Appendix 5.04: Operating expenditure step changes

Access Arrangement Information for the 2016-21 ACT, Queanbeyan and Palerang Access Arrangement

Submission to the Australian Energy Regulator

June 2015

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Overview

ActewAGL Distribution has applied a ‘base, step, trend’ approach to forecast its operating expenditure (opex) requirements for the 2016-21 regulatory period. The base year used as the starting point for ActewAGL Distribution’s opex forecast is 2014/15.

The ‘base’ and ‘trend’ components of the forecast are detailed in appendix 5.01 of this access arrangement information. This appendix details the opex step changes required during the 2016-21 access arrangement period. These include recurrent, non-recurrent and periodic opex step changes. A summary of the proposed step changes is set out in Table 1.1.

Table 1.1 2016-21 step change proposal summary ($million, 2015/16)

Proposed step change	Total	Key driver(s)	Recurrent / non-recurrent
Management services step changes			
National Energy Customer Framework	0.77	Change in regulatory obligation	Includes non-recurrent and recurrent costs
National B2B harmonisation	1.06	Change in regulatory obligation	Recurrent
IT asset utilisation fee	4.18	In lieu of capex	Non-recurrent
Network risk and security management	0.54	Periodic/ Good industry practice	Recurrent/ periodic
Asset services step changes			
Hoskinstown operations and maintenance (O&M) contract	[redacted]	Good industry practice	Recurrent
Periodic Inspections	0.31	Periodic/Good industry practice	Recurrent (periodic)
New capex driven opex	0.63	Capex driven	Recurrent (periodic)
Revised metering technical codes compliance and service delivery strategy	(0.45)	Change in regulatory obligation	Recurrent
ActewAGL Distribution /JAM step changes			
RIN reporting	1.63	Expected change in regulatory obligation	Recurrent
2021 access arrangement review	3.23	Periodic regulatory obligation	Non-recurrent (periodic)
ActewAGL Distribution step change			
Change in capitalisation policy	(6.58)	Change in policy	Recurrent
Total	**5.57**		

The management services and asset services step changes listed above will be implemented by Jemena Asset Management (JAM) under the Distribution Asset Management Services (DAMS) Agreement with ActewAGL Distribution. The Regulatory Information Notice (RIN) reporting and 2021 access arrangement revision step changes will cover activities undertaken together by ActewAGL Distribution and JAM, and the change in capitalisation policy step change will effect changes to ActewAGL Distribution's cost allocation method.

Step change assessment framework

In preparation for the 2016-21 access arrangement, ActewAGL Distribution and JAM identified opex activities that will need to be undertaken during the 2016-21 access arrangement period but are not fully captured (or captured at all) in base year (2014/15) opex or in the rate of change component of the opex forecast. In other cases, the step changes identified are to account for changes in allocation of costs or service provision. These costs have been assessed against the requirements of Rule 91(1) of the National Gas Rules (the Rules):

> (1) 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.
>
> (2) The [Australian Energy Regulator] AER's discretion under this rule is limited.

ActewAGL Distribution has included opex related to these activities as 'step changes' in its opex forecast for the 2016-21 access arrangement period. ActewAGL Distribution considers that each proposed step change reflects expenditure required by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services. The forecasts of costs for these step changes have been arrived at on a reasonable basis and represent the best forecast in ActewAGL Distribution's circumstances.

ActewAGL Distribution notes that this report addresses the information requirements of sections 7.7 and 7.8 of schedule 1 to RIN requests additional information relevant to proposed step changes. This information is provided in ActewAGL Distribution's response to the access arrangement RIN.

1 National Energy Customer Framework

1.1 Driver

The driver of this step change is a significant change in ActewAGL Distribution's regulatory obligations relating to the implementation of the National Energy Customer Framework (NECF). The costs are not captured in base year costs because the new obligations commence with the new access arrangement period, and are not in the nature of trend escalation for scale or scope.

ActewAGL Distribution is required to comply with full NECF requirements under the National Energy Retail Rules (NERR) by 1 July 2016. It is required to comply with the connection requirements Part 12A of the Rules by 1 July 2015.

1.2 Impacted opex activities

There are two activities impacted by this driver: (1) customer support and billing, and (2) customer connections.

1.2.1 Customer support and billing

Under full NECF, customers can seek a range of gas services directly from ActewAGL Distribution (through JAM), which are currently performed by, or administered through, gas retailers. Jemena will need to expand its service delivery capabilities and capacity to manage increased enquiries, transactions and complaints as customers move their service expectations from retailers to ActewAGL Distribution (through JAM) for certain services. In order to meet full NECF compliance obligations, ActewAGL Distribution, through JAM, will need to:

- maintain and provide access to customer data;
- determine, track and notify customer classification and occupancy status and ensure compliance with privacy and related laws;
- maintain systems to notify retailers and customers of planned and unplanned gas supply interruptions, de-energisations and disconnection of premises;
- implement a billing and debt collection system to recover new connections and alterations charges; and
- manage network revenue recovery consistent with National Energy Retail Law (NERL)/NERR entitlement of the retailers to recover distributor charges from the customer and administer retailer credit support requirements

ActewAGL Distribution through JAM will progressively introduce full NECF capable operating processes in parallel with their introduction on the Jemena Gas Networks (JGN) in NSW, which shares the OneSAP operating solution platform. Full NECF capability will be achieved on ACT gas network processes in advance of the introduction date of 1 July 2016.

ActewAGL Distribution through Jemena proposes to implement the minimum required system changes to comply with full NECF, in light of the prudent decision to replace the Customer Management Framework on the GASS+ information technology (IT) system by March 2016. This replacement will incorporate the functionality required to comply with full NECF.

1.2.2 Customer connections

The costs of processing basic and standard connection applications have been recovered by ActewAGL Distribution's 'Connect Direct' service through an administrative fee, which has been payable by the connection applicant.

The way in which these costs are recovered will need to change in the 2016-21 access arrangement period, because ActewAGL Distribution will be subject to a range of new obligations under the Connection for Retail Customers provisions in Part 12A of the Rules from 1 July 2015. In short, these provisions are expected to:

- prevent Connect Direct from recovering the costs of processing basic and standard connection applications from applicants; and
- trigger both an increase in the number of basic and standard connection applications coming directly to Connect Direct (rather than via retailers) and a change in the type of customer (e.g. more households) to whom the service must be provided because:
    - standing offers for basic and standard connections must be made available to all retail customers; and
    - retailers may encourage customers to come directly to ActewAGL Distribution (rather than acting as an intermediary) if there is no administrative fee.

To accommodate these changes the following will need to occur:

- an alternative mechanism for recovering the costs of processing basic and standard connection applications will be required; and
- JAM will require additional resources to deal with the expected increase in applications and different types of customers.

1.3 Prudence assessment

1.3.1 Customer support and billing

ActewAGL Distribution has considered the following options:

Option 1: Do nothing. This option would result in non-compliance with full NECF obligations until delivery of replacement of the GASS+ Customer Management Framework.

This option has high regulatory and reputational risk with full NECF customer service expectations not deliverable.

Option 2: Accept JAM's approach of carrying out targeted minimal changes to GASS+ and support full NECF through manual operational processes.

This option is considered a prudent, efficient and effective means for ActewAGL Distribution to meet full NECF compliance obligations, with delivery of GASS+ replacement Customer Management Framework by March 2016. Risk-managed transition to the Customer Management Framework would see resources phased out of the business in June 2016.

Option 2 is therefore the preferred option.

1.3.2 Part 12A connections

ActewAGL Distribution with advice from JAM has considered the following options:

Option 1: Do nothing. This option would result in non-compliance with full NECF obligations, which has high regulatory and reputational risk with full NECF customer service expectations not deliverable. It also would prevent ActewAGL Distribution from recovering costs of processing basic and standard connections

Option 2: Efficiently increase operational resourcing to provide the new services of the access arrangement period.

Option 2 is considered the only viable option to address the need.

1.4 Opex step change forecast

Forecast opex required to meet full NECF requirements has been based on a portion of JGN's forecast for these activities provided through JAM, which was considered reasonable by the AER in its final decision for JGN's 2015-20 access arrangement.[1] JAM estimates that services provided for ActewAGL Distribution are equivalent to 10 per cent of those for JGN. This has been based on the ratio of customer numbers. Details of JGN's activities and forecast costs, which form the basis of ActewAGL Distribution's estimate, are provided in Appendix A of this document.

Table 3.3 sets out the NECF step change forecast for ActewAGL Distribution calculated as 10 per cent of JGN's costs.

Table 3.1 NECF step change forecast summary ($millions, 2015/16)

	2016/17	2017/18	2018/19	2019/20	2020/21	Total
Customer support & billing	0.14	0.03	0.03	0.03	0.03	**0.27**
Connections under Part 12A	0.09	0.09	0.09	0.09	0.09	**0.47**
Total step change exc. cost escalation	**0.24**	**0.13**	**0.13**	**0.13**	**0.13**	**0.74**
Total step change inc. cost escalation	**0.24**	**0.13**	**0.13**	**0.13**	**0.14**	**0.77**

[1] AER 2015, *Final decision: Jemena Gas Networks 2015–20, Attachment 7 – Operating expenditure*, June, p. 7-23

2 National B2B harmonisation

2.1 Driver

The driver of this step change is the requirement to meet ActewAGL Distribution's obligations for Business to Business (B2B) transactions with energy retailers. The Australian Energy Market Operator (AEMO) has approved the approach being taken by JAM for both JGN and ActewAGL Distribution. This approach will apply the same service obligations and participant transactions that apply in Victoria and to manage these transactions through the AEMO Hub rather than via JAM's GASS+ system. Harmonisation generates future operating cost savings by enabling JAM to implement a consistent market solution across its network assets and ActewAGL Distribution network assets.

The B2B harmonisation will adopt the Victorian market design, modified to support hot water metering obligations. Back office processes will need to be updated in 2016 during 'reasonable endeavours' period. While the B2B harmonisation project will come under the umbrella of the OneSAP project its costs are additional to the One SAP project estimate.

2.2 Impacted opex activities

There are three phases to B2B harmonisation. The first two phases leads to obtaining AEMO endorsement for the harmonisation solution. The third phase is the implementation of the solution.

Services that are covered by the harmonisation are:

- Meters data reading
- Service order completion
- Service order notification

Elements of the harmonisation will be:

- Market design
- Service obligations
- Process simplification
- NECF interactions

2.3 Prudence assessment

The following options have been considered:

Option 1: Do nothing. This option would result in an inability to provide B2B transactions that are consistent with the accepted market approach and a potential lack of compliance with market obligations.

Option 2: Adopt JAM proposed solution (proposed). This option enables market consistent B2B transactions with retailers and can be expected to result in future cost savings.

2.4 Opex step change forecast

Forecast opex required to achieve B2B harmonisation has been based on a portion of JGN's forecast for these activities provided through JAM, which was considered reasonable by the AER in its final decision for JGN's 2015-20 access arrangement.[2] JAM estimates that services provided for ActewAGL Distribution are equivalent to 10 per cent of those for JGN. This has been based on the ratio of customer numbers. Details of JGN's activities and forecast costs, which form the basis of ActewAGL Distribution's estimate, are provided in Appendix B of this document.

Table 4.1 sets out a summary of the B2B harmonisation step change forecast for JGN and ActewAGL Distribution's forecast based on 10 per cent of these, with additional minor costs ActewAGL Distribution will incur. Table 4.2 provides the total step change included in ActewAGL Distribution's opex forecast, including cost escalation in 2015/16 dollars.

