APPENDIX 8

Application of Base-Step-Trend (BST) Model

Energex

Application of Base-Step-Trend

AER Determination 2015-20

energex

positive energy

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1 Application of Base-Step-Trend (BST) model

1.1 Overview

This appendix provides information on Energex's base-step-trend model, including an explanation of the base-step-trend methodology used to forecast direct operating and indirect expenditure and a description of the parameters and assumptions used.

The appendix includes the following sections:

- Section 1.2 – provides an overview of the methodology used to forecast expenditure using the base-step-trend model
- Section 1.3 – provides an overview of the expenditure categories
- Section 1.4 – outlines the base year used and any adjustments to the base year which have been made to provide for an efficient base expenditure
- Section 1.5 – includes a description of efficiency adjustments included over the regulatory control period
- Section 1.6 – includes details of all non-recurrent cost adjustments required during the regulatory control period that are not accounted for in the base year
- Section 1.7 – includes details of all step changes as a result of changes in obligations, requirements or Energex's policies and strategies
- Section 1.8 – includes details of the output drivers and efficiency drivers
- Section 1.9 – includes a discussion on cost escalation
- Section 1.10 – provides a summary of the forecast expenditure by category
- Section 1.11 – provides a summary of total indirect expenditure from the BST model and other methods
- Section 1.12 – provides the allocation of indirect costs to capital and operating expenditure
- Section 1.13 – provides a discussion on the treatment of leave provisions
- Section 2 – contains supporting information for the adjustments made in the BST model.

This appendix contains information on the expenditure categories forecast using the base-step-trend methodology.

Additional detail on the expenditure relating to ICT (asset usage fee and service level agreement) is included as an appendix to the regulatory proposal.

Additional detail on expenditure items subject to alternative forecasting methods (as identified in Table A1.1) are explained further in Chapter 10: Forecast operating expenditure of the regulatory proposal.

1.2 Expenditure forecasting methodology

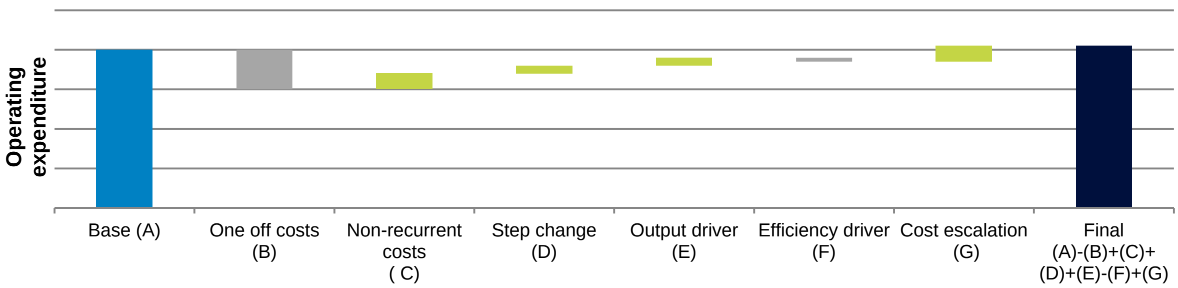
In accordance with section 6.8.1A of the Rules, Energex submitted its Expenditure Forecasting Methodology to the AER on 25 November 2013. This document is included as an appendix to the regulatory proposal. In summary Energex uses:

- where appropriate, a base-step-trend model to forecast direct operating and indirect expenditure incorporating costs allocated as overhead
- a bottom up methodology to forecast a range of direct operating and indirect expenditure not suitable for base-step-trend forecasting (eg demand management, levies, self-insurance, debt raising and ICT asset usage fee), and
- a bottom up methodology to forecast direct capital expenditure.

The high level base-step-trend methodology is shown diagrammatically in Figure A1.1 and includes the following steps:

- determining the base year
- adjustments to base year expenditure
- adjustments, in identified years, for significant (non-recurrent) items
- adjustments to reflect changes in scope (step changes)
- applying trends (escalation) over the regulatory control period to account for:
  - output drivers: network and customer growth
  - efficiency drivers: technical efficiencies, economies of scale and productivity improvements
  - cost escalation: labour, materials and contractor costs.

Figure A1.1 – Example of a base-step-trend calculation



1.3 Expenditure categories

Energex has categorised expenditure for base-step-trend consistent with the categories required in the Category Analysis (CA) RIN and regulatory proposal submission RIN. However Energex advises that a number of categories reported in the overhead template in the RINs as network overhead and corporate overhead are included as direct operating expenditure in Chapter 10 – Forecast operating expenditure of the regulatory proposal. These include:

- Network operating costs
- Network billing and other energy market services
- Customer services (incl call centre)
- DSM initiatives
- Levies
- Debt raising costs
- Self Insurance
- Other operating costs

The representation of costs in Chapter 10 of the regulatory proposal, reflect the application of Energex's approved CAM incorporating the allocation of overheads and other operating costs

A short description of Energex's expenditure categories applied in the base-step-trend model is provided below.

- Inspection – includes the inspection program to detect potential defects requiring remedial response.
- Planned maintenance – includes the development and implementation of maintenance plans to ensure delivery of supply, reliability, security and safety objectives.
- Corrective repair – includes corrective repair works undertaken after a failure of an asset to either restore the network to a state in which it can perform its required function or render the installation safe to allow future planned maintenance or replacement.
- Vegetation – including planned programs and reactive maintenance activities. The key outcome for Energex's vegetation management program is to provide a safe and reliable network, and to drive value for money and continuous improvement in this significant spend area.
- Emergency response/storms – includes the repair of damaged equipment and all storm-related repairs. Material costs above the average historical level (eg storm

events on the scale of a natural disaster) will be managed through the pass through provisions within the Rules.

- Network overheads – including network operating costs, Demand Side Management (DSM) initiatives, network billing, customer services, levies, procurement and logistics and training and OHS.

- Corporate overheads – including support costs such as office of the CEO, legal and secretariat, human resources, finance, regulatory, IT and communications, motor vehicles, property and debt raising costs.

Energex has developed a base-step-trend model which forecasts expenditure by functional area. Table A1.1 outlines the functional areas used in the Energex model and how these relate to the expenditure categories above. The table below also identifies the forecasting methodology used for each category.

Table A1.1 – Expenditure categories and forecast methodology used

Expenditure category	Energex functional area	Forecast method
Inspection	Inspection	Base-step-trend
Planned maintenance	Planned maintenance	Base-step-trend
Corrective repair	Corrective repair	Base-step-trend
Vegetation	Vegetation	Base-step-trend
Emergency response	Emergency response	Base-step-trend
Network overheads	Network management	Base-step-trend
	Network planning	Base-step-trend
	Network control and operational switching - direct	Base-step-trend
	Network control and operational switching	Base-step-trend
	Network monitoring	Base-step-trend
	Quality and standard functions	Base-step-trend
	Project governance and related functions	Base-step-trend
	Training and development	Base-step-trend
	OHS	Base-step-trend
	Customer service - direct	Base-step-trend
	Customer service - indirect	Base-step-trend
	Network billing & other market services	Base-step-trend
	DSM Initiatives	Bottom up (individual projects)
	Levies	Bottom up (calculation)
	Network property	Base-step-trend
Corporate overheads	Office of CEO	Base-step-trend
	Legal and secretariat	Base-step-trend
	Audit	Base-step-trend
	Strategy and regulation	Base-step-trend
	Human resources	Base-step-trend
	Finance	Base-step-trend
	Business support services	Base-step-trend
	Business operations and performance	Base-step-trend
	Field support services	Base-step-trend
	Stakeholder engagement and management	Base-step-trend
	Corporate programs	Bottom up
	Corporate restructuring	Base-step-trend
	IT & Communications	SPARQ asset usage & service fee[1]
	Property	Base-step-trend
	Fleet	Base-step-trend
	Debt raising costs	Bottom up (PTRM modelling)
	Self-insurance	Actuarial consultant forecast

[1] SPARQ provides ICT services to Energex and charges service and asset usage fees on a cost recovery basis. These fees are included in Energex's Corporate overhead costs for allocation to regulated services consistent with Energex's approved CAM.

1.4 Determining the efficient base year

1.4.1 Selection of financial year

Financial year 2012-13 was selected as the base year as it represents the latest actual and audited expenditure information for the organisation.

1.4.2 Adjustments to base year expenditure

The revealed costs in 2012-13 have been adjusted to reflect an efficient recurrent expenditure level for the 2015-20 regulatory control period including allowances for one-off costs, new recurrent costs, step changes and escalation.

For 2012-13, Energex has identified the unusual expenditure items outlined below, with the financial adjustments to actual expenditure identified by category in Table A1.2.

Section 2.1 contains a detailed description and justification of each adjustment.

Table A1.2 – Adjustments to the 2012-13 base expenditure for base-step-trend model

Expenditure category	Functional area	2012-13 actual ($m)	2012-13 adjust ($m)	2012-13 base ($m)[1]	Description of the adjustments (Section 2 contains a detailed justification sheet)
Inspection	Inspection	7.8	5.3	12.9	Provisions (service cable) (see section 2.1.1)
			0.5		LV crossarm replacement program (see section 2.1.2)
			(0.7)		Streetlight pole inspection (see section 2.1.3)
Planned maintenance	Planned maintenance	43.7	1.2	44.9	LV crossarm replacement program (see section 2.1.2)
Corrective repair	Corrective repair	25.8	(1.5)	24.3	Historical average (see section 2.1.4)
Vegetation	Vegetation	51.6	0.0	51.6	No adjustment
Emergency response/storms	Emergency response/storms	15.1	(7.8)	7.3	Historical average (see section 2.1.5)
Network overheads	Network Management	55.1	(16.0)	39.1	Cancelled projects (see section 2.1.6)
	Network Planning	8.4	(0.8)	7.6	Reallocation of expenditure (see section 2.1.7)
	Network Control and Operational Switching - direct	15.4	1.3	17.3	Matrix support costs (see section 2.1.8)
			0.7		Protection review program (see section 2.1.9)
	Network Control and Operational Switching	6.8	0.0	6.8	No adjustment
	Network Monitoring	1.2	0.0	1.2	No adjustment
	Quality and Standard Functions	20.9	0.0	20.9	No adjustment
	Project Governance and Related Functions	50.4	0.0	50.4	No adjustment
	Training and Development	15.3	0.0	15.3	No adjustment
	OHS	4.6	0.0	4.6	No adjustment
	Customer service - direct	7.5	2.7	7.9	Overhead service inspection (see section 2.1.10)
			(2.2)		Reclassification of services to ACS (see section 2.1.11)
	Customer Service - indirect	9.1	0.0	9.1	No adjustment
	Meter reading, network billing and metering support	16.3	(12.4)	3.9	Reclassification of services to ACS (see section 2.1.12)

Expenditure category	Functional area	2012-13 actual ($m)	2012-13 adjust ($m)	2012-13 base ($m)[1]	Description of the adjustments (Section 2 contains a detailed justification sheet)
	DSM Initiatives	11.5	(11.5)	0.0	Excluded from base-step-trend (see section 3.1)
	Levies	9.1	(9.1)	0.0	Excluded from base-step-trend (see section 3.2 and Chapter 10)
	Network Property	2.1	5.2	7.3	Reallocation of expenditure (see section 2.1.7)
Corporate overheads	Office of CEO	0.7	0.0	0.7	No adjustment
	Legal and Secretariat	1.6	0.0	1.6	No adjustment
	Audit	2.7	(0.4)	2.3	Reallocation of expenditure (see section 2.1.7)
	Strategy and Regulation	6.1	0.0	6.1	No adjustment
	Human Resources	11.4	0.0	11.4	No adjustment
	Finance	11.8	0.4	12.3	Reallocation of expenditure (see section 2.1.7)
	Business support services	21.1	(0.4)	22.9	Insurance provision (see section 2.1.13)
			1.5		Reallocation of expenditure (see section 2.1.7)
			0.6		Reallocation of expenditure (see section 2.1.7)
	Business Operations and Performance	3.5	0.0	3.5	No adjustment
	Field Support Services	10.0	0.0	10.0	No adjustment
	Stakeholder Engagement and Management	7.6	0.0	7.6	No adjustment
	Corporate programs	4.5	(4.5)	0.0	Excluded from base-step-trend (non-recurrent cost) (see section 2.1.14 and section 3.3)
	Corporate restructuring	51.0	(51.0)	0.0	Excluded from base-step-trend (non-recurrent cost) (see section 2.1.15)
	IT and Communications	106.9	(106.9)	0.0	Excluded from base-step-trend (see section 3.4)
	Property	48.7	2.8	45.5	Property rent (see section 2.1.16)
			(1.5)		Property make good provision (see section 2.1.17)
			(4.4)		Reallocation of expenditure (see section 2.1.7)
	Fleet	22.7	1.5	23.8	Fleet - fuel tax credit (see section 2.1.18)

Expenditure category	Functional area	2012-13 actual ($m)	2012-13 adjust ($m)	2012-13 base ($m)[1]	Description of the adjustments (Section 2 contains a detailed justification sheet)
			(0.4)		EWP repairs - fleet (see section 2.1.19)
	Debt Raising Costs	4.5	(4.5)	0.0	Excluded from base-step-trend (see Chapter 10)
	Self-insurance	1.7	(1.7)	0.0	Excluded from base-step-trend (see Chapter 10 and section 3.5)
Note: Base year expenditure includes direct operating expenditure and total indirect expenditure which is later allocated between SCS (capex and opex), ACS (capex and opex) and unregulated services.					

1.4.3 Benchmarking assessment

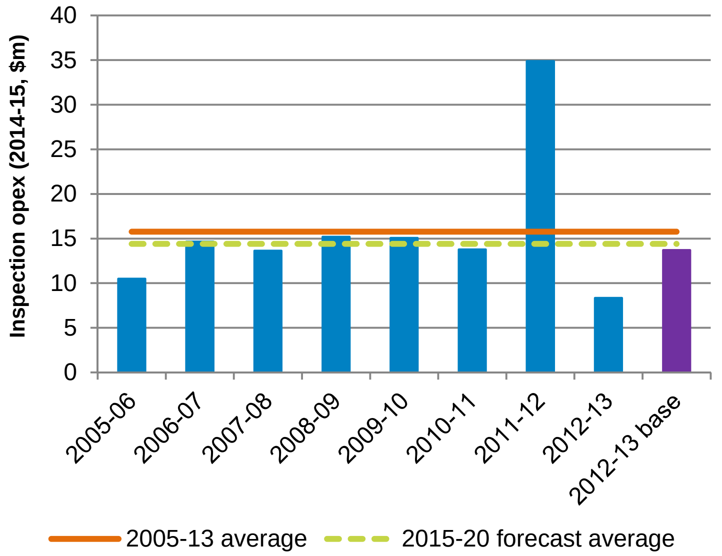
Historical benchmarking (Energex only)

To assess the efficiency of the base year Energex has reviewed historical and forecast expenditure at category level. This is shown in Figure A1.2 below.

The expenditure used for category level benchmarking includes:

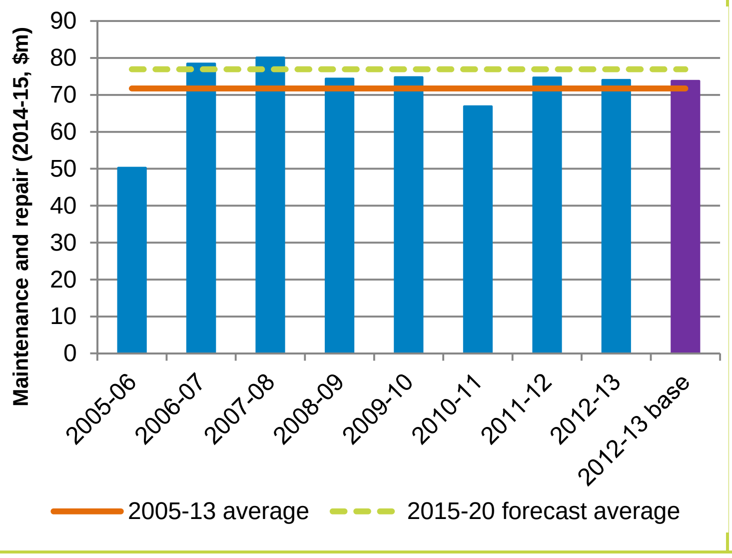
- historical data (2005-06 to 2012-13) contained in Energex's regulatory accounts
- forecast expenditure for 2015-20 based on the forecasts contained in this regulatory proposal
- conversion to $2014-15 using published and forecast March CPI figures.

