Revised 2016-21 access arrangement proposal

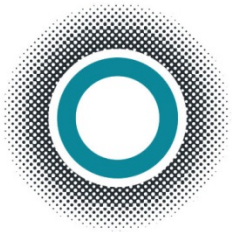
Response to the AER's draft decision

Appendix 9.01

HoustonKemp

Efficiency Carryover Mechanism

4 January 2016



HOUSTONKEMP
Economists

Efficiency carryover mechanism

A report for DLA Piper for ActewAGL

4 January 2016

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Executive Summary

I have been asked to prepare this report by DLA Piper on behalf of ActewAGL Distribution (ActewAGL). The context for my report is the Australian Energy Regulator's (AER's) draft decision in relation to the distribution determination applying to ActewAGL's gas distribution network for the period commencing on 1 July 2016 through to 30 June 2021 (the draft decision).[1]

DLA Piper has asked that I address a question concerning the operation of the efficiency carryover mechanism that applies in the current access arrangement period and the calculation of the efficiency carryover amounts to be added to the revenues for the forthcoming access arrangement period. DLA Piper's instructions to me are attached as Annexure A to my report. For ease of exposition, I set out the specific question I have been asked to consider below.

> Assuming that an efficiency increment or decrement for the 2014/15 year should be calculated using the formula stated in clause 4.6 of the 2010 Access Arrangement to apply to the second, third and fourth years of the 2010 Access Arrangement Period (and not using the formula for A5*), and in light of the interrelationship between an opex incentive scheme applying in one regulatory period and the adoption of a revealed cost approach to forecasting opex for the following regulatory period, do you consider that the AER's decision on the efficient base year opex used to determine opex forecasts in the Draft Decision for the 2015/16 year and the Upcoming Regulatory Period are consistent with the AER's determination of the increments (decrements)?

I find that the draft decision incorrectly applies the operating expenditure efficiency mechanism for the current access arrangement period. Specifically, the proposed adjustments to base year operating expenditure for non-recurring costs have been made without regard to the operation of the efficiency carryover mechanism.

The effect of these proposed adjustments to base year operating expenditure is that:

- there is an unanticipated retrospective change to the incentives applying to operating expenditure that results in a material financial loss to ActewAGL by imposing excessive penalties in relation to the one-off costs in 2014-15;
- there is not a fair sharing of gains and losses between ActewAGL and its customers; and
- the efficiency objectives of providing continuous and time invariant incentives for operating expenditure efficiency are undermined.

The correct application of the operating expenditure efficiency mechanism would be to retain the one-off costs in the base year operating expenditure. This, together with the negative efficiency carry forward amounts, delivers an appropriate effective target opex allowance.

I note that the retention of one-off costs in the base year was explicitly modelled by the AER as part of its 2008 efficiency benefit sharing scheme (EBSS) for electricity distribution network service providers. This worked example demonstrated that retaining one-off costs in the base year opex allowance, together with the efficiency carryover amounts, delivers a fair sharing of these costs between the regulated business and its customers.[2]

Further, the most recent version of the EBSS recognised that one-off factors in operating expenditure in the base year result in an opex allowance that does not reflect efficient operating costs of the firm.[3] To address

[1] Australian Energy Regulator, *Draft decision | ActewAGL Distribution Access Arrangement 2016 to 2021*, November 2015.

[2] See table B7 in section 2.1 of this report.

[3] AER, *Better Regulation| Explanatory Statement | Efficiency Benefit Sharing Scheme for Electricity Network Service Providers*, November 2013, p 14.

the optics of this outcome the EBSS for electricity networks was modified to accommodate for the removal of one-off factors from operating expenditure in the base year without changing the incentives for efficiency.[4] I note that an equivalent modification is not present in the efficiency carryover mechanism applied in the draft decision.

Finally I note that, to the extent that the opex allowance for the 2016-21 period should be adjusted to recognise the expected cost of preparing the 2021-24 access arrangement proposal, this cost should be provided for through a discrete adjustment (i.e. a step change) in addition to the adjustments reflected in these calculations.

[4] AER, *Better Regulation | Explanatory Statement | Efficiency Benefit Sharing Scheme for Electricity Network Service Providers*, November 2013, p 14.

1. Introduction

I have been asked to prepare this report by DLA Piper on behalf of ActewAGL Distribution (ActewAGL). The context for my report is the Australian Energy Regulator's (AER's) draft decision in relation to the distribution determination applying to ActewAGL's gas distribution network for the period commencing on 1 July 2016 through to 30 June 2021 (the draft decision).[5]

DLA Piper has asked that I address a question concerning the operation of the efficiency carryover mechanism that applies in the current access arrangement period and the calculation of the efficiency carryover amounts to be added to the revenues for the forthcoming access arrangement period. DLA Piper's instructions to me are attached as Annexure A to my report. For ease of exposition, I set out the specific question I have been asked to consider below.

> Assuming that an efficiency increment or decrement for the 2014/15 year should be calculated using the formula stated in clause 4.6 of the 2010 Access Arrangement to apply to the second, third and fourth years of the 2010 Access Arrangement Period (and not using the formula for A5*), and in light of the interrelationship between an opex incentive scheme applying in one regulatory period and the adoption of a revealed cost approach to forecasting opex for the following regulatory period, do you consider that the AER's decision on the efficient base year opex used to determine opex forecasts in the Draft Decision for the 2015/16 year and the Upcoming Regulatory Period are consistent with the AER's determination of the increments (decrements)?

1.1 My experience and expertise

I am a senior economist at the economic consulting firm, HoustonKemp. For the twelve years prior to joining HoustonKemp, I was an economist with NERA economic consulting, where I held the position of Senior Consultant for seven years. Over the last fourteen years I have advised infrastructure service providers, regulators and governments on the application of the building block approach, incentive mechanisms, operating and capital allowances, regulatory finance and asset valuation matters.

I attach a copy of my curriculum vitae as Annexure B.

[5] Australian Energy Regulator, *Draft decision | ActewAGL Distribution Access Arrangement 2016 to 2021*, November 2015.

1.2 Structure of this report

This report is structured as follows:

- section 2 – provides context to this report, including the development of the efficiency carryover mechanism and the efficiency mechanism set out in clauses 4.6 to 4.9 of ActewAGL's 2010 access arrangement; and
- section 3 – provides a summary of pertinent features of the 2015 draft decision and then addresses the question from DLA Piper and assesses the approach adopted in the draft decision on the calculation of efficiency carryover amounts.

I confirm that in the course of preparing this report, I have been provided with a copy of and read, understood and complied with Federal Court of Australia Practice Note CM7, entitled Expert Witnesses in Proceedings in the Federal Court of Australia (the Practice Note). My declaration, made in accordance with clause 2.2 of the Practice Note, is contained at the end of my report, as section 4.

2. Context to this report

This section provides context for the analysis undertaken in this report. Specifically, it:

- covers the development of the efficiency carryover mechanism; and
- reproduces the efficiency mechanism set out clauses 4.6 to 4.9 of ActewAGL's 2010 access arrangement.

Each of these is covered below.

2.1 Development of the efficiency carryover mechanism

The building block and 'fixed period' approach to regulation for covered services set out in the National Gas Rules (the "rules") is coupled with a 'no claw-back' principle, which means that there is no adjustment at the end of the access arrangement period to account for differences between forecast costs and actual outturn costs during the access arrangement period itself. The no claw-back principle provides incentives for a regulated pipeline to make efficiency improvements, so as to retain any difference between actual costs and forecast costs (or, conversely, that the regulated pipeline wears the financial penalty when forecast costs exceed actual costs).

However, the fixed period approach and no claw-back principle provide a regulated pipeline with incentives that are inconsistent with the objectives of the regulatory framework by encouraging the delayed implementation of efficiency or cost saving initiatives. This incentive arises because a regulated pipeline retains efficiency improvements for a longer period if they are made early in an access arrangement period, before passing these gains to consumers in the subsequent access arrangement period. Consequently, a regulated pipeline has an incentive to delay any efficiency improvements to the start of each access arrangement period.

The efficiency carryover mechanism operates alongside the 'no claw-back' principle (and the revealed cost approach to setting the opex allowance) and is intended to remove this perverse incentive. Where applied, the scheme seeks to have the following impacts:[6]

- a fair sharing of any outperformance or under performance, with a five year carry forward period resulting in a notional sharing ratio of 30:70 between the regulated business and its customers, respectively;
- a rate of retention of any gains or losses that is *invariant as to the timing* within an access arrangement period at which those gains/losses occur and so encourages firms to remain efficient throughout the access arrangement period rather than concentrate efficiency gains during the early part of the period; and
- symmetrical incentives that reward outperformance and penalise underperformance equally.