Table 4.1 Summary of B2B harmonisation costs ($millions, $2014/15)

	2016/17	2017/18	2018/19	2019/20	2020/21
JGN forecast					
Meter data provision	1.08	0.97	0.97	0.97	0.97
Service order completion	0.28	0.28	0.28	0.28	0.28
Miscellaneous service order charges	0.45	0.45	0.45	0.45	0.45
Total opex for JGN	***1.81***	***1.73***	***1.73***	***1.73***	***1.73***
ActewAGL Distribution equivalent opex (10% of JGN costs)	**0.18**	**0.17**	**0.17**	**0.17**	**0.17**
ActewAGL Distribution additional costs*	0.01	0.02	0.02	0.02	0.02
Total ActewAGL Distribution forecast	**0.19**	**0.19**	**0.19**	**0.19**	**0.19**

**Note: Dis-synergy in gas meter reading costs associated with breaking ActewAGL multi-utility meter reading contract.*

Table 4.2 B2B harmonisation opex step change forecast summary ($million, 2015/16)

	2016/17	2017/18	2018/19	2019/20	2020/21	Total
National B2B Harmonisation	0.20	0.21	0.21	0.22	0.22	**1.06**

[2] AER 2015, *Final decision: Jemena Gas Networks 2015–20, Attachment 7 – Operating expenditure*, June, pp. 7-26 – 7-28

3 IT asset utilisation fee

3.1 Driver

Under the Distribution Asset Management Services (DAMS) Agreement between JAM and ActewAGL Distribution, JAM provides customer management, works management and a range of related services using the IT system, GASS+.

GASS+ has been used by JAM to support the functions of running gas networks and billing customers. GASS+ acts as a point of coordination for employees, contractors and retail users. The GASS+ system is at the end of its life, having commenced operation in 1992.

Deloitte conducted an independent 'Stay on GASS+' review during July 2013 as an input into the JGN's solution replacement justification. The Deloitte review assessed the viability of remaining on the GASS+ system.

The Deloitte review identified 76 key risks across five categories (business and operational, technology, support, regulatory and control), and provided recommended mitigating options, including tactical remediation of GASS+, or modernisation of components. The review found that GASS+, left unmitigated, has an overall risk profile that will increase from a 'significant' to 'extreme' business and customer impact with a high likelihood of occurring by 2018.

In response to the 'Stay on GASS+' review Jemena has initiated an IT system project to replace GASS+ with OneSAP. This will mitigate the risk associated with remaining on GASS+ and improve Jemena's system capability to meet future process requirements and integration with the market in a predominantly SAP landscape.

The solution replacement project is named 'Jemena Gas Networks Solution Replacement Project.' The ActewAGL Distribution GASS+ replacement solution is a subset of this project.

The new OneSAP solution is designed to enable future delivery of business as usual (BAU) services to ActewAGL Distribution that meet ActewAGL Distribution business requirements and regulatory specifications. The initial scope of the solution replacement project includes three IT system projects that enable the future delivery of business as usual (BAU) and new services (including NECF and B2B harmonisation) to ActewAGL Distribution.

The forecast for ActewAGL Distribution's portion of GASS+ replacement costs is $2.74 million, as detailed in Table 5.1 below. The ActewAGL Distribution allocation of system solution costs for meeting full NECF and national B2B harmonisation obligations are $0.15 million and $0.53 million respectively.

JGN included the OneSAP replacement of GASS+ for approval as part the IT capex requirement in its 2015-20 access arrangement proposal. The AER accepted JGN's proposed IT capex in its final decision.[3] The allocated ActewAGL Distribution costs for GASS+ were not part of JGN's proposed capex for the 2015-20 access arrangement period, but have been based on a percentage of these costs.

3.2 Impacted opex activities

ActewAGL Distribution's core processes supported by GASS+ include:

- works and asset management (including supply chain management);
- customer and market management;
- meter reading management;
- revenue management; and
- network management.

1. The initial scope of the solution replacement project includes three IT system projects that enable future delivery of BAU and new services to ActewAGL Distribution:

- replacement of Jemena GASS+ (due to end-of-life)
- full NECF compliance capability; and
- National Energy Market harmonisation for B2B
- all three projects rely on a new SAP platform - Jemena (OneSAP).

2. The SAP system design incorporated functionality to meet ActewAGL Distribution business requirements and regulatory specifications. There are 201 impacted process, configuration, development and conversion deliverables, plus user training, which are required for ActewAGL Distribution. These include the following:

- conversion of fixed asset master data;
- conversion of bank master data and bank open items;
- conversion of asset under construction;
- conversion of ActewAGL cost and profit centres (i.e. general ledger balances that apply to ActewAGL Distribution);
- context-based training communications that are different for ActewAGL Distribution compared to JGN;
- SAP licenses;

[3] AER 2015, *Final decision: Jemena Gas Networks 2015–20, Attachment 6 –Capital expenditure*, June, p. 6-39

- incremental hardware costs; and
- delivery of training for ZNX(2) (Hume) who work specifically for ActewAGL Distribution in providing asset services and capital works

The budgeted capital cost of the base solution for ActewAGL Distribution (ACT and Nowra gas networks) is $2.6 million ($2014/15).

An IT asset utilisation fee (ITAUF) charged annually over the term of 2016-21 access arrangement is the preferred mechanism for recovering ActewAGL Distribution's share of IT system design, development and implementation costs of Jemena's capitalised IT system assets. The ITAUF will recover IT costs over a five year period (which corresponds to the AER's regulatory life of IT assets). The derivation of the ITAUF and an estimated cost over the 2016-21 access arrangement period is provided below.

3.3 Prudence assessment

Failure to deliver GASS+ replacement would make it impossible to deliver the BAU operations of the ACT gas network.

GASS+ is at end-of-life. The GASS+ replacement project will allow BAU processes to operate on a new platform capable of meeting the ongoing needs of the ACT gas network.

3.4 Opex step change forecast

GASS+ replacement project

The GASS+ replacement solution project approved budget is $61.5 million, covering capex and opex expenditure for JGN and ActewAGL Distribution networks.

Apportionment of GASS+ replacement costs to ActewAGL Gas Network

The ActewAGL Distribution budget (covering ACT gas network and Nowra gas network is $2.74 million, derived as follows, based on estimated activity or apportionment of costs on the basis of service points. (ActewAGL Distribution gas network has 10.14 per cent of the total service points for the JGN and ActewAGL Distribution gas networks.):

Table 5.1 Capital cost of OneSAP changes for ActewAGL Distribution ($millions, 2014/15)

Component	Cost	Basis of allocation
Jemena capex (Base solution cost)		
Labour costs	2.10	Estimated based on effort estimated to deliver the solution for ActewAGL Distribution: • conversion of fixed asset master data • conversion of bank master data and bank open items • conversion of asset under construction • conversion of ActewAGL Distribution cost and profit centres (i.e. general ledger balances that apply to ActewAGL Distribution) • changes to Network Invoice Summary • sending change requests to the market • standing data queries

Component	Cost	Basis of allocation
SAP licence incremental	0.40	Apportioned based on ActewAGL Distribution having 10.14% service points
Incremental hardware costs	0.10	Apportioned based on ActewAGL Distribution having 10.14% service points
Subtotal capex	**2.60**	
Training costs	0.01	Based on 10.14% of total ZNX(2) training to be delivered. An allocation was made for some context based training communications that are different for ActewAGL Distribution compared to JGN
Opex – data cleansing	0.13	Apportioned based on ActewAGL Distribution having 10.14% service points
Total costs	**2.74**	

National B2B harmonisation

The breakdown of incremental IT capex required to achieve B2B harmonisation and ActewAGL Distribution's allocation of costs to be expensed as part of the ITAUF, based on 10.14 per cent. This excludes costs relating to the Nowra gas network.

Table 5.2 IT incremental capex forecast - National B2B Harmonisation ($millions, 2014/15)

SAP configuration	1.84
Integration development	0.70
Data conversion	0.14
Project infrastructure delivery	0.40
Business process training	0.95
Acceptance testing	1.16
Business intelligence	0.29
Release management	0.88
Total	**5.20**
ActewAGL Distribution forecast based on 10.14%	**0.53**

Apportionment of full NECF solution costs to ActewAGL Distribution

The estimated solution costs for the full NECF solution for ActewAGL Distribution's gas networks is $0.30 million. This excludes costs relating to the Nowra gas network.

Derivation of ITAUF

The ITAUF will be used to recover IT asset capital value for the GASS+ replacement system (OneSAP), B2B harmonisation project and full NECF establishment costs over a five year period. In determining the proportion of the total ActewAGL Distribution GASS+ replacement cost that is to be allocated to the ACT gas network, it was determined that the ACT region network contains 97.5 per cent of service points of the combined ACT region and Nowra gas networks. This percentage has been applied to ActewAGL Distribution's budgeted capex of $2.6 million to determine that the allocated capital cost of replacing GASS+ for the ACT gas network is $2.54 million.

The proposed ITAUF formula is:

ITAUF = $\frac{\boldsymbol{TC}}{\boldsymbol{RL}} + (\boldsymbol{DB} * \boldsymbol{ICC})$

Where:

TC = Total cost of IT systems. For ActewAGL Distribution's ACT network this includes the following:

- GASS+ replacement project = $2.54 million
- National B2B harmonisation = $0.53 million
- Full NECF = $0.30 million
- Total cost of IT systems = $3.36 million

RL = Regulatory life of asset (5 years for IT assets)

DB = Declining balance of the asset value

ICC = Internal cost of capital [redacted]

Table 5.3 shows the annual ITAUF for ActewAGL Distribution's network for each year of the 2016-21 access arrangement period.

Table 5.3 Calculation of ITAUF ($million, 2014/15)

	2016/17	2017/18	2018/19	2019/20	2020/21	Total
Declining balance	3.36	2.69	2.02	1.34	0.67	
Amortization over 5 years	0.67	0.67	0.67	0.67	0.67	3.36
Calculated interest	0.24	0.19	0.14	0.10	0.05	0.72
Total ITAUF	**0.91**	**0.86**	**0.82**	**0.77**	**0.72**	**4.08**
Per month	*0.08*	*0.07*	*0.07*	*0.06*	*0.06*	

Table 5.4 provides the total step change included in ActewAGL Distribution's opex forecast, including cost escalation.

Table 5.4 ITAUF opex step change summary ($million, 2015/16)

	2016/17	2017/18	2018/19	2019/20	2020/21	Total
ITUAF step change	0.93	0.89	0.84	0.79	0.74	**4.18**

4 Network risk and security management

Through Jemena ActewAGL Distribution manages the risks of natural gas distribution through its network and security of its gas network assets in accordance with the requirements of Australian Standard (AS) 2885. This involves the application of AS 2885 to undertake safety management studies of its high pressure networks and regular assessment of the security of its assets.

4.1 AS 2885 Safety management studies

4.1.1 Driver

The AS2885 suite of Australian Standards has been adopted through legislative instruments by all Australian jurisdictions under a Council of Australian Government agreement. The suite of Standards, in particular AS2885.0, AS2885.1 and AS2885.3 require pipeline owners to undertake periodic safety management studies (in effect risk assessments) of their assets to ensure the continuing safe and reliable operation of those assets. With respect to access ActewAGL Distribution, the asset affected are the Licenced pipeline (L29), the extension of this pipeline from the ACT border to Fyshwick, the primary pipeline system (Watson to Gungahlin, Watson to Phillip/Hume) and the associated facilities (PRSs and TRSs) that are directly connected to the pipelines.