Figure A1.2 – Historical benchmarking



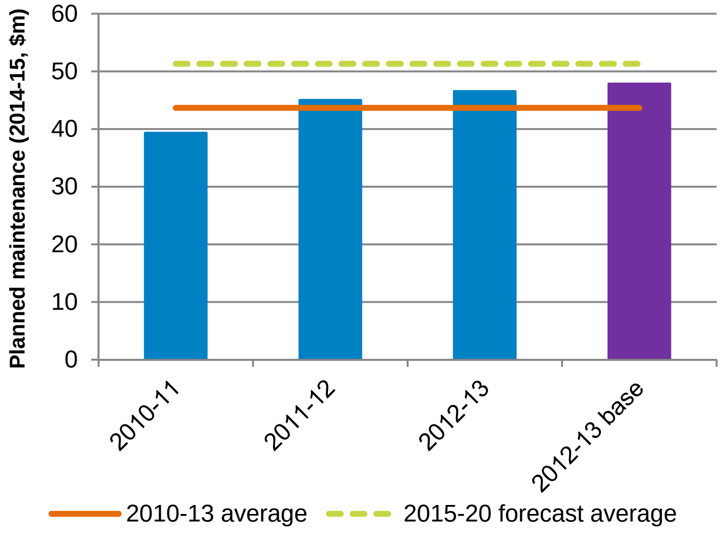
Inspection

- the 2012-13 base level expenditure has been adjusted (increased) to reflect an estimate of recurrent costs
- the base level expenditure is below average historical expenditure
- forecast expenditure is slightly above the efficient base level due to network scale growth over the regulatory period
- forecast expenditure is below the historical average



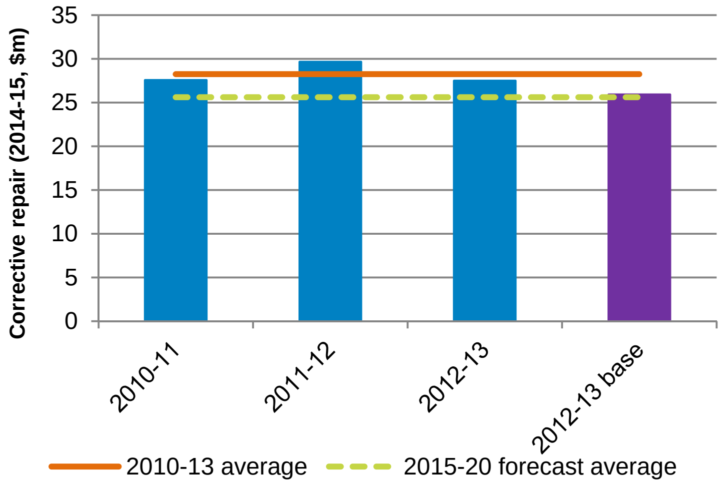
Planned maintenance and corrective repair

- prior to 2010-11 planned maintenance and corrective repair were reported as a single expenditure category



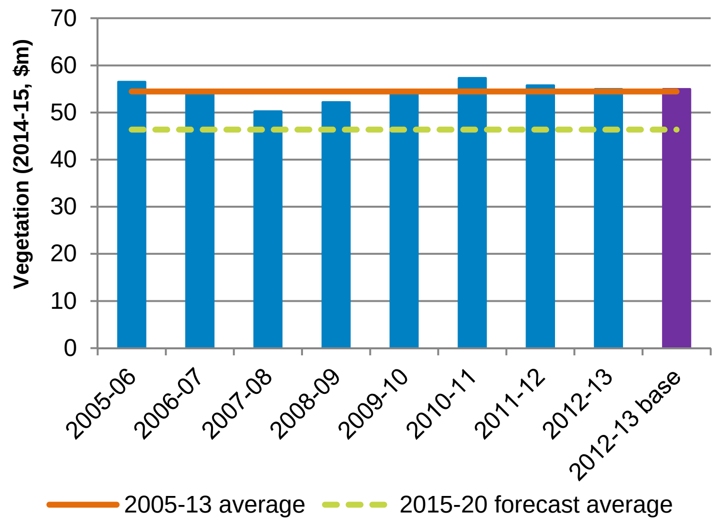
Planned maintenance

- the 2012-13 base level expenditure has been adjusted (increased) to reflect an estimate of recurrent costs
- forecast expenditure is above the efficient base level due to network scale growth and additional requirements over the regulatory period



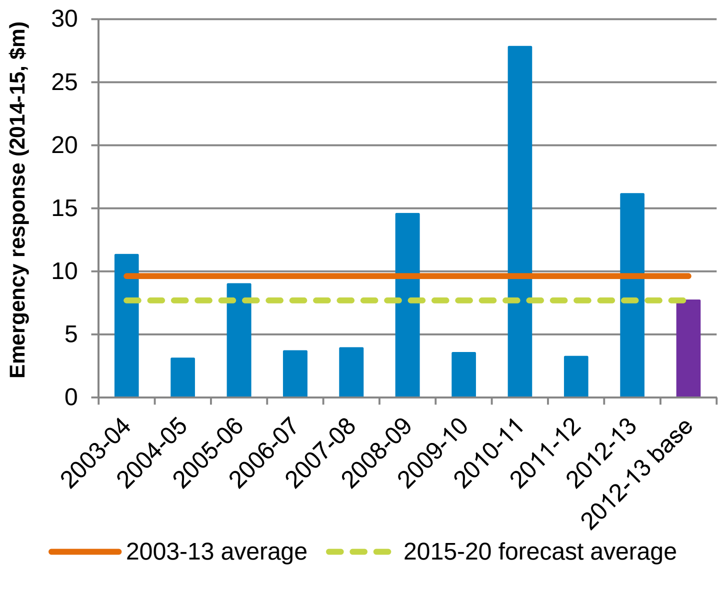
Corrective repair

- the 2012-13 base level expenditure for corrective maintenance was adjusted to reflect a ten year average.
- the base level expenditure is below average historical expenditure
- forecast expenditure is equal to the efficient base level
- forecast expenditure is below the historical average



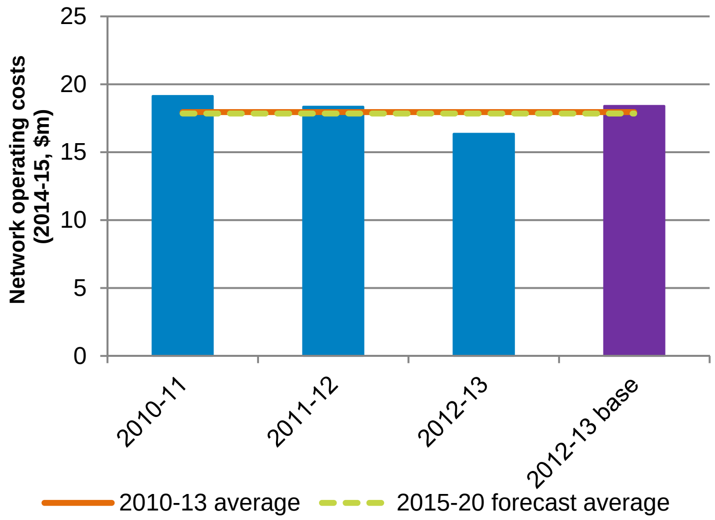
Vegetation

- the 2012-13 base level expenditure has been adjusted (reduced) to reflect an estimate of recurrent costs
- the base level expenditure is largely consistent with average historical expenditure
- forecast expenditure is below the efficient base level due to efficiencies which are realised over the next regulatory period



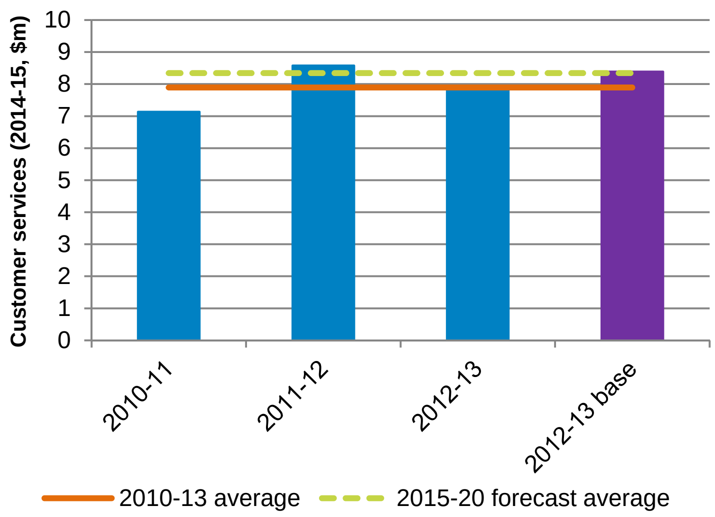
Emergency response

- the 2012-13 base level expenditure has been adjusted (reduced) to reflect an estimate of recurrent costs
- the base level expenditure has been set to the ten year historical average for 2003-04 to 2012-13, excluding the Brisbane floods
- forecast expenditure is consistent with the efficient base level expenditure
- forecast expenditure is below the historical average



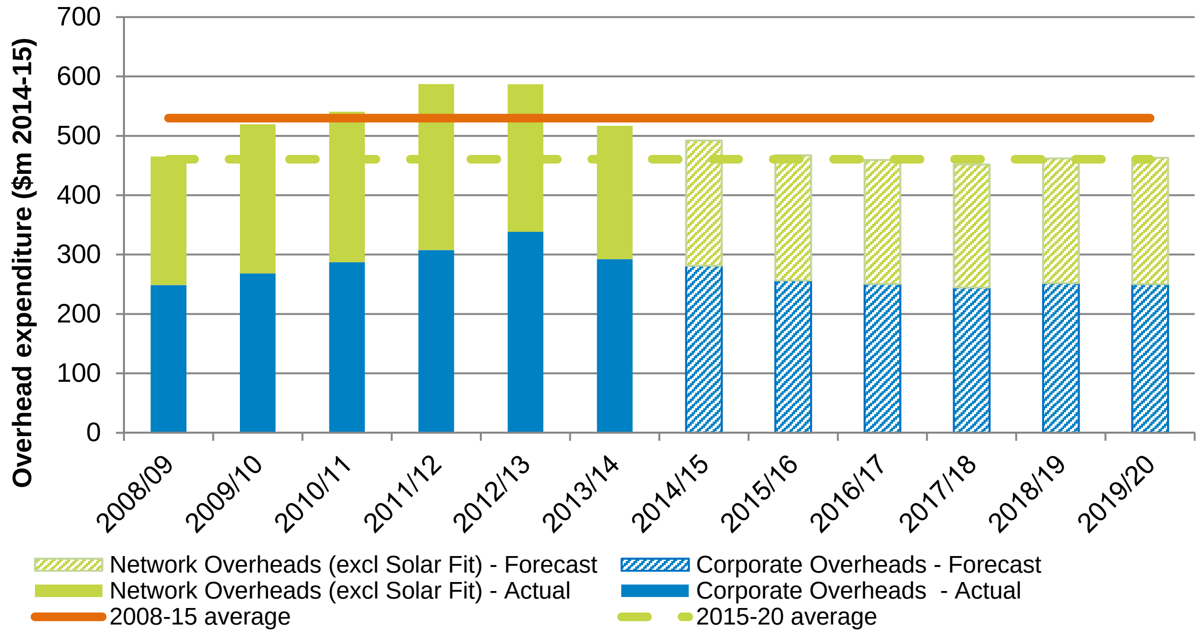
Network operating

- prior to 2010-11 network operating costs were not reported separately in the RIN
- the 2012-13 base level expenditure has been adjusted (increased) to reflect an estimate of recurrent costs
- the base level expenditure is largely consistent with average historical expenditure
- future expenditure is below the efficient base level due to efficiencies which are realised over the next regulatory period



Customer services

- prior to 2010-11 customer service costs were not reported separately in the RIN
- the 2012-13 base level expenditure has been adjusted (increased) to reflect an estimate of recurrent costs
- forecast expenditure is consistent with the efficient base level expenditure



Overheads

Overheads reflect the functional categorisation consistent with the regulatory proposal Reset RIN. Overheads include those derived on a base-step-trend methodology and those derived from alternate methods per Energex's Expenditure Forecasting Methodology.

Network overhead

- A number of functions included as network overhead, (DSM Initiatives, Network Control & Switching, Customer Service, Network Billing and Levies), are included as direct operating costs in Chapter 10 of the regulatory proposal.
- Forecast network overhead is lower than historical average in recognition of Energex's ongoing efficiency and productivity improvement initiative, however it should be noted that the forecast includes additional expenditure associated with Energex's expanding Demand Management program.

Corporate overhead

- Corporate overhead includes debt raising and self-insurance costs which are included as direct operating costs in Chapter 10 of the regulatory proposal.
- Forecast corporate overhead is lower than historical average consistent with Energex's focus on realising efficiencies through its business efficiency program.
- Corporate overhead also includes fees paid to SPARQ for the delivery of ICT infrastructure and services.

1.4.4 Benchmarking against other DNSPs

To assess the efficiency of the 2012-13 base year Energex has also reviewed historical expenditure at a total level against other DNSPs.

- Energex has used the 2012-13 expenditure, customer and circuit length data contained in the Economic Benchmarking (EB) RINs provided to the AER in April 2014.
- The expenditure data has been converted to $2014-15 using published and forecast March CPI figures.
- For the two Queensland DNSPs, solar FiT expenditure has been removed from the total opex reported in the EB RIN as this represented a significant non-recurrent cost.
- Redundancy costs have been removed from Energex's opex in 2012-13 as this represented a significant non-recurrent cost (approx $50m)

The modelling results shown in the figures below indicate that Energex's 2012-13 total operating expenditure level compares favourably with other DNSPs and the industry benchmark. In addition, adjustments to the 2012-13 base year have resulted in a reduction to the 2012-13 revealed costs used in the base-step-trend model.

Energex has engaged Huegin to provide benchmarking at a category level based on the data contained in the Category Analysis (CA) RINs provided to the AER in May 2014. A copy of this report is included as an appendix to the regulatory proposal.

