ratio. The ERA considers 11.1(c) not relevant because AGA has reported no full retail contestability operating expenditure since 2010 and has not forecast operating expenditure in this area over the next period. The ERA does not consider there to be any justification why the FRC should be a fixed principle and has rejected the proposal to extend this fixed principle.

1310. The ERA rejects the proposed depreciation methodology proposed by AGA. Therefore fixed principle 11.3, which allows AGA to transition its depreciation from Current Cost Accounting (**CCA**) to Historical Cost Accounting (**HCA**) over the two access arrangement periods, is also rejected.

1311. The ERA rejects AGA's proposed revenue yield price control for B2 and B3 customers and therefore rejects fixed principle 11.4, which allows revenue to be recovered associated with this revenue price yield control.

1312. The ERA proposes a new fixed principle that will bind the ERA and AGA to apply an adjustment to the revenue in AA5 for any differences between the debt risk premium set at the start of the fourth access arrangement and the annual updated debt risk premium that applied in each of the second to fifth year of the AA4 period.

16.2 AGA response

AGA has implemented required amendment 22 in part, with some modifications

1313. AGA accepts the ERA's requirement to remove fixed principle 11.1(a) and 11.1(c) as set out in the Draft Decision.

1314. AGA does not accept the ERA's decision to reject the Fixed Principles 11.3 and 11.4.

16.3 Fixed principle 11.3 - calculation of depreciation

1315. The application of a nominal rate of return, now required under rule 89(4) of the NGR, to a capital base indexed for inflation would result in a double count of inflation. This can be avoided by not indexing the capital base. In order to reduce the short-term price impact caused by switching to a non-indexed capital base, AGA proposed a transition to HCA over two access arrangement periods.

1316. Fixed principle 11.3 is designed to fix the transition period so that the HCA method must apply to the entire capital base from no later than 1st January 2025. The proposed fixed principle 11.3 is replicated below.

The fixed principle would be as follows (clause 11.3 of the revised access arrangement):

"The following principles are declared as fixed principles for the period 1 July 2015 until 1 January 2030.

1) Calculation of depreciation for Opening Capital Base for the Access Arrangement Period commencing immediately after the Next Access Arrangement Period

(a) Forecast depreciation over the Next Access Arrangement Period (ie the Access Arrangement Period commencing 1 January 2020) is to be the sum of depreciation calculated as follows:

(i) for capital assets in existence at 1 January 2000, of the inflation indexed opening capital base in any year divided by the remaining asset life less the amount of any indexation on that opening capital base;

(ii) of the Opening Capital Base for the Access Arrangement Period commencing 1 July 2014 (other than capital assets in existence at 1 January 2000) the opening capital base in any year (indexed for inflation to 1 January 2020) divided by the remaining asset life;

(iii) of capital expenditure made during the Current Access Arrangement Period (ie the Access Arrangement Period commencing 1 July 2014), the opening capital base in any year at acquisition value (not indexed for inflation) divided by the remaining asset life; and

(iv) of the forecast Capital Expenditure for the Next Access Arrangement Period (being the amount of forecast Capital Expenditure used for the purpose of determining Haulage Tariffs for the Next Access Arrangement Period), at acquisition value (not indexed for inflation) divided by the remaining asset life.

(b) For the calculation of the Opening Capital Base for the ATCO Gas Australia GDS for the Access Arrangement Period commencing immediately after the Next Access Arrangement Period (ie the Access Arrangement Period expected to commence 1 January 2025):

(i) the capital assets in existence at 1 January 2000 are to be indexed for inflation to 1 January 2025;

(ii) the capital assets comprising the Opening Capital Base for the Access Arrangement Period commencing 1 July 2014 (other than capital assets in existence at 1 January 2000) are to be indexed for inflation to 1 January 2020;

(iii) all other capital assets are not indexed for inflation; and

(iv) for the purposes of rule 77(2)(d) of the National Gas Rules, depreciation over the Next Access Arrangement Period will be as calculated above in clause 1(a)(i)

2) Calculation of depreciation for Opening Capital Base for Subsequent Arrangement Periods

(a) In this clause, Subsequent Access Arrangement Period means an Access Arrangement Period commencing after the Access Arrangement Period commencing immediately after the Next Access Arrangement Period (ie a Subsequent Access Arrangement Period is an Access Arrangement Period expected to commence 1 January 2030 and thereafter).

(b) Forecast depreciation over the Access Arrangement Period commencing immediately after the next Access Arrangement Period (ie the Access Arrangement Period expected to commence 1 January 2025), and every Subsequent Access Arrangement Period, is to be the sum of depreciation calculated as follows:

(i) for capital assets in existence at 1 January 2000, of the opening capital base in any year (indexed for inflation to 1 January 2025) divided by the remaining asset life;

(ii) of the Opening Capital Base for the Access Arrangement Period commencing 1 July 2014 (other than capital assets in existence at 1 January 2000) the opening capital base in any year (indexed for inflation to 1 January 2020) divided by the remaining asset life;

(iii) of actual capital expenditure made on and after 1 July 2014, the opening asset base in any year at acquisition value (not indexed for inflation) divided by the remaining asset life;

(iv) of the forecast Capital Expenditure for the Access Arrangement Period (being the amount of forecast Capital Expenditure used for the purpose of determining Haulage Tariffs for the that Access Arrangement Period), at acquisition value (not indexed for inflation) divided by the remaining asset life.

(c) For the calculation of the Opening Capital Base for Subsequent Access Arrangement Periods:

(i) the capital assets in existence at 1 January 2000 are to be indexed for inflation to 1 January 2025;

(ii) the capital assets comprising the Opening Capital Base for the Access Arrangement Period commencing 1 July 2014 (other than capital assets in

existence at 1 January 2000) are to be indexed for inflation to 1 January 2020

(iii) all other capital assets are not indexed for inflation; and

(iv) for the purposes of rule 77(2)(d) of the National Gas Rules, depreciation over the Access Arrangement Period immediately before the Subsequent Access Arrangement Period will be as calculated above in clause 2(b)(iv).

(d) For the avoidance of doubt, for the Access Arrangement Period commencing immediately after the Next Access Arrangement Period (ie the Access Arrangement Period expected to commence 1 January 2025) and all Subsequent Access Arrangement Periods, all capital assets will be depreciated at the rate of their opening asset value divided by their remaining asset life. No inflation indexation will occur after the Access Arrangement Period commencing immediately after the Next Access Arrangement Period."

1317. In its Draft Decision the ERA rejected AGA's proposal and requires the capital base to be indexed. However, AGA maintains its view that the capital base should not be indexed and proposes a transition to HCA. Therefore under AGA's revised proposal fixed principle 11.3 is still required and has therefore not been removed.

1318. AGA's proposed approach for calculating depreciation is discussed in Chapter 3 (Total Revenue) and Chapter 11 (Depreciation).

16.4 Fixed principle 11.4 - Revenue yield

1319. AGA proposed a second new principle to address rule 97(2) of the NGR, which provides for a revenue yield control (or a combination of controls) for variation of reference tariffs. Fixed principle 11.4 allows AGA to recover the revenue impact of the revenue yield formula for B2 and B3 customers from the fourth access arrangement period in the fifth access arrangement period. The proposed fixed principle is replicated below.

"The following principle is declared as a fixed principle for the Access Arrangement period commencing 1 January 2020:

1) The revenue to be determined in the Next Access Arrangement Period is to include an amount determined for the year commencing 1 January 2018, and an amount estimated for the year commencing 1 January 2019, that is the under-recovery or over-recovery of revenue for that year calculated under the tariff variation mechanism to be applied to B2 and B3 reference service revenue yield.

2) The revenue to be calculated in the Access Arrangement Period commencing immediately after the Next Access Arrangement Period (ie the Access Arrangement Period expected to commence 1 January 2025) is to include an amount to adjust the estimate for the year 1 January 2019 for actual revenue outcomes for that year.

3) These amounts are to be adjusted for the rate of return applicable in the AA4 access arrangement period (ie: the Access Arrangement Period commencing on 1 July 2014)."

1320. In its Draft Decision the ERA rejects AGA's proposed revenue yield price control for B2 and B3 customers. However, in this revised proposal AGA resubmits the revenue yield price control. AGA provides further evidence to support its implementation in its response to required amendment 16 (Haulage Tariff Variation Mechanism) in Chapter 14. Therefore AGA proposes fixed principle 11.4 should be included in the revised access arrangement.

16.5 ERA's new fixed principle - adjustment to the debt risk premium

1321. The ERA requires AGA to insert a fixed principle binding it to apply an adjustment to revenue for the fifth access arrangement in present value neutral terms, which will account for the difference between the forecast and the actual debt risk premium in each year of the AA4 regulatory period.

1322. As discussed in Chapter 9 (Rate of Return), the ERA annual update does not reflect the efficient debt management strategy of a benchmark efficient entity and AGA has not accepted the inclusion of the ERA's fixed principle.

1323. AGA submits that it is necessary for the cost of debt to be based on a well-defined debt management strategy for a benchmark efficient firm and AGA's proposed hybrid approach reflects such a strategy. This strategy will determine the starting point for the benchmark efficient debt management strategy to be implemented in the next access arrangement period starting in January 2020 (AA5).[518]

1324. In determining the cost of debt methodology to be used in AA5, it will be necessary to have regard to the methodology used in the current access arranging period. For this reason, AGA proposes two new fixed principles to apply to the next access arrangement as follows

11.5 Debt Risk Premium Fixed Principle

> *The following principles are declared as fixed principles for the Next Access Arrangement Period commencing on or about 1 January 2020.*
>
> *Where the return on debt for the Next Access Arrangement Period (commencing on or about 1 January 2020) is estimated using a methodology that is the same as that used in the Current Access Arrangement Period (commencing 1 July 2014) the provisions of this Access Arrangement that implement that methodology will continue into the Next Access Arrangement Period.*
>
> *Where the return on debt for the Next Access Arrangement Period is estimated using a methodology that is different from that used in the Current Access Arrangement Period, the adoption of the methodology for the Next Access Arrangement Period shall have regard to the application and effect of the methodology in the Current Access Arrangement Period.*

[518] CEG Cost of debt consistent with the NGR and NGL, November 2014, para 329

17. Template haulage contract

17.1 Introduction

1325. This chapter sets out AGA's response to required amendments 23 to 45, which are all associated with the template haulage contract. The amended template haulage contract is attached at Appendix 17.1.

1326. AGA's proposed amendments to the template haulage contract are made by reference to:

a) the requirements set out in rules 40 and 48 of the NGR;

b) the requirements set out in rule 100 of the NGR;

c) the National Gas Objective (NGO) set out in S.23 of the NGL(WA); and

d) Australian Competition Tribunal decisions and decisions of the AER in respect of similar contract terms.

1327. AGA notes the references in the Draft Decision to submissions made by the parties during the third access arrangement review, including those made before the Australian Competition Authority (ACT), those made by AGA's predecessor WA Gas Networks Pty Ltd, and those made by interested parties including Alinta. AGA contends that those submissions are not relevant to the proposed revisions in the fourth access arrangement period as the circumstances in which those submissions have altered significantly. In particular:

a) The ownership of the Gas Distribution System (GDS) has passed from the previous WA Gas Networks Pty Ltd shareholders to ATCO Ltd, bringing material changes to the investment and risk assessment methodologies applied to the management, operation and growth of the GDS[519]

b) Kleenheat Gas, a wholly owned subsidiary of the Wesfarmers Limited, entered the Western Australian retail gas market in March 2013 and is now a major customer for the services provided by AGA along with Alinta[520], marking a change to the nature and allocation of risks faced by AGA, its customers and end users

c) The National Gas Rules and National Gas Law were amended during the third access arrangement period. Amendments to rules 87 and 87A of the NGR came into force in November 2012[521], and the merits review amendments to Part 5 of the *National Gas Access (Western Australia) Act 2009* (WA) came into force in March 2014[522]

d) Major legislative changes including the introduction and subsequent repeal of the Clean Energy (carbon tax) legislation[523] and amendments to the Privacy Act[524] have also marked changes to the nature and allocation of risks faced by AGA, its customers and end users;

1328. AGA notes that in its Draft Decision[525] the ERA has in some cases arrived at different conclusions from those reached during the third access arrangement review, either by striking a different balance or as a result of

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519 See discussion in EMCa, Review of Technical Aspects of the Proposed Access Arrangement, June 2014 .

520 The owners of Alinta announced in late October, 2014 that they are "exploring future ownership options for the company" [*Sydney Morning Herald on-line, 29 October, 2014*].

521 *Price and Revenue Regulation of Gas Services Rule 2012 No. 3* (SA).