This step change reflects the periodic nature of the requirement. No safety management studies were planned or required during the base year 2014/15.

4.1.2 Impacted opex activities

The scope of works includes:

1. 2016/17: safety management study for primary mains as described above
2. 2017/18: safety management studies for three of the six high pressure facilities
3. 2019/20: safety management studies for three of the six high pressure facilities
4. 2020/21: safety management studies for licence 29 and extension to Fyshwick

4.1.3 Prudence assessment

Not doing the project will result in:

- As a minimum: a non-compliance with ActewAGL Distribution's regulatory obligations in both NSW and ACT. Both jurisdictions regulations (NSW Pipelines Act and regulations and the *Utilities (Technical Regulation) Act* (ACT) require compliance with the AS 2885 suite of standards.
- In the worst case there is potential for a failure of one or more parts of the infrastructure, leading to a range of consequences with the worst being a major gas explosion.

4.1.4 Opex step change forecast

Total costs for these activities and included as a step change in ActewAGL Distribution's opex forecast are set out below.

Safety management studies for Canberra Primary and Hoskinstown- Fyshwick Trunk Mains:

Engineer planning the SMS: = 100 days

Validation workshop: 15 FTE x 2 days = 30 days

Validation pre-work: 15 FTE x 2 days = 30 days

Total time: 160 days

Labour cost: [redacted] [redacted]

Expenses (facilitator, travel, etc.): [redacted]

Total cost ($2014/15): = $150,000

Safety management studies for stations:

Engineer planning the SMS: = 60 days

Validation workshop: 15 FTE x 2 days = 10 days

Validation pre-work: 15 FTE x 2 days = 20 days

Total time: 160 days

Labour cost: [redacted] [redacted]

Expenses (facilitator, travel, etc.): [redacted]

Total cost($2014/15): = $82,000

Table 6.1 Summary of AS 2885 safety management study cost summary ($million, 2014/15)

	2016/17	2017/18	2018/19	2019/20	2020/21	Total
AS 2885 SMS	0.15	0.08	-	0.08	0.15	**0.46**

4.2 Physical security review

4.2.1 Driver

The security review is designed to provide an overview of the current physical state of all sites against the new national security threat level and identify any shortcomings and possible improvements to physical asset security that could be undertaken to upgrade and align the sites to industry best practices in light of their criticality. It is undertaken every five years.

4.2.2 Impacted opex activities

Phase 1: Engagement of an appropriately qualified consultancy to conduct a Security Risk Assessment (SRA) of all nominated sites to provide a report on their current security status and any recommendations for further improvement. The scope of work will include site visits (one day per site accompanied by ZNX(2) and/or JAM staff) and then SRA write up, presentation and review by JAM staff (two days per site).

Six sites have been identified in the ACT gas network:

- Watson;
- Phillip;
- Bungendore – Hoskinstown;
- Jerrabomberra or its replacement Hume;
- Fyshwick; and
- Gungahlin

Phase 2: Recommendations arising from the SRA will be addressed and actioned in priority order. The required allocation of funds will be determined from the findings of Phase 1. As the rectifications will involve capital changes, no costs are included in this opex step change document for Phase 2.

4.2.3 Prudence assessment

Not undertaking the review could expose the sites and the network to unacceptable risk either by facility damage or possible network supply disruptions plus injury to members of the public who gain unauthorized access to a site.

Undertaking the review will provide a level of surety that the physical security measures in place are in line with industry best practices, to a level that is acceptable. Or, additionally, it will provide a clear understanding of the physical protective measures that will need to be put in place to address any shortcomings in the current configuration against the threat that should be considered.

4.2.4 Opex step change forecast

The costs are estimated to involve a security consultant undertaking a review for each of the six sites and providing a report. Costs of ZNX(2) personnel accompanying the consultant are not included. [redacted]

Table 7-2 Physical Security Review cost summary ($millions, 2014/15)

	2016/17	2017/18	2018/19	2019/20	2020/21
Physical security review	-	-	-	-	[redacted]

4.3 Step change summary

A summary of the costs associated with this step change is provided below. These costs include real cost escalation.

Table 6.2 Risk and security management cost summary ($millions, 2015/16)

	2016/17	2017/18	2018/19	2019/20	2020/21	Total
Total risk and security management step change	0.16	0.09	0.00	0.09	0.21	**0.54**

5 Hoskinstown metering station operation and maintenance contract

5.1 Driver

The Hoskinstown metering station O&M agreement of May 2005 will expire on 31 March 2015. [redacted] JAM intends to negotiate a 12 month extension of the agreement through to 31 March 2016. It is possible that during the extension period a termination clause in the agreement will be technically triggered due to an increased quantity of gas being delivered through Hoskinstown to the ACT gas network, the extension document will recognise this and agree not to trigger the termination clause.

Hoskinstown will take an increasingly important role as the primary gas delivery source for the ACT network over the next few years, with likely introduction of additional capacity funded by capital investment.

The Hoskinstown O&M agreement must be renegotiated to account for additional O&M requirements associated with expanded capacity and an updated agreement reflecting a cost based on good industry practice for delivering O&M services must be in place by 1 April 2016.

From 1 April 2016, the fee to deliver O&M services at Hoskinstown will be set by the new agreement, based on market pricing. [redacted]

5.2 Impacted opex activities

The scope of services provided under the current agreement includes:

- Monitoring and control;
- Operation;
- Recording and reporting;
- Maintenance and repairs;
- Cathodic protection testing;
- Calibration; and
- Logging and documentation.

There are two phases to the renegotiation of the contract:

- Phase 1: Choose service provider for O&M services and negotiate new O&M agreement; and

- Phase 2: Deliver O&M services on the Hoskinstown metering station for the period FY2016/17 – 2020/21. [redacted]

5.3 Prudence assessment

Failure to renegotiate the agreement may lead to the Hoskinstown metering station temporarily operating without an O&M service provider

Renegotiating the contracts will provide ongoing O&M of this key ActewAGL asset and take into account increases in the volume of gas delivered through the Hoskinstown metering station, and any future O&M impact this may have

5.4 Opex step change forecast

There are two phases to this step change:

- Phase 1 - three months of new contract = [redacted] and
- Phase 2 – for each year of the access arrangement period = [redacted]

Estimated annual cost is based on actual cost in $2013/14 incurred by Jemena Pipelines of [redacted]

A summary of the costs associated with this step change is provided below. These costs include real cost escalation.

Table 7.1 Summary of Hoskinstown metering station O&M contract cost summary ($millions, 2015/16)

	2016/17	2017/18	2018/19	2019/20	2020/21	Total
Hoskinstown O&M contract	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

6 Periodic inspections

ActewAGL Distribution’s Network includes exposed main and water bath heater assets that require periodic inspection as part of its good industry practice. The periodic inspections included in this step change were not undertaken in the base year and therefore are not included in base opex.

6.1 Exposed mains inspections

6.1.1 Driver

The ACT distribution system includes five exposed mains:

- Kings Avenue Bridge – Secondary Main;
- Woolshed Creek – Primary Main;
- Silvia Curly Bridge – Primary Main;
- McEwan Avenue – Medium Pressure; and
- Kitchener Street and Yamba Drive – Medium Pressure.

An exposed main is a section of pipe located on (above/below) a bridge (spanning over obstacle such as a water course or railway line). The obstacle prevented the main from being installed as a ’direct lay’. The main at Kitchener Street is not included in this opportunity brief as it is easily accessible without the need for special access equipment.

Mains are steel and require substantial design and construction techniques to ensure a safe and reliable gas supply.

The design of exposed mains includes brackets to support the main, and expansion joints to protect the main from fatigue stresses imposed through thermal expansion/contraction of the main and movement of the bridge.

An example is the Kings Avenue exposed main (DN350). This main provides the supply link between Canberra’s North and South secondary network (MAOP 1,050kPa). The exposed main is approximately 280m in length and is installed under the Kings Avenue Bridge.

In 2008, an engineering assessment, *Kings Avenue Bridge – Exposed Main Assessment*, was developed. An integrity inspection was conducted on the main (including the exposed section) to assess the insulation joint, protection system, the expansion joint, the neoprene rollers and the heat shrink sleeves. Only approximately 15 per cent of the main’s length was inspected due to accessibility issues.

The engineering assessment recommended regular and comprehensive inspections of the main, not just visual inspections from the shoreline.

Failure to manage the exposed mains integrity can result in corrosion and/or failure of the expansion joint. Both issues can result in major gas escapes with ‘knock on’ affects including loss of supply to multiple customers, disruption to traffic and increased regulatory scrutiny.

The objective of this project is to conduct an integrity inspection on all four exposed mains. This project will provide the following benefits:

- support a safe and reliable supply system;
- reduce the ActewAGL Distribution's technical and regulatory risk profile;
- assist in defining any repair/remediation works, if required; and
- assist in defining any capital forecasts.

6.1.2 Impacted opex activities

Scope of works:

- determine methodology and equipment to safely inspect entire length of exposed main (includes brackets and rollers);
- assessment to ensure inspection activities (cleaning of the main) do not impact upon the environment;
- assessment to ensure issues such as bird nesting/excrement do not impose a WHS issue (lice);
- authorisations (closure of pathways, use of barges, working over railway);
- cleaning of the main to remove foreign material (bird excrement);
- identify appropriate metrology to performing ongoing stress analysis on the exposed main and expansion joint;
- engagement of an engineering consultant to review results and provide findings and recommendations;
- replacement of parts, such as rollers and brackets; and
- recommendations – action(s) where required.

Any addition scope of work, including expense forecast in the capital budget, will be based on the outcome of the inspection.

6.1.3 Prudence assessment

Without a full assessment the integrity of the main, supports and expansion joint is unknown. It is possible that corrosion has reduced the mains’ integrity, which can result in a gas escape, or potential gas escape. In addition, the condition of the supports and expansion joint may have deteriorated to a point where failure is imminent. Under either scenario, failure would result in a gas escape causing a major interruption to the ACT's gas supply. Failure of a major main, installed as an exposed main would take considerable time (months) and resources to repair.

The mains may be subject to bending stresses and corrosion. Both issues reduce the main's integrity and provide a possible source for gas escapes. As the assets operate a high pressure the threat is a major gas escape exposing the public to a health safety risk.

Unplanned replacement of this type of asset is costly and time consuming. Replacement requires project planning and coordination of resources. Activities include working with the local council, road authorities and costly civil works. Unplanned replacement has the potential to increase repair cost in the order of 100 per cent to 200 per cent.

6.1.4 Opex step change forecast

Jemena's technical policies and work scopes (work scopes 919 and 919A) specify inspections of exposed mains at specific frequencies. Frequencies vary between one to five years.

Work Code 919, annual cursorily inspections, are performed on all exposed mains. However, where an access issues prevent inspection of the main at a level where integrity can be fully assessed work code 919A is performed. Work code 919A is designed to ensure all elements of the main are inspected which requires project planning, specific access equipment (boom lifts), NDT and/or contractors (abseiling).

Jemena specifies a five yearly frequency (the maximum frequency) for 919A inspections of these mains.

Costs ($40,000 per main) are based on a scope of works developed in 2014 for inspection of the Kings Avenue Bridge main. This cost has been applied to the other three mains as the requirements of all main are very similar.

A fifth exposed main, accessible without access equipment, has been excluded from this step change.

Table 8.1 Exposed mains inspections cost summary ($millions, 2014/15)

	2016/17	2017/18	2018/19	2019/20	2020/21
Exposed main inspections	-	-	-	0.160	-

6.2 Water bath heater inspections

6.2.1 Driver

The Hoskinstown Custody Transfer Station (CTS) connects the Eastern Gas Pipeline to the ACT and Queanbeyan Gas Networks through a 250mm steel trunk main. The Facility incorporates a meter station for custody transfer and a flow control facility to manage flow nomination between the two systems.