Further, the AER has also highlighted that the efficiency carryover mechanism provides a fair sharing of:[7]

- *one-off changes to operating expenditure*, with the firm retaining the benefit (or cost) of the one-off operating expenditure change in the year it is incurred, however, the firm has to refund the operating expenditure reduction to consumers (or is reimbursed by consumers for *the* operating expenditure increase) six years after the expenditure change occurs;
- *ongoing changes to operating expenditure*, with the firm retaining the benefit of any outperformance, or bearing the cost of any underperformance for a period of five years after the change is made, ie, before this expenditure change is passed through to consumers; and

[6] AER, *Final decision | Electricity transmission network service providers | Efficiency benefit sharing scheme*, September 2007, pp 2-3.

[7] AER, *Final decision | Electricity distribution network service providers | Efficiency benefit sharing scheme*, June 2008, p 23.

- *changes to the timing of operating expenditure*, with the firm sharing the benefits, or costs, of any change in the timing of operating expenditure.

The efficiency carryover mechanism that operates for electricity networks is known as the Efficiency Benefit Sharing Scheme (EBSS). The EBSS operates in a similar manner as the efficiency carryover mechanism applied to gas pipelines.

I note that the 2008 EBSS for electricity distributors provided an example of how this efficiency carryover mechanism would operate for a non-recurring change in the base year (year 4 of the current regulatory period) operating expenditure. This example is reproduced below.

Table B.7: Impact of a one-off opex reduction in regulatory period year 4 ($m, year 1 dollars)

Regulatory year	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*
Forecast (F)	100	100	100	100	100	90	90	90	90	90
Actual (A)	100	100	100	90	100	100	100	100	100	100
Incremental saving (E)	0	0	0	10	0	0	0	0	0	0
Carryover of gains made in										
1		0	0	0	0	0				
2			0	0	0	0	0			
3				0	0	0	0	0		
4					10	10	10	10	10	
5						0	0	0	0	0
Carryover amount						10	10	10	10	0
Effective target	100	100	100	100	100	100	100	100	100	90
Discount factor	1.19	1.12	1.06	1.00	0.94	0.89	0.84	0.79	0.75	0.70
Net present value										3.0

Source: AER, Efficiency benefit sharing scheme (September 2007).

This worked example shows that a one-off decrease in operating expenditure in year 4 would result in:

- a lower opex allowance in the second access arrangement period (ie, years 6 through 10) since year 4 is the base year for setting the opex allowance in the subsequent period;
- a positive EBSS carry forward amount which offsets the lower opex allowance in years 6 through 9; and
- a lower effective opex target in year 10 that ensures the firm refunds the one-off operating expenditure saving to consumers in that year and leads to the notional sharing of the one-off expenditure reduction in year 4 between the firm and customers on a 30:70 basis in present value terms.

A consequence of the operation of the efficiency carryover mechanism was that the opex allowance in the second regulatory period would not necessarily equal the efficient expenditure of the firm. Rather, the opex allowance is set at a level below the firm's efficient recurring cost. However, the efficiency carryover amount ensures that the effective target (the efficiency carryover amount plus the opex allowance) matches the firm's efficient recurring cost in all years except in year 10 when the firm is required to refund the one-off operating expenditure reduction to customers and so give effect to the notional 30:70 sharing ratio.

Since the mechanism is symmetric, a one-off increase in operating expenditure in the base year would be expected to result in:

- an opex allowance higher than the firm's efficient recurring operating expenditure costs in the second regulatory period (years 6 through 10);
- a negative efficiency carryover amount, that offsets the higher opex allowance in years 6 through 9, that results in an effective opex target in those years which equals the efficient recurring expenditure ; and

- a higher effective target in year 10, which ensures that the firm is reimbursed its one-off operating expenditure costs in the base year and gives effect to the notional 30:70 sharing between the firm and its customers.

The most recent version of the EBSS recognised that the one-off factors in operating expenditure in the base year result in an opex allowance that does not reflect efficient expenditure of the firm. Specifically, the AER noted that:[8]

> NSPs raised concerns that comparing their subsequent expenditure with their opex allowance could make them appear inefficient.

To address these concerns the 2013 EBSS was modified as follows:[9]

> We consider there should be flexibility in the EBSS to enable revenue to be shifted from the EBSS carryover to the opex allowance to account for non-recurrent efficiency gains in the base year.
>
> As a result, we have amended the EBSS to account for any adjustments made to base opex to remove the impacts of one-off factors.

The substance of this modification to the EBSS is that any change to base year operating expenditure is offset by a change to the year 5 incremental savings. Table 1 below illustrates how the 2013 EBSS operates and is based on the example set out in Table B.7 above, where there has been a one-off decrease in operating expenditure of $10m in year 4.

Under the 2013 EBSS the opex allowance in the second regulatory period is set to $100m (ie, the expected efficient level of recurring expenditure). To offset this higher opex allowance a negative EBSS carry over amount is now calculated for year 5, which is then carried forward into years 6 through 10. The net effect is that the effective opex target (the efficiency carryover amount plus the opex allowance) is equal to the expected efficient level of recurring expenditure in years 6 through 9. In year 10 the firm is required to refund the one-off operating expenditure saving made in year 4 to consumers to give effect to the notional 30:70 sharing of the one-off operating expenditure outperformance.

[8] AER, *Better Regulation| Explanatory Statement | Efficiency Benefit Sharing Scheme for Electricity Network Service Providers*, November 2013, p 14.

[9] AER, *Better Regulation | Explanatory Statement | Efficiency Benefit Sharing Scheme for Electricity Network Service Providers*, November 2013, p 14.

Table 1: 2013 EBSS treatment of a one-off decrease in opex in the base year ($m, year 1 dollars)

Regulatory year	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*
Forecast (F)	100	100	100	100	100	100	100	100	100	100
Actual (A)	100	100	100	90	100	100	100	100	100	100
Incremental saving (E)	0	0	0	10	-10	0	0	0	0	0
Carryover of gains made in										
1		0	0	0	0	0				
2			0	0	0	0	0			
3				0	0	0	0	0		
4					10	10	10	10	10	
5						-10	-10	-10	-10	-10
Carryover amount						0	0	0	0	-10
Effective target	100	100	100	100	100	100	100	100	100	90
Discount factor	1.19	1.12	1.06	1.00	0.94	0.89	0.84	0.79	0.75	0.70
Net present value										3.0

Source: HoustonKemp calculation.

A comparison of Table B.7 and Table 1 demonstrates that the modification to the EBSS made in 2013 does not have any impact on the effective opex target of a firm. That is, any one-off changes to operating expenditure continues to be retained by the regulated firm for a period of five years before being reimbursed to its customers in the sixth year.

2.2 ActewAGL's 2010 Access Arrangement

Clauses 4.6 to 4.9 of ActewAGL's 2010 access arrangement decision set out the efficiency carryover mechanism to apply to any under or over performance of actual operating expenditure compared to the allowance.[10]

This specification of the efficiency carryover mechanism mirrors the mechanism set out in the AER's 2007 EBSS scheme for electricity transmission networks.[11] However, it does not contain the modifications to the EBSS outlined in the 2013 scheme for electricity networks, which gives the regulator the flexibility to remove one-off costs in base year operating expenditure in a manner that does not undermine the objectives of the scheme.[12]

[10] AER, *Access Arrangement for the ACT, Queanbeyan and Palerang gas distribution network 1 July 2010 – 30 June 2015 | Amended by the order of the Australian Competition Tribunal made on 23 September 2010*, September 2010.

[11] AER, *Final decision | Electricity transmission network service providers | Efficiency benefit sharing scheme*, September 2007.

[12] AER, *Better Regulation | Efficiency Benefit Sharing Scheme for Electricity Network Service Providers*, November 2013.

3. ActewAGL draft decision

This section addresses the question raised by DLA Piper, specifically:

> Assuming that an efficiency increment or decrement for the 2014/15 year should be calculated using the formula stated in clause 4.6 of the 2010 Access Arrangement to apply to the second, third and fourth years of the 2010 Access Arrangement Period (and not using the formula for A_5^*), and in light of the interrelationship between an opex incentive scheme applying in one regulatory period and the adoption of a revealed cost approach to forecasting opex for the following regulatory period, do you consider that the AER's decision on the efficient base year opex used to determine opex forecasts in the Draft Decision for the Upcoming Regulatory Period are consistent with the AER's determination of the increments (decrements)?

I find that the draft decision incorrectly applies the operating expenditure efficiency mechanism for the current access arrangement period. Specifically, the proposed adjustments to base year operating expenditure for non-recurring costs have been made without regard to the operation of the efficiency carryover mechanism.

The effect of these proposed adjustments to base year operating expenditure is that:

- there is an unanticipated retrospective change to the incentives applying to operating expenditure that results in a material financial loss to ActewAGL by imposing excessive penalties in relation to the one-off costs in the 2014-15;
- there is not a fair sharing of gains and losses between ActewAGL and its customers; and
- the efficiency objectives of providing continuous and time invariant incentives for operating expenditure efficiency are undermined.

The correct application of the operating expenditure efficiency mechanism would be to retain the one-off costs in the base year operating expenditure. This, together with the negative efficiency carry forward amounts, delivers an appropriate effective target opex allowance.