522 *Statutes Amendment (National Electricity and Gas Laws — Limited Merits Review) Act 2013 (WA) Pt. 3.*

523 *Clean Energy Act 2011* (C'w); *Clean Energy (Charges—Customs) Act 2011* (C'w); *Clean Energy (Charges—Excise) Act 2011* (C'w); *Clean Energy (Unit Issue Charge—Auctions) Act 2011* (C'w); *Clean Energy (Unit Issue Charge—Fixed Charge) Act 2011* (C'w); *Clean Energy (Unit Shortfall Charge—General) Act 2011* (C'w);

524 *Privacy Act 1988* (C'w)

525 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1316 and 1318.

new information. AGA submits that the ERA should also take into account the changed circumstances listed above.

1329. AGA's responses to each of the required amendments to the template haulage contract are provided below. Where relevant, AGA provides more detailed analysis of the changed circumstances, including supporting evidence. AGA considers its proposed amendments satisfy the NGO by promoting efficient outcomes through the certainty created by an appropriate level of prescription and comprehensiveness and the facilitation of quicker access.

17.2 AGA response to template haulage contract amendments

ERA required amendment 23

Clause 1 of the proposed revised template haulage contract should be amended as follows:

(a) Other than this clause 1 and clauses ~~15,~~ 16, ~~17, 18, 19, 20~~, 21, 22 and 23 this Template Haulage Contract has no force or effect until…

(a)(iii)(D) <User> is~~, and will for the duration of this Haulage Contract remain,~~ able to deliver…

(d) Other than with respect to the Conditions Precedent referred to in clauses 1(a)(ii) ~~and 1(a)(iv)~~, <Service Provider> must promptly advise …

AGA Response: accept with modifications

Summary Only – AGA proposes alternative wording and additional deletions for Clause 1(a) and accepts the proposed amendment to clause 1(d) and the insertion of an additional clause 3(b).

1330. AGA has considered the ERA's comments[526] and by way of explanation and clarification provides the following responses.

> (a) Other than this clause 1 and clauses ~~15,~~ 16, ~~17, 18, 19, 20~~, 21, 22 and 23 this Template Haulage Contract has no force or effect until…

1331. AGA acknowledges the purpose of clause 1 is to confirm which terms of the contract bind the parties upon execution and those which do not come into effect until satisfaction of a condition precedent. In each case, the clauses that have been added are necessary to give efficacy to the contract from the time of execution. A prospective User is entitled to certain contractual protections while it is taking steps to satisfy conditions precedent. Those steps will require the User to commit considerable resources to negotiate and finalise the conditions precedent, including arrangements with third parties, such as obtaining required insurances and membership of the Retail Market Scheme.

1332. Addressing each required deletion in turn:

1333. Clause 15: Default and Termination – it is possible a party may be in default of an obligation that applies from execution but prior to satisfaction of a condition precedent. An example is clause 16.2 (Security for Performance) which imposes obligations on both parties, a breach of which may result in significant loss or damage. Without the rights and obligations under clause15, the innocent party would be disadvantaged by such a breach.

1334. Clause 17: Liability of Parties – it is possible a party may act or fail to act or be in default of an obligation that applies from execution but prior to satisfaction of a condition precedent. An example is clause 21 (Intellectual Property, Confidentiality and Information Exchange), which imposes confidentiality and privacy obligations on

[526] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1328 -1340.

the parties, a breach of which or negligent act or omission in the relation to which, may result in significant loss or damage, including claims by third parties. Without the rights and obligations under clause15, the innocent party would be disadvantaged in such circumstances.

1335. Clause 18: Representations and Warranties –representations and warranties are fundamental to the assessment and allocation of risk in the formation of a contract. In the context of this document, the warranties are statements or acknowledgments of accuracy of certain facts and the existence of key approvals. They relate to pre-contractual negotiations or approvals that comprise part of the contract including the capacity to enter into a contract, and are relied upon as part of the decision to enter into the contract. Without the rights and obligations under clause 18, if any are untrue, or are breached, the innocent party would be disadvantaged in such circumstances. For example, the representations and warranties in clauses 18 (e) and (g) relate to matters that are fundamental threshold requirements, a breach of which go to the capacity of the party to lawfully enter into the contract and perform its contractual obligations. Under clause 18.3, the representations and warranties are to be given at the commencement of the haulage contract and repeated each day for the duration of the contract, so they need to be capable of being given as condition precedent.

1336. Clause 20: Notices – certain clauses of the contract in force from the date of execution and prior to satisfaction of conditions precedent (such as clause 16.1, 16.3(b) and 16.3(c) and 22.2) include notice provisions or requirements for certain matters to be communicated. Clause 20 specifies the requirements for such notices and communications and is in the nature of an interpretation provision, similar to clauses 22 and 23. Having a comprehensive and clear notice clause provides certainty for the benefit of both parties.

(a)(iii)(D) <User> is~~, and will for the duration of this Haulage Contract remain,~~ able to deliver…

1337. AGA notes the ERA has accepted the inclusion of similar wording in clause 1(a)(iii)(A). AGA refers to its response to required amendment 19 and confirms that AGA has proposed that clauses 1(a)(iii)(A) and clause 1(a)(iii)(B) remain in place to avoid overlap with the equivalent provisions in the Access Arrangement, being clauses 5.5(a)(vi) and clause 5.5(a)(x) respectively, which AGA proposes to remove from the Access Arrangement as required by the ERA.

1338. AGA confirms clause 1(a)(iii)(D) relates to certain User obligations under the REMCo Rules[527] which the ERA has not taken issue with. The user obligations under the REMCo rules must be met at all times that the User is operating in the Network. On that basis, AGA submits this is consistent with the NGO that the User will meet those obligations at all times.

1339. AGA also notes the comments made by the ERA[528] in respect of required amendment 39 relating to representations and warranties, and notes further that Victorian[529] distributors have similar provisions in place approved by the AER. AGA acknowledges that those provisions relate to warranties of future compliance, rather than preconditions of future compliance. This is also reflected in clause 18.3, which the ERA has accepted.

1340. AGA proposes to address the ERA's concerns, to satisfy the NGO and to achieve consistency within the document and equivalent provisions in place with other distributors in Australia, by:

(a) amending both clause 1(a)(iii)(A) and clause 1(a)(iii)(D) by deleting the words "*and will for the duration of this haulage Contract*";

(b) deleting clause 18.1(a) and inserting a new clause 3(b) (iii) to expressly include an obligation that reflects the requirement for the user to deliver and receive gas on the relevant sub-networks[530]:

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527 REMCo, Retail Market Rules, Version 6.5, 8 November 2013.

528 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1521 to 1544.

529 Envestra, *Victorian Access Arrangement Annexure F General Terms and Conditions April 2013,* clause 16.2; Multinet *Access Arrangement Information: Part C – Terms and Conditions, April 2013*, clause 15.1.

530 See also AGA's response to required amendment 39 below.

(b) <User> is and will at all times:

(i) remain a member of and a "user" for the purposes of the Retail Market Scheme;

(ii) comply with the Retail Market Scheme; and

(iii) ensure that it remains able to, deliver Gas to the Receipt Point or Receipt Points on the relevant Sub-network or Sub-networks from which <User> is to receive Gas at one or more Delivery Points under this Haulage Contract, in volumes sufficient to meet <User>'s Gas receipt requirements at each Delivery Point.

(d) Other than with respect to the Conditions Precedent referred to in clauses 1(a)(ii) ~~and 1(a)(iv)~~, <Service Provider> must promptly advise …

AGA accepts the required amendment to clause 1(d)

ERA required amendment 24

Clauses 13.5(b), 13.5(c) and 13.5(d) of the proposed revised template haulage contract should be deleted.

AGA Response: accept with modifications

Summary Only – AGA accepts the deletion of 13.5(c) and 13.5(d). AGA does not accept the deletion of clause 13.5(b).

1341. AGA accepts the deletion of clauses 13.5(c) and 13.5(d) but not for the reasons expressed by the ERA. AGA accepts that if the parties have entered into a regulated contract for reference services only, then any other non-regulated or non-reference services could only be included as a result of bilateral agreement and by definition, would be non-regulated. AGA also refers to its response to required amendment 35 below.

AGA does not accept the deletion of clause 13.5(b)

1342. By way of clarification, AGA confirms clause 13.5(a) does include what is in clause 2(c)(i) of the current template haulage contract. AGA notes the ERA has accepted clause 13.5(a), which incorporates the Change Notice provisions in clause 13.2, which the ERA in required amendment 25 has stated should be deleted. AGA notes and agrees with the ERA's revised position as set out in paragraph 1355.

1343. AGA notes the ERA's analysis of 13.5(b) in paragraph 1358.

1344. AGA accepts that if the agreement is terminated, the User can make a fresh application for access, however, the purpose of clause 13.5(b) is to minimise disruption and facilitate continuation of the agreement (subject to any variations agreed under the process set out in clause 13.2) rather than putting the parties to the expense and delay of undertaking a fresh application process if they wish to agree suitable variations.

1345. This is consistent with the NGO as it complements the variation process in clause 13.2, provides certainty for the parties and allows quicker access to services.

1346. Were the access arrangement terminates or expires without making provision for how the agreement will terminate, and the parties have undertaken the process in clause 13.2 and not reached agreement, clause 13.5(b) complements clause 13.5(a) (which provides the User with a right to terminate) by providing a reciprocal right for the Service Provider to terminate the agreement. If this provision is not included, the Service Provider may be bound to continue to provide services under the agreement for a period of time on onerous terms or in circumstances where it may not be possible to provide certain services any longer.

1347. Clauses 13.5(a) and 13.5(b) are consistent with the Victorian examples referred to by the ERA[531] in its analysis of required amendment 25, and meet the ERA's requirements[532] when read in conjunction with clauses 13.2, 13.3 and 13.4, that the parties consider and define, in light of their individual requirements, how the haulage contract will be affected by changes in an access arrangement. The provisions suggested are consistent with and enhance the process and principles set out in the Victorian examples. They are also consistent with the NGO by providing certainty by allowing for a comprehensive yet flexible process that accommodates both parties, and promotes continued uninterrupted access to services for the benefit of consumers.

1348. AGA supplements the above points in its response to required amendment 25.

ERA required amendment 25

Clauses 13.2, 13.3 and 13.4 of the proposed revised template haulage contract should be deleted.

Clause 22.3 of the proposed revised template haulage contract should be amended as follows:

22.3 Amendment

This Haulage Contract may only be amended:

(a) In the absence of revisions to the access arrangement, by written agreement of the Parties; or

(b) where the access arrangement has been revised, [User and Service

Provider to insert agreed terms for the amendment of the haulage contract upon revision of the access arrangement].

AGA Response: do not accept

Summary Only – AGA does not accept the required amendments.

1349. AGA submits that clauses 13.2, 13.3 and 13.4 provide a comprehensive, cost effective and clear means for the parties to the agreement to consider and manage necessary changes that flow from revisions to the access arrangement.

1350. AGA acknowledges that the parties and any interested third parties have the ability to participate in the access arrangement revision process and thereby contribute to the process of settling the form of the template haulage contract. These clauses enable the parties to engage in a change process in any resulting contract which minimise the cost and time involved in managing subsequent access arrangement changes during the term of contract that is entered into by the parties. The clauses provide a clear means of assisting the parties with identifying and agreeing changes in the risk profile of both parties to the contract that may result from revisions to the access arrangement during the term of the contract. This is consistent with the NGO as it will effectively reduce the costs incurred by Users and Service Providers, promote quicker access and through such cost and time efficiencies, mitigate price impacts, all of which is for the long term benefit of consumers.

1351. AGA notes the ERA has characterised the template haulage contract as:

> *…effectively a regulated standing offer, which provides a basis on which users can negotiate a contract. This standing offer is necessarily subject to amendments approved by the Authority and the requirement to offer it does not survive the expiry of the access arrangement. The*

531 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1371.

532 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1374.

bilateral contract arises when the user either accepts the standing offer or a negotiated modified offer.[533]

1352. AGA interprets the statements above to mean that:

a) the Service Provider submits a template haulage contract based on the document approved as part of the current access arrangement period, with proposed amendments, for approval by the ERA for the next access arrangement period; and

b) the template haulage contract is effectively a regulated standing offer that is capable of acceptance either as it stands, or acceptance following negotiated modifications.