The Bungendore Package Off-take Station (POTS) branches off the Hoskinstown to Fyshwick trunk main and supplies approximately 900 customers in the Bungendore medium pressure system.

The water bath heaters (WBH) located at these sites need to be maintained with monthly to eight yearly planned maintenance regimes to meet manufacturer requirements and that of AS/NZS 3788:2006 (AS3788) in particular.

The planned maintenance regimes to meet manufacturers' requirements and regulatory requirements are detailed below.

6.2.2 Impacted opex activities

The same scope of work applies to both the Hoskinstown WBH and the Bungendore WBH and includes all work as specified in the work codes at frequencies and resource requirements as noted below.

Table 8.2 Water bath heater inspection works

Work code / activity	Frequency	Resource requirement
H74 - Gas Water Bath Heater Operational Inspections	monthly	34 minutes, 2 Electrical Technicians
H75 - Gas Water Bath Heater Minor Service	biannually	89 minutes, 2 Electrical Technicians
76 - Gas Water Bath Heater Medium Service	annually	240 minutes, 2 Electrical Technicians
80 - Gas Water Bath Heater Gas Equipment Overhaul	six-yearly	80 minutes, 2 Mechanical Technicians
81 - Gas Water Bath Heater Internal Inspection	eight-yearly	1800 minutes mechanical technicians, 900 minutes electrical and instrumentation technician plus Gas Water Bath Heater Internal Inspection
85 - Gas Water Bath Heater Inhibitor Level Check	monthly	120 minutes, 1 Mechanical Technician

6.2.3 Prudence assessment

Assets are required to be maintained to manufacturers and regulatory requirements as noted in the 'Summary and Objectives' section. Not doing the project will result in failure to meet these requirements, including but not limited to the requirements set out in AS2885.3-2012 (AS2885.3), AS3788, AS/NZS 3000:2007 (AS3000), *Utilities Act 2000* and the *Work Health and Safety Regulation 2011*.

Not doing the project may result in ad-hoc budgeting not supported through financial planning and cost recoveries.

6.2.4 Opex step change forecast

The same costs are applicable to both the Hoskinstown WBH and the Bungendore WBH. A charge out rate of [redacted] per hour has been used for mechanical technicians and [redacted] per hour for electrical and instrumentation technicians. This is based on 2014/15 rates for ZNX(2) technicians.

Indicative times and resource requirements have been used as a basis for estimating the cost of conducting the works.

Table 8.3 Periodic water bath heater cost summary ($'000, 2014/15)

	2016/17	2017/18	2018/19	2019/20	2020/21
Bungendore	5.4	5.4	5.4	5.4	5.4
Hoskinstown	5.4	5.4	5.4	68.2	5.4
Total	**10.8**	**10.8**	**10.8**	**73.6**	**10.78**

6.2.5 Periodic Inspection cost summary

A summary of the costs associated with this step change is provided below. These costs include real cost escalation.

Table 8.4 Periodic inspection cost summary ($millions, 2015/16)

	2016/17	2017/18	2018/19	2019/20	2020/21	Total
Total periodic inspections	0.012	0.012	0.012	0.258	0.012	**0.306**

7 Capex driven step changes

7.1 Fyshwick TRS upgrade

7.1.1 Driver

Major modifications and additions were made to the Fyshwick Trunk Receiving Station (TRS) in 2013.

The 'Heater Package' (Water Heaters, Heat Exchangers), second regulating run, generators and Filter installed, and commissioned in 2013, as part of the Fyshwick TRS upgrade, need to be maintained on regular intervals to meet the manufacturers' requirements and that of AS/NZS 3788:2006 (AS3788) in particular.

The two heat exchangers and filter are classified as "pressure vessels" in AS3788. The two boilers that are part of the 'heater package' are classified as a "water heaters" in accordance with AS3788.

The addition of this new equipment at the TRS has associated maintenance and inspection requirements. The planned maintenance regimes to meet manufacturers' requirements and regulatory requirements are detailed in the work codes as listed below.

7.1.2 Impacted opex activities

The scope of work covered in this step change is for the additional equipment, specifically the water heaters, heat exchangers, generators and equipment on the additional regulating run installed at Fyshwick TRS. Details of the additional activities are provided in Appendix C.

7.1.3 Prudence assessment

Assets are required to be maintained to manufacturers and regulatory requirements as noted in the 'Summary and Objectives' section. Not doing the project will result in failure to meet these requirements, including but not limited to the requirements set out in AS2885.3-2012 (AS2885.3), AS3788, AS/NZS 3000:2007 (AS3000), Utilities Act 2000 (ACT) and the Work Health and Safety Regulation 2011 (ACT).

Not doing the project may result in ad-hoc budgeting not supported through financial planning and cost recoveries.

7.1.4 Opex step change forecast

Details of the basis for this opex step change forecast are provided in Appendix C. A summary of these costs is provided in Table 10.1 below.

Table 10.1 Fyshwick TRS upgrade opex forecast summary ($'000, 2014/15)

	2016/17	2017/18	2018/19	2019/20	2020/21
Fyshwick TRS upgrade	39.40	34.19	148.53	30.82	39.40

7.2 Hoskinstown Custody Transfer Station upgrade

7.2.1 Driver

ActewAGL Distribution is planning to upgrade of the Hoskinstown CTS in response to changes in gas supply into the ACT gas network. The Hoskinstown CTS upgrade is scheduled to occur in FY17 and is the subject of a separate capex proposal included in ActewAGL Distribution's forecast capex documentation.

The second metering run, second flow/pressure control valve run, new power gas panel and additional valves to be installed as part of the Hoskinstown (CTS) upgrade will need to be maintained on regular intervals to meet the equipment manufacturer requirements and that of AS/NZS 3788:2006 (AS3788) in particular.

The planned maintenance regimes to meet manufacturers' requirements and regulatory requirements are detailed in the work codes as listed in Appendix C.

7.2.2 Impacted opex activities

Details of the additional activities required as a result of the Hoskinstown CTS upgrade are provided in Appendix C.

7.2.3 Prudence assessment

Assets are required to be maintained to manufacturers and regulatory requirements as noted in the 'Summary and Objectives' section. Not doing the project will result in failure to meet these requirements, including but not limited to the requirements set out in AS2885.3-2012 (AS2885.3), AS3788, AS/NZS 3000:2007 (AS3000), *Utilities Act 2000* and the Work Health and Safety Regulation 2011.

Not doing the project may result in ad-hoc budgeting not supported through financial planning and cost recoveries.

7.2.4 Opex step change forecast

Details of the basis for this opex step change forecast are provided in Appendix C. A summary of these costs is provided in Table 10.2 below.

Table 10.2 Hoskinstown TRS upgrade opex forecast summary ($'000, 2014/15)

	2016/17	2017/18	2018/19	2019/20	2020/21
Hoskinstown TRS upgrade	30.0	19.2	19.2	19.2	25.8

7.3 Philip Primary Regulating Station upgrade

7.3.1 Driver

ActewAGL Distribution's PRS currently has one operational regulating (duty) run and a bypass constituting of straight pipe with two isolating ball valves and a spade.

A regulator, pressure relief valve and associated components are to be installed on the bypass run in 2014/15. These new components will require maintenance.

The planned maintenance regimes to meet manufacturers' requirements and regulatory requirements are detailed in the work codes as listed in Appendix C.

7.3.2 Impacted opex activities

The scope of work covered in this step change is for the additional equipment installed on the Phillip PRS bypass. Details of the additional activities are provided in Appendix C.

7.3.3 Prudence assessment

Assets are required to be maintained to manufacturers and regulatory requirements as noted in the 'Summary and Objectives' section. Not doing the project will result in failure to meet these requirements, including but not limited to the requirements set out in AS2885.3-2012 (AS2885.3), AS/NZS 3788:2006 (AS3788), AS/NZS 3000:2007 (AS3000), Utilities Act 2000 (ACT) and the Work Health and Safety Regulation 2011 (ACT).

Not doing the project may result in ad-hoc budgeting not supported through financial planning and cost recoveries.

7.3.4 Opex step change forecast

Details of the basis for this opex step change forecast are provided in Appendix C. A summary of these costs is provided in Table 10.3 below.

Table 10.3 Philip PRS upgrade opex forecast summary ($'000, 2014/15)

	2016/17	2017/18	2018/19	2019/20	2020/21
Philip TRS upgrade	1.50	1.50	7.13	1.50	1.50

7.4 *Jerrabomberra Packaged Off-Take Station shut down*

7.4.1 Driver

With the completion and commissioning of the new Hume PRS in 2015, Jerrabomberra POTS is no longer needed. Consequently, maintenance work for this station will no longer be required. This will result in a negative step change.

7.4.2 Impacted opex activities

All PM work codes for Jerrabomberra POTS will no longer be required once it is decommissioned and removed. Details of these activities are provided in Appendix C.

7.4.3 Prudence assessment

As the Jerrabomberra POTS is no longer required and removed, maintenance is no longer required.

7.4.4 Opex step change forecast

Details of the basis for this opex step change forecast are provided in Appendix C. A summary of these costs is provided in Table 10.4 below.

Table 10.4 Jerrabomberra POTS opex forecast summary ($'000, 2014/15)

	2014/15 (base yr)	2015/16 (ext. yr)	2016/17	2017/18	2018/19	2019/20	2020/21
Jerrabomberra POTS shutdown	3.75	-	-	-	-	-	-

7.5 *Watson Pressure Limiting Station*

7.5.1 Driver

A Pressure Limiting Station (PLS) is to be constructed at the Watson CTS outlet in FY17 with the following configuration:

Inlet Isolation Valve > Filter > Pressure Control Valve > Non-Return Valve > Outlet Isolation Valve

The PLS will have a standby run for maintenance purposes which will be identical to the duty run. This new PLS will need to be maintained on regular intervals to meet equipment manufacturer requirements and regulatory requirements.

The filter vessel would be classified as a “pressure vessel” in accordance with AS/NZS 3788:2006 (AS3788) and would require inspection by a qualified pressure vessel inspector on regular intervals.

The planned maintenance regimes to meet manufacturer requirements and regulatory requirements are detailed below.

7.5.2 Impacted opex activities

The scope of work covered in this step change is for the additional activities relating to the installation of Watson PLS. Details of these activities are provided in Appendix C.

7.5.3 Prudence assessment

Assets are required to be maintained to manufacturers and regulatory requirements as noted in the ‘Summary and Objectives’ section. Not doing the project will result in failure to meet these requirements, including but not limited to the requirements set out in AS2885.3-2012 (AS2885.3), AS3788, AS/NZS 3000:2007 (AS3000), Utilities Act 2000 (ACT) and the Work Health and Safety Regulation 2011 (ACT).

Not doing the project may result in Ad-hoc budgeting not supported through financial planning and cost recoveries.

7.5.4 Opex step change forecast

Details of the basis for this opex step change forecast are provided in Appendix C. A summary of these costs is provided in Table 10.5 below.

Table 10.5 Watson Pressure Limiting Station opex forecast summary ($’000, 2014/15)

	2014/15 (base yr)	2015/16 (ext. yr)	2016/17	2017/18	2018/19	2019/20	2020/21
Watson PLS	-	-	2.49	6.90	8.63	21.91	12.19

7.6 Primary mains extensions

7.6.1 Driver

ActewAGL Distribution has extended its Primary (high pressure up to 3,500 kPa) mains to supply the Hume PRS and will be extending the main to Molonglo in 2019/20 (subject of a capex opportunity brief).