I note that the retention of one-off costs in the base year was explicitly modelled as part of the 2008 EBSS for electricity distribution network service providers. This worked example demonstrated that retaining one-off costs in the base year operating expenditure, together with the efficiency carryover amounts, delivers a fair sharing of these costs between the regulated business and its customers.[13]

The following sections:

- sets out the principal elements of the draft decision that impact the incentives for the efficient operating expenditure;
- outline the implications of the two adjustments to base year operating expenditure proposed by the AER in its draft decision; and
- demonstrate that retaining these one-off costs in base year operating expenditure, together with the operation of the efficiency carryover mechanism set out in the draft decision, results in an appropriate effective opex target over the 2016-21 access arrangement period.

3.1 Draft decision

The efficiency incentive arrangements in relation to operating expenditure arise from three essential features of the regulatory framework, namely:

[13] See table B7 in section 2.1 of this report.

- no claw-back for differences between forecast and outturn operating expenditure;
- the resetting of the opex allowance by reference to ActewAGL's revealed operating expenditure in a "base year" (normally the penultimate year of the current access arrangement period); and
- the efficiency carryover mechanism.

This section summarises the pertinent components of ActewAGL's draft decision, noting that the principle of "no claw-back" is an implicit element of the regulatory framework.

3.1.1 Opex allowance

Table 2 in the AER's draft decision reproduces its proposed opex allowance for the 2015-16 to 2020-21 period.[14]

Table 2: Draft decision on ActewAGL's total opex ($m, $2015-16)

	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	Total (2016-21)
AER draft decision	24.7	26.0	26.1	26.5	27.1	27.3	133.0

Source: AER, Draft decision (November 2015).

This opex allowance was calculated by the AER using its base-step-trend approach.[15] Importantly, the AER used ActewAGL's reported operating expenditure for 2014-15 as the "base year" for determining the opex allowance for the 2015-16 year and the 2016-21 access arrangement period. Notably, the AER in assessing the efficiency of ActewAGL's reported base year operating expenditure has:

- removed one-off costs in 2014-15 of $2.45 million ($2014-15), ie:
  - the costs associated with preparing the access arrangement proposal;
  - the costs of consumer engagement associated with the access arrangement proposal; and
  - the cost allocation changes in the Distribution Asset Management Services (DAMS) agreement; and
- added back 20 per cent of the costs associated with preparing the access arrangement proposal in 2014-15 of $0.45 million ($2014-15).

3.1.2 Efficiency carryover mechanism

Table 3 sets out the AER's draft decision on the incremental gains (losses) for the 2010-15 period together with the efficiency carryover amounts that it proposes to apply to the 2015-16 year and the 2016-21 period.[16]

[14] AER, *Draft Decision | ActewAGL Distribution Access Arrangement 2016 to 2021 | Attachment 7 – Operating expenditure*, November 2015, p 7-6.

[15] The AER's base-step-trend approach to forecasting a networks opex allowance is set out at:

AER, *Draft Decision | ActewAGL Distribution Access Arrangement 2016 to 2021 | Attachment 7 – Operating expenditure*, November 2015, pp 7-10 to 7-11.

[16] AER, *Draft Decision | ActewAGL Distribution Access Arrangement 2016 to 2021 | Attachment 9 – Efficiency carryover mechanism*, November 2015, p 9-13.

Table 3: Draft decision on carryover amounts from the 2010-15 period ($m, $2015-16)

	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	Total
Incremental gain (loss)							
2010-11	-2.2						
2011-12	3.0	3.0					
2012-13	1.0	1.0	1.0				
2013-14	2.0	2.0	2.0	2.0			
2014-15	-2.4	-2.4	-2.4	-2.4	-2.4		
AER draft decision	**1.5**	**3.6**	**0.6**	**-0.4**	**-2.4**	**0**	**2.9**

Source: AER, Draft decision (November 2015).

The incremental gains (losses) have been calculated using the following formulae:

- the 2010-11 has been estimated using the following equation:

  $E_1 = (F_1 - A_1)$
- for years 2011-12 through 2015-16 has been estimated using the following equation:

  $E_i = (F_i - A_i) - (F_{i-1} - A_{i-1})$
- for 2014-15 actual operating expenditure has been estimated using the following equation:

  $A^*_{14-15} = F_{14-15} - (F_{13-14} - A_{13-14})$

Importantly, the 2014-15 actual operating expenditure used to calculate the incremental gains (losses) in the draft decision has not been adjusted for the one-off costs that have been removed from the "base year" operating expenditure used to determine the opex allowance for the 2015-16 year and over the 2016-21 period.

3.2 Preparation of the 2016-21 access arrangement

The draft decision noted that ActewAGL's estimated[17] base year operating expenditure (ie, 2014-15) included $2.3 million ($2015-16) of non-recurring costs associated with the preparation of the 2016-21 access arrangement. This expenditure is not expected to be incurred in each year of the 2016-21 access arrangement period and was removed from the base year operating expenditure for the purpose of calculating the opex allowance for that period. Instead the AER included:[18]

> … a proportion (20 per cent) of the 2014-15 costs associated with preparation of the 2016-21 access arrangement proposal in our assessment of efficient base year costs. This is because we consider the addition of this amount ensures compliance with the opex criteria.

[17] For completeness, I note that ActewAGL Distribution's proposal estimated base year (2014-15) operating expenditure using actual expenditure up to February 2015 month end and the remaining months using budgeted forecasts. See: ActewAGL, *2016-21 access arrangement proposal | Attachment 5: Operating expenditure*, June 2015, p 20.

[18] AER, *Draft Decision | ActewAGL Distribution Access Arrangement 2016 to 2021 | Attachment 7 Operating expenditure*, November 2015, p 7-16.

The impact of this decision is set out below. For ease of exposition, Table 4 isolates the impact of the proposed treatment of the costs associated with preparing the 2016-21 access arrangement proposal. I have therefore assumed that all forecast and actual recurring operating costs are equal to zero.

Table 4: Proposed treatment of the costs of preparing the 2016-21 access arrangement proposal ($m, $2015-16)

Regulatory year	*10/11*	*11/12*	*12/13*	*13/14*	*14/15*	*15/16*	*16/17*	*17/18*	*18/19*	*19/20*	*20/21*
Forecast (F)	0	0	0	0	0	0.46	0.46	0.46	0.46	0.46	0.46
Actual (A)	0	0	0	0	2.3	0	0	0	0	0	0
Incremental saving (E)	0	0	0	0	-2.3	0	0	0	0	0	0
Carryover of gains made in											
10/11		0	0	0	0	0					
11/12			0	0	0	0	0				
12/13				0	0	0	0	0			
13/14					0	0	0	0	0		
14/15						-2.3	-2.3	-2.3	-2.3	-2.3	
15/16							0	0	0	0	0
Carryover amount						-2.3	-2.3	-2.3	-2.3	-2.3	0
Effective target	0	0	0	0	0	-1.84	-1.84	-1.84	-1.84	-1.84	0.46
Discount factor[19]	1.26	1.19	1.12	1.06	1.00	0.94	0.89	0.84	0.79	0.75	0.70
Net present value											-9.7

Source: HoustonKemp calculation.

Table 4 illustrates that the cost of preparing the access arrangement proposal (ie, $2.3 million) results in an efficiency carryover amount of -$2.3 million ($2015-16) in the 2014-15 year. This is then carried forward as an annual negative efficiency carryover amount (ie, a penalty) in the 2015-16 year as well as the first four years of the 2016-21 period (ie, 2016-17 to 2019-20).

This negative efficiency carryover amount would be partially offset by the AER's higher opex allowance that includes 20 per cent of the cost of preparing the access arrangement proposal (ie, $0.46 million per annum). However, Table 4 illustrates that ActewAGL bears a penalty of $9.7 million (in present value terms[20]) for its $2.3 million expenditure on the access arrangement proposal – ie, the combined effect of the cost of the initial $2.3m ($2015-16) in expenditure in 2014-15, the negative efficiency carryover amount which results in an effective penalty of $1.84m ($2015-16) per annum in the 2015-16 to 2019-20 period and the slightly higher opex allowance of $0.46m ($2015-16) per annum in that period.

In other words, every $1 ActewAGL spent on preparing the access arrangement proposal will result in a financial penalty of just under $4.23 (in present value terms). In my opinion, this outcome is clearly inconsistent with the intent of the incentive arrangements applying to ActewAGL over the 2010-15 access arrangement period. Specifically, that:

- one-off changes in operating expenditure would be retained by the firm for a period of 6 years before being reimbursed to customers;
- the effective opex target (efficiency carryover amount plus the opex allowance) should match the firm's recurring costs for the first four years of the following access arrangement period; and

[19] Assuming an indicative discount rate of 6 per cent.

[20] Assuming an indicative discount rate of 6 per cent.

- the effective opex target in the final year of the following access arrangement period should reimburse $2.3 million ($2015-16) to ActewAGL for the non-recurring costs associated with its 2014-15 costs of preparing the access arrangement proposal.

Only then would the costs of preparing the access arrangement proposal be shared between ActewAGL and its customers on a notional 30:70 basis.