AGA agrees with this analysis

1353. The ERA goes on to state:

"A user may wish to acquire services exclusively on the terms currently defined in the access arrangement. The template haulage contract should be drafted with this notional user in mind, even though the service provider and the Authority may fully expect users to negotiate away from this starting position in their individual haulage contracts. The question for the Authority then must be which template haulage contract terms will achieve this result while placing the minimum constraint on the parties' ability to negotiate away from the access arrangement if they wish."[534]

1354. AGA takes the statements above to mean that:

a) the template haulage contract must be drafted so that an individual haulage contract can be based on an unamended template haulage contract or a negotiated and amended template haulage contract; and

b) the degree to which amendments to the template haulage contract can be negotiated and agreed by the parties is limited only by the requirement that in so far as the haulage contract is for reference services, any amendments must be consistent with the terms currently defined in the access arrangement.

1355. AGA acknowledges that the template haulage contract must therefore be in a form that is both capable of acceptance without amendment by a notional user, and minimises the constraint on the parties' ability to negotiate away from the access arrangement, for example by the inclusion of non-reference services.

1356. AGA notes that the effect of the required amendment to clause 22.3 would be that this would be the only clause in the template haulage contract that is not capable of being accepted without amendment. Having a placeholder in the document instead of a comprehensive and flexible mechanism is less clear. AGA submits clauses 13.2, 13.3 and 13.4 provide an effective, clear and efficient process for amendment that provides a balance of certainty and flexibility which required amendment 22.3 does not provide.

1357. AGA notes that the Victorian distributor examples proceed on a different basis to the template haulage contract[535]. Those documents operate as terms and conditions for supply of reference services, and in the case of changes to the Access Arrangement during the term of the contract, specify a default position. In contrast, the template haulage contract does not specify a default position, but instead provides an enhanced procedure for variation by way of a change control process as set out in clause 13.2, 13.3 and 13.4. AGA submits clause 13.2, 13.3 and 13.4 in comparison to the required amendment to clause 22.3

533 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1345.

534 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1346.

535 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1371.

provides a clearer and more cost effective means of managing change and variations to contracts which meets the NGO and is in keeping with the ERA's analysis above.

ERA required amendment 26

Clause 13.6 of the proposed revised template haulage contract should be deleted and replaced with the following provision:

13.6 Laws to take precedence

(a) In the event of any inconsistency between:

(i) a party's obligations or rights under a Law; and

(ii) its obligations or rights under this Haulage Contract,

its obligations and rights under the Law shall take precedence to the extent of the inconsistency.

(b) Where this Haulage Contract contains provisions which regulate a matter in greater detail than the provisions of a Law then the provisions of this Haulage Contract will not be taken to be inconsistent merely by reason of the inclusion of that additional detail and the provisions of this Haulage Contract will continue to apply to that matter to the extent permitted by the terms of the Law.

AGA Response: accept with modifications

Summary Only – AGA does not accept the deletion of proposed clause 13.6. AGA accepts the ERA's proposed wording should be inserted as clause 13.6 and that AGA's proposed clause 13.6 should be retained and re-numbered as clause 13.7.

1358. By way of explanation and clarification, clauses 13.1 to 13.6 have been drafted as a comprehensive set of interlinked variation provisions collected in one place in the document.

1359. Clause 13.6 sets out clearly the means by which changes to services, changes to the access arrangement and changes by way of Regulatory Events are to be implemented as amendments and provides the User with a clear right of access to the dispute resolution mechanism in clause 19.

1360. For the same reasons explained in the response to required amendment 25 above, the process set out in clause 13.6 adds certainty, saves the parties cost and time, and meets the NGO.

1361. AGA notes the comments made by the ERA as to the proposed clause 13.6 and the references to the Victorian gas distributors' terms and conditions.[536]

1362. AGA submits there is a clear distinction between the function of the Victorian gas distributors' terms and conditions and the function of proposed clause 13.6. The Victorian terms and conditions clarify the order of precedence and the way in which inconsistency between terms of the haulage contract and the Law are to be resolved. The function of AGA's proposed clause 13.6 differs, as its function is to set out the means by which changes to services, changes to the access arrangement and changes by way of Regulatory Events are to be implemented as amendments.

1363. AGA accepts the ERA's proposed clause 13.6 does provide the minimum flexibility necessary to manage conflicts between contractual and regulatory requirements, provides certainty, saves the parties cost and time, and meets the NGO.

[536] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1382 to 1385.

1364. AGA submits consistent with the NGO, such a clause should be included to complement AGA's proposed clause 13.6 rather than to replace it, as AGA accepts the ERA's proposed clause 13.6 clearly establishes the order or precedence and how inconsistencies are to be resolved in the case of conflicts at a detail level.

1365. By retaining AGA's proposed clause 13.6, the parties have the additional benefit of a clear and comprehensive variation process that deals with changes arising from a Regulatory Event in addition to the ERA's proposed clause 13.6, which provides the parties with clarity in the case of an inconsistency that is existing rather than arising as a later consequence of change.

1366. AGA submits the inclusion of both clauses will not lead to unforeseen effects. The clauses will accommodate a mechanism where a change can be proposed by AGA and the User can respond by either accepting the proposed change, negotiating the prosed change or rejecting the proposed change and then for the parties to proceed to dispute resolution. Such a proposal allows a proactive and effective way to manage change that is consistent with the NGO.

1367. AGA therefore accepts the inclusion of the ERA's proposed clause 13.6 and proposes that AGA's clause 13.6 is retained and re-numbered as clause 13.7.

ERA required amendment 27

Clause 5.3(b) of the proposed revised template haulage contract should be deleted.

AGA Response: accept with modifications

Summary Only – AGA accepts the proposed deletion.

1368. AGA notes the ERA's analysis of the User's obligations under the Retail Market Rules and AGA's rights to sue for damages arising from a breach of the Retail Market Rules[537].

1369. AGA agrees it is consistent with the NGO that conflicts or overlaps between provisions of the Law and the terms of the template haulage contract should be avoided[538].

1370. If the proposed clause 5.3(b) is removed, AGA submits that consistent with the NGO an express clause is included in the contract, which makes it clear that the rights of the parties to enforce any breach or act or omission giving rise to any liability under the contract are without prejudice to any rights of the parties under any statutory enforcement regime.

1371. AGA submits for the proposed deletion of clause 5.3(b) to be consistent with the NGO requires that a comparable outcome is achieved by the inclusion of the ERA's clause 13.6 as set out in required amendment 26 and by a consequential amendment to clause 15.6 to ensure that rights under any statutory enforcement regimes are clearly and expressly retained, as follows:

> 15.6 Saving of other remedies
>
> A Party's rights under clause<u>s</u> 15.4 <u>and 15.5</u> are in addition to any other rights and remedies available to the Party, whether under any Law, the Access Arrangement, this Haulage Contract or otherwise <u>and without prejudice to any rights of the Party under any statutory enforcement regime</u>.

537 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1391 to 1393.

538 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1394 and 1395.

ERA required amendment 28

Schedule 1, clause 9(a); Schedule 2, clause 9(a); Schedule 3, clause 8(a); Schedule 4, clause 7(a); and Schedule 5, clause 7(a) should be revised to ensure consistency with clause 5.6 of the proposed revised template haulage contract.

Schedule 1, clause 9(c); Schedule 2, clause 9(c)(i); Schedule 3, clause 8(d); Schedule 4, clause 7(c); Schedule 5, clause 7(c) should all be deleted.

AGA Response: accept

Summary Only – AGA accepts the requirement for revision and deletion of the clauses.

1372. AGA notes the ERA's analysis of the amended delivery points deregistration process and the consequential impacts that flow from those amendments.

1373. AGA accepts the required revisions and deletions set out in in required amendment 28. AGA has included revised wording for Schedule 1, clause 9(a); Schedule 2, clause 9(a); Schedule 3, clause 8(a); Schedule 4, clause 7(a); and Schedule 5, clause 7(a) to ensure consistency with clause 5.6 of the proposed revised template haulage contract and to meet the consequential amendments required as a result of required amendment 30 below.

ERA required amendment 29

Clause 6.2 of the proposed revised template haulage contract should be deleted

Clause 6.5 of the proposed revised template haulage contract should be redrafted to ensure that ATCO retains liabilities for harm that arises from its own negligence or default.

Clause 6.6 of the proposed revised template haulage contract should be amended as follows:

> (b) <Service Provider> will have no liability to <User> for any loss, damage, cost or expense <User> suffers or incurs in relation to or connection with such conveyance, where the loss, damage, cost or expense is a result of the gas being Off-specification Gas.

AGA Response: accept with modifications

Summary Only – AGA proposes clarifying amendments to clause 6.2 and 6.5. AGA accepts the required amendment to clause 6.6(b).

1374. AGA does not accept clause 6.2 should be deleted, but proposes that the clause is redrafted to address the concerns expressed by the ERA.

1375. It was not AGA's intention to introduce a right for itself to unilaterally amend the gas quality specifications[539], rather the purpose of clause 6.2 was to ensure that there was an effective, clear and quick means of addressing and implementing changes to gas specifications as required by law. Examples include the amendment of the gas specifications to accommodate new sources of supply and the consequent need to address any adjustment or replacement of downstream equipment or consumer appliances, as was the case with the Macedon gas field during the second and third access arrangement periods.[540]

[539] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1405 and 1409.

[540] See Department of Finance website: http://www.finance.wa.gov.au/cms/Public_Utilities_Office/Energy_Initiatives/Broadening_the_gas_specification.aspx

1376. AGA proposes that clause 6.2(a) is redrafted as follows:

a) Subject to clause 6.2(b), <Service Provider> as required or permitted by Law may, from time to time, amend all or part of the Gas Quality Specifications by written notice to <User>.

1377. AGA submits that clause 6.5 as submitted to the ERA does include in clause 6.5(b) an express exclusion of the provisions of clause 6.5(a) in circumstances where AGA is negligent.

1378. AGA accepts the ERA's requirement that such an exclusion should extend to AGA's default as well as negligence[541], as it is reflected in existing provisions of the Template Haulage Contract, for example clause 7.6(b)(i).

1379. AGA proposes that clause 6.5(b) is amended as follows:

a) Clause 6.5(a) does not apply in respect of any Off-specification Gas delivered or sought to be delivered into the AGA GDS as a result of <Service Provider>'s negligence or default.

AGA accepts the required amendment to clause 6.6(b) which is consistent with the treatment of clause 6.5 above

ERA required amendment 30

Clauses 6.5(a), 6.7(b), 6.8(b), 6.9(c)(ii) and 6.11(e)(ii) of the proposed revised template haulage contract should be amended to remove references to indirect damage.

Clause 18.3(b) should be deleted.

AGA Response: accept with modifications

Summary Only – AGA accepts the amendments required for clauses 6.5(a), 6.7(b), 6.8(b), 6.9(c)(ii) and 6.11(e)(ii) of the proposed revised template haulage contract subject to further proposed amendments to clauses 7.6, 17.1, 17.8 and Schedules 1 to 5. AGA accepts the required deletion of clause 18.3(b).

1380. AGA has considered the ERA analysis[542] and notes that the ERA has cited two main reasons for rejecting the proposed amendments: (i) that AGA has offered no explanation for why it considers a modified allocation of liabilities is appropriate[543]; and (ii) that users must have insurances to cover their losses[544].

1381. In respect of (i) above, AGA submits it is entirely consistent with the NGO that the template haulage contract should be drafted in such a way that where it provides certainty and is for the long term benefit of consumers, risk and the cost of managing risk should be allocated to the party that has the best control over the management of that risk. AGA's March[545] submission included reference to these underlying risk allocation and management principles.

1382. AGA has reconsidered the proposed amendments in the light of the totality of the proposed amendments that the ERA has accepted, rejected and amended in the Draft Decision.

541 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1414 to 1416.

542 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1424 to 1440.

543 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1428 and 1431.

544 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1436 and 1438.

545 ATCO Gas Australia, Access Arrangement Information, 17 March 2014, page 41.

1383. Save for the reference in clause 17.3 excluding the liability of the parties for Indirect Damage, there is now no requirement to separately define Direct Damage and Indirect Damage, but to simply refer to “loss, damage, cost or expense”, which is consistent with the terminology used throughout the Template Haulage Contract.

1384. Subject to AGA’s comments in respect of point (ii) below, AGA submits that on the basis that clause 17.3 remains in place, the ERA’s required amendments to clauses 6.5(a), 6.7(b), 6.8(b), 6.9(c)(ii) and 6.11(e)(ii) of the proposed revised template haulage contract are accepted with the further minor amendments set out below.