Newly built pipelines must be managed in accordance with the Pipeline Integrity Management Plan. This entails undertaking a weekly pipeline patrol and performing a cathodic protection (CP) survey twice a year.

7.6.2 Impacted opex activities

Details of these additional maintenance activities required are provided in Appendix C.

7.6.3 Prudence assessment

If the proposed activities are not undertaken the mains will not be managed in accordance with the requirements of the standard and to the requirements as outlined in the Safety Management Studies required under AS 2885. This will ultimately result in a breach of ActewAGL Distribution's Licence under the *Utilities Act 2000*.

7.6.4 Opex step change forecast

The opex attributable to the primary mains extensions is set out in Table 10.6 below.

Table 10.6 Primary mains extensions opex forecast summary ($'000, 2014/15)

	2014/15 (base yr)	2015/16 (ext. yr)	2016/17	2017/18	2018/19	2019/20	2020/21
Hume PME Patrol	0.625	1.25	1.25	1.25	1.25	1.25	125
Hume PME CP survey	0.625	1.25	1.25	1.25	1.25	1,25	1,25
Molonglo Patrol	-	-	-	-	-	2.50	2.50
Molonglo CP survey	-	-	-	-	-	2.50	2.50
Total	**1.25**	**2.50**	**2.50**	**2.50**	**2.50**	**7.50**	**7.50**

7.7 Capex driven step change cost summary

A summary of the costs associated with these capex driven step changes is provided in Table 10.7 below. These costs included real cost escalation.

Table 10.7 Capex driven step change opex step change forecast summary ($million, 2015/16)

	2016/17	2017/18	2018/19	2019/20	2020/21	Total
Total capex driven step change	0.09	0.08	0.25	0.10	0.11	**0.63**

8 Compliance to revised technical codes for metering

8.1 Driver

Within the past two years the ACT Government has introduced amended safety and compliance codes for new gas services and metering installations. These codes are:

- GS&I Rules Code July 2013;
- Gas Network Boundary Code May 2013; and
- Draft Gas General Metering Code is expected to be finalised in 2015/16.

These codes increase the level of activity required to achieve and maintain compliance for ActewAGL Distribution’s gas network.

In addition, the findings of a recently Formal Safety Assessment (FSA) study conducted by Jemena on ActewAGL Distribution’s network (as required by AS/NZS 4645.1:2008) into the metering asset class indicated there is a need to increase in the annual quantity of maintenance inspections for specific classes of meters. The objective of this step change is to maintain code compliance and address the outcomes of the FSA. The additional activity can only be performed with additional resources.

8.2 Impacted opex activities

These additional resources will perform the following works over and above any existing resources:

- Implement and maintain a meter QA system to ensure that all new meter sets are safe, fit for purpose, comply with requirements and are documented in the applicable record systems.
- Liaise with commercial and high-rise planners, developers and builders along the design and construct process chain to assure that correct meters are specified and installed.
- Develop plans and programs, in conjunction with clients, to apply safety, compliance and fitness-for-purpose requirements retrospectively to in-service metering equipment where required by ACT codes.
- Manage Authorised Persons (accredited gas fitters) performance of works on ActewAGL Distribution’s assets (both contracted and third-party) to ensure compliance of gas connection and metering installations.

- Apply Hazardous Area expertise to gas metering installation activities and ensure metering installations comply with all relevant Hazardous Area requirements.
- Carry out additional periodic fitness-for-purpose inspections of existing in-service meters (particularly internal I&C meters) in accordance with ActewAGL Distribution's requirements.
- Scope includes the requirement to perform 5 yearly inspections of meter sets installed in high-rise dwellings and commercial meter sets. This is a proposed requirement of the draft Gas General Metering Code to be finalised late 2014 or early 2015.
- Installation and maintenance of Meter Data Loggers (MDLs).

8.3 Prudence assessment

Not undertaking the activities under this step change will result in failure to:

- comply with the requirements of the ACT Government;
- comply with the outcomes of the Formal Safety Assessment, and non-compliance with AS/NZS 4645.1 2008; and
- adequately manage a potential public safety issue.

Undertaking these activities will enable ActewAGL Distribution to:

- maintain a safe distribution system; and
- comply with regulation and code requirements and Australia Standards.

8.4 Opex step change forecast

The three new resources for this team are:

- **Team Leader, Metering Compliance:** 1.0 FTE (Gas Fitting/Electrical background) at a total cost of [redacted] per annum, (inclusive of applicable motor vehicle), whose role will be to manage the performance of the team, implement the QA system, execute plans and programs, manage projects and perform inspections.
- **Instrument/Electrical Technician:** 1.0 FTE (Hazardous area endorsement) at a total cost of [redacted] per annum, (inclusive of applicable motor vehicle and trade specific tools and equipment), whose role will be to provide improved Hazardous Area knowledge and expertise in the team, carry out Hazardous Area inspections, manage high-rise metering projects and apply quality assurance to ensure meter installation compliance.
- **Administration Officer/Metering Scheduler:** 0.5 FTE additional at a total cost of [redacted] per annum to provide Administration/work scheduling support to the new Metering Compliance Team with scheduling of site visits and meetings with builders, developers and/or building operators and to assist in maintaining the quality assurance system.

- One-off transactional cost $20,000.

At the same time as establishing additional personnel within Zinfra to take on work to meet the new regulatory obligations, Jemena Asset Management will take the opportunity to consolidate Zinfra's metering team arrangements by terminating a contract with McNamara for installation and maintenance work on MDLs.

The total annual cost is allocated between capital related costs (construction management fee) and operating related costs (asset services fee). Concurrently the management services fee will reduce to reflect the termination of the contract with McNamara.

Table 9.1 Total costs of compliance to ACT technical metering codes ($'000, 2014/15)

	2015 (base yr)	2016 (ext. yr)	2016/17	2017/18	2018/19	2019/20	2020/21	Total 2016-21
Opex								
Management services fee	164	20	-	-	-	-	-	-
Asset services fee	23	102	102	102	102	102	102	510
Capex								
Construction management fee		321	321	321	321	321	321	1,607
Total	**187**	**443**	**423**	**423**	**423**	**423**	**423**	**2,117**

A summary of the net opex step change resulting from these total compliance costs is provided in Table 9.2 below. The change in service delivery model for MDL installation and maintenance results in a negative step change to the management services fee. The metering code compliance activities result in a step change to the asset services fee. These costs include real cost escalation.

Table 9.2 ACT technical metering codes opex step change forecast summary ($millions, 2015/16)

	FY17	FY18	FY19	FY20	FY21	Total
Recontracting MDL installation and maintenance	(0.17)	(0.17)	(0.17)	(0.18)	(0.18)	**(0.87)**
Technical metering codes compliance	0.08	0.08	0.08	0.09	0.09	**0.42**
Total opex step change	**(0.09)**	**(0.09)**	**(0.09)**	**(0.09)**	**(0.09)**	**(0.45)**

9 RIN reporting requirements

9.1 Driver

ActewAGL Distribution and JAM anticipate that the AER will significantly escalate annual regulatory reporting requirements from the first year of ActewAGL Distribution's next access arrangement period. This would be consistent with significantly increased reporting requirements for electricity networks and ActewAGL Distribution's access arrangement RIN.

It is also expected that the AER will require an audit of most, if not all, annual data submitted by ActewAGL Distribution and JAM in response to the RIN.

9.2 Impacted opex activities

JAM accounting staff have prepared the annual RIN responses for JAM each year from 2010/11 to 2013/14. However to complete RIN responses that are of an equivalent requirement as has applied to Jemena's electricity network the following would be required:

- backfill resources for two FTE analysts to plan, collect, populate and validate the information in the manner required; and
- an annual audit of financial and non-financial data.

Additionally, annual auditing of ActewAGL Distribution's data would be required.

9.3 Prudence assessment

The AER has information gathering powers under sections 48(1)(a) and 55 of the National Gas Law. There are financial penalties for not complying with a RIN as well as reputational and relationship damage. The AER has signalled its intent to adopt a much more forensic approach to information gathered from all regulated network businesses through the requirement on electricity networks.

ActewAGL Distribution will not be able to meet additional RIN reporting requirements without the additional resources and funding for audits.

9.4 Opex step change forecast

There are three components to increased RIN reporting opex:

- Completing the RIN - This is estimated based on an annual cost of [redacted] per cent on-costs) per FTE, required for a six month period from May to November. (i.e. equivalent to one FTE p.a.)

- JAM annual audit - Cost of $110,000 (based on JEN's annual costs, with a $20K carve-out for the S-factor component of JEN's RIN). This assumes one annual RIN submission only. Year 1 cost is $220,000, to reflect additional costs for the first audit as the auditor develops an understanding of the requirements and the business.
- ActewAGL Distribution annual audit – Cost of $40,000 per annum for external auditing of ActewAGL Distribution's RIN data.

A summary of ActewAGL Distribution's forecast opex for this step change is provided in the table below. These values include real cost escalation.

Table 11.1 RIN reporting opex step change forecast summary ($millions, 2015/16)

	2016/17	2017/18	2018/19	2019/20	2020/21	Total
RIN reporting	0.41	0.30	0.30	0.31	0.32	**1.63**

10 2021 access arrangement revision

10.1 Driver

Under clause 52 of the National Gas Rules, ActewAGL Distribution must prepare and submit to the AER its access arrangement revision proposal for the period commencing 1 July 2021 comprising:

- ActewAGL Distribution's proposed revisions to the access arrangement, to apply in the new access arrangement period;
- access arrangement information, which provides background information about the access arrangement proposal, and
- additional information supporting the access arrangement revision proposal (which might include, for example, reports from expert advisors relating to particular aspects of the access arrangement proposal).

ActewAGL Distribution must also prepare a response to the AER's RIN.

Assuming the 2016 access arrangement period ends on 30 June 2021, the 2021 access arrangement proposal is to be lodged with the AER by 30 June 2020. A final decision would be due in May 2021.

Due to the periodic nature of the costs associated with the access arrangement revision, ActewAGL Distribution has adjusted base year opex to remove these costs and therefore requires a step change in opex in 2018/19- 2020/21 for efficient costs related to this regulatory requirement.

10.2 Impacted opex activities

This step change impacts ActewAGL Distribution's 'Regulatory operations' opex category. The step change forecast is based on actual and forecast incremental costs for preparing the current 2016-21 access arrangement submission, with additional costs to account for real price escalation over the period. ActewAGL Distribution has assumed that the incremental cost of the 2016-21 access arrangement revision project is comparable to the expected incremental costs of the 2021-26 access arrangement project. ActewAGL Distribution considers this is a conservative estimate as regulatory requirements for access arrangements have tended to increase substantially from review to review.

These costs have been grouped into the following activities:

1. initial scope;
2. access arrangement proposal preparation including:
   a) access arrangement revisions;
   b) access arrangement information; and

c) RIN response;

3. AER review and revised access arrangement proposal, and final decision; and
4. consumer engagement.

10.3 Prudence assessment

ActewAGL Distribution has considered the following three options in assessing the need for this step change:

Option 1: Do nothing

Failure to submit a 2021 access arrangement is not considered a viable option as it would result in breach of clause 52 of the Rules. This rule is a civil penalty provision. A poor regulatory outcome will have a significant negative impact on ActewAGL Distribution's ability to invest in, and operate its 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.