By contrast, the correct application of the operating expenditure efficiency mechanism is presented in Table 5 below.

Table 5: Correct treatment of the costs of preparing the 2016-21 access arrangement proposal ($m, $2015-16)

Regulatory year	*10/11*	*11/12*	*12/13*	*13/14*	*14/15*	*15/16*	*16/17*	*17/18*	*18/19*	*19/20*	*20/21*
Forecast (F)	0	0	0	0	0	2.3	2.3	2.3	2.3	2.3	2.3
Actual (A)	0	0	0	0	2.3	0	0	0	0	0	0
Incremental saving (E)	0	0	0	0	-2.3	0	0	0	0	0	0
Carryover of gains made in											
10/11		0	0	0	0	0					
11/12			0	0	0	0	0				
12/13				0	0	0	0	0			
13/14					0	0	0	0	0		
14/15						-2.3	-2.3	-2.3	-2.3	-2.3	
15/16							0	0	0	0	0
Carryover amount						-2.3	-2.3	-2.3	-2.3	-2.3	0
Effective target	0	0	0	0	0	0	0	0	0	0	2.3
Discount factor[21]	1.26	1.19	1.12	1.06	1.00	0.94	0.89	0.84	0.79	0.75	0.70
Net present value											-0.7

Source: HoustonKemp calculation.

Table 5 shows that the retention of the one-off costs that ActewAGL incurred in preparing the access arrangement proposal in base year operating expenditure, together with the draft decision's efficiency carryover amount calculation, would result in an effective opex target that:

- reflects ActewAGL's expected efficient operating expenditure in 2015-16 through to 2019-20, as the higher opex allowance offsets the negative efficiency carryover amounts over that period;
- reimburses ActewAGL in 2020-21 for the one-off costs incurred in preparing the access arrangement proposal in 2014-15; and
- gives effect to the intended fair sharing of cost overruns between ActewAGL and its customers, ie, the one-off increase in operating expenditure in 2014-15 is retained by ActewAGL for a period of 5 years before being reimbursed by customers in the sixth year, i.e. 2020-21.

Note that the efficiency carryover mechanism operates to give effect to a fair sharing of over or under performance by a firm relative to its opex allowance. That is, the extra $2.3 million ($2015-16) reimbursed to ActewAGL in 2020-21 is necessary to share the costs incurred in 2014-15 in preparing the 2016-21 access arrangement proposal. I note that, to the extent that the opex allowance for the 2016-21 period should be adjusted to recognise the expected cost of preparing the 2021-24 access arrangement proposal, this cost

[21] Assuming an indicative discount rate of 6 per cent.

should be provided for through a discrete adjustment (i.e. a step change) in addition to the adjustments reflected in these calculations.

3.3 Changes to the Distribution Asset Management Services (DAMS) agreement

The draft decision proposes to make a further adjustment to ActewAGL's 2015-16 base year operating expenditure to account for the cost allocation changes in the DAMS agreement. This proposed adjustment results in $0.2 million ($2015-16) being removed from base year operating expenditure. Again this adjustment has not been reflected in the calculation of the efficiency carryover amounts.

In other words, the draft decision:

- included the $0.2 million in expenditure incurred in 2015-16 in its calculation of the efficiency carryover amounts; and
- removed $0.2 million from the actual base year operating expenditure used to calculate the opex allowance for the 2015-15 year and the 2016-21 access arrangement period.

Table 6 calculates the financial impact of this proposed adjustment. Again, for simplicity, I have assumed that all other costs are recurring and all forecast and actual recurring operating costs are equal to zero.

Table 6: Proposed treatment of the DAMS costs ($m, $2015-16)

Regulatory year	*10/11*	*11/12*	*12/13*	*13/14*	*14/15*	*15/16*	*16/17*	*17/18*	*18/19*	*19/20*	*20/21*
Forecast (F)	0	0	0	0	0	0	0	0	0	0	0
Actual (A)	0	0	0	0	0.2	0	0	0	0	0	0
Incremental saving (E)	0	0	0	0	-0.2	0	0	0	0	0	0
Carryover of gains made in											
10/11		0	0	0	0	0					
11/12			0	0	0	0	0				
12/13				0	0	0	0	0			
13/14					0	0	0	0	0		
14/15						-0..2	-0.2	-0.2	-0.2	-0.2	
15/16							0	0	0	0	0
Carryover amount						-0.2	-0.2	-0.2	-0.2	-0.2	0
Effective target	0	0	0	0	0	-0.2	-0.2	-0.2	-0.2	-0.2	0
Discount factor[22]	1.26	1.19	1.12	1.06	1.00	0.94	0.89	0.84	0.79	0.75	0.70
Net present value											-1.0

Source: HoustonKemp calculation.

Table 6 shows that including the non-recurring DAMS costs in the calculation of the efficiency carryover amounts results in a carryover amount associated with 2014-15 performance of -$0.2 million ($2015-16). However, this amount is not included in ActewAGL's opex allowance for the 2015-16 year or the 2016-21 period. Consequently, the proposed adjustment results in ActewAGL bearing a penalty of $1.0 million (in present value terms) for spending $0.2 million ($2015-16) on non-recurring DAMS costs in 2014-15. In other words, every $1 spent by ActewAGL on DAMS in 2014-15, which is not recurring in the 2016-21 access arrangement period, results in a penalty of $5.21 (in present value terms).

[22] Assuming an indicative discount rate of 6 per cent.

The correct application of the operating expenditure efficiency mechanism for the DAMS fees one-off costs is presented in Table 7 below.

Table 7: Corrected treatment of the DAMS costs ($m, $2015-16)

Regulatory year	*10/11*	*11/12*	*12/13*	*13/14*	*14/15*	*15/16*	*16/17*	*17/18*	*18/19*	*19/20*	*20/21*
Forecast (F)	0	0	0	0	0	0.2	0.2	0.2	0.2	0.2	0.2
Actual (A)	0	0	0	0	0.2	0	0	0	0	0	0
Incremental saving (E)	0	0	0	0	-0.2	0	0	0	0	0	0
Carryover of gains made in											
10/11		0	0	0	0	0					
11/12			0	0	0	0	0				
12/13				0	0	0	0	0			
13/14					0	0	0	0	0		
14/15						-0..2	-0.2	-0.2	-0.2	-0.2	
15/16							0	0	0	0	0
Carryover amount						-0.2	-0.2	-0.2	-0.2	-0.2	0
Effective target	0	0	0	0	0	0	0	0	0	0	0.2
Discount factor[23]	1.26	1.19	1.12	1.06	1.00	0.94	0.89	0.84	0.79	0.75	0.70
Net present value											-0.1

Source: HoustonKemp calculation.

Table 7 shows that including the DAMS fees one-off costs in the base year operating expenditure used to determine the opex allowance, when combined with the efficiency carryover amounts set out in the draft decision, ensures that this one-off increase in operating expenditure in 2014-15 is retained by the ActewAGL for a period of 6 years before being reimbursed by customers in 2020-21.

I note that if ActewAGL had incurred these non-recurring costs in any year other than the base year, the efficiency carryover mechanism would have operated as intended. This point is illustrated below in Table 8.

[23] Assuming an indicative discount rate of 6 per cent.

Table 8: Scenario where the DAMS fees one-off costs occur in 2013-14 ($m, $2015-16)

Regulatory year	*10/11*	*11/12*	*12/13*	*13/14*	*14/15*	*15/16*	*16/17*	*17/18*	*18/19*	*19/20*	*20/21*
Forecast (F)	0	0	0	0	0	0	0	0	0	0	0
Actual (A)	0	0	0	0.2	0	0	0	0	0	0	0
Incremental saving (E)	0	0	0	-0.2	0.2	0	0	0	0	0	0
Carryover of gains made in											
10/11		0	0	0	0	0					
11/12			0	0	0	0	0				
12/13				0	0	0	0	0			
13/14					-0.2	-0.2	-0.2	-0.2	-0.2		
14/15						0.2	0.2	0.2	0.2	0.2	
15/16							0	0	0	0	0
Carryover amount						0	0	0	0	0.2	0
Effective target	0	0	0	0	0	0	0	0	0	0.2	0
Discount factor[24]	1.19	1.12	1.06	1.00	0.94	0.89	0.84	0.79	0.75	0.70	0.67
Net present value											-0.1

Source: HoustonKemp calculation.

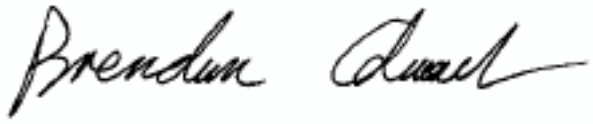
Table 8, shows that if the DAMS expenditure had occurred in 2013-14, rather than the base year 2014-15, then:

- this would have generated a negative efficiency carryover amount for 2013-14 of $0.2m ($2015-16);
- as these costs would not be incurred in 2014-15, there would be a positive efficiency carryover amount for this year of $0.2m ($2015-16); and
- the effective opex target in 2019-20 would be $0.2m ($2015-16) higher than forecast recurring operating costs and so give effect to the objective of a notional 30:70 sharing of outperformance (under performance).

