Annual Performance RIN Supporting Information

Schedule 1

2013-2014

energex

positive energy

Schedule 1 – Provide Information

Item No.	Requirement	Energex Response
1.1(a)	The information required in the Regulatory Accounting Statement, being the information required in the worksheets in the Microsoft Excel workbook attached at Appendix B, as amended by the AER on 6 August 2014.	Please see attached financial templates for 2013/2014.
1.1(b)	The information required in the Non-Financial Regulatory Templates in the Microsoft Excel workbook attached at Appendix C, as amended by the AER on 6 August 2014.	Please see attached non-financial templates for 2013/2014.
1.1(c)	In relation to the information provided in the response to paragraph 1.1(a) and 1.1(b) explain, where application: (i) The assumptions and methodologies underlying the information provided; and (ii)Each instance where the information cannot be provided or is not provided in full:	**<u>Financial Templates</u>** **Table 1.1 – Income statement** **1 Assumptions and/or methodologies** Adjustments relate to: • Under/over recovery of revenue, consistent with the previous submission of the Annual Performance (AP) Regulatory Information Notice (RIN). These include: ○ Distribution Revenue (DUOS and STPIS revenue); ○ TUOS Revenue; and ○ Capital Contributions. • Difference in Depreciation and Amortisation due to different valuation methodologies for statutory and regulatory reporting. • Difference in Loss from Sale of Fixed Assets due to different valuation methodologies for statutory and regulatory reporting. • Adjustment for intercompany transactions for work performed by non-regulated business for regulated business which are eliminated for statutory

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		reporting purposes but required to be recognised for regulatory reporting purposes. • Specific recognition of Self Insurance Cost as this cost is not recognised in statutory accounts. • Escalation on under-recoveries which is recognised as Interest Revenue for statutory reporting whereas for regulatory reporting it is recognised through future DUOS charges. • Adjustments for Impairment Losses which are not permitted unless agreed to or required by the AER. Impairment losses relate to supply system disposals. • Reclassification of revenue and expense items from the statutory view to the regulatory view. These include: o reclassification of Alternative Control Services (ACS) revenue from Other Revenue to Distribution Revenue in accordance with the definitions in the RIN; o reclassification of written down value of assets disposed from Profit from Sale of Fixed Assets to Loss from Sale of Fixed Assets for the Distribution Business; o reclassification of amount from Other Revenue to Capital Contributions for the portion of assets funded via government grant; and o reclassification of Debt Raising Costs from Finance Charges to Operating Expenses. • Exclusion of non-regulated services from the Distribution Business. These include: o Gross Proceeds from Sale of Assets as agreed with the AER for submission of the previous RIN; o Interest Income from investments and inter-company loans; o Sale of Goods Revenue consistent with the previous RIN; o Government Grant Revenue for the Demand Side Management (DSM) initiatives funded by the Queensland State government and related expenditure; o Other Revenue and Other Operating Costs for the provision of other non-regulated services; o Depreciation and Amortisation for non-regulated assets; o Full salary sacrifice vehicles; o Finance Charges for borrowings related to the non-regulated activities; and o Taxation Expense for the proportion related to non-regulated tax profits, consistent with the previous RIN. **2 Instances where information cannot be provided or is not provided in full** Not applicable **Table 5.1 – Standard control service by Reason**

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		1 Assumptions and/or methodologies The appropriate disaggregation of Forecast amounts has been determined based on the AER's Queensland Distribution Determination 2010-11 to 2014-15 (the Final Decision), which is the culmination of: Energex's proposed expenditure and revenue requirements sourced from Energex's Regulatory Proposal 2010-2015 (the Proposal); Amendments to the Proposal's capital and operating programs as directed by the AER in the Final Decision; and Amendments to the Proposal's expenditure and revenue requirements (including escalation factors) as directed by the AER in the Final Decision. Energex prepared detailed Forecast calculations which formed the Forecast totals included in the Final Decision. The detailed information was sourced from the Proposal at the detailed level and updated based on the AER advice. The same mappings and classifications applied in the Forecast amounts has been used for the Actuals. For the AP RIN, the Forecast amounts also include an adjustment for actual Consumer Price Index (CPI). In accordance with the Final Decision, the CPI applied is for the March to March Weighted Average of Eight Capital Cities as per the Australian Bureau of Statistics and is consistent with the annual pricing proposal. **2 Instances where information cannot be provided or is not provided in full** Not applicable. **Table 5.2 – Material difference explanation** **1 Assumptions and/or methodologies** Not applicable. **2 Instances where information cannot be provided or is not provided in full** Not applicable. **Table 5.3 – Capex by Asset Class** **1 Assumptions and/or methodologies** Refer to Table 5.1 for the methodology applied to derive Forecast amounts. Forecast amounts reported for Substation Bays also includes Distribution Substation Switchgear. At the time the Proposal was prepared, Distribution Substation Switchgear was not material and therefore combined with Substation Bays. The Proposal included 5% of 110KV Circuit Breakers as UG Sub-

<table>
<tr><th>Item No.</th><th>Requirement</th><th>Energex Response</th></tr>
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transmission Cables, with the remaining 95% included as Substation Bays.
However, consistent with prior years, it was determined that 110KV Circuit Breakers should be reclassified as 100% Distribution Substation Switchgear. Accordingly, the actuals have been updated to reflect this change and have been separately reported for Distribution Substation Switchgear – refer to table below.
Similarly, the Proposal included 5% of 33KV Capacitor Banks, Circuit Breakers, Regulators and Terminators as UG Sub –Transmission Cables. The remaining 95% of 33KV Capacitor Banks, Circuit Breakers, Regulators and Terminators were included as Substation Bays. However, consistent with prior years, it was determined that 33KV Capacitor Banks, Circuit Breakers, Regulators and Terminators should be reclassified as 100% Substation Bays. Accordingly, the actuals have been updated to reflect this change – refer to table below.
These changes are summarised in the table below and have been made to provide more accurate reporting of actuals throughout this regulatory control period. This treatment is consistent with the previous RIN proposals and definitions included in the current RIN. It should be noted that continual improvements in classification of costs will occur over the regulatory period where appropriate.
<table>
<tr><th>Category</th><th>Proposal</th><th>Actuals</th></tr>
<tr><td>UG Sub-Transmission Cables:</td><td></td><td></td></tr>
<tr><td>110KV Circuit Breaker</td><td>5%</td><td>-</td></tr>
<tr><td>33KV Capacitor Banks, Circuit Breakers, Regulators & Terminators</td><td>5%</td><td>-</td></tr>
<tr><td></td><td></td><td></td></tr>
<tr><td>Substation Bays:</td><td></td><td></td></tr>
<tr><td>110KV Circuit Breaker</td><td>95%</td><td>-</td></tr>
<tr><td>33KV Capacitor Banks, Circuit Breakers, Regulators & Terminators</td><td>95%</td><td>100%</td></tr>
<tr><td></td><td></td><td></td></tr>
<tr><td>Distribution Substation Switchgear:</td><td></td><td></td></tr>
<tr><td>110KV Circuit Breaker</td><td>-</td><td>100%</td></tr>
</table>
Capex projects which do not have specific asset categories assigned are allocated to regulatory asset categories based on the general ledger activity code used for the project.
Metering capex includes a one off transfer from Low Voltage Services to Meters. The transfer amount of $331.4M represents 10 years of capex (from 2003/04) for meters and the relevant portion of load control devices (previously included in low voltage services). These categories were previously combined as the work is typically completed together. Disaggregation was required in preparation for the reclassification of metering services to ACS from 1 July 2015.
</td></tr>
</table>

Item No.	Requirement	Energex Response
		2 Instances where information cannot be provided or is not provided in full Not applicable. **Table 5.4 – Alternative control services** **1 Assumptions and/or methodologies** Refer to Table 5.1 for the methodology applied to derive Forecast amounts. **2 Instances where information cannot be provided or is not provided in full** Not applicable. **Table 5.5 – Other services** **1 Assumptions and/or methodologies** There are no AER forecasts for Negotiated Services and Unregulated Services as these do not form part of the current determination. **2 Instances where information cannot be provided or is not provided in full** Not applicable. **Table 5.5 – Related party transactions** **1 Assumptions and/or methodologies** In accordance with the instructions for this table, only items which are more than 5% of the total standard control or alternative control capex are reported. Energex has no related party transactions in excess of the materiality threshold with its counterparties, being Energy Impact, Ergon and Powerlink. The related party capex reported in this table for Energex's IT service provider (SPARQ) differs from the IT Systems capex reported in Table 5.3 (Capex by Asset Class). This is due to:

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		SPARQ transactions in Table 5.5 (Related Party) also include IT expenditure reported against other asset categories in Table 5.3; and Capital expenditure for IT Systems reported in Table 5.3 also includes purchases from other vendors. Most SPARQ transactions are incurred as an Asset Usage Fee or Service Fee with the costs included in the general overhead pool. The remainder are direct costs booked directly to the relevant projects for both opex and capex. Related party costs included in the general overhead pool are allocated to SCS and ACS opex and capex. For this table, an estimate of the related party costs has been allocated based on the allocated proportions of general overheads. **2 Instances where information cannot be provided or is not provided in full** Not applicable. **Table 5.6 – Capital Contributions by Asset Class** **1 Assumptions and/or methodologies** Refer to Table 5.1 for the methodology applied to derive Forecast amountss. Capital Contributions that do not have specific asset categories recorded against them are allocated to regulatory asset categories based on the proportions of identified asset categories. In instances where this results in an allocation of a capital contributions balance to a regulatory asset category that would not otherwise have capital contributions, the balance is allocated to the most material category with capital contributions. For 2013/14 this adjustment was for $3,044. **2 Instances where information cannot be provided or is not provided in full** Not applicable. **Table 5.7 – Disposals by Asset Class** **1 Assumptions and/or methodologies** Refer to Table 5.1 for the methodology applied to derive Forecast amounts.

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		2 Instances where information cannot be provided or is not provided in full Not applicable. **Table 7.1– Tax standard lives and Capex Additions – Standard control services** **1 Assumptions and/or methodologies** Not applicable. **2 Instances where information cannot be provided or is not provided in full** Not applicable. **Table 8.1 – Network maintenance expenditure by category** **1 Assumptions and/or methodologies** Refer to Table 5.1 for the methodology applied to derive Forecast amounts. **2 Instances where information cannot be provided or is not provided in full** Not applicable. **Table 8.2 – Explanation of material difference** **1 Assumptions and/or methodologies** Not applicable. **2 Instances where information cannot be provided or is not provided in full** Not applicable.

Item No.	Requirement	Energex Response
		Table 8.3 – Other network maintenance costs **1 Assumptions and/or methodologies** In accordance with the instructions for this table, only items which are more than 5% of the total standard control or alternative control network maintenance costs are reported. **2 Instances where information cannot be provided or is not provided in full** Not applicable. **Table 8.4 – Related party transactions** **1 Assumptions and/or methodologies** In accordance with the instructions for this table, only items which are more than 5% of the total standard control or alternative control network maintenance costs are reported. Refer to Table 5.5 – Related party transactions. **2 Instances where information cannot be provided or is not provided in full** Not applicable. **Table 10.1 – Operating expenditure - operating costs** **1 Assumptions and/or methodologies** Refer to Table 5.1 for the methodology applied to derive Forecast amounts. Fee Based Services and Quoted Services are also included in Other Operating Costs per definitions in the RIN. **2 Instances where information cannot be provided or is not provided in full** Not applicable.

Item No.	Requirement	Energex Response
		Table 10.2 – Explanation of material difference **1 Assumptions and/or methodologies** Not applicable. **2 Instances where information cannot be provided or is not provided in full** Not applicable. **Table 10.3 – Other operating costs** **1 Assumptions and/or methodologies** In accordance with the instructions for this table, only items which are more than 5% of the total standard control or alternative control network operating costs are required to be reported. However, Self Insurance and Network Insurance have been included in this table to aid transparency for Table 18.1 (EBSS). Accordingly, the total of this table balances to "Other operating costs (itemise in table 3 below)" in Table 10.1. The amount reported for Feed-in-Tariff (FIT) payments represents actual payments made for Solar Photovoltaic (PV). It excludes the CPI applied to the base amount and is consistent with the AER's preferred methodology to verify actual FIT payments for the annual pass through application. **2 Instances where information cannot be provided or is not provided in full** Not applicable. **Table 10.4 – Related party transactions** **1 Assumptions and/or methodologies** In accordance with the instructions for this table, only items which are more than 5% of the total standard control or alternative control network operating costs are reported. Refer to Table 5.5 – Related party transactions. **2 Instances where information cannot be provided or is not provided in full**

Item No.	Requirement	Energex Response
		Not applicable. **Table 10.5 – Operating expenditure – non-recurrent operating costs** **1 Assumptions and/or methodologies** In accordance with the instructions for this table, only items which are more than 5% of the total standard control or alternative control network operating costs are reported. When identifying and reporting on non-recurrent operating costs, only the incremental increase or decrease in actual direct costs are included. Charges arising from overhead costs are excluded because overheads reflect the reallocation of internal costs, as opposed to external factors which affect direct costs. **2 Instances where information cannot be provided or is not provided in full** Not applicable. **Table 10.6 – Non–network alternatives (demand management) operating costs that are not captured by the DMIS ($'000 nominal)** **1 Assumptions and/or methodologies** Not applicable. **2 Instances where information cannot be provided or is not provided in full** Not applicable. **Table 16.1 – Avoided cost payments** **1 Assumptions and/or methodologies** Not applicable. **2 Instances where information cannot be provided or is not provided in full** Not applicable.

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Table 17.1 – Alternative control and other services

1 Assumptions and/or methodologies

Actual costs and revenue for fee based services and quoted services are specifically identified via a segment of the account code.

Fee Based Services

Some further disaggregation was required for the specific services listed below:

Item
Alteration and additions to current metering equipment
Overhead service replacement - single phase
Overhead service replacement - multiple phase
Re-energisation - business hours
Re-energisation - after hours
Re-energisation (visual) - business hours
Re-energisation (visual) - after hours
Re-energisation non-payment (visual) - business hours
Re-energisation non-payment (visual) - after hours
Meter test
Meter Inspection

Costs associated with alteration and additions to current metering equipment, overhead service replacement and re-energisation related services were generally allocated based on volumes of services derived from the internal customer billing system.

The re-energisation - business hours costs were further refined as some costs can be directly attributed via specified work orders. The remainder of the re-energisation costs are allocated based on numbers of services. Re-energisation revenue was allocated based on data from the internal customer billing system.

Meter test and meter inspection was allocated based on volume of services derived from the internal customer billing system.

Revenue reported for some Fee Based Services reflects the State government imposed price caps, which override the maximum prices approved by the AER in the annual Pricing Proposal. These services are published in Schedule 8 of the Queensland Electricity Regulations 2006 and include re-energisations, de-energisations, meter tests, temporary connections and special meter reads.

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		Quoted Services Contractually, where Energex designs and constructs a Large Customer Connection (LCC) and the asset is funded by the customer, the asset is owned by Energex from the outset, and the transaction is recognised on this basis. The transaction is recognised as an increase in PP&E and a corresponding Cash Contribution upon completion of the project. Operating expenditure is not recognised as Energex assumes ownership of the asset from commencement of the build. This is consistent with the Australian Accounting Standards and is in compliance with item 1.1 (f) of Appendix A of the RIN which requires consistency with the policies applied in the Audited Statutory Accounts except as otherwise required. The contribution due and payable by the customer is determined on the basis of the ACS Quoted Service formula per Energex's Final Determination. The asset is classified as one funded by the customer and it is excluded from the Regulated Asset Base values. Energex intends to revise its basis of providing LCCs such that ownership passes from the customer to Energex on completion of project. This would lead to two distinct transactions for: recognising the Design and Construction of a LCC as Recoverable ACS opex and the associated revenue; and the contribution of the resulting asset upon completion of construction. **Other Activities – Unregulated** Direct opex includes the Depreciation, Finance Charges, Cost of Goods Sold and Income Tax Expense so that the total revenue less direct opex and opex overheads reported in Table 17.1 agrees to the Unregulated Profit After Tax in Table 1.1. **2 Instances where information cannot be provided or is not provided in full** Not applicable. **Table 18.1 – Opex for EBSS purposes** **1 Assumptions and/or methodologies** As noted in the assumptions and methodologies for Table 10.3, Self Insurance and Network Insurance have been separately disclosed in that table to aid transparency for this table. Non-network alternative costs are only that portion of DSM Initiatives costed to the appropriate area. Pass through event costs are those for Solar PV FIT payments and the amount reported is the difference between the Actuals and Forecast. This amount has been used for EBSS exclusion purposes because the underlying opex amount is the actual payments made, without being indexed by CPI.