1385. Clause 6.5(a) – amend to read:

1386. Indemnifies <Service Provider> against all ~~Direct Damage and Indirect Damage~~ loss, damage, cost or expense suffered or incurred by <Service Provider> in relation to or connection with any delivery or attempted delivery of Off-Specification Gas into the AGA GDS by <User> or a Related Shipper of <User>

1387. 6.7(b) – amend to read:

<User> hereby indemnifies **<Service Provider>** against any

~~(i) Direct Damage;~~

~~(ii) Indirect Damage; or~~

~~(iii)~~ loss, damage, cost or expense suffered or incurred by **<Service Provider>** in relation to or connection with any Claim brought by any person against **<Service Provider>**,

6.8(b) – amend to read:

<User> hereby indemnifies <Service Provider> against any

~~(i) Direct Damage;~~

~~(ii) Indirect Damage; or~~

~~(iii)~~ loss, damage, cost or expense in relation to or connection with any Claim brought by any person against <Service Provider>,

1388. 6.9(c)(ii) – amend to read:

1389. (ii) indemnifies <Service Provider> against all claims from:

(A) any Downstream Person of the <User>;

(B) any other User; or

(C) any Downstream Person of any other User

1390. for ~~Direct Damage and Indirect Damage~~ any loss, damage, cost or expense arising out of or in connection with:

1391. 6.11(e)(ii) – amend to read:

(ii) hereby indemnifies <Service Provider> against any:

~~(A) Direct Damage;~~

~~(B) Indirect Damage; or~~

~~(C)~~ loss, damage, cost or expense in relation to or connection with any Claim brought by any person against <Service Provider>,

1392. To ensure consistency with all relevant clauses in the template haulage contract, consequential amendments should also be made to the following clauses:

1393. 7.6(b)(i) – amend to read:

1394. (i) as a result of the negligence or default of <Service Provider> then, subject to this Haulage Contract, <Service Provider> is liable to <User> for any ~~Direct Damage~~ loss, damage, cost or expense suffered by <User> as a result of an interruption or Curtailment of Gas delivery under clause 7.6(a)(ii);

1395. Clause 17.1 – amend to read:

~~1396.~~ **17.1 Liability for negligence and default ~~limited to Direct Damage~~**

1397. (a) Subject to clauses 17.1(b) and 17.3, if a Party:

1398.

1399. (i) is negligent in any matter relating to or arising out of this Haulage Contract; or

1400.

1401. (ii) defaults in respect of any obligation to the other Party under this Haulage Contract,

1402.

1403. then the Party is liable to the other Party (including its directors, servants, consultants, independent contractors and agents) for, and indemnifies the other Party (including its directors, servants, consultants, independent contractors and agents) against, any ~~Direct Damage~~ loss, damage, cost or expense to the other Party caused by or arising out of the negligence or default.

1404.

1405. (b) <Service Provider> is not liable to <User> for ~~Direct Damage or Indirect Damage~~ loss, damage, cost or expense caused by or arising out of:

1406.

(i) any refusal to accept Gas at a Receipt Point or Curtailment undertaken in accordance with this Haulage Contract or any Law;

1407.

(ii) any non-delivery of Gas into the AGA GDS where non-delivery has not been caused, or contributed to, by <Service Provider> (and any refusal to accept Gas at a Receipt Point or Curtailment undertaken in accordance with this Haulage Contract does not amount to <Service Provider> causing or contributing to the non-delivery); or

(iii) <Service Provider> otherwise acting in accordance with its rights under this Haulage Contract or any Law.

1408. Clause 17.1 – amend to read:

(a) A Party who is fraudulent in relation to this Haulage Contract is liable to the other Party for, and indemnifies the other Party against, any~~:~~

~~(i) Direct Damage;~~

~~1409.~~

~~(ii) Indirect Damage; or~~

~~(iii)~~ loss, damage, cost or expense in relation to any Claim brought by any person against the other Party, suffered or incurred by the other Party in relation to the fraud.

1410. Clause 17.8 – amend to read:

Each Party must ~~use its best endeavours~~ mitigate any ~~Direct Damage, Indirect Damage or other~~ loss, ~~or~~ damage, cost or expense suffered by it as a result of any breach or negligence of the other Party in connection with this Haulage Contract.

1411. In respect of clause 17.8, for the reasons explained in the response to required amendment 41 below, AGA has suggested that all references to “best endeavours” should be replaced with references to “reasonable endeavours”, however clause 17.8 should not be subject to a “reasonable endeavours” requirement for the reasons set out below. .

1412. In the case of mitigation of loss or damage, AGA submits that the template haulage contract should be consistent with common law mitigation principles. Mitigation of loss or damage is concerned with steps which the innocent party ought, as a reasonable person, to have taken so as to minimise loss or damage or at least so as not to increase it[546]. While there is at common law no positive duty to take steps to minimise loss, it is not unreasonable, and is consistent with commercial practice to include a requirement on the parties to a contract to mitigate their loss and damage to provide clarity and consistency with the NGO by reducing the scope for dispute and providing a balanced and costs effective means for the parties to manage risk.

1413. For the above reasons, AGA submits that clause 17.8 should not be qualified by a “best endeavours” or “reasonable endeavours” requirement.

1414. AGA notes that as set out in required amendment 28, the remaining references to Direct Damage in Schedule 1, clause 9(c); Schedule 2, clause 9(c)(i); Schedule 3, clause 8(c); Schedule 4, clause 7(c); and Schedule 5, clause 7(c) of the template haulage contract are dealt with by the removal of those clauses, and has updated the template haulage contract document to reflect this.

1415. In respect of point (ii) above, that users must have insurances to cover their losses[547], AGA does not accept that as a matter of commercial practice or to be consistent with the NGO, users must have insurances to cover their losses[548]. AGA submits that the correct approach is to assess the controllability of risks by the parties to the contract and then to consider insurability as one element of the assessment of where the risks should be allocated and how those risks should be managed under the contract.

1416. It is a fact that users’, and service providers’, ability to insure against liabilities under the haulage contract will depend on the individual party’s financial standing, their attitude to risk and the ability of the individual party to access insurance in the market at any time.

1417. AGA submits that the degree of control over risks under the contract[549] should determine the allocation of risk between the parties to the contract. It is the controllability, not the insurability of the risks that should be considered as the primary assessment of allocation of risk between the parties. Insurability of particular risk is subject to many factors that are peculiar to individual users, whereas controllability of risk is subject to the legal and operating environment in which the parties conduct their businesses. This includes contractual arrangements with third parties such as shippers and producers and the regulatory regimes that apply to the various elements of the gas supply chain from producers through to end users.

1418. Contractual terms also provide a means by which risk is controlled and allocated, and in the case of AGA as a regulated gas distribution service operator, the degree to which it can manage those risks contractually is determined by the regulatory regimes that apply. In comparison, customers (retailers) are subject to different levels of regulation in their contracts with shippers and producers.

1419. There are many risks under commercial contracts and the template haulage contract that either cannot be insured against (for example, liabilities for fraud under clause 17.2, liabilities for penalties that may be payable to enforcing agencies for breaches of Laws, and liabilities to make payments due under clause 17.6) or are subject to availability or the payment of premiums that will vary depending on the financial

546 Halsbury’s Laws of Australia [110-11220], Lexis Nexis.

547 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1436 and 1438.

548 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1436 and 1438 – paragraph 1437 appears to largely repeat paragraph 1435.

549 See for example the ERA’s analysis in paragraphs 1432 and 1435 of the Draft Decision.

standing, claims history, risk appetite and other factors of the individual user (for example, warranty insurance under clause 18 and public liability insurance).

1420. AGA accepts the required amendment by the deletion of clause 18.3(b) and has updated the template haulage contract document to reflect this.

ERA required amendment 31

Clause 7.7(a) of the revised template haulage contract should be as follows:

> (a) …by <Service Provider>, or its officers, servants, or agents acting reasonably in the ~~reasonable~~ course of installing…

AGA Response: accept

Summary Only – AGA accepts this amendment.

1421. AGA accepts the required amendment and has updated the template haulage contract document to reflect this.

ERA required amendment 32

Clause 8.1 of the proposed revised template haulage contract should be amended as

follows:

> 8.1 <Service Provider> to minimise Curtailment
>
> <Service Provider> will, in its operation and maintenance of the AGA GDS, use reasonable endeavours to minimise the magnitude and duration of any Curtailment of Gas deliveries to <User>, ~~except where the Curtailment is attributable to <User>'s negligence or breach of this Haulage Contract~~ subject to the service provider's rights to curtail deliveries under clauses 15.5(b), 16.1 and 16.2(i).

AGA Response: accept with modifications

Summary Only – AGA accepts the proposed amendment.

1422. AGA notes the ERA's analysis of the Service Provider's obligations[550].

1423. If the proposed clause 8.1 is amended, AGA submits that consistent with the NGO, an express clause is included in the contract which makes it clear that the rights of the parties to enforce any breach or act or omission giving rise to any liability under the contract are without prejudice to any rights of the parties under any statutory enforcement regime.

1424. AGA submits (as explained by AGA in its response to required amendment 27) for the proposed amendment of clause 8.1 to be consistent with the NGO, a comparable outcome is required that is achieved by the inclusion of the ERA's clause 13.6 as set out in required amendment 26.

1425. AGA accepts the required amendment and has updated the template haulage contract document to reflect this.

[550] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1447 to 1450.

ERA required amendment 33

Either clause 10.3 or clause 19.1(c) of the proposed revised template haulage contract should be amended such that the threshold limits imposed under 19.1(c) do not apply to invoice disputes arising under clause 10.3.

Clause 10.4 of the proposed revised template haulage contract should be amended such that the same processes, rights and obligations applicable to user-issued retrospective error notices provided for under 10.4(b) and 10.4(c) will apply for retrospective error notices issued by the service provider.

AGA Response: accept with modifications

Summary Only – AGA proposes to amend clause 19.1(c) to provide mutuality. AGA accepts the proposed amendment to clause 10.4.

1426. AGA accepts that the rights of the parties in respect of disputes for invoices and past payments should not be asymmetrical[551] and where appropriate and to meet the NGO, should be mutual.

1427. By way of clarification and explanation, the reason a threshold has been suggested is to promote efficiency and minimise cost by requiring that the number of disputes is minimised through aggregating claims to a reasonable value that is not too low to justify the expense and time of engaging in the dispute resolution process.

1428. AGA accepts the principle that subject to the reasonable aggregation limits described above, all erroneous Payment Claims of any value should be capable of being submitted for dispute resolution.

1429. AGA therefore proposes clause 10.3 should remain as drafted, but that to achieve a mutual position for both parties, clause 19.1(c) be amended as follows:

(c) A Party may only give a notice under clause 19.2(a) to initiate dispute resolution processes under this Haulage Contract in relation to a disputed or erroneous Payment Claim where~~:~~

~~(i) if a single line item in the Payment Claim is in dispute, the amount in dispute exceeds [$5,000.00] ; or~~

~~(ii) if multiple line items in the Payment Claim are in dispute, the aggregated amount in dispute exceeds [$20,000.00].~~

(i) there is any single line item or multiple line items and the single line item or multiple line items total less than $5,000 in any rolling 3 month period; or

(ii) if a single line item or multiple line items total equal to or greater than $5,000 at any time; and

(iii) there is any single line item or multiple line items of any total for any period greater than 3 months.

1430. AGA accepts the proposed required amendment to clause 10.4 and proposes clause 10.4 should be amended as follows:

10.4 Correction of payment errors after payment

(a) If a Party forms the view after a Payment Claim has been paid that there is an error in the Payment Claim that Party may give the other Party a written notice providing details of the error, and specifying each Payment Claim line item affected by the error (**Retrospective Error Notice**).

[551] Draft Decision paragraph 1465

(b) Where **~~<User>~~** a party (**Sender**) provides a Retrospective Error Notice under clause 10.4(a), **~~<Service Provider>~~** the other party **(Recipient)** must, within 5 Business Days after receiving it, give **~~<User>~~** the Sender a written notice specifying either:

(i) that **~~<Service Provider>~~** the Recipient agrees with the Retrospective Error Notice, in which case, subject to clause 10.4(e), **~~<Service Provider>~~** the Recipient will account for:

(A) the value of the error; and

(B) interest on the value of the error calculated under clause 10.5, in the

next Payment Claim; or

(ii) that **~~<Service Provider>~~** the Recipient does not agree with the Retrospective Error Notice and the reasons for this, in which case clause 10.4(c) applies.

(c) Where **~~<Service Provider>~~** the Recipient gives **~~<User>~~** the Sender notice under clause 10.4(b)(ii) that **~~<Service Provider>~~** the Recipient does not agree with a Retrospective Error Notice, **~~<User>~~** the Sender must, within 5 Business Days after receiving the notice, give **~~<Service Provider>~~** the Recipient a written notice specifying either:

(i) that the Retrospective Error Notice is withdrawn, in which case neither Party will have any liability to the other in respect of the Retrospective Error Notice or the alleged error; or

(ii) that **~~<User>~~** the Sender does not withdraw the Retrospective Error Notice, in which case the dispute is to be resolved in accordance with clause 19.