Figure A1.3 – 2012-13 benchmarking – total opex/customer (including indirect costs)

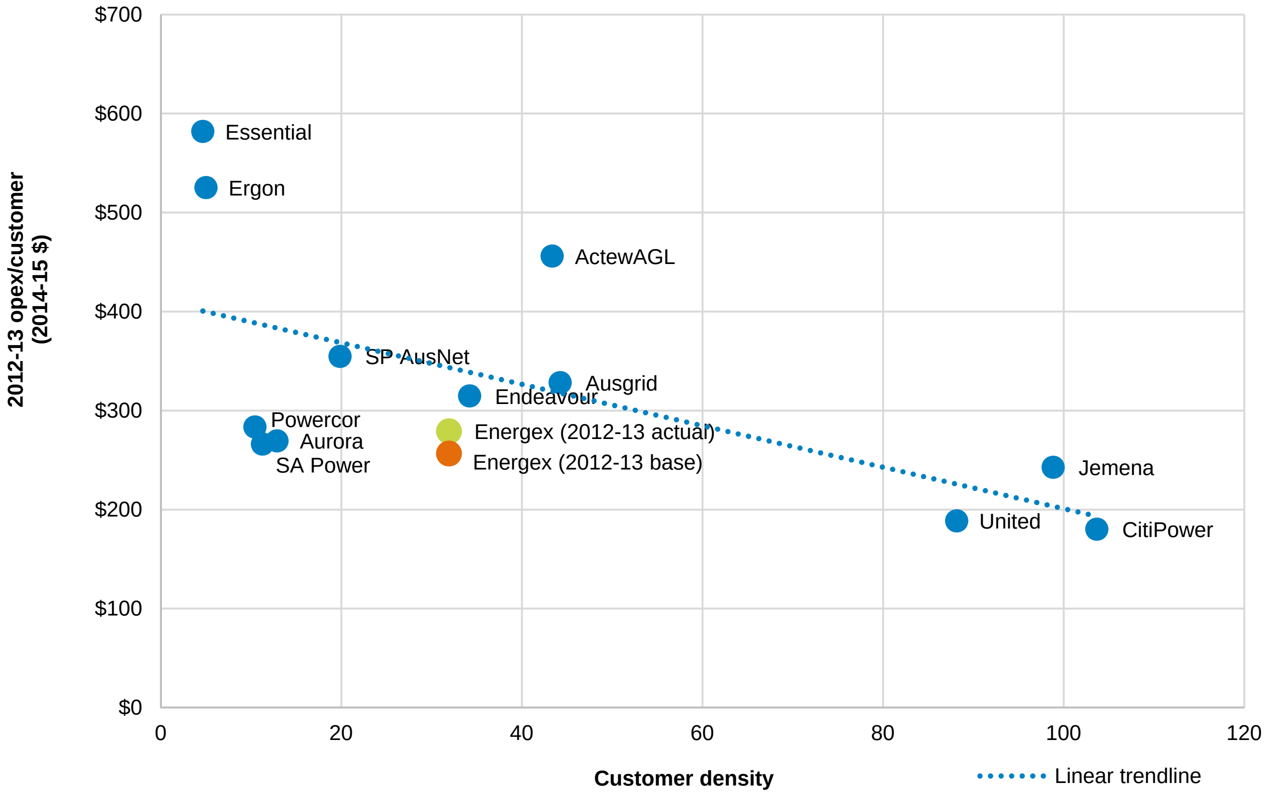
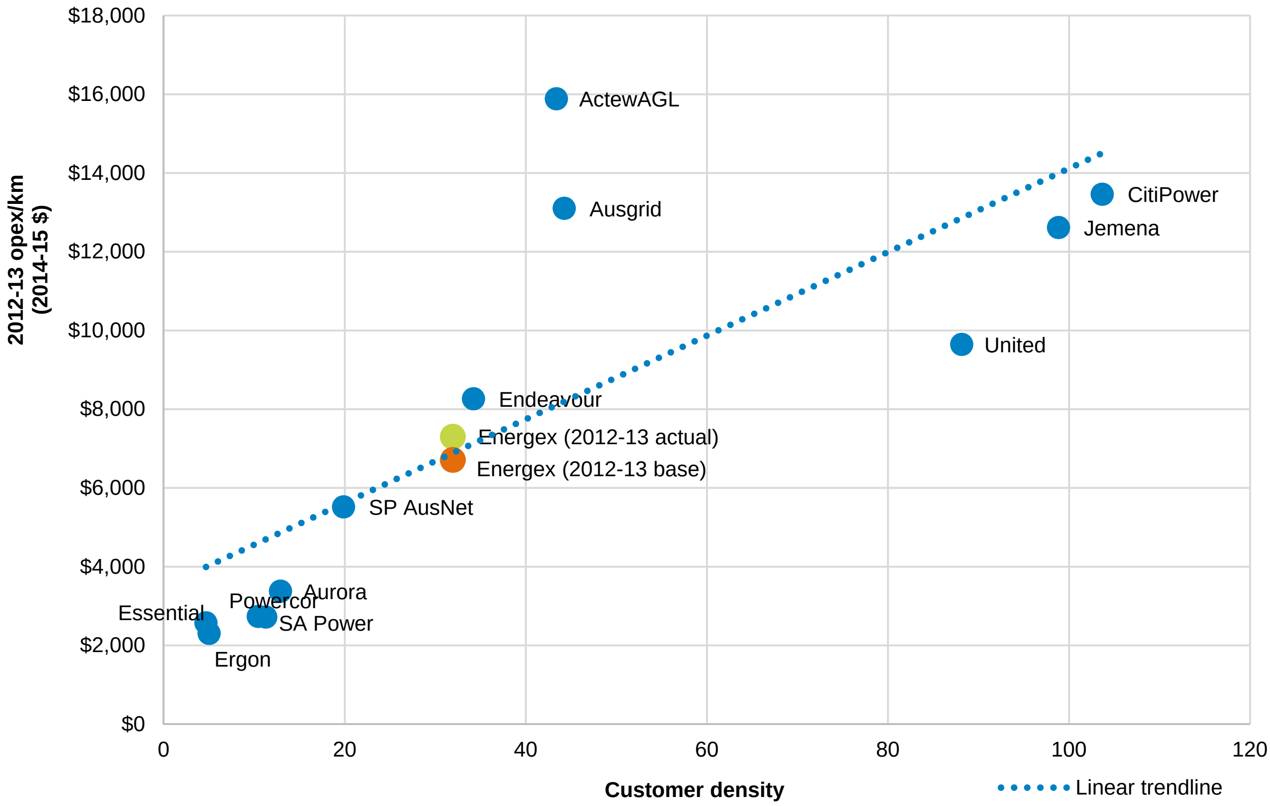


Figure A1.4 – 2012-13 benchmarking – total opex/km (including indirect costs)



1.5 Efficiency adjustments for the 2015-20 regulatory period

Energex is committed to improving operating efficiency consistent with shareholder and customer expectations. Efficiencies have been built into the base-step-trend forecast in the following categories:

- Vegetation – Energex recently changed the operating model with aligned suppliers, allowing the supplier to more efficiently manage the utilisation of their resources and make informed decisions in their area of expertise resulting in increased efficiencies and savings for Energex. Energex's role transitions from managing and dispatching the program to one of monitoring compliance to required standards and key performance indicators.

- Network operating – Energex expects the ongoing development and implementation of a fully integrated Distribution Management System (DMS) to deliver future efficiencies in control centre activities through automated and semi-automated features and tools.

- Network and corporate overheads (general efficiency) - Energex will continue to implement the efficiency program it had initiated in the 2010-15 regulatory control period. Energex expects to achieve further savings through the rightsizing of its staffing levels and identification & implementation of non-staff related efficiency savings.

These efficiency adjustments have been incorporated into the base-step-trend model as either a step change (for vegetation and network operating costs) or as a general efficiency driver (for general network and corporate overhead efficiencies).

Step changes have been used where specific efficiency changes are known so as to better relate the change to the years in which the efficiencies are forecast to occur. In this approach, double counting of the efficiency is avoided by ensuring that it is not also considered as a general efficiency driver.

1.6 Adjustments for significant (non-recurrent) items

Energex has identified a number of significant expenditure items which will be incurred over the 2015-20 regulatory control period. This expenditure is required to meet the expenditure objectives under the Rules. It is not appropriate to include these in the base year as they are non-recurrent. In addition, no output growth is applied to significant items.

Annual adjustments for these significant items are identified by category in Table A1.3.

Section 2.2 contains a detailed description of each adjustment.

Table A1.3 – Adjustments for significant items (2012-13, $m)

	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Planned maintenance						
Power transformer corrosive sulphur treatment (see section 2.2.1)	0.8	0.7	0.7	0.7	0.7	**3.8**
Corporate overheads						
Property rent reductions (see section 2.2.2)	(2.9)	(4.4)	(4.4)	(4.4)	(4.4)	**(20.6)**
Notes: Due to rounding, individual components may not sum to the total						

1.7 Adjustments to reflect changes in scope (step changes)

Step changes reflect changes in scope and may result from factors outside of Energex's control. Energex has identified a number of changes which will lead to additional expenditure over the 2015-20 regulatory control period. This expenditure is required to meet the expenditure objectives under the Rules. Energex has also identified step changes which have resulted in a decrease to expenditure over the regulatory period.

Annual adjustments for these step changes are identified by category in Table A1.4. Section 2.3 contains a detailed description of each adjustment.

Table A1.4 – Adjustments for step changes (2012-13, $m)

	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Planned maintenance						
Replacement of network equipment containing asbestos (see section 2.3.1)		0.3				
Vegetation						
Change in operating model (see section 2.3.2)	(7.1)		(0.6)			
Network overheads						
Integrated DMS (control centre) (see section 2.3.3)	(1.5)					
Notes: Due to rounding, individual components may not sum to the total						

1.8 Output and efficiency drivers

Energex has adjusted expenditure to account for escalation over the 2015-20 regulatory control period. This reflects drivers relating to the scale of the opex program, economies of scale and general efficiency adjustments which are expected over the period. Additional detail on each of the drivers is included in sections 1.8.1 and 1.8.2.

1.8.1 Output drivers

Output drivers are used to escalate expenditure over the regulatory control period. These drivers are used to account for an increase to the opex program as a result of an increase in the size, or a change to the characteristics of the distribution network. Energex has identified three output drivers for use as scale escalators in the base-step-trend model.

Each functional area has been assigned to an output driver (or composite) to escalate expenditure over the regulatory control period. The output drivers provide the gross growth rate. A subsequent allowance for economies of scale is included to calculate the net growth rate as outlined in section 1.8.2 and Table A1.9.

Network growth

Network growth represents growth in the size of the network and increase of assets contained within the Energex distribution area. Network growth is based on an average of[2]:

- length of lines (km)
- number of distribution transformers
- installed substation capacity.

The forecast for installed substation capacity is based on Energex's demand forecast as outlined in Chapter 8 of the regulatory proposal.

Energex collected data on the growth in lines and distribution transformers from 2006-07 to 2012-13. A significant proportion of the growth in these areas is due to new customer growth. Using historical customer growth, Energex was able to determine an average line length and number of transformers for every 1000 new customers. These average rates were then applied to the customer number forecast to forecast line length and transformer numbers over the period from 2014-15 to 2019-20.

[2] In accordance with the methodology approved by the AER in the recent Victorian distribution decision. Victorian electricity distribution network service providers, Distribution determination 2011–2015, October 2010, Appendix J, p194

Table A1.5 – Network growth driver

	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Total NCC Zone Substation Capacity MVA	11,521	11,868	12,251	12,341	12,506	12,599	12,742
Annual growth (%)	1.9%	3.0%	3.2%	0.7%	1.3%	0.7%	1.1%
Lines - total overhead and underground km	52,100	52,688	53,337	53,949	54,558	55,166	55,779
Annual growth (%)	0.6%	1.1%	1.2%	1.1%	1.1%	1.1%	1.1%
Distribution transformers	47,923	48,685	49,525	50,318	51,106	51,894	52,688
Annual growth (%)	1.0%	1.6%	1.7%	1.6%	1.6%	1.5%	1.5%
Average network growth	**1.2%**	**2.0%**	**2.2%**	**1.2%**	**1.5%**	**1.1%**	**1.3%**

Customer numbers growth

The forecast for customer numbers is based on the base case forecast as outlined in Chapter 8 of the regulatory proposal.

Table A1.6 – Customer growth driver

	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Customer numbers (000)	1,364	1,381	1,401	1,419	1,437	1,454	1,473
Customer numbers growth (%)	**1.3%**	**1.3%**	**1.4%**	**1.3%**	**1.3%**	**1.2%**	**1.2%**

Solar PV growth

Solar PV growth is based on a forecast of exports, which forms part of the energy forecast as outlined in Chapter 8 of the regulatory proposal. Solar PV growth has only been used for selected expenditure relating to voltage balancing and investigations as this is strongly linked to solar PV growth.

Table A1.7 – Solar PV growth driver

	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Solar PV net exports (GWh)	613	709	799	866	932	995	1059
Solar PV growth (%)	**58.4%**	**15.7%**	**12.7%**	**8.4%**	**7.6%**	**6.8%**	**6.4%**

1.8.2 Efficiency drivers

Economies of scale

Economies of scale are used to adjust the output growth factors to reflect opex efficiency outcomes. This accounts for a reduction in costs on a per unit basis as the scale increases. The economies of scale factors relating to each opex category are based on the approach used by the AER in previous determinations and on Energex's own experience of the detailed program build. The economies of scale factors and corresponding net growth rates are provided in Table A1.9.

A basic overview of the application is as follows

- An output driver is assigned to each functional area.
- Each output driver has a growth rate (gross) for each year of the regulatory control period as shown in section 1.8.1.
- An economies of scale factor is assigned to each functional area.
- The growth rates for each functional area are reduced by a factor (economies of scale) to account for expenditure not increasing in direct proportion to growth.
- The net growth rates are applied to the expenditure over the regulatory control period.

General efficiencies

Energex is committed to improving operating efficiency consistent with shareholder and customer expectations. General network and corporate overhead efficiencies have been included as part of the efficiency driver.

Table A1.8 – Efficiency driver adjustments (2012-13, $m)

		2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Network overheads									
General efficiency (see section 2.4.1)	annual	(14.5)	(5.8)	(2.9)	(4.8)	(2.8)	(0.7)	(0.7)	
	cumulative		(20.3)	(23.2)	(28.0)	(30.7)	(31.4)	(32.1)	**(32.1)**
Corporate overheads									
General efficiency (see section 2.4.1)	annual	(10.9)	(2.5)	(2.7)	(3.2)	(2.6)	(0.6)	(0.6)	
	cumulative		(13.4)	(16.0)	(19.2)	(21.8)	(22.4)	(23.0)	**(23.0)**
Notes: Due to rounding, individual components may not sum to the total									

Table A1.9 – Output growth drivers and economies of scale by expenditure category

Expenditure category	Functional area	Output growth driver	Avg annual scale driver (gross)	Economies of scale[3] (EOS)	Avg annual scale driver (net)	Rationale
Inspection	Inspection	Network	1.4%	20%	1.1%	Only minimal economies of scale achievable as additional inspections are strongly linked to network growth. The EOS adjustment includes an allowance for productivity improvements.
Planned maintenance	Planned maintenance	Network	1.4%	20%	1.1%	Only minimal economies of scale achievable as planned maintenance is strongly linked to network growth. The EOS adjustment includes an allowance for productivity improvements.
Corrective repair	Corrective repair	n/a	0%	n/a	0.0%	No output growth has been applied as improved planned maintenance programs are expected to prevent growth in corrective repair. This forecast also takes into account Energex's proposed asset replacement program.
Vegetation	Vegetation	n/a	n/a	n/a	0.0%	No output growth applied to vegetation costs
Emergency response/storms	Emergency response/storms	n/a	0%	n/a	0.0%	No output growth has been applied as the 10 year historical average has been used.
Network overheads	Network Management	n/a	n/a	n/a	0.0%	No output growth applied to indirect costs
	Network Planning	n/a	n/a	n/a	0.0%	No output growth applied to indirect costs

[3] The economies of scale factor represents the reduction in the output driver due to efficiencies. eg net growth = gross growth*(1-economies of scale factor)

Expenditure category	Functional area	Output growth driver	Avg annual scale driver (gross)	Economies of scale[3] (EOS)	Avg annual scale driver (net)	Rationale
	Network Control and Operational Switching - direct	Network and solar PV (composite)	2.2%	50.8% (20% for opex growth related to solar PV, 75% for all other opex growth)	1.1%	Opex relating to solar PV works: Minimal economies of scale are achievable for the portion of this expenditure relating to voltage balancing and investigations as this is strongly linked to solar PV growth. The EOS adjustment includes an allowance for productivity improvements. All other network operating costs: Economies of scale are achievable through effective maintenance of other general activities under this category.
	Network Control and Operational Switching	n/a	n/a	n/a	0.0%	No output growth applied to indirect costs
	Network Monitoring	n/a	n/a	n/a	0.0%	No output growth applied to indirect costs
	Quality and Standard Functions	n/a	n/a	n/a	0.0%	No output growth applied to indirect costs
	Project Governance and Related Functions	n/a	n/a	n/a	0.0%	No output growth applied to indirect costs
	Training and Development	n/a	n/a	n/a	0.0%	No output growth applied to indirect costs
	OHS	n/a	n/a	n/a	0.0%	No output growth applied to indirect costs
	Customer service - direct	Customer	1.3%	90.0%	0.1%	Significant economies of scale are achievable in this area.
	Customer Service - indirect	n/a	n/a	n/a	0.0%	No output growth applied to indirect costs

Expenditure category	Functional area	Output growth driver	Avg annual scale driver (gross)	Economies of scale[3] (EOS)	Avg annual scale driver (net)	Rationale
	Meter reading, network billing and metering support	n/a	n/a	n/a	0.0%	No output growth applied to indirect costs
	Network Property	n/a	n/a	n/a	0.0%	No output growth applied to indirect costs
Corporate overheads	Office of CEO	n/a	n/a	n/a	0.0%	No output growth applied to indirect costs
	Legal and Secretariat	n/a	n/a	n/a	0.0%	No output growth applied to indirect costs
	Audit	n/a	n/a	n/a	0.0%	No output growth applied to indirect costs
	Strategy and Regulation	n/a	n/a	n/a	0.0%	No output growth applied to indirect costs
	Human Resources	n/a	n/a	n/a	0.0%	No output growth applied to indirect costs
	Finance	n/a	n/a	n/a	0.0%	No output growth applied to indirect costs
	Business Support Services	n/a	n/a	n/a	0.0%	No output growth applied to indirect costs
	Business Operations and Performance	n/a	n/a	n/a	0.0%	No output growth applied to indirect costs
	Field Support Services	n/a	n/a	n/a	0.0%	No output growth applied to indirect costs
	Stakeholder Engagement and Management	n/a	n/a	n/a	0.0%	No output growth applied to indirect costs
	Property	n/a	n/a	n/a	0.0%	No output growth applied to indirect costs
	Fleet	n/a	n/a	n/a	0.0%	No output growth applied to indirect costs
Note: This table only includes functional areas which are forecast using the base-step-trend approach						

1.9 Cost escalation

The forecast opex and capex values in this regulatory proposal are represented in 2014-15 dollar terms, and escalated using real cost escalation factors. Energex engaged Jacobs SKM and PricewaterhouseCoopers to provide expert advice on appropriate cost escalators over the 2015-20 regulatory control period. A summary of the cost escalators and the detailed expert advisors' reports are provided as appendices to the regulatory proposal.