Option 2: Remove access arrangement review costs from base year opex and incur as a step change in 2018/19, 2019/20 and 2020/21

As access arrangement review costs are included in ActewAGL Distribution's proposed base year of 2014/15, this option involves making an adjustment to the base year to remove this expenditure due to its periodic/non-recurrent nature. This option results in the requirement for a step change in opex in 2018/19 to 2020/21 for ActewAGL Distribution's efficient costs for the 2021-26 access arrangement revision process.

Option 3: Retain access arrangement review costs in base year opex

Alternatively, ActewAGL Distribution would not make an adjustment to base year opex, but rather retain the access arrangement review costs, which would result in proposed base opex being greater than efficient costs for the first three years of the 2016-21 access arrangement period, as access arrangement revision expenditure will not be incurred in these years.

Option 2 is ActewAGL Distribution's preferred option.

10.4 Opex step change forecast

Inclusions

The step change forecast is based on actual and forecast incremental costs for preparing the current 2016-21 access arrangement revision submission, with additional costs to account for real price escalation over the period. ActewAGL Distribution has assumed that the incremental cost of the 2016-21 access arrangement revision project is comparable to the expected incremental costs of the 2021-26 access arrangement revision project. ActewAGL Distribution considers this is a conservative estimate as regulatory requirements for access arrangements have tended to increase substantially from review to review. The forecast cost for the 2021-26 access arrangement revision proposal has been developed based on the following:

- actual costs for initial scoping of the access arrangement revision project in 2013/14 as the basis for the 2018/19 estimate;

- actual/forecast costs in 2014/15 for preparing ActewAGL Distribution's access arrangement revision proposal including access arrangement revisions, access arrangement information and RIN response as well as consumer engagement activities as the basis for the 2019/20 estimate;
- cost estimates in accordance with the access arrangement revision budget in 2015/16 for responding to the draft decision, further consumer engagement and implementing the final decision as the basis for the 2020/21 estimate; and
- forecast real price change for labour as explained in the access arrangement information opex attachment.

These costs include the following:

- incremental costs for services provided by JAM labour and its consultants under the DAMS Agreement between ActewAGL Distribution and Jemena; and
- incremental costs for technical expert advice on key regulatory parameters, consumer engagement and legal advice for both the access arrangement revision proposal and associated access arrangement information.

These costs have been grouped into the following stages/activities:

1. Initial scope;
2. access arrangement proposal preparation including:
   a) access arrangement revisions;
   b) access arrangement information; and
   c) RIN response;
3. AER review and revised access arrangement revision proposal, and final decision; and
4. consumer engagement.

Exclusions

The following costs are excluded from this step change:

- non-incremental costs (e.g. business as usual resources assigned to ActewAGL Distribution's gas networks); and
- merits and/or judicial review costs.

Table 12.1 Step change inclusions ($millions, 2014/15)

	2016/17	2017/18	2018/19	2019/20	2020/21	Total
1. Initial scope	0.00	0.00	0.04	0.00	0.00	**0.04**
2. access arrangement proposal preparation including:	0.00	0.00	0.00	2.00	0.00	**2.00**
a) access arrangement revisions	0.00	0.00	0.00	0.42	0.00	**0.42**
b) access arrangement information	0.00	0.00	0.00	1.31	0.00	**1.31**
c) RIN response	0.00	0.00	0.00	0.28	0.00	**0.28**
3. AER review and revised access arrangement proposal, and final decision	0.00	0.00	0.00	0.00	0.71	**0.71**
4. Consumer engagement	0.00	0.00	0.05	0.11	0.03	**0.19**
Total	**0.00**	**0.00**	**0.10**	**2.10**	**0.75**	**2.95**

A summary of ActewAGL Distribution's forecast opex for this step change including real cost escalation is provided in Table 12.2 below.

Table 12.2 21 access arrangement revision opex step change forecast summary ($millions, 2015/16)

	2016/17	2017/18	2018/19	2019/20	2020/21	Total
Total 2021 access arrangement revision step change	0.00	0.00	0.10	2.30	0.83	**3.23**

11 Change in policy for capitalisation of corporate overheads

11.1 Driver

ActewAGL Distribution's cost allocation method (CAM) sets out the manner in which its shared costs are allocated between the services it provides as well as determines what costs are expensed to opex or capitalised as capex. Allocation of costs between services is required to accurately represent costs incurred in providing the respective services. This prevents cross-subsidisation between gas distribution services and other services ActewAGL provides and ensures costs are appropriately recorded as opex or capex.

In December 2012, ActewAGL Distribution submitted a revised CAM to the AER for its electricity distribution network. This was approved by the AER in June 2013 and applied in ActewAGL Distribution's electricity distribution network determination for 2014-19.

ActewAGL Distribution engaged McGrathNicol Corporate Advisory to assist with the review and development of the revised CAM, as well as Deloitte to provide a limited assurance review. The review found that the methodology used to allocate overhead costs to projects at that time did not best reflect the resources required to bring those projects to fruition. The recommendation made by McGrathNicol was to adopt a CAM based on total direct costs as the driver for allocating overheads across projects.

Current cost allocations for ActewAGL Distribution's gas distribution business are inconsistent with the revised CAM for ActewAGL Distribution's electricity distribution business. ActewAGL Distribution proposes to align the CAM for the gas network with that of the electricity network as of 1 July 2015. This change in the CAM results in a greater proportion of ActewAGL Distribution's corporate overheads expenditure being allocated to capex as this allocation is now based on total direct costs. Annual variations in the amount of corporate overheads to be capitalised under the CAM are due to fluctuations in the capital expenditure to be incurred year on year.

This negative step change is to effect this change. Annual variations in the amount of corporate overheads to be capitalised under the CAM are due to fluctuations in the capex incurred year on year.

11.2 Impacted opex activities

This step change impacts annual corporate overheads. ActewAGL Distribution's total annual forecast of corporate overheads has been based on an estimate of costs incurred in the base year, 2014/15, but with a change in the way in which these costs are allocated between opex and capex. This negative step change is met with a corresponding increase in capex.

11.3 Prudence assessment

ActewAGL Distribution has considered the following options in assessing the need for this step change.

Option 1: Do nothing

This option involves maintaining the CAM applied over the 2010-16 access arrangement period, which results in the continuation of expensing corporate services and gas networks management costs to opex.

Option 2: Bring gas network CAM in line with ActewAGL Distribution's CAM for its electricity network

This option involves a change in ActewAGL Distribution's CAM to now allocate corporate services and gas network management costs to the program of work and capitalising a portion of those costs. This option results in ActewAGL Distribution's treatment of corporate overheads for the gas network to be consistent with its electricity network, which reflects the treatment recommended by independent consultants.

Option 2 is ActewAGL Distribution's preferred option.

11.4 Opex step change forecast

This step change includes annual allocations of total corporate overheads from opex to capex to reflect a change from the CAM applied in the base year used to forecast corporate overheads. A summary of ActewAGL Distribution's forecast opex for this step change is provided in Table 13.1 below.

Table 13.1 Change in policy for capitalisation of corporate overheads step change forecast summary ($millions, 2015/16)

	2016/17	2017/18	2018/19	2019/20	2020/21	Total
Capitalisation of corporate overheads	(1.27)	(1.51)	(1.39)	(1.37)	(1.03)	**(6.58)**

Appendix A – JGN's estimate of costs for National Energy Customer Framework compliance

ActewAGL Distribution's forecast opex required to meet full NECF requirements has been based on a portion of Jemena Gas Network's (JGN's) forecast for these activities, which was considered reasonable by the AER in its final decision for JGN's 2015-20 access arrangement.[4] Jemena estimates that services provided for ActewAGL Distribution are equivalent to 10 per cent of those for JGN, based on the relative number of customers. This addendum provides details of JGN's activities and forecast costs. ActewAGL Distribution's forecast step change based on this information is provided in section 3.4 of this report.

Customer support and billing

JGN's customer services team currently receives approximately 30,000 calls per annum covered by three FTEs for JGN. This translates to an average of around 40 calls per day per FTE. For more complex calls involving consumption enquiries, maintenance of customer data, and complaints handling (which reflect the full NECF impact), the effective handling rate is lower, at 30 calls per day.

Jemena has customer service Key Performance Indicators to answer calls within certain times, minimise call abandonment rates, target enquiry response times and complaint resolution times.

In the context of full NECF obligations and the potential for retailers to refer end use customers directly to JGN for distribution services, eight FTEs would have the capacity to handle approximately 60,000 more complex calls per annum. This is considered reasonable in an environment of rising gas prices and the potential for retail price deregulation, following the NSW government announcement on 7 April 2014 to remove retail electricity price regulation.

For manual billing production, three FTEs would have the capacity to produce approximately 12,000 distribution billing transactions per annum, which would cover 0.1 per cent of customers which could be billed monthly or 0.25 per cent of customers which could be billed quarterly directly for distribution services.

The FTEs will perform multiple duties to flexibly resource the demand for customer service activities. Following the implementation of new self-service and automated customer management systems, it is expected that a nominal telephone handling capability will be required to provide services to customers who elect not to, or are unable to, access self-service portals. Three FTEs would have the capacity to handle approximately 20,000 to 30,000 calls per

[4] AER 2015, *Final decision: Jemena Gas Networks 2015–20, Attachment 7 – Operating expenditure*, June, p. 7-23

annum, equating to one call per annum from 1.7 per cent to 2.5 per cent of JGN's 1.2 million connections base.

The team leader role is to produce effective and NECF-compliant delivery of customer services from a newly formed team to an increasing end use customer base where JGN will have a direct service relationship in lieu of retailers. The increased support costs for system functionality and business processes are necessary to deliver full NECF compliance.

Part 12A connections

Part 12A connections

Jemena has developed a forecast of the costs that a prudent service provider acting efficiently would incur in providing the re-scoped connection service. This has taken into account:

- the increase in the number of applications that Connect Direct will receive and the different types of customers that will approach Connect Direct when Part 12A comes into effect; and
- the operational resources that will be required to service the projected number of applications and the different types of customers.

The forecast does not include the costs of providing services to negotiated connection applicants, because under Part 12A these costs can still be recovered from the applicant.

JGN estimates that Connect Direct's market share will increase significantly in the first two years of full NECF, to around 80 per cent in FY18 and then holding steady. JGN has made this estimate based on market behaviour experienced when JGN first introduced the Connect Direct service. In 2009, AGL charged between $300 and $600 for residential connections and $1,100 for commercial connections. JGN then set a lower fee: $220 for residential and $550 for commercial connections. As a result, in 2010-11, JGN's market share grew to 60 per cent. This suggests:

- builders and developers develop a relationship with their connection provider and may take time to switch in response to price signals; and/or
- there are information barriers, which prevents all customers understanding the connection options available to them.

Jemena has taken these circumstances and behaviours into account, including that under full NECF its connection fee would fall to $0 and basic/standard connection processes would be streamlined and more accessible for customers. JGN considers than an increase to 80 per cent market share would be reasonable taking these factors into account. Additional headcount to service the increased market share is incremental to the current base headcount of seven people in the Connect Direct team.

Table A.1 JGN's assumptions for Part 12A connections costs

	Assumptions					
	As at Dec 2013	2015-16	2016-17	2017-18	2018-19	2019-20
Connect Direct market share (%)	21	50	65	80	80	80
Offers made – new homes, E to G, Commercial (# p.a.)	7,300	17,400	22,620	27,840	27,840	27,840
Additional headcount required (incremental, #)	0	5	2	1	0	0
Average remuneration (inc. on-cost)	0.11	0.11	0.11	0.11	0.11	0.11

Table 1.2 sets out the NECF step change forecast. Note that, for customer support and billing, costs incurred from 2016-17 reflect those activities that will not be captured by the Customer Management Framework upgrade to GASS+.