(d) Where **~~<Service Provider>~~** the Recipient provides a Retrospective Error Notice under clause 10.4(a), **~~<Service Provider>~~** the Recipient will account for:

(i) the value of the error; and

(ii) interest on the value of the error calculated under clause 10.5, in the next Payment Claim.

(e) If:

(i) **~~<Service Provider>~~** the Recipient is required under clause 10.4(b)(i) or 10.4(d) to account for an error in a future Payment Claim; and

(ii) as at the date of the Retrospective Error Notice for the error, there are no further Payment Claims to be made by **~~<Service Provider>~~** the Recipient under this Haulage Contract,

then:

(iii) where the error would require a deduction from the future Payment Claim, **~~<Service Provider>~~** the Recipient must pay to **~~<User>~~** the Sender an amount equal to the amount to be deducted; and

(iv) where the error would require an addition to the future Payment Claim, **~~<User>~~** the Sender must pay to **~~<Service Provider>~~** the Recipient an amount equal to the amount to be added, in each case within 20 Business Days after the date of the Retrospective Error Notice for the error.

ERA required amendment 34

Clause 11.1 of the proposed revised template haulage contract should be deleted.

Clause 22.5(a) of the proposed revised template haulage contract should be amended to specify which duties it refers to and to ensure that the user's liability is limited to duties payable as a result of things done specifically pursuant to the bilateral relationship with the user.

AGA Response: accept with modifications

Summary Only – AGA proposes to make clarifying amendments to clause 11.1. AGA accepts the required amendment to clause 22.5(a).

1431. AGA does not accept clause 11.1 should be deleted, but proposes the clause, and clause 22.5, are both redrafted to address the concerns expressed by the ERA.[552]

1432. The underlying reason for clause 11.1 is to allocate Tax (as that phrase is defined in the Dictionary) liability clearly between the parties consistent with the NGO. It is unclear on what basis the ERA believes clause 11.1 does not meet the NGO, except that it may have unintended consequences. AGA submits that the clause can be amended to more clearly meet its objective in the same way that the ERA has recognised that clause 22.5(a) should be amended to provide a clearer delineation.

1433. AGA acknowledges that the focus of the clause is principally to deal with duty liabilities, rather than broader tax liabilities, and proposes to address the ERA's concerns by narrowing the scope of the clause to refer specifically to duty, and in turn, to specific categories of duty. AGA has also added express wording to confirm that the user is not liable for any duty that may be assessed as payable for any transfer or assignment by the service provider under clause 14.8.

1434. AGA is not looking to "possible future duties or taxes"[553]. Any future duty or tax changes would be addressed through the processes set in clause 13.

1435. AGA notes the ERA's analysis of clauses 11.1, 11.2 and 22.5(a)[554] and in particular its consideration of the Victorian gas distributors regulated terms and conditions.[555]

1436. Consistent with the approach taken by Envestra[556], AGA proposes to amend clauses 11.1 and 11.2 to clarify that the clauses deal with Duty liability, and to amend clause 22.5 by deleting clause 22.5(a) to address the ERA's concerns.

11.1 ~~Taxes~~ Duty

(a) Subject only to clause 11.2, all ~~Taxes~~ Duty arising in respect of:

(i) the transfer of title to Gas to **<Service Provider>** at a Receipt Point;

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552 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1472 to 1477.

553 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1476.

554 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1476 to 1485.

555 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1477 and 1481.

556 Envestra, Victorian Access Arrangement Annexure F General Terms and Conditions April 2013, clause 16.2; Multinet Access Arrangement Information: Part C – Terms and Conditions, April 2013, clause 41.11.

(ii) the delivery, transportation or handling of Gas before receipt at a Receipt Point and after delivery at a Delivery Point; ~~and~~

(iii) the transfer of title to Gas to **<User>** at a Delivery Point in accordance with clause 7.1(a)(iii);

(iv) this Agreement;

(v) any statement of charges, invoice or notice issued pursuant to this Agreement; and

(vi) any easement, licence or other document required pursuant to this Agreement (other than any transfer or assignment executed pursuant to clause 14.8)

shall be paid by **<User>.**

(a) All ~~Taxes~~ Duty arising in respect of a Pipeline Service (including a Haulage Service) relating to Gas after receipt at a Receipt Point and before delivery at a Delivery Point shall be paid by **<Service Provider>**.

1437. Clause 22.5 – amend as follows:

22.5 ~~Duty and c~~Costs of Haulage Contract

~~(a) **<User>** must pay all Duty that may be payable on or in connection with this Haulage Contract, any transaction evidenced by or effected under this Haulage Contract and any instrument or transaction entered into under this Haulage Contract.~~

~~(b)~~ Each Party must bear its own legal and other costs in relation to the preparation of this Haulage Contract.

ERA required amendment 35

Clauses 13.5(c) and 13.5(d) of the proposed revised template haulage contract should be deleted.

AGA Response: accept

Summary Only – AGA accepts the required amendment.

1438. AGA accepts the required amendment, but notes the reasons set out by the ERA[557] in this required amendment differ from the reasons for deleting the clauses expressed by the ERA[558] in required amendment 24.

1439. For the sake of clarity, AGA does not accept the reasons set out in this required amendment 35 and refers to and repeats the comments made in the responses to required amendment 24 and 25 above.

557 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1486 to 1491.

558 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1359.

ERA required amendment 36

Clause 14.3(c)(iii) of the proposed revised template haulage contract should be deleted.

AGA Response: accept

Summary Only – AGA accepts the required amendment.

1440. Provided that clause 14.3(c)(ii) remains as proposed and required amendments 19 and 20 are dealt with as AGA proposes, AGA accepts the required amendment, and refers to its response to required amendments 19 and 20.

1441. AGA submits (as explained in its response to required amendments 19 and 20 above) that to be consistent with the NGO, to promote certainty and efficiency of access to services, and to avoid unnecessary duplication or overlap, the amendments proposed to the access arrangement and template haulage contract are required.

ERA required amendment 37

Clause 14.8 of the proposed revised template haulage contract should be amended as follows:

<Service Provider> may assign its rights or ~~novate~~ transfer its obligations under this Haulage Contract on giving reasonable written notice to <User>.

AGA Response: accept with modifications

Summary Only – AGA accepts the proposed amendment with minor modification.

1442. By way of clarification and explanation, the purpose of clause 14.8 is to provide a clear and comprehensive process for the management of all transfer requests, including novation requests.

1443. AGA accepts the proposal to substitute the word "transfer" for "novate".

1444. In order to accurately reflect the content of the clause, AGA submits that the heading of clause 14 should be amended to read:

14. ASSIGNMENT, TRANSFER, NOVATION AND CAPACITY TRADING

1445. AGA also submits that clause 14.8 should also be amended to reflect the above change.

ERA required amendment 38

Either:

Clause 16.2 of the proposed revised template haulage contract should revert to the wording of clause 14.2 of the current template haulage contract;

Or:

Clause 16.2(a) of the proposed revised template haulage contract should be amended to limit ATCO's right to require a bank guarantee to those circumstances where ATCO might reasonably conclude that the user presents an unacceptable credit risk.

AGA Response: accept

Summary Only – AGA accepts the amendment proposed to clause 16.2(a) and does not accept the proposed amendment of clause 16.2 should revert to the wording of clause 14.2 of the current template haulage contract.

1446. AGA notes the references by the ERA to the terms of the Victorian gas distributors' regulated terms and conditions.

1447. Consistent with the requirements of the NGO, and the terms of the Victorian gas distributors' regulated terms and conditions, to save cost and time and to promote efficiency in the provision of access to regulated services, AGA proposes to amend clause 16.2(a) to read as follows:

(a) On the earlier of the date falling 10 Business Days after the date of this Haulage Contract and the date of commencement of Haulage Services, **<~~User~~ Service Provider>** may ~~ust provide to~~ request **<~~Service Provider~~ User>** to provide a bank guarantee from an Approved Bank in or substantially in the form set out at Annexure B, as security for the performance of **<User>**'s obligations under this Haulage Contract. The bank guarantee must only be provided ~~must~~ if at the time of the request:

(i) <User> cannot demonstrate:

(A) that it has an unqualified:

6. Standard & Poor's credit rating of at least BBB-; or
7. Moody's credit rating of at least Baa3; or
8. Fitch credit rating of at least BBB-,

(an "**Acceptable Credit Rating**"); or

(B) that the performance of the User's payment obligations under clause 10 of this Haulage Contract are guaranteed (on terms acceptable to <Service Provider>) by another entity who has an Acceptable Credit Rating ("**Guarantor**"); or

(ii) within the previous 12 months, (or where the commencement of this Haulage Contract occurs within the previous 12 months, since the commencement of this Haulage Contract) <User> has failed to pay in full:

(A) 5 invoices within the required time limit for payment; or

(B) 3 consecutive invoices within the required time limit for payment; or

(C) 1 invoice within 25 days of the due date; or

(iii) any undisputed amounts owing by <User> to <Service Provider> in respect of the provision of Haulage Services in the period prior to the commencement of this Haulage Contract, are not paid in full within 30 days of the commencement of this Haulage Contract; or

(iv) <User> ceases to hold a Gas Trading Licence under the *Energy Coordination Act 1994* (WA); or

(v) <User> ceases to be a member of or "user" for the purposes of the Retail Market Scheme;

and

(vi) subject to clauses 16.2(a) (i) to (v) above and 16.2(b), the bank guarantee shall be for the amount in dollars, notified by **<Service Provider>** to **<User>** in writing, which is the greater of:

(A) **<Service Provider>**'s reasonable estimate of all Haulage Charges and other amounts payable that will be incurred by **<User>** under this Haulage Contract in the 3 months following the date of estimation; and

(B) an amount that is necessary, in **<Service Provider>**'s reasonable opinion, to protect **<Service Provider>**'s legitimate business interests; and

(vii) commence immediately and continue for an unlimited period or, if limited, for a period which ends not less than 20 Business Days after the later of:

(A) the end of this Haulage Contract; and

(B) the time required for **<User>** to satisfy its obligations under this Haulage Contract as determined by **<Service Provider>**, acting reasonably.

provided that nothing in clause 16.2(a)(ii) or 16.2(a)(iii) shall permit **<Service Provider>** to require a Bank Guarantee under clause 16.2(b) where **<User>** has failed to pay the invoice or invoices or a relevant part of the invoices due to a bona fide dispute under clause 10.3.

ERA required amendment 39

Clauses 18.1(a), (b), (c), (d), (f), (h), (j), (k), (l), (m), (n), (o), and (p) of the proposed revised template haulage contract should be deleted.

Clause 18 of the proposed revised template haulage contract should be amended to make the obligations imposed on the user in clauses 18.1(e) and (g) reciprocal.

AGA Response: accept with modifications

Summary Only – AGA accepts the required deletion of clauses 18.1(a) and (b). AGA proposes alternative wording or additional clauses in respect of clauses18.1 (c), (d), (f), (h), (j), (k), (l), (m), (n), (o), and (p). Clauses 18.1(e) and (g) are already reciprocal (clauses 18.2 (b) and (c)).

1448. AGA notes the ERA's analysis[559] of the proposed representations and warranties but for the reasons set out below does not accept the required amendments.

1449. By way of clarification and explanation, AGA confirms that:

a) representations are statements of fact made by one party to the other[560] which is relied upon and induces a party to enter into a contract; and

b) warranties are contractually binding promises or terms that the party providing warranty undertakes to perform or abide by[561].

1450. As such, representations and warranties are fundamental to the formation of a contract, as they form the basis of the decision to enter into a contract. In some cases, representations and warranties can perform the function of allocating risk by providing one party with a remedy or a trigger for default provisions in the case of breach of a representation or warranty.

1451. In the case of the template haulage contract, breaches of representations and warranties in clause 18 give rise to rights to curtail[562], rights to GST adjustments[563], and default and termination[564].

1452. The representations and warranties included in the template haulage contract are necessary to give efficacy to the contract from the time of execution. The User will have obligations relating to the use of the gas distribution network, breaches of which can have serious public safety, system security and gas quality impacts for the general public and customer. For those reasons, it is consistent with the NGO that sufficient representations and warranties are secured from a prospective User.

1453. Addressing each required deletion in turn:

1454. 18.1(a) – compliance with Approved System Pressure Protection Plan – AGA notes the ERA has required the deletion of this clause on the basis that it reiterates obligations already owed by the User[565]. AGA accepts that clause 6.9 (a) imposes an obligation on the user to have in place and abide by an Approved System Pressure Protection Plan, a breach of which is a default under clause 15; that the User can be

559 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1525 to 1544.