Specific real cost escalators have been applied to individual expense categories, including network asset categories, labour and contractor cost, ancillary material expenditure, land and land tax value, occupancy expenditure and transport costs. Energex has used a Weighted Price Index for the escalation of labour, given that quantity and quality inputs are held constant in determining the index, no productivity compensation is included in the labour escalation.

1.10 Proposed expenditure 2015-20 by category

The following section provides a detailed breakdown of the expenditure forecasts for each of the categories in the 2015-20 regulatory control period. This forecast represents expenditure items forecast using the base-step-trend method only.

Table A1.10 – Summary of expenditure from base-step-trend model

	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Inspection						
Efficient base	13.2	13.4	13.5	13.7	13.8	67.6
Significant items	0.0	0.0	0.0	0.0	0.0	0.0
Step changes	0.0	0.0	0.0	0.0	0.0	0.0
Output driver	0.3	0.2	0.2	0.2	0.2	0.9
Efficiency driver	(0.05)	(0.03)	(0.04)	(0.03)	(0.03)	(0.2)
Cost escalation	0.7	0.8	0.9	1.0	1.1	4.5
Total (2014-15, $m)	**14.1**	**14.3**	**14.6**	**14.8**	**15.0**	**72.9**
Planned maintenance						
Efficient base	46.0	47.1	47.5	48.0	48.4	237.1
Significant items	0.8	0.7	0.7	0.7	0.7	3.8
Step changes	0.3	0.0	0.0	0.0	0.0	0.3
Output driver	1.0	0.5	0.6	0.5	0.6	3.3
Efficiency driver	(0.19)	(0.11)	(0.13)	(0.11)	(0.12)	(0.7)
Cost escalation	2.6	2.9	3.2	3.5	3.8	16.1
Total (2014-15, $m)	**50.5**	**51.1**	**51.9**	**52.7**	**53.5**	**259.8**
Corrective repair						
Efficient base	24.3	24.3	24.3	24.3	24.3	121.7
Significant items	0.0	0.0	0.0	0.0	0.0	0.0
Step changes	0.0	0.0	0.0	0.0	0.0	0.0
Output driver	0.0	0.0	0.0	0.0	0.0	0.0
Efficiency driver	0.0	0.0	0.0	0.0	0.0	0.0
Cost escalation	1.4	1.6	1.9	2.1	2.3	9.4
Total (2014-15, $m)	**25.8**	**26.0**	**26.2**	**26.4**	**26.7**	**131.1**
Vegetation						
Efficient base	44.5	44.5	43.9	43.9	43.9	220.9
Significant items	0.0	0.0	0.0	0.0	0.0	0.0
Step changes	0.0	(0.6)	0.0	0.0	0.0	(0.6)
Output driver	0.0	0.0	0.0	0.0	0.0	0.0
Efficiency driver	0.0	0.0	0.0	0.0	0.0	0.0
Cost escalation	2.1	2.0	2.0	2.0	2.0	10.1
Total (2014-15, $m)	**46.6**	**45.9**	**45.9**	**45.9**	**45.9**	**230.4**

	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Emergency response/storms						
Efficient base	7.3	7.3	7.3	7.3	7.3	36.5
Significant items	0.0	0.0	0.0	0.0	0.0	0.0
Step changes	0.0	0.0	0.0	0.0	0.0	0.0
Output driver	0.0	0.0	0.0	0.0	0.0	0.0
Efficiency driver	0.0	0.0	0.0	0.0	0.0	0.0
Cost escalation	0.4	0.4	0.5	0.5	0.6	2.5
Total (2014-15, $m)	**7.7**	**7.8**	**7.8**	**7.9**	**7.9**	**39.0**
Network overheads						
Efficient base	182.3	179.5	174.6	171.9	171.3	879.7
Significant items	0.0	0.0	0.0	0.0	0.0	0.0
Step changes	0.0	0.0	0.0	0.0	0.0	0.0
Output driver	0.7	0.4	0.5	0.4	0.4	2.4
Efficiency driver	(3.48)	(5.36)	(3.22)	(0.97)	(0.97)	(14.0)
Cost escalation	10.6	11.8	13.2	14.7	16.3	66.7
Total (2014-15, $m)	**190.1**	**186.5**	**185.1**	**186.1**	**187.1**	**934.8**
Corporate overheads						
Efficient base	134.3	131.7	128.5	126.0	125.3	645.8
Significant items	(2.9)	(4.4)	(4.4)	(4.4)	(4.4)	(20.6)
Step changes	0.0	0.0	0.0	0.0	0.0	0.0
Output driver	0.0	0.0	0.0	0.0	0.0	0.0
Efficiency driver	(2.67)	(3.16)	(2.56)	(0.63)	(0.62)	(9.6)
Cost escalation	7.6	8.1	8.8	9.6	10.4	44.6
Total (2014-15, $m)	**136.4**	**132.2**	**130.3**	**130.5**	**130.7**	**660.1**
Total expenditure forecast using BST model	**471.2**	**463.8**	**461.9**	**464.3**	**466.8**	**2,328.1**

Notes:

1. Figures for efficient base, significant items, step change, output drivers and efficiency drivers are in the base year, 2012-13 $m.
2. Total costs are in 2014-15 $m.
3. Efficiency driver includes both economies of scale and general efficiencies.
4. Overhead costs represent total expenditure forecast using the base-step-trend model, prior to application of the CAM
5. Total expenditure forecast using BST excludes demand management, debt raising, levies, corporate programs, ICT and self- insurance costs which are all subject to an alternative forecast methodology.
6. Due to rounding, individual components may not sum to the total.

1.11 Overhead costs using alternative methods

Table A1.10 includes network and corporate costs forecast using the base-step-trend model. A significant portion of network and corporate costs are forecast using alternative methods as shown in Table A1.11.

Table A1.11 – Total indirect costs over the regulatory control period (BST and alternative methods) (2014-15, $m)

	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Network overheads (BST model)	190.1	186.5	185.1	186.1	187.1	**934.8**
Network overheads (other method)	20.9	21.8	22.0	23.9	25.7	**114.2**
Total network overheads	**210.9**	**208.3**	**207.0**	**209.9**	**212.8**	**1049.0**
Corporate overheads (BST model)	136.4	132.2	130.3	130.5	130.7	**660.1**
Corporate overheads (other method)	120.1	118.7	114.4	121.4	119.7	**594.3**
Total corporate overheads	**256.4**	**250.9**	**244.7**	**251.9**	**250.4**	**1254.4**
Total indirect expenditure	**467.4**	**459.2**	**451.7**	**461.9**	**463.2**	**2303.3**
Notes: Due to rounding, individual components may not sum to total						

1.12 Allocation of indirect expenditure

Energex has categorised indirect expenditure for base-step-trend purposes consistent with the categories required in the Category Analysis and regulatory proposal submission RIN's. However a number of categories reported as network overhead and corporate overhead in the overhead template in the RIN's are reported as direct operating expenditure under Energex's approved CAM. These include:

- Network operating costs
- Network billing and other energy market services
- Customer services (incl call centre)
- DSM initiatives
- Levies
- Debt raising costs
- Self insurance
- Other operating costs

The remaining indirect expenditure, categorised above as network and corporate overhead, from Table A1.11 is allocated in accordance with Energex's approved CAM. Overheads are allocated to regulated services (operating and capital expenditure) based on total direct spend.

Table A1.12 – Allocation of indirect expenditure (2014-15 $m)

	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Network overheads						
allocated to SCS capex	88.2	87.4	83.2	81.7	83.2	**423.7**
allocated to SCS opex	93.3	92.4	94.6	98.4	100.1	**478.7**
allocated to ACS	28.3	27.5	28.1	28.7	28.3	**141.0**
allocated to unregulated	1.1	1.1	1.1	1.1	1.1	**5.5**
Total	**210.9**	**208.3**	**207.0**	**209.9**	**212.8**	**1049.0**
Corporate overheads						
allocated to SCS capex	118.7	116.9	109.0	108.6	108.8	**562.1**
allocated to SCS opex	104.5	101.8	103.0	108.9	108.0	**526.2**
allocated to ACS	25.9	25.0	25.9	27.5	26.6	**130.8**
allocated to unregulated	7.3	7.2	6.8	7.0	7.0	**35.2**
Total	**256.4**	**250.9**	**244.7**	**251.9**	**250.4**	**1254.4**
Total indirect expenditure	**467.4**	**459.2**	**451.7**	**461.9**	**463.2**	**2303.3**

Notes:
Due to rounding, individual components may not sum to total

1.12.1 Allocation to SCS operating expenditure

The overheads allocated to SCS opex from Table A1.12 are combined with the direct opex from Table A1.10 to provide the total operating expenditure forecast over the regulatory period of $1.7 billion.

Table A1.13 – Total operating expenditure forecast (2014-15 $m)

	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Inspection	14.1	14.3	14.6	14.8	15.0	72.9
Planned maintenance	50.5	51.1	51.9	52.7	53.5	259.8
Corrective repair	25.8	26.0	26.2	26.4	26.7	131.1
Vegetation	46.6	45.9	45.9	45.9	45.9	230.4
Emergency response/storms	7.7	7.8	7.8	7.9	7.9	39.0

	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Network overheads (SCS opex)	93.3	92.4	94.6	98.4	100.1	478.7
Corporate overheads (SCS opex)	104.5	101.8	103.0	108.9	108.0	526.2
Total	**342.5**	**339.4**	**344.1**	**355.0**	**357.2**	**1,738.2**
Notes: Due to rounding, individual components may not sum to total						

1.12.2 Allocation to SCS capital expenditure

The overheads allocated to SCS capex from Table A1.12 are combined with the direct capex to provide the total capital expenditure forecast over the regulatory period of $3.2 billion.

Table A1.14 – Total capital expenditure forecast (2014-15 $m)

	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Asset replacement	242.6	252.6	233.2	238.4	228.0	**1,194.7**
Augmentation	112.9	122.6	105.1	81.9	71.8	**494.3**
Connections and customer-initiated works	53.3	53.1	54.4	59.8	100.1	**320.7**
Non-system	54.5	56.0	44.1	43.1	46.5	**244.1**
Network overheads (SCS capex)	88.2	87.4	83.2	81.7	83.2	**423.7**
Corporate overheads (SCS capex)	118.7	116.9	109.0	108.6	108.8	**562.1**
Total	**670.3**	**688.5**	**629.0**	**613.3**	**638.4**	**3,239.6**
Notes: Due to rounding, individual components may not sum to total						

1.13 Treatment of Leave Provisions

Energex notes in other recent decisions the AER has reversed the movement in leave provisions from the base year and included the cash payment amount rather than the accrued employee liability incurred in that year.

Energex is of the view that it is not appropriate to substitute the amounts provided for leave liabilities with actual cash payments.

Leave provisions represent valid employee expenses necessarily incurred by Energex at a known point in time, of which the timing of settlement is uncertain. The replacement of the amounts provided with actual outflows will decrease the reliability of future forecasts significantly and would result in mismatches between revenue and “expenditure” with related volatility, inaccuracies and mismatches in pricing to customers.

Energex’s basis of accounting follows Australian Accounting Standards and particularly in this instance ‘Standard 137 Provisions, Contingent Liabilities and Contingent Assets’.

Maximum alignment between statutory and regulatory financial reporting results in efficiencies and ensures reporting within a robust and generally accepted framework. Adherence to these standards and conventions prescribed by the Corporations Act and various authoritative bodies provide customers and other stakeholders with assurance regarding the integrity of financial measurement, reporting and decision making. Forecasting based on actual cashflows would necessitate actual reporting on the same basis and would thus lead to deviations from Australian Accounting Standards.

In addition to the governance and assurance that a robust accounting framework provides, there is also an incremental cost attached to the implementation of a second accounting framework. This cost arises from variations to systems, processes, reporting and auditing requirements that come with adding non-generally accepted accounting frameworks. Potential reputational considerations for the entity and the industry also arise where the actual outcomes are unfavourable to customers compared with generally accepted accounting and commercial practice. Other unintended consequences can arise with the introduction of exceptions to fundamental accounting principles (eg accrual vs. cash accounting).

Energex also notes that in an environment of reducing staff levels, as Energex is currently undertaking, actual leave payments can vary significantly from the underlying employee expenses and therefore result in volatility in operating expenditure and consequently revenue requirements.

Actual leave payments (cash) are charged against the provision and therefore do not impact opex, consequently the incurred value included in opex more accurately represents the recognisable employee expenses, or cost of operations in any given year.

In addition, Energex applies a standard costing approach to charge labour to individual services, activities and projects, both regulated and un-regulated. Labour is charged at standard rates relative to each employee’s labour classification and includes wage costs and associated labour oncost. The oncost component incorporates allowances for leave expenses as they are incurred, rather than as paid, and other statutory expenses. (e.g. payroll tax, workers compensation premiums)

Accurate reflection of leave on a cash basis is not achievable as it is unrealistic to restate approximately 1 million labour transactions costed to individual services/activities per annum. Additionally it is unrealistic to recalculate and reallocate overhead and other oncosts (fleet and material) to services and activities to accurately reflect the labour oncost in support areas on a cash basis. Undertaking this significant effort is inefficient and would result in an outcome that in Energex’s view is sub-optimal, inconsistent with Accounting Standards and will also create permanent differences to both statutory and annual regulatory performance reporting.

In the view of Energex, in addition to the potential impacts on customers, the considerations above could hinder confidence in reporting by the industry.

Due to the above considerations Energex has not incorporated the cash accounting approach for leave provisions in applying the base-step-trend or other forecasting methodologies.

2 Supporting documentation: Base-step-trend model adjustments

2.1 Base year adjustments

2.1.1 Provisions relating to LV service cable inspections

Item description	**Provisions relating to LV service cable inspections** Actual expenditure for 2012-13 relating to inspections is required to be adjusted to account for a provision raised for cable inspections.							
Category	Inspection							
Recurrent cost	☑ Yes			☐ No				
Adjustment type	☑ Base year adjustment			☐ Significant item			☐ Step change	
Financial impact ($m 2012-13, direct)	**2012-13**	**2013-14**	**2014-15**	**2015-16**	**2016-17**	**2017-18**	**2018-19**	**2019-20**
	5.3							
Driver(s)	☑ Safety		☐ Compliance/ Legislation		☐ Risk of failure		☑ Other	
Background information	In 2011, Energex identified a manufacturing fault on certain overhead service lines which had led to the premature deterioration of these cables. Energex is legally obliged to inspect, identify and replace the deteriorated cables to ensure they meet the Electrical Safety Regulations. Under Australian accounting standards Energex recognised a provision in the 2011-12 year for the associated inspection costs. The provision resulted in higher than forecast inspection costs in 2011-12 and lower than forecast costs in 2012-13 as a portion of the forecast spend for 2012-13 had been included in the provision recognised in 2011-12. In addition, a portion of the provision was reversed in 2012-13 to reflect a revised estimate to complete the inspection program related to this issue.							