Table A.2 2016-20 JGN's NECF step change forecast ($millions, 2014/15)

	Step change forecast						
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	Total
Customer support & billing							
FTEs for consumption enquiries, manual extraction, analysis and maintenance of customer data, complaints handling and production of distribution services charges	0.82	0.31	0.31	0.31	0.31	0.31	2.05
FTEs for manual billing production of distribution service charges compliant with NECF obligations	0.31	0.00	0.00	0.00	0.00	0.00	0.31
1 FTE for management of customer service strategy and operations	0.15	0.00	0.00	0.00	0.00	0.00	0.15
1 FTE for process and systems support costs for GASS+ NECF functionality	0.15	0.00	0.00	0.00	0.00	0.00	0.15
Sub-total	**1.44**	**0.31**	**0.31**	**0.31**	**0.31**	**0.31**	**2.67**
Connections under Part 12A							
FTEs to assess and process connections	0.00	0.79	0.90	0.90	0.90	0.90	4.72
Total step change	**2.00**	**1.10**	**1.21**	**1.21**	**1.21**	**1.21**	**7.38**

Appendix B – JGN's estimate of costs for B2B harmonisation

Forecast opex required to achieve B2B harmonisation has been based on a portion of JGN's forecast for these activities provided through JAM, which was considered reasonable by the AER in its final decision for JGN's 2015-20 access arrangement.[5] JAM estimates that services provided for ActewAGL Distribution are equivalent to 10 per cent of those for JGN, based on the relative number of customers.

Costs for JGN are estimated in tables B.1 to B.4 below. Some costs are associated with developing the policies, procedures and practices with the harmonisation, and are therefore non-recurrent. Other costs are for ongoing practices and are therefore recurrent.

Table B.1 Meter Data provision ($million, $2014/15)

	Ext. year			Step change forecast		
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Meter reading management	0.00	0.10	0.10	0.10	0.10	0.10
Meter reading services	0.00	0.48	0.57	0.57	0.57	0.57
Back office and support	0.00	0.5	0.3	0.3	0.3	0.3
Total	**0.00**	**1.08**	**0.97**	**0.97**	**0.97**	**0.97**

Table B.2 Service order completion ($million, $2014/15)

	Ext. year			Step change forecast		
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Meter reading management	0.00	0.10	0.10	0.10	0.10	0.10
Meter reading services	0.00	0.08	0.08	0.08	0.08	0.08
Back office and support	0.00	0.10	0.10	0.10	0.10	0.10
Total	**0.00**	**0.28**	**0.28**	**0.28**	**0.28**	**0.28**

Table B.3 Miscellaneous change requirements ($millions, $2014/15)

	Ext. year			Step change forecast		
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Business solutions and data cleansing	0.2	0.00	0.00	0.00	0.00	0.00
Miscellaneous service level changes	0.12	0.45	0.45	0.45	0.45	0.45
Total	**0.32**	**0.45**	**0.45**	**0.45**	**0.45**	**0.45**

[5] AER 2015, *Final decision: Jemena Gas Networks 2015–20, Attachment 7 – Operating expenditure*, June, p. 7-26 – 7-28

Appendix C – Capex-driven step changes scope of works and resource requirements

Fyshwick TRS upgrade

Scope of works

3. The scope of work covered in the Fyshwick TRS capex-driven step change is for the additional equipment, specifically the water heaters, heat exchangers, generators and equipment on the additional regulating run installed at Fyshwick TRS. This includes the following activities

- maintenance of the water heaters, heat exchanges and associated components as per JAM work codes HFB, HFC, HFD, HFL, HFK, HFN, HFR, HZ1 and HZ2
- maintenance of generators as per JAM work code HFE, HFF, HFG, HFH, HFP and HFQ
- maintenance of second regulating run as per JAM work codes H15, H21, H32, H53, H55, H56, H57, H58, H59, H16, HZ1 and HZ2
- maintenance of new station operating system as per JAM work codes HFA and HFM
- maintenance of new special piping nozzle as per JAM work code HFJ
- testing of backflow device as per JAM work code HFS
- maintenance of medium pressure meter set as per JAM work code 664 and 665

All works are as specified in the following JAM work codes:

- HFA: Check Station Mechanical Operation, frequency 3 monthly
- HFB: External Inspection of Pressure Vessel at Fyshwick TRS, frequency 2 yearly: Work scope covers the external inspection of the water heaters and the heat exchangers
- HFC: Internal (Major) Inspection of Heater System at Fyshwick TRS, first year plus 4 yearly frequency[6]
- HFD: Minor Inspection of Heater System at Fyshwick TRS, frequency 1 yearly
- HFE: Six Monthly Mechanical Service of Generator, frequency 6 monthly
- HFF: Annual Mechanical Service of Generator, frequency 1 yearly
- HFG: Two Yearly Mechanical Service of Generator, frequency 2 yearly
- HFH: Three Yearly Mechanical Service of Generator, frequency 3 yearly

[6] See 'Additional Comments' section

- HFJ: Special Piping Nozzle (SP02) Inspection, frequency 5 yearly
- HFK: Check Corrosion Inhibitor Levels, frequency 1 monthly
- HFL: Inspect Water Heater Auxiliary Equipment at Fyshwick TRS, frequency 6 monthly
- HFM: Check Station electrical and instrumentation Operation, frequency 1 yearly
- HFN: Inspect electrical and instrumentation Operation of Heater System at Fyshwick TRS, frequency 1 yearly
- HFP: Check Generator Transfer Switch at Fyshwick TRS, frequency 4 weekly
- HFQ: Inspect Generator electrical and instrumentation at Fyshwick TRS, frequency 1 yearly
- HFR: External Inspection of Water Heater at Fyshwick TRS, frequency 4 yearly
- HFS: Backflow Device Test, frequency 1 yearly
- HZ1: Visual Inspection of Intrinsically Safe (Ex i) and Flame Proof (Ex denp) Installations Planned Maintenance, frequency 4 yearly
- HZ2: Detailed Inspection of Intrinsically Safe (Ex i) and Flameproof (Ex denp) Installations, frequency 4 yearly.
- H15: Mechanical Overhaul of Control Valves, frequency 3 yearly
- H21: Lubricate Inlet and Outlet Valves, frequency 6 monthly
- H32: Pressure Vessel Inspection – Internal, first year plus 4 yearly frequency
- H53: Analogue Transmitters (P/T/DP), frequency 6 monthly
- H55: Surge Diverters, frequency 3 monthly
- H56: Calibrate Switches, frequency 3 monthly
- H57: Outlet Pressure Control Loop Check, frequency 6 monthly
- H58: I to P Converters, frequency 6 monthly
- H59: Electronic and Pneumatic Controller, frequency 6 monthly
- 664: MP Operational Check reg 15kPa & Over, frequency 6 monthly
- 665: MP Reg Overhaul 15kPa & Over, frequency 4 yearly
- The inspection frequency for an internal inspection of the water heaters is based on the recommended frequency of 4-5 years provided by the manufacturer, Hunt. The period of 4 years was selected to be in line with the frequency of the heat exchangers.

Opex step change forecast basis

A high level breakdown of time and resource requirements specific to each work code is shown below for reference, frequency of activity as listed in the scope of works above. A charge out rate of [redacted] per hour has been used for Mechanical Technicians and [redacted] per hour for electrical and instrumentation Technicians. This is based on 2014/15 rates for ZNX(2) technicians.

Operational checks

- HFA: 8 hours, 2 Mechanical Technicians and $2,000 in vendor costs as ZNX Hume does not have test equipment to meet the test pressure for the 8 additional relief valves in the upgraded site.
- HFM: 10 hours, 2 electrical and instrumentation Technicians
- 664: 0.75 hours, 2 Mechanical Technicians

Heater package

The new 'Heater Package' (system) has replaced the WBH. The annual cost of the old WBH maintenance has been taken into consideration when evaluating the step change for the maintenance of the 'Heater Package'.

- HFD: 4 hours, 2 Mechanical Technicians and $1,200 in vendor costs
- HFL: 3 hours, 1 Mechanical Technician and $600 in vendor costs
- HFK: 1 hour, 1 Mechanical Technician and $220 in vendor costs
- HFN: 4 hours, 2 electrical and instrumentation Technicians
- HFS: 0.5 hour, 1 Mechanical Technician and $200 in vendor costs

Internal and external inspection of filter, heat exchangers and water heater

Prior to site upgrade there was only one pressure vessel (Filter) at Fyshwick TRS. The station upgrade introduced an additional Filter. A competent inspector is required to perform internal inspection sign off. Additional costs are also required for ongoing vessel registration with WorkSafe ACT.

The station upgrade introduced two Heat Exchangers, which have been identified as pressure vessels. Pressure vessel inspections were not required for the old WBH. The Water Heaters also require internal and external inspection.

- HFB: 5 hours, 2 Mechanical Technicians, $500 for material costs and $400 in vendor costs (four years when not combined with internal inspections, HFC). The price includes 2 Heat Exchangers and 1 Filter only.
- Combined HFC, HFB and HFR: 6 hours, 2 Mechanical Technicians, $250 for material costs and $200 in vendor costs for combined internal (HFC) and external (HFB) inspection of 1 Filter. Estimate $100,000 for combined internal (HFC) and external (HFB and HFR) inspection of 2 Heat Exchangers and 2 Water Heaters.

Hazardous area

Required as per AS/NZS 60079.17:2009.

- HZ1: 9 Hours, 2 electrical and instrumentation Technicians (includes new 'Heater package' and second run)
- HZ2: 14 Hours, 2 electrical and instrumentation Technicians (includes new 'Heater Package' and second run)

Special piping nozzle inspection

- HFJ: 8 hours, 1 Mechanical Technician and $600 in vendor costs

Generator

The Generator was added as part of the Fyshwick TRS upgrade; therefore, all maintenance would be a step change from the maintenance performed on the battery bank. An external service provider is required to perform Generator maintenance

- HFE: 4 hours, 1 Mechanical Technician and $605 in vendor costs
- HFF: 4 hours, 1 Mechanical Technician and $715 in vendor costs
- HFG: 4 hours, 1 Mechanical Technician and $733 in vendor costs
- HFH: 4 hours, 1 Mechanical Technician and $1,114 in vendor costs
- HFP: 2 hours, 1 electrical and instrumentation Technician
- HFQ: 1 hour, 1 electrical and instrumentation Technician

Second regulating run

A second regulating run was installed as part of the Fyshwick TRS upgrade. The second regulating run consists of a Filter, Isolation Valves, Slam Shut Valve, two Control Valves as well as associated electrical equipment.

- H15: 16 hours, 2 Mechanical Technicians and $10,000 in material costs
- H21: 1 hour, 2 Mechanical Technicians
- H32: Cost included as part of Work Code HFC
- H53: 1.5 hours, 2 electrical and instrumentation Technicians
- H55: 1 hour, 2 electrical and instrumentation Technicians
- H56: 2 hours, 2 electrical and instrumentation Technicians
- H57: 1.5 hours, 2 electrical and instrumentation Technicians
- H58: 1 hour, 1 E& I Technician
- H59: 2 hours, 2 electrical and instrumentation Technicians
- HZ1 and HZ2: Cost included above under subheading 'Hazardous Area'

Medium pressure meter set

- 664: 0.75 hour, 2 Mechanical Technicians

- 665: 2 hours, 2 Mechanical Technicians and $915 in material costs

Hoskinstown Custody Transfer Station upgrade

Scope of works

The Hoskinstown CTS upgrade comprises the following scope of works as the basis for forecast costs in this capex-driven step change.