[24] Assuming an indicative discount rate of 6 per cent.

4. Declaration

In accordance with the Guidelines, I confirm that I have made all inquiries that I believe are desirable and appropriate, and that no matters of significance that I regard as relevant have, to my knowledge, been withheld from the Court.



Brendan P Quach
4 January 2016

Annexure A: Instructions

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Your reference

Our reference
ACW/ACW/354593/2
AUM/1211870086.1

31 December 2015

By Email Only

Dear Brendan

ACTEWAGL DISTRIBUTION GAS ACCESS ARRANGEMENT FOR UPCOMING REGULATORY PERIOD - EXPERT REPORT ON OPEX INCENTIVE SCHEMES

ActewAGL Distribution (**ActewAGL**) is seeking an expert report from Houston Kemp in relation to issues pertaining to operating expenditure (**opex**) incentive schemes in the context of the Australian Energy Regulator's (**AER's**) gas distribution reset for ActewAGL for the forthcoming regulatory period.

Background

ActewAGL owns and operates the gas distribution network in the ACT and Queanbeyan and Palerang shires. It is subject to economic regulation in respect of this network under the National Gas Law (**NGL**) and the National Gas Rules (**NGR**). Under the NGL and the NGR, ActewAGL is required to have in place an AER approved access arrangement for its network, which (amongst other things) regulates ActewAGL's reference tariffs, and through this its revenues, for the reference services provided by means of this network.

On 23 September 2010, the Australian Competition Tribunal made an order which had the effect of determining the access arrangement (**2010 Access Arrangement**) that would apply to ActewAGL's network in the regulatory period commencing on 1 July 2010 (**2010 Access Arrangement Period**).

Subsequently, during the Australian Energy Market Commission's (**AEMC's**) consultation on the *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012* (**2012 NER Amendments**) and the *National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012* (**2012 NGR Amendments**) (together, **2012 Rule Amendments**), it became apparent to ActewAGL that the adoption of the then proposed transitional arrangements for the 2012 NER Amendments would result in ActewAGL conducting its gas and electricity distribution resets concurrently.

Accordingly, ActewAGL made submissions to the AEMC to the effect that it did not support those proposed transitional arrangements. ActewAGL also made submissions to the effect that in the alternative (that is, if the regulatory timetable proposed in the 2012 NER Amendments were adopted), then the AEMC should implement changes to the NGR that would result in the review submission date for ActewAGL's access

arrangement revision proposal (**Revision Proposal**) in respect of its 2010 Access Arrangement being delayed.

In accordance with ActewAGL's alternative request, the AEMC determined that transitional rules be made to effect the requested delay as part of the 2012 NGR Amendments. Ultimately, the requested delay was given effect by the AER by exercising a power under rule 52(3) of the NGR (as modified by clauses 34 and 35 of Schedule 1 to the NGR) to extend the review submission date for ActewAGL's Revision Proposal to 30 June 2015.

In consequence of the above, a period of time arises between the date on which revisions to the 2010 Access Arrangement were initially expected to commence (i.e. 1 July 2015) and the date on which those revisions will, in fact, commence (i.e. now expected to be 1 July 2016).

In June 2015, ActewAGL lodged with the AER a proposed Access Arrangement (**Proposed Access Arrangement**) for a regulatory period commencing 1 July 2016 (**Upcoming Regulatory Period**). Together with the Proposed Access Arrangement, ActewAGL also lodged additional information regarding that arrangement pursuant to rule 43 of the NGR (**Access Arrangement Information**).

In November 2015, the AER issued a draft decision in respect of ActewAGL's Proposed Access Arrangement for the Upcoming Regulatory Period commencing in 2016 (**Draft Decision**).

Relevant NGR provisions

Under the NGR, a full access arrangement must (amongst other things) describe the pipeline services the service provider proposes to offer to provide by means of the pipeline, specify the reference services and, for each reference service, specify the reference tariff (rule 48(1)(b) to (d)). A full access arrangement must also include a reference tariff variation mechanism for variation of a reference tariff over the course of an access arrangement period (rule 92(1)).

When submitting an access arrangement for the AER's approval, a service provider must submit, with the proposal, access arrangement information for the access arrangement proposal (rule 43(1)). The access arrangement information for a full access arrangement proposal must include (amongst other things) (rule 72(1) (e), (i), (k), (l) and (m)):

- a forecast of operating expenditure over the access arrangement period and the basis on which the forecast has been derived;
- if an incentive mechanism operated for the previous access arrangement period, the proposed carry-over of increments for efficiency gains or decrements for efficiency losses in the previous access arrangement period and a demonstration of how allowance is to be made for any increments or decrements;
- the service provider's rationale for any proposed reference tariff variation mechanism;

- the service provider's rationale for any proposed incentive mechanism; and
- the total revenue to be derived from pipeline services for each regulatory year of the access arrangement period.

When submitting an access arrangement variation proposal, the service provider must include in the access arrangement information so much of the above information as is relevant to the proposal (rule 72(2)).

Total revenue is determined for each regulatory year of the access arrangement period using the building block approach in which the building blocks include (amongst others) (rule 76(d) and (e)):

- 'increments or decrements for the year resulting from the operation of an incentive mechanism to encourage gains in efficiency (See Division 9)'; and
- 'a forecast of operating expenditure for the year (See Division 7)'.

Division 9 of Part 9 of the NGR reads as follows:

> **98 Incentive mechanism**
>
> (1) A full access arrangement may include (and the AER may require it to include) one or more incentive mechanisms to encourage efficiency in the provision of services by the service provider.
>
> (2) An incentive mechanism may provide for carrying over increments for efficiency gains and decrements for losses of efficiency from one *access arrangement period* to the next.
>
> (3) An incentive mechanism must be consistent with the revenue and pricing principles.

Division 7 of Part 9 of the NGR reads as follows:

> **91 Criteria governing operating expenditure**
>
> (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 AER's discretion under this rule is limited.

Division 8 of Part 9 of the NGR provides that total revenue must be allocated between reference and other services in the ratio to which costs are allocated between reference and other services (rule 93(1)) and that the reference tariff variation mechanism must be designed to equalise (in terms of present values) forecast revenue from reference services over the access arrangement period and the portion of total revenue allocated to reference services for the period (rule 92(2)).

Division 10 of Part 9 of the NGR provides that a full access arrangement may include a principle declared in the access arrangement to be fixed for a stated period (rule 99(1)). A principle may be fixed for a period extending over two or more access arrangement periods (rule 99(2)). A fixed principle approved by the AER is binding on the AER and the service provider for the period for which it is fixed but may be varied or revoked by the AER with the service provider's consent and, if inconsistent with the NGR, the NGR operate to the exclusion of the fixed principle (rule 99(3) and (4)).

Relevant provisions of 2010 Access Arrangement

Clause 4 of the 2010 Access Arrangement contained an opex carryover mechanism (**2010 OCM**). Clause 4.5 relevantly provides that the incentive mechanisms used in calculating reference tariffs include:

> (a) that Reference Tariffs apply each year regardless of whether the forecasts on which the Reference Tariffs were determined are realised; and
>
> (b) a rolling carryover mechanism, that results in ActewAGL retaining the reward associated with an efficiency-improving initiative for five years after the year in which the gain was achieved, that is, a reward (being the net amount of the efficiency gains (or losses) relating to operating expenditure) earned in one year of an Access Arrangement Period would be added to the total revenue and carried forward into the next Access Arrangement Period if necessary, until it has been retained by ActewAGL for a period of five years.

Clauses 4.6 to 4.9 of the 2010 Access Arrangement detail the 2010 OCM described in paragraph (b) above, providing in particular for the calculation of the carryover amounts referable to opex incurred in the 2010 Access Arrangement Period.

In so doing, the provisions contemplate that the 2010 Access Arrangement Period will be a 5 year period, with the next access arrangement period commencing on 1 July 2015. At the same time, however, the term 'Access Arrangement Period', where it appears in clauses 4.6 to 4.9, takes its defined meaning. This term is defined in clause 1.1 of Attachment 1 to the 2010 Access Arrangement to mean:

> '…the period from the Commencement Date to the Revisions Commencement Date.'

The term 'Revisions Commencement Date' is, in turn, defined to mean:

> '…the date on which the revisions to this Access Arrangement commence under clause 1.17 of Part 1 of this Access Arrangement.'

Clause 1.17 of the 2010 Access Arrangement provides:

> 'The revisions to this Access Arrangement will commence on the later of 1 July 2015 and the date on which the approval by the Relevant Regulator of the revisions to the Access Arrangement takes effect under the National Gas Rules.'

Clause 4.21 of the 2010 Access Arrangement sets out fixed principles for the purposes of section 99 of the NGR including that:

'the carryover into the access arrangement period after the Revisions Commencement Date ("Next Access Arrangement Period") of any cost savings or overspend as provided in clauses 4.6 to 4.9'.