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		2 Instances where information cannot be provided or is not provided in full Not applicable. **Table 18.2 – Explanation of Capitalisation Policy Changes** **1 Assumptions and/or methodologies** Not applicable. **2 Instances where information cannot be provided or is not provided in full** Not applicable. **Table 19.1 – Jurisdictional Scheme Amounts** **1 Assumptions and/or methodologies** Not applicable. **2 Instances where information cannot be provided or is not provided in full** Not applicable. **Table 20.1 – DMIA projects submitted for approval** **1 Assumptions and/or methodologies** Not applicable. **2 Instances where information cannot be provided or is not provided in full** Not applicable. **Table 21.1 – Self Insurance events with an incurred cost of greater than $100 000 per event**

Item No.	Requirement	Energex Response
		1 Assumptions and/or methodologies The reported claims were managed by external claims manager Gallagher Bassett Services (GBS). All claims greater than $100K were assessed by GBS to ensure completeness and correctness. Repairs and/or replacement of damaged items were arranged by GBS where possible. Details of all claimants are kept in a general claims database. On a regular basis, GBS provides payment reports for claimants that require payment by Energex. The amounts disclosed are for costs incurred in 2013/14, however, the initial event could have occurred in a previous financial year. **2 Instances where information cannot be provided or is not provided in full** Not applicable. **Table 21.2 – Self Insurance events with an incurred cost of less than $100 000 per event** **1 Assumptions and/or methodologies** Not applicable. Events with a cost less than $100 000 per event are considered part of normal business and are not captured as self insurance for regulatory purposes. **2 Instances where information cannot be provided or is not provided in full** Not applicable. **Table 21.3 – Total self insurance costs that relate to standard control services** **1 Assumptions and/or methodologies** Refer to the assumptions and methodologies for Table 21.1. **2 Instances where information cannot be provided or is not provided in full** Not applicable. **Table 22.1 – Aggregate effect of the change in accounting policy on the balance sheet and income statements** **1 Assumptions and/or methodologies**

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		On a regular basis a review is performed to monitor accounting standard updates and new standards issued by the Australian Accounting Standards Board to assess the impact on Energex. Changes are advised to the Audit & Risk Committee and implemented where required and the associated Energex accounting policies are updated accordingly. The actual retained earnings amount is per the audited statutory accounts for Energex Limited. The actual operating expense amount is reported in the Operating Expenses line in the audited statutory accounts column of Table 1: Income Statement. The actual income tax equivalent amount is reported in the same table against the Income Tax Expense/(Benefit) line. There are no other material impacts from changes in accounting standards for the 2013/14 year. **2 Instances where information cannot be provided or is not provided in full** Not applicable. **Table 22.2 – Reason for the change in accounting policy** **1 Assumptions and/or methodologies** Not applicable. **2 Instances where information cannot be provided or is not provided in full** Not applicable. **<u>Non-Financial Templates</u>** **<u>Template 1a – STPIS - Reliability</u>** **1 Assumptions and/or methodologies** In the provision of data Energex has used outage data from three sources. NFM (Network Facilities Management), EPM (Energex Performance Management) and PON OMS (Power On Outage Management System). At the time of preparation Energex was transitioning between outage recording systems so to minimise risk transformer outage data was sourced from **primary** data sources such as NFM and PON. Compiling data from these sources eliminated possible errors in untested corporate reporting system EPM. Additionally the ability to represent outage data against feeder currently doesn’t exist within EPM so it was only used in a limited capacity to retrieve single loss data. A manual activity to allocate feeder data against EPM single loss data was carried out from the source system NFM.

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		From these sources transformer interruption data was retrieved for the year resulting in a combined listing of 253,500 records. Energex compiled these transformer records to an outage table containing 20,259 sustained interruptions (>1 minute) with each record having a valid outage report number, outage category and outage feeder. Energex doesn't have any long rural feeders. There are four valid outage reports that have no cause data as below. For these outages a "No Cause" (GN-NR) code was used. **tblCA_RIN_Combined** DATE_SH | TIME_SH | OUTAGE_REPORT_SUN | OPERTN_ID | FEEDER_CATEGORY 30/06/2014 | 16:19 | INCD-6061-g | GYGGYS6 | RURAL 30/06/2014 | 08:46 | INCD-5890-g | RWD1 | RURAL 20/06/2014 | 17:48 | INCD-4165-g | NVL3 | URBAN 27/05/2014 | 08:36 | INCD-914-h | TWT12A | RURAL STPIS Reliability – Customer Minutes Lost (CML) and Customers Interrupted (CI) was calculated for each category and placed over the corresponding category and system, customer base. The customer base was calculated in accordance with the AER mandated method of customers on the first and last days of the reporting period, averaged. **2 Instances where information cannot be provided or is not provided in full** From the raw source data (253,500 records) there were 276 sustained transformer interruptions that had a valid outage report number but no category due to no feeder allocation at the time of the outage. These interruptions were not included in the data used for the three templates. This equated to a CML of 76111 and customer count value of 1271. Represented as a system SAIDI and SAIFI value as below: SYSTEM SAIDI = 0.056 minutes SYSTEM SAIFI = 0.000938 interruptions The unallocated system SAIDI and SAIFI as a percentage for normalised data (Excluding excluded data) is represented below: SAIDI – 0.056/70.04 = 0.08% SAIFI – 0.0009/0.893 = 0.1% **Template 1b – Table 1 Telephone Answering** **1 Assumptions and/or methodologies** The methods and formula used to complete this table are consistent with the latest national STPIS. **2 Instances where information cannot be provided or is not provided in full**

Item No.	Requirement	Energex Response
		Not applicable. **<u>Template 1f – STPIS GSL</u>** The AER's GSL scheme did not apply to Energex in 2012/13 **<u>Template 3 – Table 3 Customer Service</u>** **1 Assumptions and/or methodologies** The methods and formula used to complete this table are consistent with the latest national STPIS. With the exception of the *Reliability of Supply* complaints, the categories required within table 3 of the RIN do not exist within Energex systems. A process of determining Energex system categories that best align with the AP RIN categories in table 3 was undertaken. Complaints relating to the connection, maintenance or alteration to the network have been categorised within the *Connection or Augmentation* category (cell H68). Complaints relating to staff behaviour, meter reading, communication and correspondence and marketing or media have been categorised within the *Administrative Process or Customer Service* category (cell H67). Complaints relating to the driving and/or parking of Energex vehicles and general feedback relating to suppliers or installers have been categorised within the *Other* category (cell H69). **2 Instances where information cannot be provided or is not provided in full** Not applicable. **<u>Template 5b– Network data – feeder reliability</u>** **1 Assumptions and/or methodologies** In the provision of data Energex has used outage data from three sources. NFM (Network Facilities Management), EPM (Energex Performance Management) and PON OMS (Power On Outage Management System). At the time of preparation Energex was transitioning between outage recording systems so to minimise risk transformer outage data was sourced from **primary** data sources such as NFM and PON. Compiling data from these sources eliminated possible errors in untested corporate reporting system EPM.

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		Additionally the ability to represent outage data against feeder currently doesn't exist within EPM so it was only used in a limited capacity to retrieve single loss data. A manual activity to allocate feeder data against EPM single loss data was carried out from the source system NFM. From these sources transformer interruption data was retrieved for the year resulting in a combined listing of 253,500 records. Energex compiled these transformer records to an outage table containing 20,259 sustained interruptions (>1 minute) with each record having a valid outage report number, outage category and outage feeder. Energex doesn't have any long rural feeders. There are four valid outage reports that have no cause data as below. For these outages a "No Cause" (GN-NR) code was used.

tblCA_RIN_Combined

DATE_SH	TIME_SH	OUTAGE_REPORT_SUN	OPERTN_ID	FEEDER_CATEGORY
30/06/2014	16:19	INCD-6061-g	GYGGYS6	RURAL
30/06/2014	08:46	INCD-5890-g	RWD1	RURAL
20/06/2014	17:48	INCD-4165-g	NVL3	URBAN
27/05/2014	08:36	INCD-914-h	TWT12A	RURAL

Network Data Feeder Reliability – Energex used a baseline list of feeders with each feeder being defined as having greater than zero customers and greater than 1 transformer. From the compiled listing of 20,259 outages Energex grouped data in this template by feeder and category resulting in 1806 feeders on the list.