Meter Skid Upgrade:

- Install second meter run.
- Replace gearbox operators on the run inlet valves with actuators.
- Install flow conditioners upstream of the meters to satisfy the requirements of the meter manufacturer.
- Provision for series proving of meters.

Flow Control Skid Upgrade:

- Install second flow/pressure regulating run.

Power Gas Skid Upgrade:

- New power gas panel, complete with heat tracing and necessary instrumentation, to accommodate the additional 2 actuated valves (see meter skid upgrade) and additional flow control valve (see flow control skid upgrade).

Additional valves - double block and bleed:

- Redesign and fabrication of the inlet and outlet headers for water bath heater, filter, meter skid and control valve skid to accommodate additional isolation valves.
- 17 x ball valves

The additional maintenance required due to the upgrade is as follows:

Second metering run

- CTS metering accuracy as per Work Code H01 , frequency 3 monthly.
- Drafting and maintenance of new operational procedures for upgraded site (in first year of operation)
- New software/hardware for meter validation (in first year of operation)

Second flow control valve run

- Mechanical Overhaul of control valve as per Work Code H15, frequency 4 yearly
- Mechanical operational check as per Work Code H22, frequency 3 monthly
- Inspect analogue transmitter as per Work Code H53, frequency 6 monthly
- Calibrate switches (PSH’s, PSHH’s etc.) as per Work Code H56, frequency 6 monthly

- Inspect outlet pressure control loop as per Work Code H57, frequency 6 monthly
- Inspect I to P converters as per Work Code H58, frequency 1 yearly
- Inspect electronic and pneumatic controller as per Work Code H59, frequency 6 monthly
- Station operational check H67, frequency 1 yearly

Additional valves

- Fifteen additional valves for double block and bleed (includes additional valves on meter run and flow control valve run). Although there will be 17 new ball valves installed, 2 existing ball valves will be removed, thus maintenance step change will be for 15 additional valves.
- Lubricate inlet and outlet valves as per Work Code H21, frequency 6 monthly

New power gas panel

- Detailed inspection of electrical trace heating Installations as per Work Code HZ5, frequency 1 yearly.
- May require electrical and instrumentation maintenance work codes for instrumentation that accommodates the additional 2 actuated valves (for second metering run) and additional flow control valve (for second flow control valve run).

Other

- Visual Inspection of Intrinsically Safe (Ex i) and Flame Proof (Ex d e n p) Installations as per Work Code HZ1, frequency 4 yearly.
- Detailed Inspection of Intrinsically Safe (Ex i) and Flameproof (Ex d e n p) Installations as per Work Code HZ2, frequency 4 yearly

Opex step change forecast basis

Indicative times and resource requirements for conducting works at Horsley Park TRS[7] have been used as a basis for estimating the cost of conducting the works at Hoskinstown CTS.

A high level breakdown of time and resource requirements specific to each work code is shown below for reference, frequency of activity as listed in the scope of work' section above. A charge out rate of [redacted] per hour has been used for mechanical technicians and [redacted] per hour for electrical technicians. $6 has been added to each rate for hourly vehicle costs. This is based on 2014 rates for ZNX technicians.

Second metering run

- Work Code H01 — Witness Testing: 2 specialised technician, 1 day

Second flow control valve run

- Work Code H22— Mechanical Operational Check: 2 Mechanical Technician, 90 minutes
- Work Code H53 — Analogue Transmitter (P/T/DP): 2 Electrical Technician, 90 minutes
- Work Code H56 — Calibrate Switches (PSH's, PSHH's etc.): 2 Electrical Technician, 120 minutes
- Work Code H57 — Outlet Pressure Control Loop: 2 Electrical Technicians, 90 minutes
- Work Code H58 — I to P Converters: 2 Electrical Technicians, 60 minutes
- Work Code H59 — Electronic and Pneumatic Controller: 2 Electrical Technician, 120 minutes
- Work Code H67 — Station Operational Check: 2 Electrical Technician, 110 minutes
- Work Code H15 — Mechanical Overhaul of Control Valve: 4 Mechanical Technician, 180 minutes

15 additional valves

- Work Code H21 — Lubricate Inlet and Outlet Valves: 2 Mechanical Technician, 450 minutes

New power gas panel

- Work Code HZ5 — Detailed Inspection of Electrical Trace Heating Installations: 2 Electrical Technician, 240 minutes

Other

- Work Code HZ1 — Visual Inspection of Intrinsically Safe (Ex i) and Flame Proof (Ex d e n p) Installations: 2 Electrical Technician, 384 minutes
- Work Code HZ2 — Detailed Inspection of Intrinsically Safe (Ex i) and Flameproof (Ex d e n p) Installations: 2 Electrical Technician, 1056 minutes

Philip Primary Regulating Station upgrade

Scope of works

The scope of work covered in this capex-driven step change is limited to the additional equipment installed on the Phillip PRS bypass and includes all work as specified in the work codes referenced below.

- Mechanical overhaul of control valves, regulators, filters TRS/PRS as per Work Code H15, frequency 4 yearly
- Mechanical Operational Check as per Work Code H22, frequency 3 monthly

Opex step change forecast basis

Indicative time for works on one run at Penrith PRS (which has Fisher EZRs installed) has been used as a basis for estimating the cost of conducting the works as per Work Codes H15 and H22.

Resource requirement for conducting work as per Work Codes H15 and H22 has been based on Appin-Inghams POTS as it is not a confined space like Penrith PRS, which has been used for establishing the indicative times. A high level breakdown of time and resource requirements specific to each work code is shown below for reference, frequency of activity as listed in the 'Scope of Work' section. A charge out rate of [redacted] per hour has been used for Mechanical Technicians. This is based on 2014/15 rates for ZNX(2) technicians.

- H15: 360 minutes, 2 Mechanical Technicians
- H22: 90 minutes, 2 Mechanical Technicians

Jerrabomberra Packaged Off-Take Station shut down

Scope of works

All work codes for Jerrabomberra POTS will no longer be required once it is decommissioned and removed. This includes the following activties:

- H15 – Mechanical Overhaul of Regulators
- H22 – Mechanical Operational Check
- H20 – Pit Lid Maintenance
- H12 – Security (Grounds, buildings, doors, pipework)
- H65 – Station Operational Check
- 987 – TRS Audit
- H53 – Analogue Transmitters (P, T, DP)
- H66 – Heater Tapes
- H21 – Check Operation of Off Take Valve & Leak Test

Opex step change forecast basis

Actual costs incurred in 2013/14 are as follows:

- Labour costs from SAP:

  [redacted] = $4,205

  Materials cost: $800 (estimated)

  Total: $5,000

Costs in the base year 2014/15 are estimated on 9 months of operation, assuming a March 2015 decommission date. A proportion (75 per cent) of the total annual cost, calculated above, has been used.

Watson Pressure Limiting Station

Scope of works

The scope of works covered in this capex-driven step change is limited to the Watson PLS and includes all work as specified in the work codes referenced below.

- Security (Grounds/buildings/doors/pipe work) as per Work Code H12, frequency 3 monthly
- Mechanical overhaul of control valves, regulators, filters TRS/PRS as per Work Code H15, frequency 3 yearly
- Overhaul of regulators in workshop as per Work Code H16, frequency 3 yearly
- Lubricate inlet and outlet valves — TRS/PRS/ALB as per Work Code H21, frequency 6 monthly
- Maintenance Name: Mechanical Operational Check as per Work Code H22, frequency 3 monthly
- Pressure vessel inspection — external as per Work Code H30, frequency 2 yearly
- Pressure vessel inspection — internal as per Work Code H32, frequency 4 yearly
- Pressure Safety Valve (PSV), frequency 4 yearly to coincide with pressure vessel internal inspection

Electrical

- Security — gate switches and beams as per Work Code H50, 6 monthly
- Gas detector planned maintenance as per Work Code H51, frequency 3 monthly
- Analogue Transmitter (P/T/DP) as per Work Code H5, frequency 6 monthly
- Surge Diverters as per Work Code H55, frequency 3 monthly
- Calibrate Switches (PSH's, PSHH's etc.) as per Work Code H56, frequency 6 monthly
- Station Operational Check as per Work Code H65, frequency 1 yearly
- Visual inspection of intrinsically safe (Ex i) and flameproof (Ex d e n p) as per Work Code HZ1, frequency 4 yearly
- Detailed inspection of intrinsically safe (Ex i) and flameproof (Ex d e n p) as per Work Code HZ2, frequency 4 yearly

Other

- Pressure Vessel Registration, frequency 1 yearly
- Audit — Trunk & Primary Installations as per Work Code 987, frequency 6 monthly

Opex step change forecast basis

Where information is available, indicative times and resource requirements for conducting works on one run or the common site at Kooragang Island TRS have been used as a basis for estimating the cost of conducting the works at Watson PLS. Where information is unavailable, other stations were used as a reference basis (as noted). A charge out rate of [redacted] per hour has been used for Mechanical Technicians and [redacted] per hour for electrical and instrumentation technicians. This is based on 2014 rates for ZNX technicians.

Primary mains extensions

Scope of works

Additional maintenance activities are as follows:

- Hume Primary Main 5km Extension FY15 Onwards
  - Weekly Pipeline Patrol
  - CP survey twice a year
- Molonglo Primary Main 10.5km Extension FY20 onwards
  - Weekly Pipeline Patrol
  - CP survey twice a year

Opex step change forecast basis

The opex attributable to the Primary Mains extensions (PME) is set out in the table below.

Table C.1 Primary mains extensions cost summary ($'000, 2014/15)

	2014/15 (Base yr)	2015/16 (ext. yr)	2016/17	2017/18	2018/19	2019/20	2020/21
Hume PME Patrol	0.625	1.25	1.25	1.25	1.25	1.25	125
Hume PME CP Survey	0.625	1.25	1.25	1.25	1.25	1,25	1,25
Molonglo Patrol	-	-	-	-	-	2.50	2.50
Molonglo CP Survey	-	-	-	-	-	2.50	2.50
Total	**1.25**	**2.50**	**2.50**	**2.50**	**2.50**	**7.50**	**7.50**

Abbreviations used in this document

Abbreviation	Full term
ACT	Australian Capital Territory
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AS	Australian Standard
ASA	Asset Services Agreement
CAM	Cost allocation method
capex	capital expenditure
CP	cathodic protection
CTS	custody transfer station
DAMS	Distribution Asset Management Services Agreement
E-to-G	electricity to gas conversions
FTE	Full time equivalent
HP	high pressure
I&C	industrial and commercial
IT	information technology
JAM	Jemena Asset Management Pty Ltd
JGN	Jemena Gas Networks (NSW) Ltd
km	kilometre(s)
kPa	kilopascal(s)
LP	low pressure
m	metre(s) / millions (when relating to financial information)
MDL/MDLs	meter data logger
mm	millimetre(s)
MP	medium pressure
NECF	National Energy Customer Framework
NGL	National Gas Law
NGR	National Gas Rules (also 'the Rules')
NSW	New South Wales
O&M	operations and maintenance
opex	operating and maintenance expenditure
POTS	package offtake station
PRS	primary regulating station
RIN	Regulatory Information Notice
Rules, the	National Gas Rules
SCADA	supervisory control and data acquisition
TRS	trunk-receiving station
WBH	water bath heater
ZNX(2)	ZNX (2) Pty Ltd