560 Halsbury's Laws of Australia [110-5045], Lexis Nexis.

561 Halsbury's Laws of Australia [110-2370], Lexis Nexis.

562 Clause 8.3.

563 Clause 11.2.

564 Clause 15.

565 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1529 to 1532.

required under clause 16.1(b) to provide written evidence of compliance, a breach of which gives rise to the remedies available in the template haulage contract. AGA has also proposed in its response to Required Amendment 19 that clause 1(a)(iii)(A) is retained in the template haulage contract as a condition precedent, rather than in clause 5.5(a)(vi) of the Access Arrangement as a precondition, to avoid duplication and overlap.

1455. AGA accepts that the existing contractual provisions sufficiently meet the NGO and accepts the deletion of this clause.

1456. 18.1(b) - notification of suspected breach or likely breach of clause 18.1(a) – AGA accepts that as clause 6.9(b) includes an obligation to notify of known or suspected breaches of the Approved System Pressure Protection Plan, the existing contractual provisions sufficiently meet the NGO, and accepts the deletion of this clause.

1457. 18.1(c) – Compliance with Laws – AGA notes that there is no other term of the template haulage contract that directly requires the User's compliance with the access arrangement or the haulage contract. Clause 15.1(c) provides that a failure by a party to perform or observe any one or more of its obligations under the haulage contract is a default.

1458. AGA proposes that the deletion can be accepted provided that clause 15.1(c) is amended to reflect the wording of proposed clause 15.1(c) as follows:

> (c) if the Party otherwise fails to perform or observe any one or more of its obligations connected with, arising out of or in relation to ~~under~~ the Access Arrangement or this Haulage Contract, including any obligation implied by the operation of Law;

1459. 18.1(d) – licences and approvals – AGA notes the ERA believes the proposed clause could be narrowed in scope and made reciprocal[566] or commercially negotiated, although it goes on to say that it should be deleted.

1460. AGA notes clause 18.2(a) already contains an almost identical representation and warranty from the service provider, but that the ERA has made no comment on that clause.

1461. AGA notes the Multinet and SP Ausnet regulated terms and conditions contain a narrower version of this representation and warranty.

1462. AGA submits to include such clauses is entirely consistent with the NGO by providing clarity, mutuality and efficiency of access to services.

1463. AGA proposes to address the ERA's comments by deleting clause 18.1(d) and redrafting it to be consistent with clause 18.2(a), so that they are reciprocal, and to make a further clarifying amendment to clause 18.2(a) as follows:

> *it has in full force and effect all material authorisations, licences, permits, consents, certificates, authorities and approvals necessary under all Laws to enter into this Haulage Contract, to observe its obligations under the Access Arrangement and this Haulage Contract, and to allow those obligations to be enforced*

1464. 18.1(e) – power to contract – AGA notes the ERA's comments[567] but respectfully draws the ERA's attention to clause 18.2(b) which is in identical terms and is therefore reciprocal.

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566 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1535 to 1536.

567 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1537.

1465. 18.1(f) – ranking of payments – AGA notes the ERA considers that the clause should be deleted because it provides a second layer of protections and has rights to credit risk protection in the form of a bank guarantee[568].

1466. By way of explanation and clarification, the clause relates to the user's obligations to pay as being ranked at least equally with all unsecured and unsubordinated indebtedness (subject to restrictions on preferences by Law). The effect of required amendment 38, which has been accepted with modifications by AGA, is that there may be cases where AGA is not entitled to obtain a bank guarantee or there may be an insolvency event. In such cases, clause 18.1(f) provides a complementary protection for AGA where an insolvency event occurs in the absence of a bank guarantee, which is not unreasonable nor onerous and is entirely consistent with the NGO.

AGA therefore does not accept the deletion of clause 18.1(f)

1467. 18.1(g) – breaches of Law, obligation or undertaking – AGA notes the ERA's comments[569] but draws the ERA's attention to clause 18.2(c) which is in almost identical terms and is therefore reciprocal.

1468. 18.1(h) – pending or threatened legal proceedings – AGA notes the ERA's comments[570] that on the basis that it is not within the User's control to maintain compliance; that the template haulage contract should deal with it differently (by way of disclosure and notification); and that the obligations should be reciprocal.

1469. AGA draws the ERA's attention to clause 18.2(d), which is in almost identical terms and therefore reciprocal.

1470. AGA does not accept the clause as drafted operates in the onerous manner described by the ERA. The clause (and the reciprocal clause 18.2(d)) includes a materiality qualification (…pending or threatened action or proceeding…will, or might reasonably be expected to, materially affect… ability to perform…). This would address the vexatious action example cited by the ERA.

1471. AGA acknowledges the ERA's suggestion of a disclosure and notification provision would satisfy the NGO by providing further clarity, mutuality and efficiency of access to services. AGA suggests further that such provisions should apply not only for legal proceedings, but for all representations and warranties.

1472. AGA therefore proposes that an additional clause 18.4 is inserted as follows:

18.4 Disclosure and notification

(a) Each Party shall disclose in writing to the other Party any matters that would render a representation or warranty untrue or incorrect in any respect as soon as reasonably practicable.

(b) The Parties acknowledge that except as disclosed under clause 18.4(a) all representations and warranties are true and correct in all respects.

(c) Except as specifically set out in this clause 18, each Party acknowledges that in entering into this Haulage Contract it has not relied on any representations or warranties about its subject matter.

1473. 18.1(j) – Delivery Points – AGA notes the ERA's analysis[571] of this clause.

568 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1533.

569 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1538.

570 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1539 to 1541 .

571 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1529, 1535 and 1536.

1474. AGA submits that to include such a clause is entirely consistent with the NGO by providing clarity and efficiency of access to services. It is not practical or possible to identify which of a lease, licence or easement is required for each Delivery Point or other facilities as the requirement will vary depending on the specific location and nature of each Delivery Point or other facility.

1475. AGA points out that in order for the user to meet its obligations under clauses 5, 7.7 and 9.3 in respect of Delivery Points and facilities, such requirements must be met.

1476. While it would be possible for AGA to propose the inclusion of identical clauses in each relevant section of the template haulage contract, AGA submits that the proposed clause 18.1(j) is the most efficient means of doing so.

AGA therefore does not accept the deletion of clause 18.1(j)

1477. 18.1(k) – unfettered access – AGA notes the ERA's analysis of this clause[572].

1478. AGA notes that clause 9.3 obliges the User to use reasonable endeavours[573] to provide or procure unfettered access to the relevant land or premises.

1479. AGA proposes that the deletion can be accepted provided that clause 9.3(b) is amended to reflect the wording of proposed clause18.1(k) as follows:

> (b) The **<User>** must use reasonable endeavours, <u>including all leases, licences and easements materially necessary</u>, to provide or procure such unfettered access to the relevant land or premises in a timely manner.

18.1(l) – insurance – AGA notes the ERA's analysis of this clause[574].

1480. AGA notes clause 16.3 obliges the User to meet Service provider's minimum insurance and prudential requirements.

1481. AGA notes the AER has approved express requirements for both the parties to have in place adequate insurance are included in the Victorian gas distributors' regulated terms and conditions[575].

1482. AGA proposes the deletion can be accepted provided that clause 16.3(a) is amended to reflect the wording of proposed clause18.1(l) as follows:

> (a) Each party must obtain adequate insurance to meet its obligations in relation to insurance under this Haulage Contract.
>
> (b) <User> must meet <Service Provider>'s minimum insurance and prudential requirements, including requirements as to its ability to meet all financial obligations under this Haulage Contract. Unless otherwise agreed in writing, the minimum insurance requirements are:

1483. 18.1(m) and (n) – Retail Market Scheme Compliance - AGA notes the ERA's analysis of this clause[576], in particular the ERA's statement:

[572] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1529 to 1532.

[573] Please also see the response to Required Amendment 41 for a discussion of "reasonable endeavours".

[574] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1529 to 1532.

[575] AusNet Services (SP AusNet), *access arrangement - Part C – 29 April 2013*, clause 13.4; Multinet *Access Arrangement Information: Part C – Terms and Conditions, April 2013*, clause 13.4.

[576] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1529 to 1532.

If ATCO considers that the protections afforded elsewhere in the document are inadequate, it should propose modifications to those provisions. Accordingly, the Authority requires that Clauses 18.1(a), (b), (c), (k), (l), (m), and (o) be deleted[577]*.*

1484. AGA submits it is entirely consistent with the NGO that such clear and comprehensive provisions as set out in clause 18.1(m) and (n) are included in the template haulage contract. The provisions in clauses 4, 5, 6, 7, 8 and 9 either largely or entirely relate to obligations arising under the Retail Market Scheme and as such are core to the efficient, safe and secure operation of the gas distribution network by users and other providing services the subject of a haulage contract, consistent with the NGO.

1485. AGA notes that clause 1(a)(iii)(E) obliges the User to be and remain a member of the Retail Market Scheme as a precondition, however a precondition does not operate in the same way as representation or warranty operates, since a precondition is either satisfied or waived before or at the time that the contract comes into force or effect, and there is therefore no separate remedy for a breach of then subject matter of a precondition once the contract is in force.

1486. Clause 18.1(m) relates to a specific requirement under the Retail Market Scheme to be a “user” as that term is defined in the REMCo Rules[578].

1487. AGA also refers to its comments on and proposed amendments to clause 3 set out in its response to required amendment 23 above.

1488. Based on the ERA’s comments above, AGA proposes the most effective alternative available is to amend clause 3(b) and insert an additional clause 3(c) so that the issues identified above can be dealt with and the NGO can be met, as follows:

3. **HAULAGE SERVICES PROVIDED**

(a) This Haulage Contract specifies the terms and conditions on which **<Service Provider>** agrees to provide **<User>** with access to the Haulage Services by means of the AGA GDS in accordance with the Regulatory Instruments, including the Access Laws and the Retail Market Rules.

(b) <User> is and will at all times:

(i) remain a member of and a "user" for the purposes of the Retail Market Scheme;

(ii) comply with the Retail Market Scheme; and

(iii) ensure that it remains able to, deliver Gas to the Receipt Point or Receipt Points on the relevant Sub-network or Sub-networks from which <User> is to receive Gas at one or more Delivery Points under this Haulage Contract, in volumes sufficient to meet <User>’s Gas receipt requirements at each Delivery Point.

(c) <User> shall procure that all third parties with the whom <User> has contracted to provide services the subject of this Haulage Contract at all times provide those services in accordance with the Regulatory Instruments, including the Access Laws and the Retail Market Rules.

1489. 18.1(o) - Title to Gas – AGA notes the ERA’s analysis of this clause[579] and in particular the ERA’s statement:

577 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1532.

578 REMCo, Retail Market Rules, Version 6.5, 8 November 2013, Rule 2: **“user”** means an entity that has a *haulage contract* for the transport of gas through a *sub-network* under these rules.

579 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1529 to 1532.

If ATCO considers that the protections afforded elsewhere in the document are inadequate, it should propose modifications to those provisions. Accordingly, the Authority requires that Clauses 18.1(a), (b), (c), (k), (l), (m), and (o) be deleted.

1490. AGA submits that it is entirely consistent with the NGO that clause 18.1(o) is included in the template haulage contract. The provisions in clause 7 relate to title to gas, and in addition to warranty in the Envestra regulated terms and conditions referred to by the ERA, both SP AusNet and Multinet [580] have terms relating to title to gas.

1491. Based on the ERA's comments above, AGA proposes the most effective alternative available is to amend clause 7.1(a) so that the issues identified above can be dealt with and the NGO can be met, as follows

(a) Title to Gas:

(i) <u>at all times caused to be injected into the AGA GDS must be provided by <User> ensuring that <User> has good title, free and clear of all liens, encumbrances and claims of a nature inconsistent with <Service Provider>'s operation of the AGA GDS;</u>

(ii) delivered into the AGA GDS at a Receipt Point passes to **<Service Provider>** at the Receipt Point;

(iii) delivered out of the AGA GDS to **<User>** at a Delivery Point passes to **<User>** at the Delivery Point, subject to any defect to which the title was subject when it passed to **<Service Provider>** under clause 7.1(a)(i); and

18.1(p) - right to supply gas to the GDS - Compliance - AGA notes the ERA's analysis of this clause, in particular the ERA's statement:

If ATCO considers that the protections afforded elsewhere in the document are inadequate, it should propose modifications to those provisions. Accordingly, the Authority requires that Clauses 18.1(a), (b), (c), (k), (l), (m), and (o) be deleted[581].

1492. AGA submits it is entirely consistent with the NGO that such clear and comprehensive provisions as set out in clause 18.1(p) are included in the template haulage contract. They relate to obligations arising under the Retail Market Scheme and as such are core to the efficient, safe and secure operation of the gas distribution network by users and other providing services the subject of a haulage contract.