2.1.2 LV crossarm planned replacement program

Item description	**LV crossarm planned replacement program** A new program to inspect and replace LV crossarms to ensure system safety and reliability factors are maintained and compliance with legislation failure rates.							
Category	Inspection, Planned maintenance							
Recurrent cost	☑ Yes			☐ No				
Adjustment type	☑ Base year adjustment			☐ Significant item			☐ Step change	
Financial impact ($m 2012-13, direct)	**2012-13**	**2013-14**	**2014-15**	**2015-16**	**2016-17**	**2017-18**	**2018-19**	**2019-20**
	1.7							
Driver(s)	☑ Safety		☐ Compliance/ Legislation		☑ Risk of failure		☐ Other	

Background information

Driver for the adjustment

An additional program is required to inspect and replace low voltage (LV) crossarms to ensure system safety and compliance with legislative failure rates. Failure of a crossarm can lead to potential public safety risks and reliability impacts.

Due to restrictions on 'no fly' zones for aerial patrols, Energex has historically only patrolled 11kV & 33kV feeders in rural areas. The LV component of the poles inspected during these patrols is included in this assessment. However, the LV network outside of these areas has not been specifically targeted by aerial patrols. This program is a new initiative to inspect LV crossarms using a EWP to view from above and additional aerial inspections.

Consideration of other options ("do nothing" option)

Energex has assessed the risk of a "do nothing" approach.

Untreated Risk Assessment				
Safety	**Environment**	**Legislative**	**Customer Impact**	**Business Impact**
Very High	Moderate	Intolerable	Low	-

Failure to complete proposed ground and helicopter patrols of the LV network has an increased likelihood of defective low voltage crossarms not being identified leading to a failed/broken crossarm and potential wire down impacting public safety and associated network reliability issues.

Identifying and quantifying the preferred option

Work under this program includes:

- The inspection of crossarms including tests to detect internally rotted arms or arms that have significant deterioration due to solar effects
- The planned replacement of crossarms which are classified as unserviceable (where the condition is found to be below defined limits)

A pilot program was initiated in the base year (2012-13) with the full program commencing in 2013-14.

As this is a long term program, Energex has adjusted the 2012-13 base year.

- Actual expenditure 2012-13 = $0.15m Inspect + $0.3m Planned
  = $0.5m
- Forecast efficient expenditure level = $0.6m Inspect + $1.5m Planned
  = $2.1m
- Adjustment to base year = $0.5m Inspect + $1.2m Planned
  = $1.7m

Benefits of the proposed adjustment

The inclusion of this program will reduce the risk of defective low voltage crossarms not being identified which can lead to safety risks and loss of reliability.

Summary

The inclusion of this change is required to comply with legislative failure rates (as detailed in the Electrical Safety Code of Practice 2010 – Works Section 5.1) and hence is consistent with the opex objective to comply with all applicable regulatory obligations or requirements associated with the provision of standard control services. In addition, the inclusion of this program is consistent with the opex objective to maintain the safety of the distribution system through the supply of standard control services.

2.1.3 Streetlight inspection expenditure

Item description	**Streetlight inspection expenditure** Removal of estimated costs relating to inspection of street light assets							
Category	Inspection							
Recurrent cost	☑ Yes			☐ No				
Adjustment type	☑ Base year adjustment			☐ Significant item			☐ Step change	
Financial impact ($m 2012-13, direct)	**2012-13**	**2013-14**	**2014-15**	**2015-16**	**2016-17**	**2017-18**	**2018-19**	**2019-20**
	(0.7)							
Driver(s)	☐ Safety		☐ Compliance/ Legislation		☐ Risk of failure		☑ Other	
Background information	Historically, streetlight inspection costs have been captured with other pole inspection activities under the SCS inspection opex category. These costs are an ACS service, so therefore an adjustment to the 2012-13 base year is required to remove them from the forecast. Energex has estimated the cost of inspecting these units to adjust the base year. As the data has not been specifically captured by pole type in the past (eg. streetlight vs steel pole), an average inspection quantity of approximately 30,000 poles per annum has been used. • Estimated expenditure 2012-13 = $0.7m • Forecast efficient expenditure level = $0.0m (cost is included under ACS) • Adjustment to base year = ($0.7m)							

2.1.4 Corrective repair historical average

Item description	**Corrective repair historical average** A long term historical average has been included for corrective repair						
Category	Corrective repair						
Recurrent cost	☑ Yes			☐ No			
Adjustment type	☑ Base year adjustment			☐ Significant item		☐ Step change	
Financial impact ($m 2012-13, direct)	**2012-13**	**2013-14**	**2014-15**	**2015-16**	**2016-17**	**2017-18**	**2018-19**	**2019-20**
	(1.5)							
Driver(s)	☐ Safety		☐ Compliance/ Legislation		☐ Risk of failure		☑ Other	
Background information	Corrective repair costs are dependent on a number of external factors outside of Energex's control. The actual expenditure for 2012-13 in this category has therefore been removed from the base year and replaced with a long term average. The long term average is based on direct expenditure from 2003-04 to 2012-13. This is considered to provide a more accurate forecast of recurrent expenditure in the base year. • Actual expenditure in 2012-13 = $25.8m • Forecast efficient expenditure level = $24.3m • Adjustment to base year = ($1.5m)						

2.1.5 Emergency response historical average

Item description	**Emergency response historical average** A historical average has been included for emergency response costs due to extreme weather events in the 2012-13 base year							
Category	Emergency response/storms							
Recurrent cost	☑ Yes			☐ No				
Adjustment type	☑ Base year adjustment			☐ Significant item			☐ Step change	
Financial impact ($m 2012-13, direct)	**2012-13**	**2013-14**	**2014-15**	**2015-16**	**2016-17**	**2017-18**	**2018-19**	**2019-20**
	(7.8)							
Driver(s)	☐ Safety		☐ Compliance/ Legislation		☐ Risk of failure		☑ Other	
Background information	In February 2013, Energex incurred additional emergency response costs as a result of ex-Tropical Cyclone Oswald. As this was an extreme weather event, the emergency response costs for 2012-13 are not considered to be representative of a recurrent expenditure level. The actual expenditure for 2012-13 in this category has therefore been removed from the base year and replaced with an average. The long term average is based on direct expenditure from 2003-04 to 2012-13 (excluding the Brisbane flood costs in 2010-11). This is considered to provide a more accurate forecast of recurrent expenditure in the base year. • Actual expenditure in 2012-13 = $15.1m • Forecast efficient expenditure level = $7.3m • Adjustment to base year = ($7.8m)							

2.1.6 Cancelled Projects

Item description	**Cancelled Projects** **Projects which are no longer required are cancelled and closed.**							
Category	Network overheads (Network Management)							
Recurrent cost	☐ Yes			☑ No				
Adjustment type	☑ Base year adjustment			☐ Significant item			☐ Step change	
Financial impact ($m 2012-13)	**2012-13**	**2013-14**	**2014-15**	**2015-16**	**2016-17**	**2017-18**	**2018-19**	**2019-20**
	(16.0)							
Driver(s)	☐ Safety		☐ Compliance/ Legislation		☐ Risk of failure		☑ Other	
Background information	In 2012-13, $16m of costs resulting from cancelled projects were included in Energex's other operating costs. Energex has made an adjustment to remove these costs from the base year calculation. The 2012-13 cancelled projects cost is considered unusual as a number of large projects were cancelled. Cancelled projects costs are generated when it is deemed that a project is no longer required. As 3-5 years' work in advance is required to deliver capital augmentation projects (including planning, design, construction, commissioning) – requirements can change while a project is still in development resulting in the project no longer being required. If deferment is not feasible or warranted, the project is cancelled. The significant value of cancelled projects in 2012-13 resulted from: • Qld Government's 2011-12 Electricity Network Capital Program Review (ENCAP) recommended: revised security and reliability standards, • Reductions in demand growth forecasts, reduction in required augmentation, greater penetration of solar PV and energy efficiency appliances, increasing electricity prices, changing customer behaviour. Consequently a review of projects resulted in a number of projects being deemed no longer required and were cancelled with the costs incurred to date expensed.							

2.1.7 Reallocation of expenditure between functional areas

Item description	**Reallocation of expenditure between functional areas** Energex has reallocated expenditure between functional areas prior to application of the base-step-trend model.							
Category	Multiple							
Recurrent cost	☑ Yes			☐ No				
Adjustment type	☑ Base year adjustment			☐ Significant item			☐ Step change	
Financial impact ($m 2012-13)	**2012-13**	**2013-14**	**2014-15**	**2015-16**	**2016-17**	**2017-18**	**2018-19**	**2019-20**
	0.0*							
Driver(s)	☐ Safety		☐ Compliance/ Legislation		☐ Risk of failure		☑ Other	
Background information	• Network Property - Land tax - The land tax for 2012-13 was allocated based on the split between network property (75.3%) and non-network property (24.7%). The $4.4m expenditure transfer corresponds to the network property share of land tax. - Rates - In 2012-13, part of network property rates expenditure was allocated to Network Planning for the first quarter. To ensure the financial year 2012-13 expenses reflect the true operating expenditure $0.8m has been transferred to Network Property expenses. • Business Support Services - In 2012-13, Large Trade Creditor insurance was costed to Corporate Programs for that financial year. In 2013-14, Large Trade Creditors insurance was budgeted for in Business Support Services function. To ensure the financial year 2012-13 costs reflect the true operating costs $0.6m has been transferred from Corporate Programs to Business Support Services function. - In 2012-13, the majority of liability claims for the network were costed to Corporate Programs. From 2013-14, these expenses moved from Corporate Program to Business Support Services function to align with the capturing of all insurance related expenditure in the one area. To ensure the financial year 2012-13 costs reflect the true operating costs, $1.5m has been transferred from Corporate Programs to Business Support Services. These costs are subsequently adjusted for under Self Insurance. • Finance - In 2012-13, a transfer of $0.4m was made between the Audit division and Finance division. This transfer is the result of re-structuring. To ensure the financial year 2012-13 costs reflect the true operating costs $0.4m has been transferred from the Audit function to the Finance function. *Note: the net impact is $0.0m as the costs have been reallocated from one functional area to another.							

2.1.8 Additional matrix support/licencing costs

Item description	**Additional matrix support/licencing costs** **Additional costs are required to support the operation of communications equipment due to advances in technology.**							
Category	Network overheads (Network operating)							
Recurrent cost	☑ Yes			☐ No				
Adjustment type	☑ Base year adjustment			☐ Significant item			☐ Step change	
Financial impact ($m 2012-13, direct)	**2012-13**	**2013-14**	**2014-15**	**2015-16**	**2016-17**	**2017-18**	**2018-19**	**2019-20**
	1.3							
Driver(s)	☐ Safety		☐ Compliance/ Legislation		☐ Risk of failure		☑ Other	

Background information

Driver for the adjustment

The communications networks form a critical component of the Energex distribution network. It is imperative that Energex maintains its communications equipment in optimal condition in order to ensure acceptable levels of safety and reliability. The communications network provides protection signalling, protection signalling relay management communications, SCADA/RTU links, RTU management communications, substations physical security systems communications and a range of miscellaneous other services. The introduction of this type of new technology requires periodic software/firmware upgrades and license costs previously not incurred by Energex.

Consideration of other options ("do nothing" option)

Energex has assessed the risk of a "do nothing" approach.

Untreated Risk Assessment				
Safety	**Environment**	**Legislative**	**Customer Impact**	**Business Impact**
Low	Very Low	Low	Moderate	Moderate

Failure to adequately fund this activity could lead to breach of maintenance support contract and performance of the fibre optic network.

Identifying and quantifying the preferred option

Energex is currently in the process of rolling out an IP/MPLS based data network (project Matrix). This will provide a common infrastructure telecommunications network in line with Energex's long term telecommunications strategic plan. At present there are 74 commissioned nodes and growth to 280 nodes is expected by 2020. The recurrent costs associated with the increase in Matrix nodes have been included in this adjustment.

In addition, Energex is preparing to introduce a central protection relay password management system which will incur ongoing license costs. The estimated recurrent costs associated with this new system have been included in this

	adjustment. • Actual expenditure in 2012-13 = $0.6m • Forecast efficient expenditure level = $1.9m • Adjustment to base year = $1.3m **Benefits of the proposed adjustment** The inclusion of this program will reduce the risk of loss of performance in Energex’s communications network. **Summary** The inclusion of this change is consistent with the opex objective to maintain the reliability and security of the distribution system through the supply of standard control services.

2.1.9 Protection reviews

Item description	**Protection reviews** Review of 11kV feeder protection schemes and settings to ensure adequate network fault detection and clearing time.							
Category	Network overheads (Network operating)							
Recurrent cost	☑ Yes			☐ No				
Adjustment type	☑ Base year adjustment			☐ Significant item			☐ Step change	
Financial impact ($m 2012-13, direct)	**2012-13**	**2013-14**	**2014-15**	**2015-16**	**2016-17**	**2017-18**	**2018-19**	**2019-20**
	0.7							
Driver(s)	☑ Safety		☑ Compliance/ Legislation		☐ Risk of failure		☑ Other	

Background information

Driver for the adjustment

Energex has an obligation under the NER to provide adequate primary protection. Currently, Energex conducts 11kV feeder protection reviews as part of capital projects. Many 11kV feeders have had their protection settings reviewed as part of projects associated with the high growth and significant capital program over the current 2010-15 regulatory period.

However, to minimise the potential risks of protection systems not operating correctly, all 11kV feeders are to have their protection settings reviewed within a 5 year period. As such, a new program is required to review 11kV feeders in low growth areas that have had little or no capital projects to capture fault level changes due to upstream network changes.

Consideration of other options ("do nothing" option)

Energex has assessed the risk of a "do nothing" approach.

Untreated Risk Assessment				
Safety	**Environment**	**Legislative**	**Customer Impact**	**Business Impact**
Moderate	Moderate	High	Low	-

Insufficient program allocation for reviewing 11kV feeder protection schemes and their associated settings could lead to a risk of safety to the community, excessive consequential damage to plant, decreased reliability and security.

Identifying and quantifying the preferred option

The program will undertake 11kV feeder protection scheme and setting reviews at pre-determined time intervals on feeders that have not had reviews under capital projects in the 5-year cycle.

The protection scheme review will involve the following steps:

- Fault study to determine fault levels
- Protection grading study

- Check coverage of protection scheme fault detection capability
- Issue settings changes where required
- Document remedial requirements and actions

As this is a long term program, Energex has adjusted the 2012-13 base year.

- Actual expenditure in 2012-13 = $0.0m
- Forecast efficient expenditure level = $0.7m
- Adjustment to base year = $0.7m

Benefits of the proposed adjustment

The inclusion of this program will reduce the risk that protection systems are inadequate. Protection reviews improve community safety, minimise consequential plant damage when network faults occur and ensure safety requirements are met.

Summary

The inclusion of this change is consistent with the opex objective to maintain the safety of the distribution system through the supply of standard control services.

2.1.10 Overhead service inspections

Item description	**Overhead service inspections** Implementation of a routine overhead inspection program from 2013-14 to inspect PVC/twisted services on an ongoing basis.							
Category	Network overheads (Customer services)							
Recurrent cost	☑ Yes			☐ No				
Adjustment type	☑ Base year adjustment			☐ Significant item			☐ Step change	
Financial impact ($m 2012-13, direct)	**2012-13**	**2013-14**	**2014-15**	**2015-16**	**2016-17**	**2017-18**	**2018-19**	**2019-20**
	2.7							
Driver(s)	☑ Safety		☑ Compliance/ Legislation		☑ Risk of failure		☐ Other	

Background information

Driver for the adjustment

Energex has obligations under the Queensland Electricity Safety Regulations (Part 5, Division 3, Section 74 and Division 7-Maintenance of works, Subsection 147) to inspect and maintain the integrity of overhead LV services.

Consideration of other options ("do nothing" option)

Energex has assessed the risk of a "do nothing" approach.

Untreated Risk Assessment				
Safety	**Environment**	**Legislative**	**Customer Impact**	**Business Impact**
High	Very Low	Intolerable	Low	-

Insufficient program allocation for overhead service inspections could lead to a risk of safety to the community.

Identifying and quantifying the preferred option

Energex will undertake a program from 2013-14 to inspect aged PVC/twisted services on an ongoing basis.