ActewAGL's Proposal

In the Access Arrangement Information accompanying its Proposed Access Arrangement, ActewAGL made the following observations regarding the impact of the delay in the reset process (pages 6 and 7 of Attachment 10):

> In accordance with the rolling carryover mechanism prescribed in clause 4.6 of the 2010-15 access arrangement, ActewAGL Distribution has calculated the carryover amounts as shown in Table 1 below.
>
> …
>
> Table 1 shows a carryover amount of $3.7 million in 2015/16. However, as a result of the AER's extension of the revisions submission date, reference tariffs in place at 30 June 2015 will continue without variation from 1 July 2015 to 30 June 2016. This means that the carryover adjustment due in 2015/16 cannot be made in 2015/16. Given that the Rules do not require an adjustment, or true-up, of revenues or tariffs following the extension year, ActewAGL Distribution has not added the $3.7 million to the revenue building blocks for 2016-21. This is consistent with ActewAGL Distribution's treatment of other elements of the access arrangement, that is, no true-up of revenues following the extension year. The basis for this position is explained in attachment 11 to this access arrangement information.
>
> …
>
> The incentive mechanism in clause 4.6 of the 2010-15 access arrangement is defined for a period of five years. It was not intended to apply in 2015/16 (the extension year). Given that no opex allowance has been set by the AER for 2015/16, the mechanism cannot operate as intended. ActewAGL Distribution therefore proposes that no carryover mechanism should apply in 2015/16. The mechanism should re-start for the 2016-21 access arrangement period, as described in the following section.

In the Access Arrangement Information, ActewAGL made the following observations regarding the adjustments it proposed to base year opex to remove non-recurrent costs (pages 21 to 22 of Attachment 5):

> 'Costs incurred in the base year to prepare this access arrangement revision proposal and engage with consumers on the proposal have been removed from base year opex on the basis that they are non-recurrent. Because these costs have been adjusted out of base opex, ActewAGL Distribution has included a step change for costs it expects to incur to prepare and engage on the next access arrangement revision proposal between 2018/19 and 2020/21.
>
> …
>
> There are several non-recurrent costs included in the asset services and management services fees that have been adjusted out of base year opex to ensure it reflects efficient ongoing costs.

- Canberra primary main pigging project costs, which are an additional service under the DAMS agreement and are periodic in nature (nominally every ten years), have been treated as opex during the 2010-15 period.

- An adjustment to correct for an allocation of JAM costs to capex in 2013/14, which was required to be written back to opex in 2014/15 to ensure consistency with relevant accounting rules.

- Costs associated with a non-recurrent project to determine the impacts and changes required to conform to the new Gas Service & Installation Code and Network Boundary Code (due to local ACT Technical Regulation (Metering related) Code changes in 2013/14) were accrued in 2013/14, but not invoiced until 2014/15.

- A number of minor budget allocation adjustments were made for costs not incurred in 2014/15 and beyond.'

AER's Draft Decision

Attachment 9 of the Draft Decision sets out the AER's draft decision in respect of the implementation of the 2010 OCM established by the 2010 Access Arrangement and the application of the proposed new opex incentive scheme to apply during the Upcoming Regulatory Period.

In its Draft Decision, the AER determines as follows concerning the carryover amounts arising under the 2010 OCM:

- as year 5 of the 2010 Access Arrangement Period (2014/15) is proposed to be the base year used in deriving opex forecasts for the Upcoming Regulatory Period, rather than year 4 as contemplated by the 2010 Access Arrangement, the formula specified in that 2010 Access Arrangement for the calculation of carryover amounts for the second, third and fourth regulatory years of the 2010 Access Arrangement Period should also be applied to year 5 (pages 9-13 to 9-14);

- zero efficiency gains should be assumed in the 2015/16 year, as this is consistent with its usual approach which assumes the incremental efficiency gain (loss) in the final year of the access arrangement period is equal to zero (page 9-14); and

- it would be appropriate to apply the revenue increment (decrement) for 2015/16 arising under the 2010 OCM (page 9-14).

In respect of the equations to calculate incremental efficiency gains under the incentive mechanism to apply in the Upcoming Regulatory Period set out in the Proposed Access Arrangement, the AER determined that the 'usual' formula that would apply in the second to penultimate regulatory years should also be applied in calculating incremental efficiency gains (losses) for year one (2016/17), namely $E_i = (F_i - A_i) - (F_{i-1} - A_{i-1})$ (page 9-15).

Attachment 7 of the Draft Decision sets out the AER's draft decision in respect of forecast opex for the 2015/16 year and Upcoming Regulatory Period. In its Draft

Decision, the AER determines that 2014-15 will be the base year for forecasting opex for the 2015/16 year and Upcoming Regulatory Period (page 7-15).

In determining the quantum of the efficient base year opex, the AER's Draft Decision is to:

- remove the one off adjustment arising from cost allocation changes in the Distribution Asset Management Services agreement (**DAMS**) (page 7-16);

- include a portion (20%) of the 2014-15 costs associated with the preparation of the 2016-21 regulatory proposal in its assessment of efficient base year costs (page 7-16);

The AER did not exclude costs in these categories from the actual operating expenditure that it used in the derivation of incremental gains or losses arising pursuant to the 2010 Access Arrangement applicable to total revenue in the 2015/16 year and Upcoming Regulatory Period.

2010 Access Arrangement Questions

In the Attachment to this letter, we detail the documents that we are providing to you together with this engagement letter. We would be grateful if you could review those documents and provide a report setting out your conclusions, and reasoning, in relation to the following question on the basis of the assumptions stated in that question.

1. Assuming that an efficiency increment or decrement for the 2014/15 year should be calculated using the formula stated in clause 4.6 of the 2010 Access Arrangement to apply to the second, third and fourth years of the 2010 Access Arrangement Period (and not using the formula for A_5^*), and in light of the interrelationship between an opex incentive scheme applying in one regulatory period and the adoption of a revealed cost approach to forecasting opex for the following regulatory period, do you consider that the AER's decision on the efficient base year opex used to determine opex forecasts in the Draft Decision for the 2015/16 year and Upcoming Regulatory Period are consistent with the AER's determination of the increments (decrements)?

Attachments

For the purposes of undertaking this work, we will provide you with a copy of the documents listed in Attachment A. A list of the documents that we have provided to you, and any additional documents relied on by Houston Kemp in preparing the report, should be included in the report. A copy of any documents included in the list that were not provided to Houston Kemp by DLA Piper should also be provided to us with the report.

Expert witness

Included as Attachment B to this letter is a copy of Practice Note CM7: Expert Witnesses in Proceedings in the Federal Court of Australia, 4 June 2013. We request

that your report complies with the requirements of Practice Note CM7, and that you certify in your report that you have complied with Practice Note CM7.

We request that you attach to the report a copy of this engagement letter and a copy of the CVs of the authors, which contain all qualifications and relevant experience.

Yours sincerely

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ATTACHMENT A

We attach the following documents:

1. 2010 Access Arrangement;

2. Proposed Access Arrangement;

3. Attachment 5 to the Access Arrangement Information (regarding opex);

4. Attachment 10 to the Access Arrangement Information (regarding the Incentive Mechanism);

5. Appendix 5.06 to the Access Arrangement Information (which contains an AAI Opex Model)

6. Overview of the Draft Decision;

7. Attachment 7 of the Draft Decision (regarding opex);

8. Attachment 9 of the Draft Decision (regarding the Incentive Mechanism); and

9. AER Model entitled 'Draft Decision ActewAGL Distribution access arrangement - Proposed Efficiency Carryover Mechanism - November 2015.'

10. AER Model entitled 'Draft Decision ActewAGL Distribution access arrangement - Opex model - November 2015.'

ATTACHMENT B: ***PRACTICE NOTE CM7: EXPERT WITNESSES IN PROCEEDINGS IN THE FEDERAL COURT OF AUSTRALIA***

Annexure B: Curriculum vitae

Brendan Quach

Senior Economist

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Overview

Brendan has worked a consulting economist, specialising in network economics and finance in Australia, New Zealand and Asia Pacific region. Over the last 13 years Brendan has advised clients on the application of regulatory principles to airports, ports, telecommunications electricity transmission and distribution networks, water networks and gas pipelines. He has provided advice on application of the building block approach, incentive mechanisms, operating and capital allowances, financing and asset valuation to businesses, a regulators and governments.

Brendan is a specialist in the cost of capital for use in regulatory price reviews and contract arbitrations. He has authored reports on all aspects of the cost of capital including equity estimation techniques, the impact of tax imputation credits, and estimating benchmark debt costs.