2 Instances where information cannot be provided or is not provided in full

From the raw source data (253,500 records) there were 276 sustained transformer interruptions that had a valid outage report number but no category due to no feeder allocation at the time of the outage.
These interruptions were not included in the data used for the three templates. This equated to a CML of 76111 and customer count value of 1271.
Represented as a system SAIDI and SAIFI value as below:
SYSTEM SAIDI = 0.056 minutes
SYSTEM SAIFI = 0.000938 interruptions

The unallocated system SAIDI and SAIFI as a percentage for normalised data (Excluding excluded data) is represented below:

SAIDI – 0.056/70.04 = 0.08%
SAIFI – 0.0009/0.893 = 0.1%

Network Data Feeder Reliability – For the listing of 1806 feeders not all data fields have been populated due to insufficient data. These include:

- Maximum demand and feeder length.
- Energy not supplied.

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Template 5d – Outcomes planned outages

1 Assumptions and/or methodologies

In the provision of data Energex has used outage data from three sources. NFM (Network Facilities Management), EPM (Energex Performance Management) and PON OMS (Power On Outage Management System).

At the time of preparation Energex was transitioning between outage recording systems so to minimise risk transformer outage data was sourced from **primary** data sources such as NFM and PON. Compiling data from these sources eliminated possible errors in untested corporate reporting system EPM. Additionally the ability to represent outage data against feeder currently doesn't exist within EPM so it was only used in a limited capacity to retrieve single loss data. A manual activity to allocate feeder data against EPM single loss data was carried out from the source system NFM.

From these sources transformer interruption data was retrieved for the year resulting in a combined listing of 253,500 records.
Energex compiled these transformer records to an outage table containing 20,259 sustained interruptions (>1 minute) with each record having a valid outage report number, outage category and outage feeder. Energex doesn't have any long rural feeders. There are four valid outage reports that have no cause data as below. For these outages a "No Cause" (GN-NR) code was used.

tblCA_RIN_Combined				
DATE_SH	TIME_SH	OUTAGE_REPORT_SUN	OPERTN_ID	FEEDER_CATEGORY
30/06/2014	16:19	INCD-6061-g	GYGGYS6	RURAL
30/06/2014	08:46	INCD-5890-g	RWD1	RURAL
20/06/2014	17:48	INCD-4165-g	NVL3	URBAN
27/05/2014	08:36	INCD-914-h	TWT12A	RURAL

Outcomes Planned Outages – From the compiled listing of outages the normalised planned data was summed.

2 Instances where information cannot be provided or is not provided in full

From the raw source data (253,500 records) there were 276 sustained transformer interruptions that had a valid outage report number but no category due to no feeder allocation at the time of the outage.
These interruptions were not included in the data used for the three templates. This equated to a CML of 76111 and customer count value of 1271.
Represented as a system SAIDI and SAIFI value as below:
SYSTEM SAIDI = 0.056 minutes
SYSTEM SAIFI = 0.000938 interruptions

The unallocated system SAIDI and SAIFI as a percentage for normalised data (Excluding excluded data) is represented below:

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		SAIDI – 0.056/70.04 = 0.08% SAIFI – 0.0009/0.893 = 0.1%
1.1(d)	A Microsoft Excel workbook or other information that explains all movements between the Audited Statutory Accounts and the Regulatory Accounting Statements:	See Table 1.1 and notes below

Table 1.1 Income Statement

Description	Note	Adjustments per Table 1.1 Income Statement $'000 nominal	Exclude over/(under) recovery of revenue $'000 nominal (A)	Regulatory reclassification of revenue and expenses $'000 nominal (B)	Non-regulated Services $'000 nominal (C)	Other regulatory adjustments $'000 nominal (D)
Distribution revenue	1	(185,731.0)	(251,859.6)	66,128.6	-	-
TUOS revenue	2	(10,831.5)	(10,831.5)	-	-	-
Profit from sale of fixed assets	3	(2,880.6)	-	12,059.0	(14,939.6)	-
Capital contributions	4	(38,549.2)	(38,802.3)	253.1	-	-
Interest income	5	(78,391.2)	-	-	(20,060.3)	(58,330.9)
Other revenue	6	(152,692.8)	-	(66,381.7)	(86,372.6)	61.5
Total revenue		**(469,076.3)**	**(301,493.4)**	**12,059.0**	**(121,372.5)**	**(58,269.4)**
Network maintenance	7	12.5	-	-	-	12.5
Operating expenses	8	(31,078.1)	-	4,515.1	(35,642.3)	49.1
Depreciation	9	(596.1)	-	-	(3,645.2)	3,049.1
Finance charges	10	(6,067.6)	-	(4,515.1)	(1,552.5)	-
Loss from sale of fixed assets	11	23,026.7	-	12,059.0	-	10,967.7
Impairment losses (nature of impairment loss)	12	(2,922.0)	-	-	-	(2,922.0)
Other	13	(24,711.7)	-	-	(24,711.7)	-
Profit before Tax (PBT)		**(426,740.0)**	**(301,493.4)**	**0.0**	**(55,820.8)**	**(69,425.8)**
Income Tax Expenses / (Benefit)	14	(843.4)	-	-	(843.4)	-
Profit after tax		**(425,896.6)**	**(301,493.4)**	**0.0**	**(54,977.4)**	**(69,425.8)**

Note:

1(A) The Regulatory Information Notice (RIN) reports the amount actually earned excluding any over/(under) Recoveries and STPIS rewards recognised for Statutory purposes.

1(B) Reclassify Alternative Control Services revenue to Distribution revenue in accordance with the definitions in the RIN. Reclassify Office of Clean Energy (OCE) funded Demand Management assets from Government Grants to Capital Contributions (Refer to 4(B) and 6(B) below).

2(A) Refer to 1(A) above.

3(B) Written down value (WDV) of disposed assets (included in profit on disposal of assets for statutory purposes) is reclassified to Loss from sale of fixed assets.

3(C) The gross proceeds from sale of assets is classified as non-regulated consistent with the previous RIN.

Item No.	Requirement	Energex Response
		4(A) Refer to 1(A) above. 4(B) Government grants received from the State government's Office of Clean Energy (OCE) for demand management initiatives are mostly excluded from the reported regulated revenue as discussed in point 8(C) below. Only the portion of this grant used to acquire supply system assets (included in the regulatory asset base) is recognised as revenue under the regulatory framework. This amount relates to the acquisition of metering assets. 5(C) Interest income relating to investments and intercompany loans are classified as non-regulated for regulatory reporting in accordance with consultation with the AER on the RIN. 5(D) The AER allows an escalation on under recoveries to be recovered in future periods. This escalation reflects the increase in the receivable to be collected through the pricing mechanism and is recognised as interest income for statutory reporting. These increases are not recognised as interest revenue for regulatory reporting purposes as they will be recovered as DUOS revenue when included in customers' future prices. 6(B) Reclassify Alternative Control Services revenue to Distribution revenue in accordance with the definitions in the RIN (Refer to 1(B) above). Reclassify OCE funded Demand Management assets from Government Grants to Capital Contributions (Refer to 4(B) above). 6(C) Revenue from Sale of goods, State government grant revenue received for Demand Management Initiatives and Other Non-regulated revenue are classified as non-regulated in accordance with consultation with the AER on the RIN. 6(D) Adjustment for intercompany transactions performed by non-regulated business for the regulated business which is eliminated for statutory reporting purposes but required to be reinstated for regulatory reporting purposes. This amount relates to non-regulated metering services for network substation reads. 7(D) Refer to 6(D) above. 8(B) Reclassify Debt Raising Cost from Finance Charges to Other Operating Costs (which is a subset of Operating Expenses) in accordance with RIN requirements. 8(C) Non-regulated classifications include direct and indirect cost for other Non-regulated activities. It also includes an adjustment for expenditure on DSM initiatives associated with the OCE grant, which is deemed to be non-regulated (refer to item 6(C) above). As this is funded by the State government, outside of the AER framework, it is treated as non-regulated. 8(D) Meter reading adjustments and Other Operating Expenditure incurred within the Parent entity (Energex Limited) which is eliminated on consolidation for statutory reporting purposes and required to be disclosed for regulatory reporting purposes. 9(C) Depreciation on non-regulated assets is classified as non-regulated. 9(D) Depreciation adjustment due to difference in valuation bases between statutory reporting (income based approach using discounted cash flows) and regulatory reporting (Australian Bureau of Statistics Consumer Price Index adjustments). 10(B) Refer to 8(B) above. 10(C) Finance charges are allocated to services in proportion to Property, Plant and Equipment (PP&E) balances as PP&E and associated borrowings constitute the majority of the balance sheet. This is consistent with Energex's proposal during consultation with the AER. 11(B) Refer to 3(B) above. 11(D) Adjustment is due to different WDV of assets sold between statutory and regulatory reporting due to different valuation bases. For statutory reporting, supply system assets are impaired once the decision is made to dismantle but for regulatory reporting assets cannot be impaired without prior approval by the AER. Therefore the balances will be reflected as loss from sale of fixed assets in the RIN. 12(D) Impairment losses have been recognised for statutory reporting in accordance with the Australian Accounting Standards and reflect the excess WDV which cannot be offset against the Asset Revaluation Reserve. However, impairments are not permitted for regulatory reporting.