1493. AGA notes clause 1(a)(iii)(D) obliges the user only to be able to deliver gas as a precondition, however a precondition does not operate in the same way as representation or warranty operates, since a precondition is either satisfied or waived before or at the time the contract comes into force or effect, and there is therefore no separate remedy for a breach of the subject matter of a precondition once the contract is in force. The representations and warranties are, pursuant to clause 18.3, made on and from commencement of the haulage contract and anew each day for the duration of the contract, so provide rights that are enforceable for the duration of the contract.

1494. As explained in AGA's response to required amendment 23, and the response to this required amendment 39 above in respect of clause 18.1(m), based on the ERA's comments above, AGA proposes the most effective alternative available is to amend AGA's proposed revised clause 3(b)[582] so that the issues identified above can be dealt with and the NGO can be met as follows:

(b) **<User>** is and will at all times:

[580] Envestra, Victorian Access Arrangement Annexure F General Terms and Conditions April 2013, clause 16.1; Multinet Access Arrangement Information: Part C – Terms and Conditions, April 2013, clause 4.8.

[581] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1532.

[582] See response to clause 18.1(m) and (n) above in this required amendment 39.

(i) remain a member of and a "user" for the purposes of the Retail Market Scheme;

(ii) comply with the Retail Market Scheme; and

(iii) ensure that it remains able to, deliver Gas to the Receipt Point or Receipt Points on the relevant Sub-network or Sub-networks from which <User> is to receive Gas at one or more Delivery Points under this Haulage Contract, in volumes sufficient to meet <User>'s Gas receipt requirements at each Delivery Point.

ERA required amendment 40

Heading 21 should be amended as follows:

21. ~~INTELLECTUAL PROPERTY,~~ CONFIDENTIALITY AND INFORMATION EXCHANGE

Clause 21.1 should be deleted.

AGA Response: do not accept

Summary Only – AGA does not accept this required amendment and proposes clarifying amendments to clause 21.1.

1495. AGA submits clause 21.1 is entirely consistent with the NGO and provides a succinct, balanced and comprehensive statement of the management and ownership of intellectual property rights under the template haulage contract.

1496. AGA notes that the ERA states:

> *intellectual property matters dealt with in clause 21.1are not appropriate to be included in the template haulage contract. In the Authority's judgement, the intellectual property that is likely to be created and how it should be allocated will depend on the circumstances. Therefore, the Authority considers it better to leave the parties to negotiate terms reflecting their individual concerns and priorities regarding intellectual property. The Authority refers to its earlier remarks about striking a balance between facilitating access quickly and avoiding unforeseen effects (see paragraphs 1315 to 1317).*

1497. AGA notes the ERA has characterised the template haulage contract as:

1498. "…effectively a regulated standing offer, which provides a basis on which users can negotiate a contract. This standing offer is necessarily subject to amendments approved by the Authority and the requirement to offer it does not survive the expiry of the access arrangement. The bilateral contract arises when the user either accepts the standing offer or a negotiated modified offer."[583]

1499. AGA takes the statements above to mean that:

a) the Service Provider submits a template haulage contract based on the document approved from the current Access Arrangement period, with proposed amendments, for approval by the ERA for the next access arrangement period; and

b) the template haulage contract is effectively a regulated standing offer that is capable of acceptance as it stands or acceptance following negotiated modifications.

1500. AGA agrees with this analysis.

[583] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1345.

1501. The ERA goes on to state:

> *A user may wish to acquire services exclusively on the terms currently defined in the access arrangement. The template haulage contract should be drafted with this notional user in mind, even though the service provider and the Authority may fully expect users to negotiate away from this starting position in their individual haulage contracts. The question for the Authority then must be which template haulage contract terms will achieve this result while placing the minimum constraint on the parties' ability to negotiate away from the access arrangement if they wish.*[584]

1502. AGA takes the statements above to mean that:

a) the template haulage contract must be drafted so that an individual haulage contract can be entered into by the parties based on an unamended template haulage contract or can be a negotiated and amended template haulage contract subsequently entered into by the parties; and

b) the degree to which amendments to the template haulage contract can be negotiated and agreed by the parties is limited only by the requirement that in so far as the haulage contract is for reference services, any amendments must be consistent with the terms currently defined in the access arrangement.

1503. AGA acknowledges the template haulage contract must therefore be in a form that is both capable of acceptance without amendment by a notional User, and minimises the constraint on the parties' ability to negotiate away from the access arrangement, for example by the inclusion of non-reference services.

1504. AGA submits that the ERA's decision to delete clause 21.1 is inconsistent with the ERA's position stated above.

1505. As set out in AGA's footnote to clause 21.1, which the ERA does not comment on, AGA submits that clause 21.1 represents a balanced position that protects each Party's existing intellectual property rights, while protecting the Service Provider's legitimate business interest in any intellectual property created under this haulage contract, under which it provides haulage services as part of its operation of the AGA Gas Distribution System.

1506. AGA acknowledges that currently, no other regulated gas distribution system operators in Australia have such a clause, however that in itself is not a reason to reject the changes suggested by AGA. AGA notes it is consistent with the NGO to remove areas of uncertainty in the template haulage contract, particularly if there exists a market or "standard" position.

1507. AGA submits that the inclusion of such a clause does not give rise to a risk of unintended consequences. Rather it is consistent both with the characterisation of the template haulage contract as a standing offer, and consistent with the NGO and the interests of all parties and consumers to provide certainty on commercial terms to facilitate quicker access. It places the minimum constraint on the parties' ability to negotiate away from the access arrangement if they wish.

1508. In the event that the haulage contract is terminated or expires, the intellectual property created in respect of the services provided under the haulage contract, in the absence of express terms in the contract, is only and can only be relevant to those services and that contract. As the licensed operator of the GDS and the provider of the regulated services, AGA retains the obligations and responsibilities relating to the services provided under the contract at all times.

1509. AGA has considered the ERA's analysis and taken into account the likely positions of the parties to a haulage contract in respect of the minimum intellectual property rights provisions required. In addition AGA has subsequently reviewed a further number of publicly available Australian government standard intellectual

[584] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System, 14 October 2014, paragraph 1346.

property clauses, including by way of example, sample clauses published by the Government of Victoria - Department of Treasury and Finance[585].

1510. AGA therefore does not accept the ERA's required deletion of clause 21.1 nor the required amendment to heading 21 and instead proposes the following amendment to clause 21.1, which takes into account the points covered above:

(a) Subject to clauses 21.1(b) and 21.1(c), all documents, tools, software, reports, diagrams, plans and other materials provided by or on behalf of a Party under this Haulage Contract, and all associated Intellectual Property Rights, remain the property of that Party, and nothing in this Haulage Contract assigns any Intellectual Property Rights to the other Party.

(b) All documents, tools, software, reports, diagrams, plans and other materials created under this Haulage Contract, and all associated Intellectual Property Rights, will be owned absolutely by ~~<Service Provider>~~ the Party creating the same immediately on creation.

(c) To the extent that a Party (**Recipient**) requires access to the other Party's (**Provider**) documents, tools, software, reports, diagrams, plans and other materials for the purposes of complying with the Recipient's obligations under the Access Arrangement and this Haulage Contract, the Provider grants the Recipient a non-exclusive, non-transferable and royalty free licence to use such documents, tools, software, reports, diagrams, plans and other materials for purposes solely related to complying with the Recipient's obligations under the Access Arrangement and this Haulage Contract.

ERA required amendment 41

Clause 4 of Schedule 4 and Schedule 5 of the proposed revised template haulage contract should be amended as follows:

(b) <Service Provider> must use ~~reasonable~~ best endeavours to read the Meter ~~approximately~~ at least every three months ~~4 times each Year at intervals of approximately 100 days~~.

(c) <Service Provider> must provide consumption data (estimated or actual) to the user at least every three months.

AGA Response: accept with modifications

Summary Only – AGA proposes alternative wording for clause 4(b). AGA does not accept the inclusion of clause 4(c). AGA proposes the removal of "best endeavours" and the use of "reasonable endeavours" consistently throughout the template haulage contract.

1511. AGA notes the ERA's analysis[586] of clause 4 of each of Schedules 4 and 5 of the template haulage contract.

1512. For the reasons set out below, AGA does not accept the required amendments, but proposes alternative amendments to address the points raised by the ERA.

1513. AGA also proposes consequential amendments to a number of clauses in the template haulage contract to comply with recent Australian case law[587] which AGA has had the opportunity to consider since the revised Access Arrangement submission was lodged in March 2014, relating to "reasonable" and "best" endeavours.

[585] Government of Victoria - Department of Treasury and Finance - Strategy and Policy, Government Services Group: Intellectual Property – non ICT - Version 2 - Release Date: June 2009.

[586] Draft Decision paragraphs 1552 to 1563.

1514. By way of clarification and explanation, AGA confirms that:

1. Rules 144 and 145 of the Retail Market Rules[588] require that AGA (as network operator) provide each user with an annual meter reading schedule reflecting the meter reading frequency agreed between AGA and the user, and that the schedule may be amended (subject to practicability) after consultation with the user; and
2. Rule 149 of the Retail Market Rules requires that AGA must undertake a meter reading that generates an actual value (based on actual meter reading data) at least once in any 12 month period.

1515. AGA as network operator and each retailer (as users) are bound as members of REMCo by the Retail Market Rules.

1516. AGA does not accept the ERA's required amendment is necessary to comply with the retailer's obligations under the Compendium[589].

1517. The current version of clause 4.1 of the Compendium is as follows:

1518. 4.1 Billing cycle*

1519. A retailer must issue a bill –

1520. (a) no more than once a month, unless the retailer has –

1521. (i) obtained a customer's verifiable consent to issue bills more frequently; or

1522. (ii) given the customer –

1523. A. a reminder notice in respect of 3 consecutive bills; and

1524. B. notice as contemplated under clause 4.2; and

1525. (b) at least every 3 months unless –

1526. (i) the retailer has obtained a customer's verifiable consent to issue bills less frequently;

1527. (ii) the customer has a pre-payment meter installed at the customer's supply address; or

1528. (iii) the retailer has not received the required metering data from the distributor for the purposes of preparing the bill, despite using best endeavours to obtain the metering data from the distributor.

1529. AGA notes that the proposed amended Compendium which comes into force from 1 January 2015, published by the ERA on 7 November 2014, includes the same clauses save for an additional clause 4.1(b)(iv)[590] which is not material for the purposes under consideration.

1530. AGA notes further that the previous version of clause 4.1 of the Compendium was as follows:

587 Electricity Generation Corporation T/As Verve Energy v Woodside Energy Ltd & Ors; Woodside Energy Ltd & Ors v Electricity Generation Corporation T/As Verve Energy [2014] HCA 7 (5 March 2014).

588 REMCo, *Retail Market Rules Version 6.5*, 8 November 2013.

589 Draft decision paragraphs 1553 to 1561.

590 See ERA website: http://www.erawa.com.au/cproot/12989/2/20141107%20Compendium%20of%20Gas%20Customer%20Licence%20Obligations%20(Clean)%20-%202014%20Review%20(as%20published%20on%20website).PDF

1531. 4.1 Billing cycle*

1532. A retailer must issue a bill –

1533. (a) no more than once a month, unless the retailer has –

1534. (i) obtained a customer's verifiable consent to issue bills more frequently; or

1535. (ii) given the customer –

1536. A. a reminder notice in respect of three consecutive bills; and

1537. B. notice as contemplated under clause 4.2; and

1538. (b) at least every three months unless the retailer has obtained a customer's consent to issue bills less frequently or the customer has a prepayment meter installed at the customer's supply address.

1539. AGA notes that:

a) the relevant clauses of the Compendium referred to by the ERA have been in place and were unamended from their inception in 2009, until the amendments in 2012 and 2013; and

b) the wording contained in clause 4 of Schedule 4 and 5 of the template haulage contract has been in place and unamended from the first Access Arrangement under the gas regulatory regime which commenced in 1999.

1540. AGA notes that clause 5 of Schedule 3 of the current trading licence for Alinta Sales states as follows:

1541. **5. Billing Cycle**

1542. 5.1 Despite clause 4.1(b) of *Schedule 2* of this *licence*, the *licensee* must issue a bill at least every 110 days unless the *licensee* has obtained a *customer's* consent to issue bills less frequently or the *customer* has a pre-payment meter installed at the *customer's* supply address.

1543. AGA notes that the trading licence issued by the ERA for the most recent retailer to become a user of services provided by AGA, Wesfarmers Kleenheat Gas[591], does not contain this clause.

1544. It is unclear to AGA why there should be any difference between the licence conditions of individual retailers as all meters within the GDS, regardless of the retailer supplying the premises served by the meter, are read by AGA and the data submitted to the relevant users (retailers) and REMCo based on a single meter reading schedule for each GDS, and not on separate meter reading schedules agreed with each user (retailer), which is a requirement under the Retail Market Rules[592].