The program includes:

- A program where all PVC covered services (Parallel Web, Twisted - approximate population of 200,000) are visually inspected aloft at the customer's point of attachment over a 5 year interval.
- A sample inspection and testing program of XLPE services (pre 2007) either at the pole or house end of approximately 800 services (in accordance with AS1199.2 for a population of between 150,000 and 500,000.

Overhead services create a risk to the public in the following ways:

- Loss of neutral continuity can cause shocks from metal taps/fixtures that are bonded to the local earthing system
- Loss of insulation from active conductor may cause an electric shock due to inadvertent contact when working around services (eg painting, cleaning

gutters)

Energex has estimated the expenditure required:

- Actual expenditure in 2012-13 = $0.0m
- Forecast efficient expenditure level = $2.7m
- Adjustment to base year = $2.7m

The program will complement the five yearly pole inspection programs which also look at pole apparatus and services. The quantities per annum are reflective of service type populations and strategies in place for replacements.

Benefits of the proposed adjustment

This program will allow Energex to comply with regulations and minimise the risk to public safety through house end inspections of all aged PVC services 18 years and older and periodic sample testing of XLPE services over ten years.

Summary

The inclusion of this change is required to comply with obligations under the Electricity Safety Regulations and hence is consistent with the opex objective to comply with all applicable regulatory obligations or requirements associated with the provision of standard control services.

2.1.11 Reclassification of metering services to ACS (direct maintenance costs)

Item description	**Reclassification of metering services to ACS** A portion of customer services costs incurred in 2012-13 relate to services which will be reclassified as alternative control services from 1 July 2015.							
Category	Network overheads (Customer services)							
Recurrent cost	☑ Yes			☐ No				
Adjustment type	☑ Base year adjustment			☐ Significant item			☐ Step change	
Financial impact ($m 2012-13, direct)	**2012-13**	**2013-14**	**2014-15**	**2015-16**	**2016-17**	**2017-18**	**2018-19**	**2019-20**
	(2.2)							
Driver(s)	☐ Safety		☐ Compliance/ Legislation		☐ Risk of failure		☑ Other	
Background information	From 1 July 2015 metering services costs will be classified as an alternative control service. In 2012-13 Energex incurred costs relating to metering services in the customer services expenditure category. As these costs will not be included in SCS in the next regulatory control period they have been removed from the base year. This includes costs relating to meter queries, meter compliance and compliance testing of CT meters.							

2.1.12 Reclassification of metering services to ACS (indirect costs)

Item description	**Reclassification of metering services to ACS** A portion of indirect metering costs incurred in 2012-13 relate to services which will be reclassified as alternative control services from 1 July 2015.							
Category	Network overheads (Network billing and other energy market services)							
Recurrent cost	☑ Yes			☐ No				
Adjustment type	☑ Base year adjustment			☐ Significant item			☐ Step change	
Financial impact ($m 2012-13)	**2012-13**	**2013-14**	**2014-15**	**2015-16**	**2016-17**	**2017-18**	**2018-19**	**2019-20**
	(12.4)							
Driver(s)	☐ Safety		☐ Compliance/ Legislation		☐ Risk of failure		☑ Other	
Background information	From 1 July 2015 metering services associated with Type 6 metering will be classified as alternative control services. An adjustment to the 2012-13 base year is required to remove costs relating to Meter Data Management. In addition costs relating to the Metering Dynamics data warehousing charge have been removed as this charge no longer applies from 2013-14. Items remaining in the Network billing and other energy market services functional area for 2015-20 include: • Network billing • Market systems • Management office for Energy Market Services							

2.1.13 Insurance provision

Item description	**Insurance Provision**							
Category	Corporate overheads (Business support services)							
Recurrent cost	☐ Yes			☑ No				
Adjustment type	☑ Base year adjustment			☐ Significant item			☐ Step change	
Financial impact ($m 2012-13)	**2012-13**	**2013-14**	**2014-15**	**2015-16**	**2016-17**	**2017-18**	**2018-19**	**2019-20**
	(0.4)							
Driver(s)	☐ Safety		☐ Compliance/ Legislation		☐ Risk of failure		☑ Other	
Background information	A provision is taken up by Energex to recognise the future liabilities for claims under $100,000. This also includes the first $100,000 for claims in excess of this amount. The provision is accrued to profit and loss on a monthly basis based on an estimate of claims. As claims are processed, payments are allocated against the provision. To ensure the financial year 2012-13 expenses reflects efficient operating expenditure $0.4m has been deducted from the base year (2012-13).							

2.1.14 Corporate Program

Item description	**Corporate Program** Costs associated with Energex's corporate program							
Category	Corporate overheads (Other operating)							
Recurrent cost	☐ Yes			☑ No				
Adjustment type	☑ Base year adjustment			☐ Significant item			☐ Step change	
Financial impact ($m 2012-13)	**2012-13**	**2013-14**	**2014-15**	**2015-16**	**2016-17**	**2017-18**	**2018-19**	**2019-20**
	(4.5)							
Driver(s)	☐ Safety		☐ Compliance/ Legislation		☐ Risk of failure		☑ Other	
Background information	Energex has removed the corporate program expenditure from the base year (2012-13). The expenditure covers corporate program such as: • The Union Collective Agreement negotiation • Regulatory submission costs • Safety Programme Energex is of the view that the base-step-trend approach is not suitable to forecast this type of expenditure. Rather, Energex has forecast the corporate program expenditure using a project based method. Further details are provided in section 3.3 (Corporate programs).							

2.1.15 Redundancy costs

Item description	**Redundancy costs** Costs associated voluntary redundancies which occurred during the 2010-15 regulatory control period.							
Category	Corporate overheads (Other operating)							
Recurrent cost	☐ Yes			☑ No				
Adjustment type	☑ Base year adjustment			☐ Significant item			☐ Step change	
Financial impact ($m 2012-13)	**2012-13**	**2013-14**	**2014-15**	**2015-16**	**2016-17**	**2017-18**	**2018-19**	**2019-20**
	(51.0)							
Driver(s)	☐ Safety		☐ Compliance/ Legislation		☐ Risk of failure		☑ Other	
Background information	During the 2010-15 regulatory control period, Energex initiated a program aiming to downsize its labour force to match the reduction in its capital programs. This resulted in significant redundancy costs being incurred in 2012-13. To ensure the financial year 2012-13 costs reflect the true operating expenditure, $51m has been deducted from the base year (2012-13). The voluntary redundancy costs associated with Energex's efficiency program are one-off costs necessary to fully realise the on-going savings expected by the Qld Government. Detailed discussion on the overall savings Energex is expected to garner through its efficiency program is provided in section 2.4.1 below.							

2.1.16 Property Rent

Item description	**Property Rent**							
Category	Corporate overheads (Property)							
Recurrent cost	☑ Yes			☐ No				
Adjustment type	☑ Base year adjustment			☐ Significant item			☐ Step change	
Financial impact ($m 2012-13)	**2012-13**	**2013-14**	**2014-15**	**2015-16**	**2016-17**	**2017-18**	**2018-19**	**2019-20**
	2.8							
Driver(s)	☐ Safety		☐ Compliance/ Legislation		☐ Risk of failure		☑ Other	
Background information	During 2008, Energex carried out a complete review of the current and future non-network property requirements for the business. As a result of the review, Corporate Property Strategy 2010-15 (CPS) was produced and endorsed by the Board in December 2009. This strategy set out the long-term direction for the non-network property portfolio. A key outcome of the CPS was the decision to vacate the obsolete and inefficient Banyo facility. This decision created a number of accommodation changes, creating interdependent projects and the need for strategic alignment. The program had four clear stages: • acquisition of the Trade Coast Distribution Centre, which is now occupied; • leasing of Northern Metro Office , which is now occupied; • redevelopment of the existing Geebung site, which is now occupied; • exit the Banyo site. The move to Northern Metro Office was part of the broader strategic initiative to relocate some office-based functions to leased office accommodation as well as relieve congestion and inherent safety issues in some depots. In November 2010 the Energex Board approved the Northern Metro strategy program. Energex took occupancy of Northern Metro Office from February 2013. As a result, the 2012-13 base year does not represent a full year of rent expense. The rent payable for the period July 2012 to January 2013 would have been $2.8m. To ensure the financial year base year 2012-13 reflect a full year of operating expenditure, $2.8m has been added to represent a full 12 month rent for the base year.							

2.1.17 Property make good provision

Item description	Property Make Good Provision							
Category	Corporate overheads (Property)							
Recurrent cost	☐ Yes			☑ No				
Adjustment type	☑ Base year adjustment			☐ Significant item			☐ Step change	
Financial impact ($m 2012-13)	**2012-13**	**2013-14**	**2014-15**	**2015-16**	**2016-17**	**2017-18**	**2018-19**	**2019-20**
	(1.5)							
Driver(s)	☐ Safety		☐ Compliance/ Legislation		☐ Risk of failure		☑ Other	
Background information	In accordance with base-step-trend methodology provisions are adjusted and excluded when determining the base year expenditure. This is to ensure the base year reflects the actual expenditure only. As such Energex has removed a provision of $1.5m which relates to make good requirements for leased premises. In the financial year 2012-13, Energex raised a provision of $1.5m for the make good of leased premises in accordance with accounting standard – Provisions, Contingent Liabilities and Contingent Assets AASB137. This provision was raised as it was deemed Energex had a present obligation to make good several lease premises upon termination of the lease. The full provision has been removed from the base year (2012-13) in the base-step-trend calculation.							

2.1.18 Fleet – Fuel tax credit

<table>
<tr><th>Item description</th><th colspan="8">Fleet – fuel tax credit</th></tr>
<tr><td>Category</td><td colspan="8">Corporate overheads (Fleet)</td></tr>
<tr><td>Recurrent cost</td><td colspan="3">☑ Yes</td><td colspan="5">☐ No</td></tr>
<tr><td>Adjustment type</td><td colspan="3">☑ Base year adjustment</td><td colspan="3">☐ Significant item</td><td colspan="2">☐ Step change</td></tr>
<tr><td rowspan="2">Financial impact ($m 2012-13)</td><td>2012-13</td><td>2013-14</td><td>2014-15</td><td>2015-16</td><td>2016-17</td><td>2017-18</td><td>2018-19</td><td>2019-20</td></tr>
<tr><td>1.5</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Driver(s)</td><td colspan="2">☐ Safety</td><td colspan="2">☑ Compliance/ Legislation</td><td colspan="2">☐ Risk of failure</td><td colspan="2">☐ Other</td></tr>
<tr><td>Background information</td><td colspan="8">In the financial years 2012-13 and 2013-14 Energex received two fuel tax credit (FTC) adjustments from the Australian Taxation Office (ATO) relating to the period October 2008 to 30 June 2013.

Prior to July 2013, Energex had not previously claimed FTCs for EWP’s, cranes and lifter borers due to the difficulty in developing an apportionment methodology, for the on-road versus off-road use of these vehicles that was acceptable to the ATO.

Following successful court challenges in respect of the FTC, significant work was undertaken by Energex in developing an acceptable apportionment methodology. In June 2013 Energex lodged a successful submission to the ATO resulting in a FTC refund for the period October 2008 to 30 June 2012 totalling $1.7m. This credit, which is a one off backdated claim and will not be repeated, was received in the financial year ended 30 June 2013. The base year has been adjusted by $1.7m in respect of the FTC refund relating to prior years.

The apportionment methodology calculated the FTC applicable to EWP’s, cranes and lifter borers for the financial year 2012-13 year to be $0.2m. This credit was received from the ATO in the financial year ended 30 June 2014. Energex believes this represents the average fuel tax credits that will be received on an annual base for EWP’s, cranes and lifter borers and has included this credit in the 2012-13 base year.

The net adjustment in the base (2012-13) for Fuel Tax Credits is $1.5m, being the $1.7m received in relation to Oct 2008 to 30 June 2012, less the credit applicable for the financial year 2012-13 of $0.2m.</td></tr>
</table>

2.1.19 EWP Repairs – Fleet

Item description	**EWP Repairs - Fleet**							
Category	Corporate overheads (Fleet)							
Recurrent cost	☐ Yes			☑ No				
Adjustment type	☑ Base year adjustment			☐ Significant item			☐ Step change	
Financial impact ($m 2012-13)	**2012-13**	**2013-14**	**2014-15**	**2015-16**	**2016-17**	**2017-18**	**2018-19**	**2019-20**
	(0.4)							
Driver(s)	☐ Safety		☐ Compliance/ Legislation		☐ Risk of failure		☑ Other	
Background information	As part of routine electrical testing of EWPs in 2012-13, an issue was identified with crazing/mud-cracking in the fibreglass gel coat covering of the LV insulated EWP boom sections. This defect allows dirt & moisture to collect on the boom surface, compromising the insulating properties of the boom. As a result, a number of EWPs failed the visual inspection based on the criteria in Australian Standards 1418.10 and the vehicles were subsequently taken out of service. As a result a provision for the rectification of the EWP's of $0.4m was raised in June 2013. The repairs were carried out during the 2013-14 financial year and the provision was fully utilised. In accordance with base-step-trend methodology, provisions are adjusted and excluded when determining the base year expenditure. The EWP repairs were a one off expenditure relating to the rectification and it is not expected to reoccur. Therefore, the cost has been removed from the base year. To ensure the financial year 2012-13 costs reflect the true operating expenditure, $0.4m has been deducted from the base year (2012-13).							

2.2 Significant items

2.2.1 Power Transformer Corrosive Sulphur Treatment

Item description	**Power Transformer Corrosive Sulphur Treatment** Corrective work is required to address the emerging problem of corrosive sulphur content in mineral oil on affected transformers.							
Category	Planned maintenance							
Recurrent cost	☐ Yes			☑ No (years 2014-15 to 2019-20 only)				
Adjustment type	☐ Base year adjustment			☑ Significant item			☐ Step change	
Financial impact ($m 2012-13, direct)	**2012-13**	**2013-14**	**2014-15**	**2015-16**	**2016-17**	**2017-18**	**2018-19**	**2019-20**
			0.8	0.8	0.7	0.7	0.7	0.7
Driver(s)	☐ Safety		☐ Compliance/ Legislation		☑ Risk of failure		☐ Other	

Background information

Driver for the adjustment

Corrosive sulphur content in mineral oil is an emerging problem for Energex and mitigation is required to prevent insulation failure at the OLTC selector switch.

The catastrophic failure of an 80MVA transformer at Coomera substation in November 2007 demonstrates the potential severity of the problem. Two reports produced by the transformer manufacturer and the OLTC manufacturer, following the incident attributed the failure to silver sulphide formation on the OLTC's selector switch.

Consideration of other options ("do nothing" option)

Energex has assessed the risk of a "do nothing" approach.

Untreated Risk Assessment				
Safety	**Environment**	**Legislative**	**Customer Impact**	**Business Impact**
Very Low	Moderate	-	Moderate	-

The consequence associated with not addressing this issue is a reduction in network security or total loss of supply for single transformer substations. Failures occurring concurrently at multiple sites could lead to potential outages impacting customers and essential services. In the event of a failed transformer the replacement could take a significant time (ie up to 12 months) to arrange and install.

Identifying and quantifying the preferred option

To verify that the presence of corrosive sulphur oil, was in fact leading to the formation of silver sulphide, Energex detanked and internally inspected two large transformers which tested positively and inspected the selector switch. These transformers were:

- May 2013: TR5 at Archerfield (80MVA)
- January 2014: TR6 at Victoria Park (120 MVA)

In both cases the compound was found on the selector switch. While passivation of the oil will inhibit the formation of further silver sulphide, in each case it was required that the selector switch be cleaned to eliminate the risk of failure at the switch.

To evaluate the scope of the potential problem corrosive sulphur presents, Energex has performed a survey of a large portion of the transformer population to detect the presence of corrosive sulphur oil. To date, 527 transformers have been tested and 451 were found to have a level of corrosive oil.

Energex's policy to address this issue is to add a metal passivator to transformers testing positive to corrosive sulphur. Bulk supply transformers, meeting a criteria set out in the policy, are required to have their selector switch cleaned.

The bulk of the risk of silver sulphide formation is for transformers manufactured between 1997 and 2007.