Item No.	Requirement	Energex Response
		13(C) Cost of Sales is recognised as Non-Regulated under the AER framework. This expense relates to the Sale of Goods which is reported as non-regulated revenue. 14(C) Refer to 10(C). Income tax expense is recognised similar to Finance Charges.
1.1(e)	The Capitalisation Policy for the Relevant Regulatory Year; and	Refer to the attached PDF document for the Capitalisation Policy, which is an extract from Energex's Finance Policy Manual.
1.1(f)	The statement of policy/s for determining the allocation of overheads in accordance with the *Cost Allocation Method* for the Relevant Regulatory Year.	Energex's approved Cost Allocation Method (CAM) serves as a statement of policy for determining the allocation of overheads. This policy is supported by detailed calculations articulating the application of this policy. The allocation of overheads to standard control and alternative control services is via a general overhead rate which reflects the remaining general overhead pool related to Energex's services. The general overhead rate is determined by the size of the pool divided by the relevant direct operating and capital expenditure of the distribution services and is allocated based on direct labour, materials and contractor costs. The overhead cost allocation to non-regulated activities is by a three factor method based on non-regulated assets, headcount and revenue. Energex has applied the CAM consistently for the Relevant Regulatory Year and the Previous Regulatory Year to ensure that the Annual Reporting RINs are prepared on the same basis. The application of the CAM is formally monitored and reported through Energex's internal and external audit programs.
1.2	For each of the following items, identify each Material difference between that reported in the Regulatory Accounting Statements and that provided for in the 2010-15 Distribution Determination for the Relevant Regulatory Year:	
1.2(a)	Total actual revenue and total forecast revenue.	**(a) Total actual revenue and total forecast revenue**

Item No.	Requirement	Energex Response
		(table below)

Description	Forecast[1]	Actuals[2]	Difference[3]	Difference
Distribution Revenue	$'000 nominal	$'000 nominal	$'000 nominal	
DUOS	1,700,440.0	1,608,331.7	(92,108.3)	-5.42%
ACS				
Street Lighting	45,744.5	43,246.5	(2,498.0)	-5.46%
Fee Based		5,299.4		
Quoted		17,582.7		
TUOS revenue		393,354.0		
Cross boundary revenue		-		
SCS - Capital contributions	74,362.6	35,278.0	(39,084.6)	-52.56%
ACS - Customer contributions		18,003.3		
Other revenue		14,933.1		
Total Revenue	**1,820,547.1**	**2,136,028.7**	**(133,690.9)**	**-7.34%**

1 Forecasts are provided for revenue items specifically included in the 2010 Final Determination. Items for which Forecasts are not provided did not receive a specific allowance, e.g. TUOS (which is a pass-through) and price-capped services.

2 Actuals are based on revenue excluding under/over recoveries and STPIS reward.

3 Total Revenue Difference represents the difference for items which were included in the AER Determination only. It excludes reported items which were not included in the Determination forecast.

Item No.	Requirement	Energex Response
1.2(b)	Total actual Operating Expenditure and total forecast Operating Expenditure;	**(b) Total actual operating expenditure and total forecast operating expenditure**

Description	Forecast	Actual	Difference	Difference
	$'000 nominal	$'000 nominal	$'000 nominal	
SCS	146,190.1	380,862.7	234,672.6	160.53%
ACS				
Street Lighting		0.0		
Fee Based		18,835.6		
Quoted		16,574.0		
Unregulated services		35,642.3		
Total Operating Expenditure	**146,190.1**	**451,914.6**	**234,672.6**	**160.53%**

Item No.	Requirement	Energex Response
1.2.(c)	Total actual Maintenance	**(c) Total actual maintenance expenditure and total forecast maintenance expenditure**

<table>
<tr><th>Item No.</th><th>Requirement</th><th>Energex Response</th></tr>
<tr><td></td><td>Expenditure and total forecast Maintenance Expenditure; and</td><td>
<table>
<tr><th>Description</th><th>Forecast</th><th>Actual</th><th>Difference</th><th>Difference</th></tr>
<tr><td></td><td>$'000 nominal</td><td>$'000 nominal</td><td>$'000 nominal</td><td></td></tr>
<tr><td>SCS</td><td>227,241.8</td><td>225,918.9</td><td>(1,322.9)</td><td>-0.58%</td></tr>
<tr><td>ACS</td><td></td><td></td><td></td><td></td></tr>
<tr><td>Street Lighting</td><td>13,720.4</td><td>13,014.9</td><td>(705.5)</td><td>-5.14%</td></tr>
<tr><td>Fee Based</td><td></td><td>0.0</td><td></td><td></td></tr>
<tr><td>Quoted</td><td></td><td>0.0</td><td></td><td></td></tr>
<tr><td>Unregulated services</td><td></td><td>0.0</td><td></td><td></td></tr>
<tr><td>Total Maintenance Expenditure</td><td>240,962.2</td><td>238,933.8</td><td>(2,028.4)</td><td>-0.84%</td></tr>
</table>
</td></tr>
<tr><td>1.2(d)</td><td>Total actual Capital Expenditure and total forecast Capital Expenditure.</td><td>
(d) Total actual capital expenditure and total forecast capital expenditure
<table>
<tr><th>Description</th><th>Forecast</th><th>Actual</th><th>Difference</th><th>Difference</th></tr>
<tr><td></td><td>$'000 nominal</td><td>$'000 nominal</td><td>$'000 nominal</td><td></td></tr>
<tr><td>SCS</td><td></td><td></td><td></td><td></td></tr>
<tr><td>System assets</td><td>1,193,684.9</td><td>714,459.7</td><td>(479,225.2)</td><td>-40.15%</td></tr>
<tr><td>Non-system assets</td><td>67,376.8</td><td>56,123.2</td><td>(11,253.6)</td><td>-16.70%</td></tr>
<tr><td>ACS</td><td></td><td></td><td></td><td></td></tr>
<tr><td>Street Lighting</td><td>33,336.3</td><td>16,114.0</td><td>(17,222.3)</td><td>-51.66%</td></tr>
<tr><td>Fee Based</td><td></td><td>7.3</td><td></td><td></td></tr>
<tr><td>Quoted</td><td></td><td>8,213.6</td><td></td><td></td></tr>
<tr><td>Unregulated services</td><td></td><td>7,666.7</td><td></td><td></td></tr>
<tr><td>Total Capital Expenditure</td><td>1,294,398.0</td><td>802,584.5</td><td>(507,701.1)</td><td>-39.22%</td></tr>
</table>
</td></tr>
<tr><td>1.3</td><td>Explain the reasons for any underlying operational activities or drivers that caused each Material difference identified in the response to paragraph 1.2.</td><td>
DUOS