Qualifications

1991-1995	**Australian National University** Bachelor of Economics (High Second Class Honours)
1991-1997	**Australian National University** Bachelor of Laws

Career Details

2014-	**HoustonKemp Economists** Senior Economist, Sydney, Australia
2001-2014	**NERA Economic Consulting** Senior Consultant, Sydney, Australia
1998-1999	**Australian Chamber of Commerce and Industry**

Project Experience

Finance

2015	**DLA Piper/Confidential Client** **Expert reports on the economic and regulatory principles of infrastructure pricing** Brendan provided strategic advice on the appropriate cost of capital and financial models for an Australian aeronautical services business.
2015	**ESCOSA** **Cost of capital for a benchmark water business** Provided a range of reports on the cost of capital for a benchmark water utility. Reports covered the use of different cost of equity models, the value of the market risk premium, gamma, and the use of a trailing average cost of debt.
2015	**Sydney Water** **Equity beta for a regulated Australian water business** Brendan authored an expert report for submission to the Independent Pricing and Regulatory Tribunal on empirical evidence of the equity beta for a benchmark Australian water network service provider.
2014-15	**Sale of the Port of Melbourne** **Cost of capital and financial modelling** Provided strategic advice to Victorian Department of Treasury and Finance on the financial implications of different regulatory regimes. Provided a indicative cost of capital estimate for the port.
2014-15	**TransGrid** **Cost of Capital** Co-authored two expert reports submitted by TransGrid in support of its 2014-18 revenue proposal. The expert report covered all aspects of the new cost of capital framework, including return on equity estimates generated by the CAPM, Black CAPM, the Fama-French three-factor model, and DGMs, and the approach method of transitioning to a trailing average cost of debt.
2014	**New Zealand Airports Association / Powerco (New Zealand)** **Review of the WACC Percentile** Brendan assisted in the preparation of two expert reports – one for the New Zealand Airports Association, and the other for Powerco – for submission to the New Zealand Commerce Commission in response to its review of the cost of capital input methodologies. The reports reviewed the Commission's approach to setting the regulatory WACC at the 75th percentile, discussed the economic rationale for setting a WACC above an unbiased midpoint estimate of the cost of capital, and considered the merits and practicability of undertaking an in-depth empirical estimate of the 'optimal' cost of capital percentile.
2014	**Queensland Competition Authority** **Price review** Undertook an independent quality assurance assessment of the models used to calculate regulated revenues for Queensland water utilities. The review considered: the formulation of the WACC; the intra year timing of cash flows; and the structural, computational and economic integrity of the models.

2014	**DLA Piper/Confidential Client** **Expert reports on the economic and regulatory principles of infrastructure pricing** Brendan assisted in the preparation of three expert reports in relation to the economic and regulatory principles used to allocate shared costs, supporting peak pricing and developing an economic framework for pricing aeronautical services. In addition, Brendan provided strategic advice on the appropriate cost of capital and financial modelling.
2013	**Sydney Water Corporation** **Cost of capital estimation** Preparation of two expert reports for submission to the Independent Pricing and Regulatory Tribunal (IPART) on the framework for determining the weighted average cost of capital for infrastructure service providers.
2013	**Queensland Competition Authority** **Price review** Undertook an independent quality assurance assessment of the models used to calculate regulated revenues for Queensland water utilities. The review considered: the formulation of the WACC; the intra year timing of cash flows; and the structural, computational and economic integrity of the models.
2012-13	**Gilbert + Tobin/Rio Tinto Coal Australia** **Assistance in drafting expert report on port prices** Analysis and expert reports prepared in the context of an arbitration concerning the price to be charged for use of the coal loading facilities at Abbott Point Coal Terminal. Issues addressed included asset valuation, cost of capital, forecast operation and maintenance costs and the economic interpretation of building block regulation.
2012-13	**Ashurst/Brisbane Airport Corporation** **Draft access undertaking** Advice, analysis and expert report on the weighted average cost of capital (WACC) in the context of the preparation of a draft access undertaking specifying the basis for determining a ten year price path for landing charges necessary to finance a new parallel runway at Brisbane airport.
2012	**APA GasNet** **Assistance in drafting cost of capital submission** Provided drafting assistance and strategic advice to APA on GasNet's cost of capital submission to the AER for the Victorian principal gas transmission network.
2012	**APA Brisbane to Roma Pipeline** **Assistance in drafting cost of capital submission** Provided drafting assistance and strategic advice to APA on the Brisbane to Roma Pipeline cost of capital submission to the AER.
2012	**Energy Networks Association** **Rate of return framework guideline** Co-authored a number of expert reports submitted to the Australian Energy Regulator on the rate of return framework guideline. These report considered a range of financial issues including: the applicability of various financial models to the estimation of the cost of equity; the estimates of the cost of equity from the Black CAPM; estimates of the historic market, size and value premiums; and the payout ratio of created imputation credits.

2012	**Energy Networks Association** **Advice on the new rate of return framework** Advice to the Energy Networks Association on the appropriate the implications of the new allowed rate of return framework to apply to electricity and gas transmission and distribution businesses. This report considered a range of financial models and other information that the regulator should have regard to when setting the regulated return on equity.
2012	**Victorian Gas Networks** **Black Capital Asset Pricing Model** Brendan co-authored a report that examined whether a version of the Black CAPM is better able than an empirical version of the Sharpe-Lintner (SL) CAPM to produce an estimate of the cost of equity that meets the requirements of Rule 87 (1) of the National Gas Rules (NGR). Following an examination of Australian financial data we concluded that an empirical version of the Black CAPM is better able than an empirical version the SL CAPM.
2011-12	**Energy Networks Association** **Review of Economic Regulation of Network Service Providers** Advice and expert reports submitted to the Australian Energy Market Commission on the new allowed rate of return framework to apply to electricity and gas transmission and distribution businesses, as proposed by the Australian Energy Regulator and the Energy Users Rule Change Committee.
2011-12	**Energy Networks Association** **Review of Economic Regulation of Network Service Providers** Advice and expert reports submitted to the Australian Energy Market Commission on the expenditure and incentive frameworks to apply to electricity transmission and distribution businesses, as proposed by the Australian Energy Regulator.
2011	**Multinet Gas and SP AusNet - Gas Distribution** **Report on the market risk premium** Co-authored a report that examined a number of issues arising from the draft decision on Envestra's access proposal for the SA gas network. The report considered whether: the historical evidence supported the use of a long term average of 6 per cent; there is any evidence to warrant a MRP at it long term average; and the evidence relied on by the AER to justify its return to a MRP of 6 per cent.
2011	**Dampier to Bunbury Natural Gas Pipeline - Gas Transmission** **Cost of equity of a regulated natural gas pipeline** Co-authored two reports that updated the cost of equity for a gas transmission business and responded to issues raised by the regulator in its draft decision. The report re-estimated the cost of equity of a gas distribution business using the Sharpe Lintner CAPM, Black CAPM, Fama-French three-factor model and a zero beta version of the Fama-French three-factor model.
2010-11	**Queensland Competition Authority** **Weighted Average Cost of Capital (WACC) for SunWater** Retained to provide two expert reports on the WACC for SunWater a Queensland rural infrastructure business. The first report considered issues pertaining to whether a single or multiple rates of return can be applied across SunWater's network segments. The second report focuses market evidence on the appropriate rate of return for SunWater.

2011	**Mallesons Stephens Jaques/ActewAGL Distribution** **Determining the averaging period** Assisted in the development of an expert report that considered the economic and financial matters arising from the Australian Energy Regulator's decision to reject ActewAGL's proposed risk free rate averaging period.
2010	**Industry Funds Management/Queensland Investment Corporation** **Due diligence, Port of Brisbane** Brendan was retained to advise on various regulatory and competition matters likely to affect the future financial and business performance of the Port of Brisbane, in the context of its sale by the Queensland government.
2010	**Dampier to Bunbury Natural Gas Pipeline (DBNGP) - Gas Transmission** **Cost of equity of a regulated natural gas pipeline** Co-authored a report that examined four well accepted financial models to estimate the cost of equity for a gas transmission business. The report of estimating the cost of equity of a gas distribution business using the Sharpe Lintner CAPM, Black CAPM, Fama-French three-factor model and a zero beta version of the Fama-French three-factor model.
2009-10	**Jemena - Gas Distribution** **Cost of equity of a regulated natural gas distribution network** Co-authored two reports on the use of the Fama-French three-factor model to estimate the cost of equity for regulated gas distribution business. The report examined whether the Fama-French three-factor model met the dual requirements of the National Gas Code to provide an accurate estimate of the cost of equity and be a well accepted financial model. Using Australian financial data the report also provided a current estimate of the cost of equity for Jemena.
2009	**WA Gas Networks** **Cost of equity of a regulated natural gas distribution network** Co-authored a report that examined a range of financial models that could be used to estimate the cost of equity for a gas distribution business. The report of estimating the cost of equity of a gas distribution business using the Sharpe Lintner CAPM, Black CAPM, Fama-French three-factor model and Fama-French two-factor model. The report examined both the domestic and international data.
2009	**Jemena and ActewAGL** **Cost of equity of a regulated natural gas distribution network** Co-authored a report on alternative financial models for estimating the cost of equity. The report examined the implication of estimating the cost of equity of a gas distribution business using the Sharpe Lintner CAPM, Black CAPM and Fama-French models. The report examined both the domestic and international data.
2009	**Prime Infrastructure** **Sale of Dalrymple Bay Coal Terminal (DBCT)** Brendan provided regulatory advice to a number of potential bidders for the assets of DBCT. Advice included an assessment of the rate of return parameters, depreciation, regulatory modelling and the regulatory arrangements in Queensland.
2008	**Joint Industry Associations - APIA, ENA and Grid Australia** **Weighted Average Cost of Capital for a regulated energy network** Assisted in the drafting of the Joint Industry Associations submission to the Australian Energy Regulator's weighted average cost of capital review. The submission examined the current market evidence of the cost of capital for Australian regulated electricity transmission and distribution businesses.