At the end of 2013-14, in line with the strategy, Energex has completed the following:

- passivated the oil of 63 of the 97 bulk supply transformers
- cleaned the selector switch on two high risk transformers

For the financial years 2014-15 to 2019-20, Energex plans to:

- passivate the remaining 34 bulk supply transformers
- passivate approximately 250 zone supply transformers (33kV)
- test the remaining zone transformers for corrosivity
- detank /clean selector switch of the remaining 61 high risk bulk supply units

Benefits of the proposed adjustment

The past catastrophic failure of Coomera TR7 demonstrates the potential severity of the problem. The inclusion of this program reduces the serious risk to reliability and environmental impacts.

Summary

The inclusion of this change is consistent with the opex objective to maintain the reliability and security of the distribution system through the supply of standard control services.

This program is included as a significant item in the years 2015-16 to 2019-20.

2.2.2 Property Rent Reductions

Item description	**Property Rent Reductions**							
Category	Corporate overheads (Property)							
Recurrent cost	☐ Yes			☑ No Note: Due to lease arrangements having a cessation date, it is difficult to forecast savings beyond the regulatory period. Energex has therefore included savings as a significant item instead of an ongoing step change.				
Adjustment type	☐ Base year adjustment			☑ Significant item			☐ Step change	
Financial impact ($m 2012-13)	**2012-13**	**2013-14**	**2014-15**	**2015-16**	**2016-17**	**2017-18**	**2018-19**	**2019-20**
		(1.4)	(2.9)	(2.9)	(4.4)	(4.4)	(4.4)	(4.4)
Driver(s)	☐ Safety		☐ Compliance/ Legislation		☐ Risk of failure		☑ Other	

Background information

Background

The property strategy is continually reviewed to ensure it meets the requirements of the organisation. As a result of downsizing the property department has reviewed and consequently reduced the square meters of occupied floor space. The adjustments below represent the financial impacts of these changes.

Location	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Northern Metro Office	(0.693)	(0.819)					
Southern Metro Office	(0.257)	(0.127)					
Geebung Temp Site	(0.324)	(0.336)					
Level 6 Newstead	(0.121)	(0.182)		(1.575)			
Annual adjustment	**(1.395)**	**(1.464)**		**(1.575)**			
Cumulative adjustment	**(1.395)**	**(2.859)**	**(2.859)**	**(4.434)**	**(4.434)**	**(4.434)**	**(4.434)**

Notes:
1. Year on year values, $m 2012-13
2. Due to rounding, individual components may not sum to the total

Northern Metro Office (NMO)

Between the signing of the original lease agreement and the relocation to the building (February 2013), reductions in staffing numbers across Energex resulted in fewer staff being transferred to NMO than originally planned. As a result level 6 and 7 were not required for Energex staff. This provided Energex the opportunity to sub-lease these floors to third parties, and reduce indirect expenditure. Commencing in 2013-14 expenses have been reduced by $693,000 representing the lease expense savings resulting from the sub-leasing arrangement. To ensure the future years reflect efficient operating expenditure, $693,000 has been deducted from 2013-14 and future years.

From 2014-15 expenses have been reduced further by $819,000 representing the additional adjustment to reflect the full year rent reduction resulting from sub-leasing. To ensure future years reflects a full year rent reduction, $1,512,000 has been deducted from 2014-15 and future years.

Southern Metro Office (SMO)

As part of the continued review of accommodation within Energex, it was determined the occupied area required at the Southern Metro Office was less than the current leased spaced. Therefore staff were located to two floors within the SMO with the 3rd floor being returned to the landlord.

The Southern Metro Office rental expense in the 2012-13 represents the cost of all floors for a full year.

In November 2013 Energex ceased the lease of the 3rd floor. The financial year 2013-14 has been reduced by $257,000 representing the reduction in rent as a result of reducing floor space by one floor from November to June. To ensure future years reflect the efficient expenditure, $257,000 has been deducted from 2013-14 and future years.

Financial year 2014-15 has been further reduced by $127,000 representing the adjustment to reflect a full year rent reduction. To ensure the future years reflect efficient expenditure $384,000 has been deducted from 2014-15 and future years.

Geebung Leased Site

While Energex refurbished the existing Geebung site, an industrial property within close proximity was leased for staff to occupy. When the work at the existing Geebung site was completed in Dec 2013 all staff were relocated from this site and the lease was terminated.

The Geebung leased site rental expense in the 2012-13 represents the costs for the full year.

The financial year 2013-14 costs have been reduced by $324,000 representing the rent expense from January 2014 to June 2014 (when Energex exited the site). To ensure 2013-14 reflects efficient operating expenditure, $324,000 has been deducted from 2013-14 and future years. Future years from 2014-15 have been further reduced by $336,000 representing the adjustment to reflect the annual leasing cost.

Newstead Sub-Lease

With staffing numbers reducing in Energex and consolidating of office space across Newstead and the two regional offices, level 6 at Newstead was surplus to Energex's requirements. SPARQ Solutions sub-leased level 6 of the Newstead building. Energex undertook a sub-leasing arrangement with SPARQ for their original premises at Montpelier Rd, which in turn Energex has sub-leased to third parties.

The figures shown in the table are the net position of level 6 Newstead and Montpelier Rd sub-leasing arrangements To ensure the financial year 2013-14 reflects the resulting operating expenditure $121,000 has been deducted from 2013-14 and future years. To ensure the 2014-15 reflects efficient expenditure an additional $182,000 has been deducted from years 2014-15 and 2015-16. To ensure 2016-17 onwards reflects the efficient expenditure an additional $1,575,000 has been deducted from 2016-17 and future years.

2.3 Step changes

2.3.1 Replacement of network equipment containing asbestos

Item description	**Replacement of network equipment containing asbestos** A program has been introduced to remove equipment containing asbestos from the Energex network in line with the National Strategic Plan for Asbestos Awareness and Management							
Category	Planned maintenance							
Recurrent cost	☑ Yes			☐ No				
Adjustment type	☐ Base year adjustment			☐ Significant item			☑ Step change	
Financial impact ($m 2012-13, direct)	**2012-13**	**2013-14**	**2014-15**	**2015-16**	**2016-17**	**2017-18**	**2018-19**	**2019-20**
Year on year				0.3				
Cumulative				0.3	0.3	0.3	0.3	0.3
Driver(s)	☑ Safety		☑ Compliance/ Legislation		☐ Risk of failure		☐ Other	

Background information

Driver for the step change

The *National Strategic Plan for Asbestos Awareness and Management* was released in July 2013 and has been developed in consultation with Commonwealth, state and territory and local governments and a range of non-governmental stakeholders. The aim of the Plan is to prevent exposure to asbestos fibres, in order to eliminate asbestos-related disease in Australia. The Plan includes an aspirational target that all government occupied and controlled buildings are to be free of asbestos containing materials (ACMs) by 2030.

Energex have undertaken a number of steps to align with these aspirational goals. These include the creation of a specialist position to manage asbestos containing materials (ACM) across the business, engagement of an Occupational Hygienist to conduct ACM surveys of all Substations (constructed pre-2004) and establish consultation with a network of electricity distributors to identify common items of ACM and develop efficient management controls.

Consideration of other options ("do nothing" option)

Energex has assessed the risk of a "do nothing" approach.

Untreated Risk Assessment				
Safety	**Environment**	**Legislative**	**Customer Impact**	**Business Impact**
High	Low	-	-	Moderate

Due to the age and lifespan of network sites and equipment, some items of ACM will deteriorate and require action. This deterioration may increase the risk to Energex staff who are required to conduct work on or around that item, and contributes to an increased corporate risk to the business. By not reducing this risk through the removal of such items, it leads to an ever-increasing risk to staff, contractors and the public that is deemed unacceptable to those persons that may be exposed, the business and the public.

Identifying and quantifying the step change

Energex currently has approximately 1800 recorded items, equating to over 19,000m2, of asbestos identified within substations. In addition, ACM has been identified throughout our distribution network, including on poles and wires, above ground terminations and extensive amounts of below ground conduits.

Planned works to identify and record further ACM throughout the network are in place and Energex have developed plans to firstly manage and then strategically remove items of ACM to minimise the risk to staff, contractors and the public.

In-line with the National Strategic Plan, Energex has developed and implemented a risk management strategy to minimise exposure to ACM. This strategy includes a program to identify and remove ACM from our buildings and network through a prioritised risk approach and by aligning removal programs with scheduled maintenance programs to improve efficiency. The risk management strategy includes processes to identify and if possible, remove the ACM prior to Energex staff and contractors conducting works that may impact upon the item of ACM. In order to fulfil this program of works, Energex have established a Panel of Asbestos Contractors to provide a sufficient resource of competent personnel.

Due to the high cost of asbestos removal (estimated at >$5M to remove all identified ACM), and the ability to safely manage the majority of in situ ACM, Energex have not set a target date for the network portfolio to become asbestos free.

Asbestos removal budgets have been developed for the purpose of remediating or removing items of ACM that are identified as posing a risk to the health of persons accessing those areas. This may include items that have deteriorated in condition, been damaged or will be disturbed during planned maintenance or construction works.

The annual budget figure is derived through analysis of the number and the cost of previous asbestos removal projects from network equipment, combined with reviews of currently identified ACM.

Benefits of the proposed adjustment

The inclusion of this program will reduce the risk to staff, contractor and public safety and to the environment which is present with asbestos containing materials.

Summary

The inclusion of this step change is consistent with the opex objective to maintain the safety of the distribution system through the supply of standard control services.

This program is included as a step change of $0.3m in 2015-16. This is in addition to existing business as usual activities.

2.3.2 Decrease in vegetation management contract costs

Item description	**Decrease in vegetation management contract costs** Energex has recently moved to a new devolved program for vegetation management, which has resulted in significant savings.							
Category	Vegetation							
Recurrent cost	☑ Yes			☐ No				
Adjustment type	☐ Base year adjustment			☐ Significant item			☑ Step change	
Financial impact ($m 2012-13)	**2012-13**	**2013-14**	**2014-15**	**2015-16**	**2016-17**	**2017-18**	**2018-19**	**2019-20**
Year on year			(7.1)		(0.6)			
Cumulative			(7.1)	(7.1)	(7.7)	(7.7)	(7.7)	(7.7)
Driver(s)	☐ Safety		☐ Compliance/ Legislation		☐ Risk of failure		☑ Other	
Background information	The majority of expenditure in the vegetation management category relates to third party contracts. In November 2012, Energex began looking at opportunities to improve the current operating model for vegetation management. Contract negotiations resulted in significant savings. In particular, Energex moved to a devolved management program to maximise efficiency gains. Under the new operating model, the supplier takes on the responsibility for the development and execution of their vegetation management plan. This allows the supplier to more efficiently manage the utilisation of their resources and make informed decisions in their area of expertise, resulting in savings for Energex. In addition, Energex's role transitions from managing and dispatching the program to one of monitoring compliance to required standards and KPIs. The actual expenditure in 2012-13 was incurred when vegetation management was under the old operating model (Energex management and dispatch) and is not considered to be representative for the future regulatory period. An efficiency adjustment has been included to reduce the expenditure in this category to more accurately reflect future costs. • Actual expenditure in 2012-13 = $51.6m • Forecast efficient expenditure level (average over 5 year period) = $44.2m							

2.3.3 Integrated Distribution Management System (DMS)

Item description	**Control centre operations** Efficiencies resulting from the implementation of a fully integrated Distribution Management System						
Category	Network operating						
Recurrent cost	☑ Yes			☐ No			
Adjustment type	☐ Base year adjustment			☐ Significant item		☑ Step change	
Financial impact ($m 2012-13)	**2012-13**	**2013-14**	**2014-15**	**2015-16**	**2016-17**	**2017-18**	**2018-19**	**2019-20**
Year on year			(1.5)					
Cumulative			(1.5)	(1.5)	(1.5)	(1.5)	(1.5)	(1.5)
Driver(s)	☐ Safety		☐ Compliance/ Legislation		☐ Risk of failure		☑ Other	
Background information	The expenditure incurred in this area is associated with preparing, checking, authorising, controlling and executing of planned switching for capex and opex work, control of restoration activities for unplanned network events, network engineering studies and development of network contingency plans. The ongoing development and implementation of a fully integrated Distribution Management System will deliver future efficiencies through automated and semi-automated features and tools. • Actual expenditure in 2012-13 = $11.4m • Forecast efficient expenditure level (average) = $9.8m							

2.4 Efficiency adjustments

2.4.1 General cost efficiencies

Item description	Cost efficiencies - Impact of all cost efficiency initiatives							
Category	Network overheads Corporate overheads							
Recurrent cost	☐ Yes			☑ No				
Adjustment type	☐ Base year adjustment			☐ Significant item			☑ Efficiency adjustment	
Financial impact ($m 12-13)	**2012-13**	**2013-14**	**2014-15**	**2015-16**	**2016-17**	**2017-18**	**2018-19**	**2019-20**
Network overheads								
Year on year		(14.5)	(5.8)	(2.9)	(4.8)	(2.8)	(0.7)	(0.7)
Cumulative			(20.3)	(23.2)	(28.0)	(30.7)	(31.4)	(32.1)
Corporate overheads								
Year on year		(10.9)	(2.5)	(2.7)	(3.2)	(2.6)	(0.6)	(0.6)
Cumulative			(13.4)	(16.0)	(19.2)	(21.8)	(22.4)	(23.0)
Total Cumulative (note: Due to rounding, individual components may not sum to the total)		**(25.4)**	**(33.6)**	**(39.2)**	**(47.1)**	**(52.5)**	**(53.8)**	**(55.1)**
Driver(s)	☐ Safety		☐ Compliance/ Legislation		☐Legislation		☐ Other	
Background information	Since Energex's 2010-15 regulatory proposal, there have been considerable changes in the regulatory and economic environment confronting the business. This has resulted in a significant change of focus from delivering capital investment driven by growth to network replacement and maintenance. In 2011-12 the Qld Government established measures within the 2010-15 regulatory control period aimed at reducing costs, including the Electricity Network Capital Program Review (ENCAP) which undertook a review of the Qld NSPs and identified savings. Recognising Energex's significant investment in its network, the ENCAP panel recommended, among other things, the relaxation of the N-1 standard at zone substations. Building on the work of the ENCAP panel, in 2012 the Qld Government established the Interdepartmental Review Committee on Electricity Sector Reforms (IDC). The objective of the IDC was to take a broad assessment of the electricity sector with a view to reduce costs to electricity customers. The IDC appointed a network specific Independent Review Panel (IRP) to make recommendations to the IDC on the optimal structure of the Qld DNSPs, the							

efficiency of the network and a timeframe for potential reductions in network costs. Most of the IRP/IDC final recommendations were accepted by the Qld Government.

Rightsizing of workforce and associated savings for support costs

In July 2012, Energex initiated a Business Efficiency Program (BEP) to identify areas of cost savings within the business to drive change in Energex's costs resulting in a flow on reduction to opex and capex.

PwC was engaged to lead the diagnostic assessment phase of BEP and identified several opportunities across the business to remove duplication and inefficiency and highlight activities, roles and functions that were not considered core business which could be delivered more efficiently through alternative channels. Based on their benchmarking exercise and experience in similar efficiency programs in utilities and government owned corporations in Queensland, PwC calculated potential FTE savings of 497 (based on June 2012 baseline).

Energex adopted this as a benchmark level of FTE savings, but also determined an additional 153 FTEs were needed to right-size resourcing requirements with the reduction in the PoW. This established the FTE savings target for the first phase of BEP at 650. At the end of 2013-14, Energex has reduced by 664 FTEs, 601 directly attributable to specific BEP initiatives.

In addition to labour cost savings, accommodation was rationalised, with sub-leasing of excess floor space as it became available. A reduction in fleet vehicles, in addition to a significant reduction in the use of professional services contractors, consultants and labour hire was also achieved.

In December 2012, the Queensland Government established IRP review was completed. This review was in response to the emergent challenges impacting Energex and the broader electricity industry, providing options to address the impact of network costs on electricity prices in Queensland. IRP modelling indicated that Energex should be able to achieve FTE savings of 845 from the high point in 2012.

PwC were again engaged to identify further opportunities to reduce costs and enable the business to achieve these additional savings as highlighted by the IRP. Several initiatives were identified and factored into the second phase of BEP to be delivered during 2014-15.