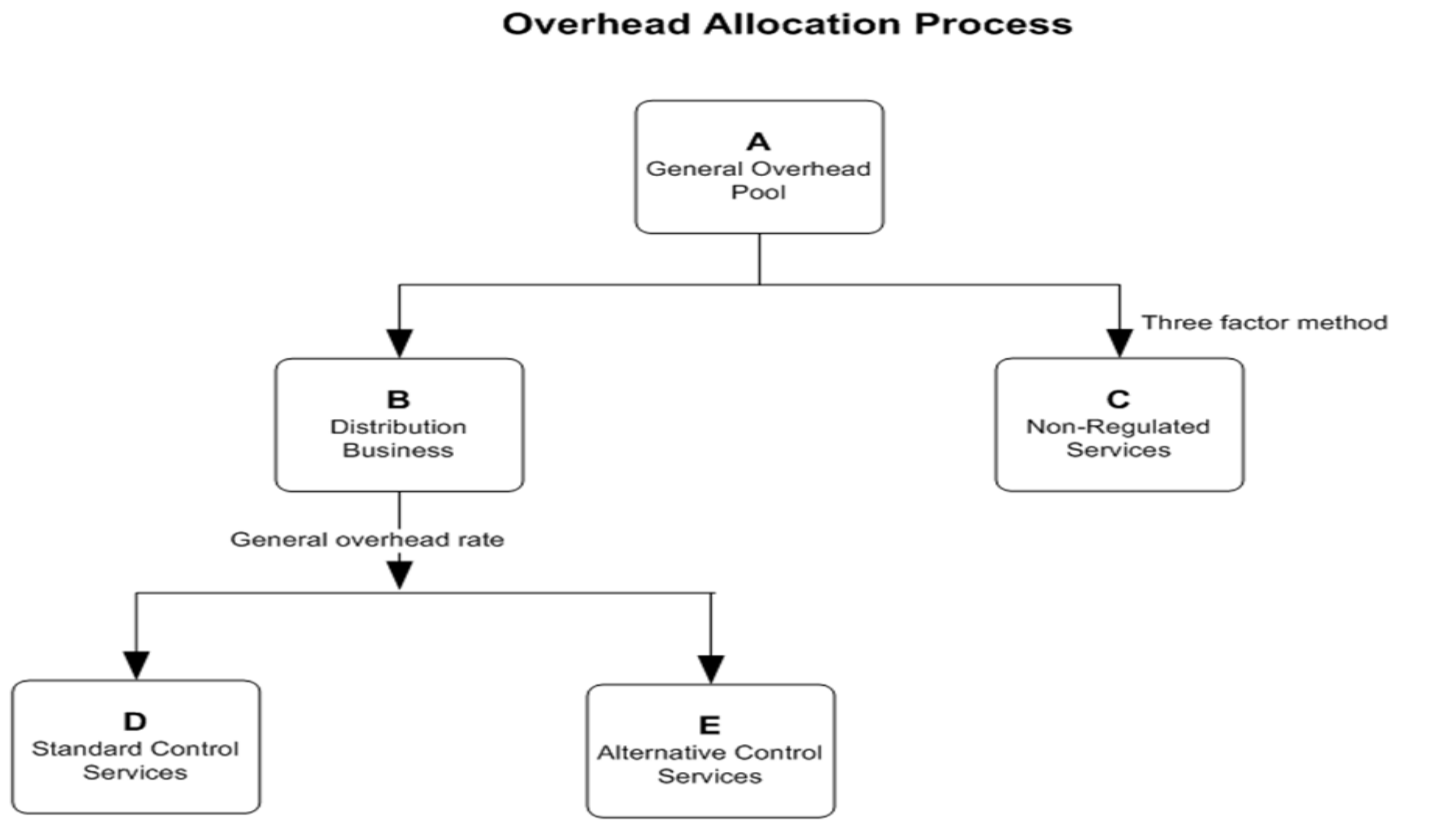
The DUOS Revenue was under recovered by $92.1M. This was largely attributable to lower demand than forecast in the 2013/14 financial year with the demand variance making up $84.8M of the under recovery. This variance is mainly driven by a continued focus on reducing peak demand and energy efficiency improvements, along with a lower volume of new connections than historical averages.

The under recovery attributable to the fixed portion of DUOS of $4.5M is mainly due to SAC-Non Demand ($3.3M) having lower customer numbers than expected on the Residential Tariffs (NTC8400, NTC8900, NTC7600).

The volume variance of $2.8M is mainly due to lower customer usage in the Residential Controlled Load tariffs than forecast in the 2013/14 financial year.
</td></tr>
</table>

Item No.	Requirement	Energex Response
		Capital Contributions Cash contributions were in line with expectations however, due to lower economic activity, the in-kind contributions were substantially down compared to forecast. This activity is 100% customer driven and is subject to market fluctuations. **Operating Expenditure** Refer to the Regulatory Information Notice (RIN) Template 10, Table 2. **Maintenance Expenditure** Refer to the Regulatory Information Notice (RIN) Template 8, Table 2. **Capital Expenditure** ACS streetlighting is significantly below forecast due to lower economic activity. Refer to the Regulatory Information Notice (RIN) Template 5, Table 2 for SCS Capex.
1.4	Explain the procedures and processes used by Energex to ensure that the distribution services have been classified as determined in the 2010-15 Distribution Determination.	In accordance with clause 6.2.3 of the National Electricity Rules, a classification of services operates for the entire regulatory control period. Prior to the start of current 2010-15 regulatory period a review of all services provided by Energex was undertaken and system changes were made to reflect the new classification of services as approved by the Australian Energy Regulatory (AER) in the Distribution Determination. The new classification of services and system changes were then communicated to the entire organisation. As part of the system changes, Energex reviewed and modified its chart of accounts (CoA) to align with the AER's approved service classifications. The CoA ensures that revenues and costs are correctly captured for each service. During the regulatory control period, any proposed CoA changes are required to be approved by a number of key staff including the Statutory and Regulatory Reporting Manager to ensure compliance with regulatory obligations. The classification of services is also considered in Energex cost allocation method (CAM) and the associated business rules incorporated into Energex's internal financial and operational policies. Compliance with the CAM is subject to audit each year as part of the RIN reporting requirements. Energex monitors the classification of services on an ongoing basis predominantly through its monthly internal management reporting which includes segment reporting based on service classification. Any discrepancies in service classification are identified and rectified during the monthly review. If and when a new service arises, Energex undertakes an internal consultation process with guidance provided by the Energex Regulation and Pricing Group to ensure that the new service is classified in accordance with the AER determined guidelines.
1.5	Explain the procedures and processes used by Energex to ensure that the negotiated distribution service criteria, as set out in	Energex does not have any negotiated services under the current classification of services.

Item No.	Requirement	Energex Response
	the 2010-15 Distribution Determination, have been applied.	
1.6	Describe the process the DNSP has in place to identify negative change events under clause 6.6.1(f) of the NER and the threshold of materiality applied by the DNSP to these events.	The National Electricity Rules define the following events as pass through events: A regulatory change event; A service standard event; A tax change event; A retailer insolvency event; and Any other event specified in a distribution determination The AER accepted four nominated pass through events applicable to the Queensland distributors in the 2011-15 distribution determination: A smart-meter event; carbon pollution reduction scheme (CPRS); feed-in tariff event; and a general nominated pass through With respect to the pass through events defined in the Rules (with the exception of a retailer insolvency event) as well as the smart-meter and CPRS events, Energex actively monitors and reviews government policy changes and the resulting materiality of the change in costs (if any). Feed-in tariffs payments are reviewed annually against the forecasts in the regulatory determination to determine if a change event has taken place i.e. there is variance between actual and forecasts. For general nominated pass though events, Energex monitors actual costs against forecast or budgeted costs on a monthly basis as part of its internal management reporting. Significant variances in costs are investigated to establish the causes of those variances. These monthly reviews are used to determine if some unexpected and uncontrollable event has occurred resulting in a material change in the ongoing costs of delivering the applicable service. Potential pass through events (negative or positive) are brought to the attention and monitored by the Energex's Customer and Strategy Committee. As agreed by the AER in the distribution determination, for general pass through events Energex applies a materiality threshold of 1% of the smoothed revenue allowance in the year an event takes place. For specific pass through events Energex applies a threshold set to the administrative costs of assessing the application.
2.	Cost Allocation to the Regulated Distribution Business	

Item No.	Requirement	Energex Response
		
2.1	Identify each item in the Regulatory Accounting Statements that is:	
2.1(a)	not allocated on a directly attributable basis but is allocated on a causation basis from the *distribution business*;	General overheads reported in the following RIN template is not allocated on a directly attributable basis but is allocated on a causation basis to the distribution business in accordance to the AER approved Cost Allocation Method (CAM): Template 17: Alternative control and other services.

Item No.	Requirement	Energex Response
	and	
2.1(b)	not allocated on a directly attributable basis and cannot be allocated on a causation basis from the *distribution business.*	Not applicable.
2.2	For each item identified in the response to paragraph 2.1(a):	
2.2.(a)	State the amount of the item that has been allocated;	For completeness, the table below shows the total overheads for the distribution business and unregulated business. However disclosure is only required for Alternative Control and Other Services as a result of various overhead templates being removed from the 2013/14 AP RIN. A breakdown of the Alternative Control Services overheads is provided below in Table 3.2.