2008	**Joint Industry Associations - APIA, ENA and Grid Australia** **Weighted Average Cost of Capital for a regulated energy network** Expert report for the Joint Industry Associations on the value of imputation credits. The expert report was attached to their submission to the Australian Energy Regulator's weighted average cost of capital review. The report examined the current evidence of the market value of imputation credits (gamma) created by Australian regulated electricity transmission and distribution businesses.

Regulatory Analysis

2015	**Public Utilities Office, WA** **Advice on the transitional arrangements for Western Power** Advisor to the PUO and working with the Steering Committee and stakeholders to develop a transitional regulatory framework for Western Power for its first regulatory control period.
2015	**ActewAGL GAS Distribution** **Operation of the efficiency benefit sharing scheme** Brendan is providing strategic on responding to the Australian Energy Regulator's draft decision on the efficiency benefit sharing scheme (EBSS) carry forward amounts to be included in the revenues for 2016/17 to 2020/21 period.
2015	**Jemena Gas Networks** **Estimation of standalone, avoidable and LRMC of the ACT gas network** Brendan authored an expert report that estimated the standalone, avoidable and long-run marginal cost of the ACT gas network. This report was submitted ot the AER as part of ActewAGL's 2015 access arrangement proposal.
2015	**Government of New South Wales** **Economic regulation for privatisation** Advisor to government of New South Wales on all economic regulatory aspects of the proposed partial lease the electricity transmission and distribution entities, TransGrid, AusGrid and Endeavour Energy.
2015	**SA Power Networks** **Expert report on regulatory depreciation** Brendan authored an expert report for submission to the Australian Energy Regulator on whether SA Power Network's the proposed depreciation schedules were compliant with the requirements of the National Electricity Rules to depreciate assets over their economic lives.
2015	**Ergon Energy** **Review of regulatory depreciation** Provided Ergon with an internal strategy paper assessing different methods for calculating the remaining lives of asset or groups of assets.
2014/15	**ActewAGL Electricity Distribution** **Incentive arrangements applying with opex benchmarking** Brendan authored an expert report on the application of the EBSS for ActewAGL electricity distribution in the circumstances where the regulator has not used revealed costs to determine the forthcoming opex allowance. This report focuses on the incentive arrangements existing for ActewAGL and whether these arrangements are consistent with the national electricity objective.

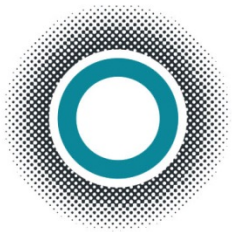
2014	**Ausgrid** **Application of the AER's efficiency benefit sharing scheme** Brendan provided expert advice to Ausgrid on the estimation of the efficiency carry-forward to be applied in the 2014-19 period. This advice extended to strategic advice on the implications of the AER's Better Regulation new EBSS.
2014	**ActewAGL Gas Distribution** **Tariff control mechanism for gas distribution network** Brendan provided analysis and advice in relation to the tariff variation mechanisms available under the National Gas Rules (NGR), and the issues that ActewAGL should consider in arriving at a decision on the mechanism to be proposed in its 2016-21 gas network access arrangement.
2014	**Johnson Winter & Slattery/ATCO GAS** **Application of depreciation options under the new gas rules** Assisted in the drafting of an expert report on depreciation options consistent with the new gas rules for ATCO Gas for submission to the Economic Regulation Authority of Western Australia.
2013	**Energy Networks Association** **Submission to the AER's Proposed Efficiency Incentive Schemes** Brendan led a team that undertook to quantitatively investigate the incentive properties of the Australian Energy Regulator's (AER's) proposed efficiency schemes. The output of this assignment was an expert report to the AER's Better Regulation issues paper and internal advice to the ENS on the implications on aspects of the draft determination.
2013	**Actew Corporation** **Interpretation of economic terms** Advice on economic aspects of the draft and final decisions of the Independent Competition and Regulatory Commission in relation to the price controls applying to Actew.
2012-13	**Gilbert + Tobin/Rio Tinto Coal Australia** **Assistance in drafting expert report on port prices** Analysis and expert reports prepared in the context of an arbitration concerning the price to be charged for use of the coal loading facilities at Abbott Point Coal Terminal. Issues addressed included asset valuation, cost of capital, forecast operation and maintenance costs and the economic interpretation of building block regulation.
2012	**ACTEW Water** **Review of regulatory models** Brendan provided strategic and analytical advice to ACTEW on its regulatory models. The analysis included analysis of the risks and challenges of adopting a post-tax revenue model and the application of expenditure incentive mechanisms.
2012	**Queensland Competition Authority** **Review of the retail water regulatory models** Brendan undertook an independent quality assurance assessment of the financial models relied on by the QCA to set the regulated revenues of SunWater. The review considered: SunWater's Financial model, a model used by SunWater to calculate future electricity prices, an renewals annuity model, as well as the QCA's regulatory model. These models established a set of recommended prices for each of the 30 irrigation schemes operated by SunWater for the period 2014 to 2019.

2011	**Queensland Competition Authority** **Review of the retail water regulatory models** Undertook an independent quality assurance assessment of the models used to calculate regulated revenues for Queensland Urban Utilities, Allconnex Water, and Unitywater. The review considered: the formulation of the WACC; the intra year timing of cashflows; and the structural, computational and economic integrity of the models.
2011	**Queensland Competition Authority** **Review of the wholesale water regulatory models** Undertook an independent quality assurance assessment of the models used to calculate regulated revenues for LinkWater, Seqwater; and WaterSecure. The review considered: the formulation of the WACC; the intra year timing of cashflows; and the structural, computational and economic integrity of the models.
2010-11	**Minter Ellison /UNELCO** **Review of regulatory decision by the Vanuatu regulator** Assisted in the development of an expert report on a range of matters arising from the Vanuatu regulator's decision to reset electricity prices under four concession contracts held by UNELCO. The matters considered included the methodology employed to calculate the new base price, the appropriateness of the rate of return, the decision by the regulator to reset future prices having regard to past gains/losses.
2010	**Orion Energy, New Zealand** **Information disclosure regime** Provided advice and assistance in preparing submissions by Orion to the New Zealand Commerce Commission, in relation to the Commission's proposed weighted average cost of capital for an electricity lines businesses. Issues addressed included the financial model used to calculate the required return on equity, the appropriate term for the risk free rate and the WACC parameter values proposed by the Commission.
2010	**Grid Australia** **Amendments to the AER's transmission revenue and asset value models** Developed and drafted a submission to the AER on the proposed amendments to the AER's post-tax revenue model (PTRM) and roll forward model (RFM). The proposal focused on a number of suggestions to simplify and increase the usability of the existing models.
2009	**CitiPower and Powercor – Victorian Electricity Distribution** **Network Reliability Incentive Mechanism (S-factor)** Brendan was engaged by CitiPower and Powercor to provide advice on the proposed changes to the operation of the reliability incentive mechanism and was subsequently engaged to analysis the final version of the new arrangements. The advice considered the effects of the proposed changes to the operation of the two distribution network service providers. Specifically, how the 'S-factors' would be changed and implications this has to the revenue streams of the two businesses. A comparison was also made with the current ESC arrangements to highlight the changes to the mechanism.

2007	**Electricity Transmission Network Owners Forum (ETNOF)** **Amendments to the AER's transmission revenue and asset value models** Developed and drafted a submission to the AER on the proposed post-tax revenue model (PTRM) and roll forward model (RFM) that would apply to all electricity transmission network service providers (TNSPs). The proposal focused ensuring that the regulatory models gave effect to the AER's regulatory decisions and insures that TNSPs have a reasonable opportunity to recover their efficient costs.

Policy

2010	**Ministerial Council on Energy, Smart Meter Working Group** **The costs and benefits of electricity smart metering infrastructure in rural and remote communities** This report extends NERA's earlier analysis of the costs and benefits of a mandatory roll out of smart meters, by consider the implications of a roll out in rural and remote communities in the Northern Territory, Western Australia and Queensland. The project has focused on eight case study communities and has examined the implications of prepayment metering and remoteness on the overall costs and benefits of a roll out.
2007-08	**Ministerial Council on Energy, Smart Meter Working Group** **Assessment of the costs and benefits of a national mandated rollout of smart metering and direct load control** Part of a project team that considered the costs and benefits of a national mandated rollout of electricity smart meters. Brendan was primarily responsible for the collection of data and the modelling of the overall costs and benefits of smart metering functions and scenarios. The analysis also considering the likely costs and benefits associated with the likely demand responses from consumers and impacts on vulnerable customers.



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