A breakdown of the FTE reductions for the last three years and the 2014-15 forecast as provided in the table below:

	2011-12	2012-13	2013-14	2014-15
Active FTEs	3,802	3,433	3,141	2,990

Energex will continue to seek further opportunities to streamline support processes, improve spans of control, reduce duplication and drive productivity initiatives. These efficiency initiatives and the expected productivity improvements in the program of work will assist Energex to meet its efficiency improvement objective while focusing on rightsizing the workforce to the above levels.

Continuing this co-ordinated and targeted approach that has successfully achieved significant savings over the last three years will be a key enabler for the success of

	future initiatives. It is also vital that safety, network reliability and community service standards are not adversely affected by employee reductions, process improvement and efficiency programs being undertaken too quickly. The impact of the FTE reductions have been incorporated in the general efficiencies sought by Energex.

3 Supporting documentation: Expenditure forecast using alternative methods

3.1 Demand management initiatives

Item description	Demand management							
Category	Network overhead							
This expenditure is forecast using an alternative method and is then included in the total overhead expenditure.								
Financial impact ($m 2012-13)	**2012-13**	**2013-14**	**2014-15**	**2015-16**	**2016-17**	**2017-18**	**2018-19**	**2019-20**
Year on year	(11.5)			11.4	12.4	12.6	14.4	16.1
Background information	Given that demand management expenditure is largely project based, the base-step-trend approach is not considered appropriate to forecast this expenditure. As a result, demand management has been removed from the base year and Energex has prepared a bottom up forecast for the 2015-20 regulatory control period. Energex's demand management program comprises the following core elements: • targeted area demand management - for areas where the program of work indicates significant investment is expected • broad based demand management - based on deferral benefits that broad penetration can achieve at a localised level • power factor correction for customers on demand tariffs • managing and optimising existing load control. Further information is provided in Chapter 10 (Forecast Operating Expenditure) of this regulatory proposal and in the Demand management strategy, included as an appendix to the regulatory proposal.							

3.2 Levies

Item description	**Levies**							
Category	Corporate overhead							
This expenditure is forecast using an alternative method and is then included in the total overhead expenditure.								
Financial impact ($m 2012-13)	**2012-13**	**2013-14**	**2014-15**	**2015-16**	**2016-17**	**2017-18**	**2018-19**	**2019-20**
Year on year	(9.1)			8.4	8.3	8.2	8.1	8.1
Background information	Levies are expenditure payable by Energex to the Electrical Safety Office (ESO) and the Queensland Competition Authority (QCA). Given the nature of levies being determined by external parties, the base-step-trend approach is not considered appropriate to forecast this expenditure. Expected expenditure levels for the ESO levies are derived using the methodology published by the Department of Employment of Industrial Relations. The forecast expenditure for the QCA levies is derived using the QCA methodology and Energex's annual revenue reported in this regulatory proposal. As a result, levies have been removed from the base year and a bottom up forecast prepared for the 2015-20 regulatory control period. Further information is provided in Chapter 10 (Forecast Operating Expenditure) of this regulatory proposal.							

3.3 Corporate Programs

Item description	**Corporate programs**							
Category	Corporate overheads (Corporate programs)							
This expenditure is forecast using an alternative method and is then included in the total overhead expenditure adjustment								
Financial impact ($m 2012-13)	**2012-13**	**2013-14**	**2014-15**	**2015-16**	**2016-17**	**2017-18**	**2018-19**	**2019-20**
Regulatory project							3.0	3.5
Union agreement				0.5	0.5	0.5		0.5
Safety program				0.25	0.25	0.25	1.0	
Total corporate programs				0.75	0.75	0.75	4.0	4.0
Background information	Given the nature of corporate programs, the base-step-trend approach is not considered appropriate to forecast this expenditure. As a result, the expenditure has been removed from the base year and a bottom up forecast has been prepared for the 2015-20 regulatory control period. Regulatory determination project Energex is subject to economic regulation by the Australian Energy Regulator (AER) through the regulatory determination process under Chapter 6 of the National Electricity Rules (Rules). The regulatory determination process determines the revenue that Energex is permitted to recover over the period of the determination to support its operational activities. Therefore the quality of information contained in, and supporting, Energex's regulatory proposal to the AER significantly impacts Energex ability to achieve its strategic directives. In 2018-19 Energex will commence work on the 2020-2025 regulatory proposal. The forecast costs of $7.5m for 2018-19 and 2019-20 have been determined based on the budget and project plan for the current regulatory determination project submitted to and approved by the Energex Investment Review Committee in May 2014. Union collective agreement negotiation project A majority of Energex employees (97%) are employed under the Energex Union Collective Agreement (EUCA). This is a 3 year agreement which sets out the employment conditions for all award based Energex employees. Every 3 years this agreement is renegotiated. The Energex Union Collective Agreement 2014 (EUCA 2014) nominally expires in late 2017, with the subsequent agreement expiring in late 2020. The EUCA is developed through extensive negotiation and bargaining between Energex and bargaining representatives (including industry unions and individual								

bargaining representatives). Discussions to gain approval of a replacement Agreement normally commence 12 to 9 months prior to the nominal expiry date.

Due to the complexity and sensitivity of the EUCA and impact of outcomes on employees and Energex, negotiations are taken very seriously and Energex invests time and money into ensuring a fair outcome for both parties.

The recent negotiations have resulted in many positive outcomes and these outcomes can be attributed to:

- Clear bargaining and communication strategies
- Understanding the difficulty in negotiating an outcome in accordance with the objectives
- Engaging with employees, business representatives and stakeholders throughout the process to manage the likelihood of employee disengagement and distrust.
- Regular communication and information share with leaders to ensure they are equipped to answer employee questions, clarify misinterpretations and are supported through periods of protected industrial action.

The forecast costs of the EUCA 2017 and EUCA 2020 projects have been based on the 2014 EUCA negotiation project costs, as approved by the Energex Investment Review Committee in April 2014.

<u>Safety program</u>

Energex's number one value is Safety.

Put Safety First

Think safe, work safe, home safe. We are committed to achieving an injury free workplace

To support Energex's number one value, it is imperative that the focus on safety remains a priority. As such Energex launches new safety programs every 4 to 5 years to enhance the safety culture, value and message within the organisation. Programs which have been previously implemented include "ZIP – Zero Incident Process" in 2009-10 and "Our Safety Roadmap" in 2014-15. The proposed costs in 2015-16 and 2016-17 are implementation costs associated with these continuing safety initiatives.

To ensure consistent messages and focus on safety, a new initiative will be launched in 2018-19. The costs of the 2018-19 safety initiative are based on the 2014-15 project costs as approved by the Energex Investment Review Committee in December 2013.

3.4 ICT expenditure

Item description	**ICT expenditure**							
Category	Corporate overhead							
This expenditure is forecast using an alternative method and is then included in the total overhead expenditure.								
Financial impact ($m 2012-13)	**2012-13**	**2013-14**	**2014-15**	**2015-16**	**2016-17**	**2017-18**	**2018-19**	**2019-20**
Year on year	(106.9)			105.3	103.1	98.8	102.2	100.4
Background information	A significant proportion of the costs making up the ICT expenditure recovered by SPARQ, relates to the return on and return of underlying ICT assets held by SPARQ. The return on these assets charged by SPARQ to Energex is dependent on the AER approved rate of return which changes with each regulatory control period. Also, ICT project related capex and opex is not generally of a consistent recurrent nature. Due to these factors the base-step-trend approach was not considered suitable for deriving the ICT expenditure forecast. The proposed ICT expenditure for the 2015-20 regulatory control period has been derived using a bottom up approach as per the ICT Forecasting Method and Approach. The ICT expenditure is made up of the following elements: • Asset service fees: operating expenditure reflecting the value of SPARQ's ICT assets • Service Level Agreement (SLA): costs associated with the on-going operation, support and maintenance of ICT services • Telecommunications: costs associated with carrier, mobile, data, voice and device management services • Non-capital project expenditure: non-recurrent operating expenses reflecting the ICT specific expenses which cannot be capitalised. As a result, the ICT expenditure has been removed from the base year and a bottom up forecast is prepared for the 2015-20 regulatory control period. More information on the proposed ICT expenditure is provided in the Energex ICT Plan 2015-16 to 2019-20, included as an appendix to the regulatory proposal.							

3.5 Self-insurance

Item description	**Self-insurance**							
Category	Corporate overhead							
This expenditure is forecast using an alternative method and is then included in the total overhead expenditure.								
Financial impact ($m 2012-13)	**2012-13**	**2013-14**	**2014-15**	**2015-16**	**2016-17**	**2017-18**	**2018-19**	**2019-20**
Year on year	(1.7)			2.5	2.5	2.6	2.6	2.6
Background information	Consistent with the 2010-15 regulatory control period, Energex will continue to self-insure for the below deductable values less than $1.0m ($2.0m for bushfire events) associated with its public liability policy. In line with the regulatory requirements setting out the methodology to be used when estimating self-insurance costs, Energex has derived its forecast allowance using statistical analysis of historical claims between 2001-02 and 2012-13. Recognising that the base-step-trend approach is unsuitable for self-insurance, Energex has removed the self-insurance expenditure from the base year and prepared a bottom up forecast for the 2015-20 regulatory control period. Further information is provided in Chapter 22 (Uncertainty regime) of this regulatory proposal.							

4 Compliance checklist

RIN Clause	Description	Response
Schedule 1 Clause 4.1 (a) to (b)	For all Step changes in forecast expenditure (including those due to changes in regulatory obligations or requirements and those due to changes in Energex's own policies and strategies) provide: a. in regulatory template 2.17.1 and regulatory template 2.17.2 of regulatory template 2.17, the quantum of the Step change Energex: i. forecasts to incur in each year of the forthcoming regulatory control period; ii. if applicable, has incurred, or expects to incur, in the current regulatory control period relative to expenditure previously approved by the AER; and b. a description of the Step change:	RIN template 2.17.1 Section 2.3
Schedule 1 Clause 4.2 (a) to (d)	Provide an explanation of: a. when the change occurred, or is expected to occur; b. what the driver of the Step change is; c. how the driver has changed or will change (for example, revised legislation may lead to a change in a regulatory obligation or requirement); and d. whether the Step change is recurrent in nature;	Section 2.3
Schedule 1 Clause 4.3 (a) to (d)	Provide justification for when, and how, the Step change affected, or is expected to affect: a. the relevant opex category; b. the relevant capex category; c. total opex; and d. total capex;	Section 1.7 Section 2.3
Schedule 1 Clause 4.4 (a) to (b)	Provide the process undertaken by Energex to identify and quantify the Step change; provide cost benefit analysis that demonstrates Energex proposes to address the Step change in a prudent and efficient manner, including: a. the timing of the Step change; and b. if Energex considered a 'do nothing' option, evidence of how Energex assessed the risks of this option compared with other options;	Section 2.3

RIN Clause	Description	Response
Schedule 1 Clause 4.5 (a) to (b)	Provide, if the Step change is due to a change in a regulatory obligation or requirement: a. any relevant variations or exemptions granted to Energex during the previous regulatory control period or the current regulatory control period; b. any relevant compliance audits Energex conducted during the previous regulatory control period or the current regulatory control period;	Section 2.3
Schedule 1 Clause 4.6 (a) to (b)	With reference to specific clauses of the relevant legislative instrument(s), provide the: a. previous regulatory obligation or requirement; and b. how the changed regulatory obligation or requirement is driving the Step change.	Section 2.3
Schedule 1 Clause 10.1	Provide: a. the model(s) and the methodology Energex used to develop its total forecast opex; b. justification for Energex's total forecast opex, including: i. why the total forecast opex is required for Energex to achieve each of the objectives in clause 6.5.6(a) of the NER; ii. how Energex's total forecast opex reasonably reflects each of the criteria in clause 6.5.6(c) of the NER; and iii. how Energex's total forecast opex accounts for the factors in clause 6.5.6(e) of the NER;	Chapter 10
Schedule 1 Clause 10.2 (a) to (b)	Provide: a. the quantum of non-recurrent costs for each year of the forthcoming regulatory control period; and b. an explanation of each non-recurrent cost;	Section 1.6 Section 2.2
Schedule 1 Clause 10.3 (a) to (b)	if Energex used a revealed expenditure Base year approach to develop its total forecast opex, provide: a. the Base year Energex used; and b. explanation and justification for why that Base year represents efficient and recurrent costs;	Section 1.4

RIN Clause	Description	Response
Schedule 1 Clause 10.6 (a) to (d)	Provide: a. the output growth drivers Energex used to develop the amount of total forecast opex attributable to output growth changes; b. any economies of scale factors applied to the growth drivers; c. evidence that the growth drivers explain cost changes due to output growth; and d. if Energex applied any composite multiple output growth drivers: i. the inputs for each composite multiple output growth driver; and ii. the weightings for each input;	Section 1.8.1 Section 1.8.2
Schedule 1 Clause 10.7 (a) to (b)	Provide an explanation of how, in developing the amount of total forecast opex attributable to output growth changes, Energex: a. applied the output growth drivers; and b. accounted for economies of scale.	Section 1.8.1 Section 1.8.2
Schedule 1 Clause 10.8	Provide the amount of total forecast opex attributable to changes in the price of labour and materials for each year of the forthcoming regulatory control period in regulatory template 2.16.1 for standard control services opex.	RIN Template 2.16.1
Schedule 1 Clause 10.9 (a) to (b)	Provide an explanation of: a. how, in developing the amount of total forecast opex attributable to changes in the price of labour and materials, Energex applied the real price measures in regulatory template 2.14; and b. whether Energex's labour price measure compensates for any form of labour productivity change.	Section 1.9
Schedule 1 Clause 10.10	Provide the amount of total forecast opex attributable to changes in productivity for each year of the forthcoming regulatory control period in regulatory template 2.16.1 for standard control services opex.	Section 1.8.2 Section 2.2
Schedule 1 Clause 10.11	Provide, in percentage year on year terms, the productivity measure that Energex used to develop the amount of total forecast opex attributable to changes in productivity;	Section 1.8.2 Section 2.2

RIN Clause	Description	Response
Schedule 1 Clause 10.12 (a) to (c)	Provide an explanation of: a. how, in developing the amount of total forecast opex attributable to changes in productivity, Energex applied the productivity measure in paragraph 10.11; b. whether Energex's forecast productivity changes capture the historic trend of cost increases due to changes in regulatory obligations or requirements and industry best practice; and c. whether Energex's productivity measure includes productivity change compensated for by the labour price measure used by Energex to forecast the change in the price of labour.	Section 1.8.2 Section 2.2
Schedule 1 Clause 10.13	Provide the amount of total forecast opex attributable to opex step changes for each year of the forthcoming regulatory control period in regulatory template 2.16.1 for standard control services opex.	RIN template 2.16.1
Schedule 1 Clause 10.14	Provide an explanation of why Energex considers: a. the efficient costs of the Step change are not provided by other components of Energex's total forecast opex such as base opex, output growth changes, real price changes or productivity change; b. the total forecast opex will not allow Energex to achieve the objectives in clause 6.5.6(a) of the NER unless the Step change is included; and c. the total forecast opex will not reasonably reflect the criteria in clause 6.5.6(c) of the NER unless the Step change is included	Section 2.3

5 Glossary

Acronym	Definition
ACM	Asbestos Containing Material
ACS	Alternative Control Service
AER	Australian Energy Regulator
ATO	Australian Tax Office
BMS	Business Management System
BST	Base-Step-Trend
CAM	Cost Allocation Methodology
CPI	Consumer Price Index
CT	Current transformer
DMS	Distribution Management System
DSM	Demand Side Management
EB	Economic Benchmarking
ENCAP	Electricity Network Capital Program Review
ESO	Electrical Safety Office
EUCA	Energex Union Collective Agreement
EWP	Elevated work platform
FTC	Fuel Tax Credit
FTE	Full Time Equivalent
ICT	Information and Communication Technology
IDC	Interdepartmental Review Committee
IRP	Independent Review Panel
LV	Low Voltage
NMO	Northern Metro Office
OLTC	On load tap changer
PVC	Polyvinyl chloride
QCA	Queensland Competition Authority
RIN	Regulatory Information Notice
SCS	Standard Control Service
SLA	Service Level Agreement
SMO	Southern Metro Office
XLPE	Cross linked polyethylene