Total Overheads

Functional Group Name	Total Overheads $'000 nominal (A)	Less Non-Regulated OH Allocation $'000 nominal (C)	Total Overheads for allocation on a causation basis to the distribution business $'000 nominal (B)	OH allocated to Distribution Business $'000 nominal (D+E)
Service Delivery	72,824.1	1,047.9	71,776.2	71,776.2
IT Services	115,003.5	1,654.9	113,348.6	113,348.6
Property	48,137.4	692.7	47,444.7	47,444.7
Asset Management	39,067.9	562.2	38,505.7	38,505.7
Procurement Services	43,909.1	631.8	43,277.3	43,277.3
Customer and Corporate Relations	6,469.3	93.1	6,376.2	6,376.2
Finance, Regulation and Strategy	1,987.2	28.6	1,958.6	1,958.6
Human Resources	5,781.7	83.2	5,698.5	5,698.5
Office of the CEO	616.2	8.9	607.3	607.3
TOTAL	333,796.3	4,803.2	328,993.1	328,993.1

Item No.	Requirement	Energex Response
2.2(b)	Explain the method of allocation and reasons for	Indirect costs (overheads) are costs that are necessarily incurred in the provision of distribution services, but are not directly attributed to a specific activity or service. Overhead costs in Energex's context include common or shared functions that support all distribution services. Costs associated with

Item No.	Requirement	Energex Response
	choosing that method; and	these functions would only be classified as indirect to the extent that they cannot be directly attributed to a service. The general overhead for the distribution business is the remaining overhead expenditure excluding corporate support costs and the cost allocation to the non-regulated activities. In accordance with Section 7.6 of the AER approved CAM, the allocation of overheads to the distribution business is based on the regulated general overhead rate. The general overhead rate is determined by the size of the pool divided by the direct operating and capital expenditure of the distribution services (including labour, materials and contractor spend inclusive of on-costs). This rate is used to allocate general overheads to services based on direct spend as this reflects a strong correlation with the consumption of the overhead. The overhead cost allocation to non-regulated activities is generally by a three factor method based on Non-Regulated Assets, Headcount and Revenue. The three factor method is applied to each year's forecast to determine the cost allocation for that year. The allocation can be adjusted where there is a material change in size, scale and scope of the non-regulated activities or a material increment or decrement in the services provided. Refer to Section 7.7 of Energex's AER approved CAM.
2.2(c)	State the numeric amount of the allocator(s) used.	The general overhead rates applied in the 2013/14 year for the distribution business were 43.00% (1 July 2013 to 28 February 2014) and 45.00% (1 March 2014 to 30 June 2014) of the direct costs that attract overhead.
2.3	For each item identified in the response to paragraph 2.1(b):	
2.3(a)	State its amount;	Not applicable
2.3(b)	State whether it was Material;	Not applicable
2.3(c)	Explain the method of allocation and reasons for choosing that methods; and	Not applicable
2.3(d)	Explain the reason(s) why it cannot be allocated on a causation basis.	Not applicable
3.	Cost Allocation to Service Segments.	
3.1	Identify each item in the Regulatory Accounting Statements that is:	
3.1(a)	not allocated on a directly attributable basis but is allocated on a causation basis from the *distribution business* to a service	General overheads reported in the following template is not allocated on a directly attributable basis but are allocated on a causation basis from the distribution business to a service segment. Template 17: Alternative control and other services.

Item No.	Requirement	Energex Response
	segment; and	
3.1(b)	Not allocated on a directly attributable basis and cannot be allocated on a causation basis from the *distribution business* to a service segment.	Not applicable
3.2	For each item identified in the response to paragraph 3.1(a);	
3.2(a)	State the amount of the item that has been allocated;	**Overheads allocated to service segment**

Functional Group Name	Standard Control Services	Alternative control services			Total Distribution Business
	$'000 nominal (D)	Street lighting $'000 nominal (E)	Fee based services $'000 nominal (F)	Quoted services $'000 nominal (G)	$'000 nominal (D to G)
Service Delivery	67,520.7	1,621.8	1,306.6	1,327.1	71,776.2
IT Services	106,628.4	2,561.1	2,063.3	2,095.8	113,348.6
Property	44,631.8	1,072.0	863.7	877.2	47,444.7
Asset Management	36,222.8	870.0	700.9	712.0	38,505.7
Procurement Services	40,711.5	977.8	787.8	800.2	43,277.3
Customer and Corporate Relations	5,998.1	144.1	116.1	117.9	6,376.2
Finance, Regulation and Strategy	1,842.4	44.3	35.7	36.2	1,958.6
Human Resources	5,360.6	128.8	103.7	105.4	5,698.5
Office of the CEO	571.3	13.7	11.1	11.2	607.3
TOTAL	309,487.6	7,433.6	5,988.9	6,083.0	328,993.1

Item No.	Requirement	Energex Response
3.2(b)	Explain the method of allocation and reasons for choosing that method; and	***Allocation of cost to SCS and ACS (Distribution Business) - Refer to D to G*** As mentioned above in section 2.2 (b), the general overhead for the distribution business is the remaining overhead expenditure excluding corporate support costs and after the cost allocation to the non-regulated activities. The allocation of overheads to service segment is based on the regulated general overhead rate. This rate is used to allocate general overheads to services based on direct spend as this reflects a strong correlation with the consumption of the overhead.
3.2(c)	State the numeric amount of the allocator(s) used.	The general overhead rates applied in the 2013/14 year for the distribution business were 43.00% (1 July 2013 to 28 February 2014) and 45.00% (1 March 2014 to 30 June 2014) of the direct costs that attract overhead.
3.3	For each item identified in the response to paragraph 3.1(b)	

Item No.	Requirement	Energex Response
3.3(a)	State its amount;	Not applicable
3.3(b)	Sate whether it was Material;	Not applicable
3.3(c)	Explain the method of allocation and reasons for choosing that methods; and	Not applicable
3.3(d)	Explain the reason(s) why it cannot be allocated on a causation basis.	Not applicable
4	Related Party Transactions	
4.1	Identify each Related Party with which a transaction has been conducted.	**4.1 Identify each Related Party with which a transaction has been conducted.**

Related Party	Comments
Energy Impact Pty Ltd	Not material - the transaction amount is less than 5% of the relevant total expenditure
Ergon Energy Corporation Limited	Not material - the transaction amount is less than 5% of the relevant total expenditure
SPARQ Solutions Pty Ltd	Material - the transaction amount is greater than 5% of the relevant total expenditure
Powerlink Queensland	TUOS costs are not part of opex and all other transactions are less than 5% of the relevant total expenditure.

Item No.	Requirement	Energex Response
4.2	Identify each transaction relating to the provision of *standard control services, alternative control services* or *negotiated distribution services* between *Energex* and a Related Party, where the transaction amount is great than five per cent of the relevant total expenditure or revenue category. Relevant categories are standard control revenues, alternative control revenues, negotiated distribution services revenues, standard control capex, alternative control capex, standard control operations expenditure, standard control maintenance expenditure, alternative control operations expenditure, alternative control maintenance expenditure and negotiated distribution services expenditure.	See table below