1545. In any event, notwithstanding the requirements of the Retail Market Rules, to separately develop meter reading schedules for each retailer would lead to inefficient and costly additional meter readings being undertaken at various addresses and locations, rather than the current system of established meter reading routes which involve sequential readings of meters in each street or location.

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591 See ERA website: http://www.erawa.com.au/cproot/12Letter818/2/Gas%20Trading%20Licence%2010%20-%20Version%209%20-%201%20August%202014%20-%20GTL010%20-%20Wesfarmers%20Kleenheat%20Gas%20Pty%20Ltd.pdf

592 See rules 144 and 145 of the Retail Market Rules.

1546. AGA notes the ERA decision relating to the amendment contained in clause 5 of Schedule 3 of Alinta Sales' trading licence[593] included the following statement:

> *10. Alinta Energy's application follows the Authority's decision on 17 September 2013 to insert clause 4 in Schedule 3 of GTL9 to align the maximum billing interval prescribed in clause 4.1(b) of the Compendium with the metering frequency in the approved access arrangement for the distributor.*
>
> *11. The Authority agrees that it is appropriate to also align the record keeping and reporting requirement in GTL 9 with the 110 day maximum billing interval prescribed in clause 4.1(b) of Schedule 3 of the licence.*

1547. AGA notes the reference to the ERA's earlier decision on 17 September 2012[594] which includes the following statements:

> *5.The Authority notes that Alinta's 2011 Performance Audit disclosed that Alinta contravened Schedule 2, clause 4.1(b) by billing some customers at an interval greater than the three months. The Authority notes that the cause of the contravention relates to the timing of meter readings (approximately every 100 days) provided to Alinta by the gas distributor, WA Gas Networks Pty Ltd trading as ATCO Gas Australia (ATCO). The Authority further notes that the timing of the meter readings provided by ATCO is dictated by the approved access arrangement.*

1548. As explained above, the REMCo rules bind both the user (retailer) and service provider (network operator).

1549. The parts of the Compendium referred to by the ERA, being clauses 4.1(b), 4.6(1) and 4.8(1) bind the retailer (user), but do not bind the distributor (network operator).

1550. The ERA's required amendment would override the Retail Market Rules requirements under which both the retailer (user) and AGA are obliged to operate.

1551. AGA submits the inclusion of the clause required by the ERA adds to rather than aids the resolution of conflict between the Retail Market Rules and the licence conditions. It is also inconsistent with the NGO to introduce such a requirement as it does not aid efficiency of access or clarity or reduce cost for the long term benefit of consumers.

1552. The annual billing frequency is based on meeting the obligations that bind retailers under the Retail Market Rules and their licence conditions, and the obligations of AGA as service provider and network operator under its licence and the Retail Market Rules.

1553. The annual billing frequency is based on the most efficient and lowest cost means of meeting the obligations set out above.

1554. In the absence of any submissions from existing retailers (users) in respect of this required amendment, AGA refers to the fact that the wording proposed by AGA reflects the practice in place with retailers (users) the GDS which is for a read frequency at intervals of between 88 and 105 days.

1555. AGA points out that notwithstanding the actual meter readings undertaken by AGA, the Retail Market Rules provide for the use of estimated readings and for retailers to request "special" meter readings.

1556. To comply with the required amendment of at least 3 months would require the shortening of the read cycle across all MIRNS to a frequency of 89-92 days. This would require changes to AGA's billing systems and

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593 "Decision on amendment of Alinta Sales Pty Ltd's Gas trading Licence No.9 (GTL9)" , 23 April, 2013 - see ERA website: http://www.erawa.com.au/cproot/11313/2/Decision%20on%20amendment%20of%20Alinta%20Sales%20Pty%20Ltd%E2%80%99s%20Gas%20Trading%20Licence%20No.%209%20(GTL9).pdf

594 The decision referred to is dated 17 September 2012 - "Decision on amendment of Gas trading Licence No.9 (GTL9)" , 17 September 2012.

meter reading interfaces together with increased costs in meter reading as more meter readers would be required to read the same volume of meters within a shorter period. The current meter reading intervals achieve efficiency by ensuring there is an even distribution of meter reads of around 10,000-12,000 conducted each business day. If the read cycle is reduced, this efficiency would be loss resulting in higher meter reading costs from more frequent readings being undertaken by meter readers.

1557. AGA also does not agree with the ERA's statement at paragraph 1558:

> *The Authority understands that for customers on the B2 and B3 reference services, ATCO generally supplies retailers with consumption data every 90 days. In a large number of instances, the data reflects estimated rather than actual meter readings. The fact that ATCO has been supplying data typically at a 90 day frequency, suggests that it probably plans its reading schedule to deliver reads "approximately four times each year" rather than "at intervals of approximately 100 days".*

1558. The basis of the ERA's understanding is not stated, and the assertion that "in a large number of instances, the data reflects estimated rather than actual meter readings" is false.

1559. Consumption data is not provided to retailers every 90 days, rather 10,000-12,000 meter readings are provided each business day, each with 90 days of consumption data on average. As explained above, meters are read at frequency intervals of between 88 and 105 days. Of this amount, less than 1% are estimated.

1560. AGA proposes for the reasons set out above, not to accept the ERA's required amendment, but acknowledges that the current wording of clause 4 of Schedule 4 and Schedule 5, which has been in place for over 15 years, should be and remain reflective of actual practice.

1561. AGA therefore proposes that clause 4 in each of Schedules 4 and 5 of the template haulage contract should be amended as follows:

1562. (b) <Service Provider> must use reasonable endeavours to read the meter at intervals of ~~approximately 100~~ no less than 88 days and no more than 105 days.

1563. The required amendment that consumption data is provided to the user at least every three months is otiose, as the Retail Market Rules[595] oblige AGA as network operator to provide metering data to current users (retailers) and REMCo, and the proposed amendment to clause 4(b) establishes a firm interval frequency range.

1564. Finally, AGA wishes to address the issue of the use of "reasonable" and "best" endeavours terminology within the template haulage contract.

1565. The current position under Australian case law is that there is no substantive difference between the terms 'best endeavours', 'reasonable endeavours' and 'all reasonable endeavours'.

1566. The leading case dealing with the term "best endeavours" is the High Court Hospital Products case[596]. In that case, the High Court stated that the term "does not require the person who undertakes the obligation to go beyond the bounds of reason" as "he is required to do all he reasonably can in the circumstances to achieve the contractual object but no more."

1567. In an earlier case, Transfield[597] , the High Court also stated that the obligation "prescribed a standard of endeavour which is measured by what is reasonable in the circumstances, having regard to the nature, capacity, qualifications and responsibilities of the licensee viewed in the light of the particular contract", and there was no basis for importing a negative implication into a positive obligation.

595 See Part 4.4 of the Retail Market Rules.

596 Hospital Products Ltd v United States Surgical Corp (1984) 156 CLR 41.

597 Transfield Pty Ltd v Arlo International Ltd (1980) 144 CLR 83.

1568. The High Court decisions have been applied in State Supreme Court decisions which have dealt with the term “all reasonable endeavours”, and have confirmed that there does not appear to be any substantive difference between the meaning of “reasonable endeavours” and “best endeavours”.

1569. In the Centennial Coal case[598], the NSW Court of Appeal found that the “all reasonable endeavours” term was equivalent in effect to a “best endeavours” term. The Court held that such a term suggested an objective standard requiring the party with the obligation to do what can reasonably be done in the circumstances to achieve the object of the contract; not to hinder or prevent achievement of the object of the contract; to continue to endeavour until it reasonably judges in the circumstances that further efforts would have such remote prospects of success that they are likely to be wasted; and to allow for events, including extraordinary events, as they unfold.

1570. In the most recent case of Verve[599], the High Court made some further statements about obligations to use “reasonable endeavours”, and confirmed that the obligations are absolute or unconditional, but are to be considered by what is reasonable in the circumstances. The Court also stated that contracts containing those obligations may contain their own internal standard of what is reasonable.

1571. AGA has reviewed the template haulage contract and the Access Arrangement in the light of the Verve decision, and notes that the terms “best endeavours” and “reasonable endeavours” are both used.

1572. It is also the case that the NGR contains references to both “best endeavours” and “reasonable endeavours”.

1573. AGA submits for consistency with the NGO, the template haulage contract terms should be stated clearly and consistently to minimise potential for dispute and to reflect the allocation of risk between the parties, and as contractual terms, should be drafted to be consistent with the body of law applying to contracts in Australia.

1574. AGA submits to comply with current Australian contract law and to satisfy the NGO, one term should be used throughout the document and the term clearly specified in the contract, and for consistency, the term “reasonable endeavours” should be used.

1575. AGA has considered whether a “reasonable endeavours” defined term should be included in the Dictionary, however AGA submits there is sufficient guidance from case law and industry practice that is available.

1576. AGA submits “*reasonable endeavours*” for both parties should reflect, for example, “good gas industry practice” as that term is defined in rule 364 of the NGR and the standards that apply to a “reasonable and prudent person” as that term is defined in rule 2 of the Retail Market Rules, and take into account all relevant commercial, economic and operational matters.

598 Centennial Coal Company Ltd v Xstrata Coal Pty Ltd (2009) 76 NSWLR 129.

599 Electricity Generation Corporation T/As Verve Energy v Woodside Energy Ltd & Ors; Woodside Energy Ltd & Ors v Electricity Generation Corporation T/As Verve Energy [2014] HCA 7 (5 March 2014).

ERA required amendment 42

Clause 21.1 of the current version of the template haulage contract should be retained in the revised template haulage contract.

Clause 12.1 of the current access arrangement should retained in the revised access arrangement.

Both clauses should be revised, as necessary, to ensure that any shared terms are defined identically in both dictionaries.

AGA Response: accept with modifications

Summary Only – AGA accepts the required amendments with modifications.

1577. AGA accepts the required amendments, save that a common Dictionary is included for the access arrangement and template haulage contract. The access arrangement and template haulage contract document has been updated to reflect this.

ERA required amendment 43

Footnote 46 should be amended as follows:

ATCO Gas Australia operates a Guaranteed Service Level scheme which provides for compensation to Small Use Customers (as defined in s 3 of the Energy Coordination Act 1994 (WA)) who have been inconvenienced by disruption to their gas supply. ~~The specific requirements of this scheme are set out in the Authority's Gas Compliance Reporting Manual and are a condition of ATCO Gas Australia's Gas Distribution Licence (Clause 16 – Individual Performance Standards)) and a requirement of s 11M of the Energy Coordination Act 1994 (WA).~~

AGA Response: accept with modifications

Summary Only – AGA accepts the proposed amendment and proposes a further amendment by deleting the entirety of clause 10.6.

1578. AGA notes that subsequent to the date that AGA lodged its access arrangement revision submission in March 2014, the ERA advised[600] it did not require reporting of any Guaranteed Service Level payments.

1579. As AGA is not required to have in place a Guaranteed Service Level scheme nor report on any aspect of such a scheme, AGA shall withdraw the scheme for the next access arrangement period and therefore remove any reference to such a scheme from the template haulage contract.

1580. Performance levels for specific services are mandated in reporting requirements under the ERA's Gas Compliance Reporting Manual and are a condition of AGA's Gas Distribution Licence and S.11M of the *Energy Coordination Act 1994* (WA).

1581. AGA therefore proposes to delete clause 10.6 in its entirety.

1582. As a consequence, clause 10.1(a)(i)(D) also requires deletion. The changes have been included in the draft template haulage contract.

[600] By email dated 1 August 2014 from the ERA to AGA.

ERA required amendment 44

The term "pipeline service" should be replaced with the term "reference service" throughout the template haulage contract, except in the case of any specific provisions for which this would have unintended consequences.

The term "haulage service" should be replaced with the term "reference service" wherever it is intended for the provision to also apply to ancillary services.

The template haulage contract should be renamed "template service agreement" and any references to "template haulage contract" in other access arrangement documents should be amended as appropriate.

References to "haulage contracts" should be replaced with the phrase "service agreements" and any references to "haulage contracts" in other access arrangement documents should be amended as appropriate.

AGA Response: accept

Summary Only – AGA accepts this required amendment.

1583. AGA accepts the required amendment and has updated the template service agreement document to reflect this.

ERA required amendment 45

The revised wordings set out in Required Amendment 24 to Required Amendment 43 are to be read as if the substitutions described in Required Amendment 44 had been made.

AGA Response: accept

Summary Only – AGA accepts this required amendment.

1584. AGA accepts the required amendment and has updated the template service agreement document to reflect this.