Name of the Related Party	Other parties involved	Nature and Purpose	State the actual costs incurred not including any profit margin or management fee incurred by Energex ($'000 nominal)		Explain how the actual costs of the good(s) or service(s) incurred was determined	Identify the actual costs of the good (s) or service(s) in the Regulatory Accounting Statement, including the Asset category, Maintenance Cost category or Operating Cost category to which the actual cost (s) is allocated to	Explain the basis upon which the actual cost of the good(s) or service (s) was or were allocated, as identified in the response to paragraph (f), and state the amount of any allocator applied
(4.3a)	(4.3b)	(4.3c)	(4.3d)		(4.3e)	(4.3f)	(4.3g)
GENERAL OVERHEAD POOL							
SPARQ Solutions Pty Ltd	SPARQ costs directly attributable to Energex	Asset Usage Fee - Depreciation	$	51,916.9	Depreciation expense on assets held by Sparq and used by Energex. Calculated using straightline method by Sparq fixed asset register.	Costs included in the general overhead pool	Allocated in accordance with the AER approved CAM. General overhead rate is used to allocate overheads to services based on direct spend as this reflects a strong correlation with the consumption of the overhead.
SPARQ Solutions Pty Ltd	SPARQ costs directly attributable to Energex	Sparq Resource Costs. Cost of Sparq resources (labour and other employee expenses) to support business	$	27,103.3	Cost of Sparq resources (labour and other employee expenses) to support Sparq business	Costs included in the general overhead pool	Allocated in accordance with the AER approved CAM. General overhead rate is used to allocate overheads to services based on direct spend as this reflects a strong correlation with the consumption of the overhead.
SPARQ Solutions Pty Ltd	SPARQ costs directly attributable to Energex	Sparq Licence & Maintenance Fees	$	14,027.9	Cost of Energex system & program licences and maintenance	Costs included in the general overhead pool	Allocated in accordance with the AER approved CAM. General overhead rate is used to allocate overheads to services based on direct spend as this reflects a strong correlation with the consumption of the overhead.
SPARQ Solutions Pty Ltd	SPARQ costs directly attributable to Energex	Asset Usage Fee - Finance Fee	$	13,538.5	Finance expense on assets held by Sparq and used by Energex. Calculated on WDV of assets by agreed interest rate between Energex & Sparq (8.5% for assets capitalised pre July 2010, 9.72% for loans capitalised post July 2010). Interest rate is WACC as set in each regulatory determination period.	Costs included in the general overhead pool	Allocated in accordance with the AER approved CAM. General overhead rate is used to allocate overheads to services based on direct spend as this reflects a strong correlation with the consumption of the overhead.
SPARQ Solutions Pty Ltd	SPARQ costs directly attributable to Energex	Sparq Telecommunications Expenses	$	6,670.6	Cost of telecommunications support provided by Sparq and other passthrough items including Legal Costs, Procurement On Costs and Non-Capitalised Borrowing Costs.	Costs included in the general overhead pool	Allocated in accordance with the AER approved CAM. General overhead rate is used to allocate overheads to services based on direct spend as this reflects a strong correlation with the consumption of the overhead.
SPARQ Solutions Pty Ltd	SPARQ costs directly attributable to Energex	Project Opex Costs - Multiple projects including minor ICT requests, business case preparation etc.	$	2,822.0	General Sparq operational expenses i.e.labour. Labour hours charged to project at standard labour rate.	Costs included in the general overhead pool	Allocated in accordance with the AER approved CAM. General overhead rate is used to allocate overheads to services based on direct spend as this reflects a strong correlation with the consumption of the overhead.
SPARQ Solutions Pty Ltd	SPARQ costs directly attributable to Energex	Project Opex costs - Cognos Business Intellegence for budget across Energex	$	34.1	General Sparq operational expenses i.e.labour. Labour hours charged to project at standard labour rate.	Costs included in the general overhead pool	Allocated in accordance with the AER approved CAM. General overhead rate is used to allocate overheads to services based on direct spend as this reflects a strong correlation with the consumption of the overhead.
SPARQ Solutions Pty Ltd	SPARQ costs directly attributable to Energex	Project Opex Costs - Business change documentation	$	18.6	Labour hours charged to project at standard labour rate.	Costs included in the general overhead pool	Allocated in accordance with the AER approved CAM. General overhead rate is used to allocate overheads to services based on direct spend as this reflects a strong correlation with the consumption of the overhead.
SPARQ Solutions Pty Ltd	SPARQ costs directly attributable to Energex	Project Opex Costs - General Expenses Opex (e.g. Energex ICT relocation expenses)	$	11.7	Sparq labour cost in Energex ICT relocation. Labour hours charged to Energex property department at standard labour rate.	Costs included in the general overhead pool	Allocated in accordance with the AER approved CAM. General overhead rate is used to allocate overheads to services based on direct spend as this reflects a strong correlation with the consumption of the overhead.
		TOTAL INCLUDED IN GENERAL OVERHEAD POOL (REFER TO TABLES 5.5, 8.4 and 10.4)	**$**	**116,143.6**		**Refer to allocation of related party transactions included in the general overhead pool in Table 5.5 (SCS $77,712.7, ACS$1,680.0), Table 8.4 (SCS $25,637.7, ACS $1,471.7) and Table 10.4 (SCS $5,907.3, ACS $3,734.2)**	

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Name of the Related Party	Other parties involved	Nature and Purpose	State the actual costs incurred not including any profit margin or management fee incurred by Energex ($'000 nominal)	Explain how the actual costs of the good(s) or service(s) incurred was determined	Identify the actual costs of the good (s) or service(s) in the Regulatory Accounting Statement, including the Asset category, Maintenance Cost category or Operating Cost category to which the actual cost (s) is allocated to	Explain the basis upon which the actual cost of the good(s) or service (s) was or were allocated, as identified in the response to paragraph (f), and state the amount of any allocator applied
(4.3a)	(4.3b)	(4.3c)	(4.3d)	(4.3e)	(4.3f)	(4.3g)
OPEX						
SPARQ Solutions Pty Ltd	SPARQ cost directly attributable to Energex	Project Opex Costs - Smartgrid	$ 37.9	Project Costs (labour) - Smartgrid. Labour hours charged to project at standard labour rate.	Opex - Operating Costs. Refer to Table 10.4 Related Party Transactions	Not Allocated - Costs booked directly to Opex
SPARQ Solutions Pty Ltd	SPARQ cost directly attributable to Energex	Project Opex Costs - Cartography work for DMS	$ 35.0	Labour hours charged to project at standard labour rate.	Opex - Operating Costs. Refer to Table 10.4 Related Party Transactions	Not Allocated - Costs booked directly to Opex
SPARQ Solutions Pty Ltd	SPARQ cost directly attributable to Energex	Project Opex Costs - EPM (Energex Performance Management). Data warehouse project for Energex.	$ 152.3	Labour hours charged to project at standard labour rate.	Opex - Operating Costs. Refer to Table 10.4 Related Party Transactions	Not Allocated - Costs are excluded from the general overhead pool
		TOTAL OPEX (REFER TO TABLE 10.4)	**$ 225.3**			
CAPEX						
SPARQ Solutions Pty Ltd	SPARQ cost directly attributable to Energex	PC Laptops ($1,000 plus)	$ 355.6	PC Hardware ($1,000 plus) - purchase price	Capex - IT Systems. Refer to Table 5.5 Related Party Transactions.	Not Allocated - Costs booked directly to Capex
SPARQ Solutions Pty Ltd	SPARQ cost directly attributable to Energex	Interim Secondary Control System (ISCS) Migration	$ 203.0	New Master Data Concentrators MDCs for DMS2 PowerOn and ISCS migration - Labour hours charged to project at standard labour rate.	Capex - Communications. Refer to Table 5.5 Related Party Transactions.	Not Allocated - Costs booked directly to Capex
SPARQ Solutions Pty Ltd	SPARQ cost directly attributable to Energex	PC Hardware ($1,000 plus)	$ 182.4	PC Hardware ($1,000 plus) - purchase price	Capex - IT Systems. Refer to Table 5.5 Related Party Transactions.	Not Allocated - Costs booked directly to Capex
SPARQ Solutions Pty Ltd	SPARQ cost directly attributable to Energex	PC Hardware ($100-$999)	$ 170.8	PC Hardware ($100-$999) - purchase price	Capex - IT Systems. Refer to Table 5.5 Related Party Transactions.	Not Allocated - Costs booked directly to Capex
SPARQ Solutions Pty Ltd	SPARQ cost directly attributable to Energex	Construction Works Raceview	$ 129.4	Refurbishment Raceview Depot - ICT Fitout eg. hardware, software, capitalised labour	Capex - Non System Buildings. Refer to Table 5.5 Related Party Transactions.	Not Allocated - Costs booked directly to Capex
SPARQ Solutions Pty Ltd	SPARQ cost directly attributable to Energex	Matrix Stage 3 - G20, Sparq Data Centre Upgrade	$ 103.8	G20,Sparq Data Centre Upgrade - labour hours charged to project at standard labour rate	Capex - Communications. Refer to Table 5.5 Related Party Transactions.	Not Allocated - Costs booked directly to Capex
SPARQ Solutions Pty Ltd	SPARQ cost directly attributable to Energex	Plant Overload Protection System Enhancements for Electricity Network Capital Program	$ 83.8	Labour hours charged to project at standard labour rate.	Capex - Distribution Equipment. Refer to Table 5.5 Related Party Transactions.	Not Allocated - Costs booked directly to Capex
SPARQ Solutions Pty Ltd	SPARQ cost directly attributable to Energex	Mobile Phones and Accessories (over $100)	$ 40.1	PC Hardware ($100-$999) - purchase price	Capex - IT Systems. Refer to Table 5.5 Related Party Transactions.	Not Allocated - Costs booked directly to Capex
SPARQ Solutions Pty Ltd	SPARQ cost directly attributable to Energex	Sub Network Cutover to operational technology environment	$ 25.8	Labour hours charged to project at standard labour rate	Capex - Distribution Equipment. Refer to Table 5.5 Related Party Transactions.	Not Allocated - Costs booked directly to Capex
SPARQ Solutions Pty Ltd	SPARQ cost directly attributable to Energex	Newstead - Establish data connectivity and upgrade digital surveillance	$ 24.8	Labour hours charged to project at standard labour rate.	Capex - IT Systems. Refer to Table 5.5 Related Party Transactions.	Not Allocated - Costs booked directly to Capex
SPARQ Solutions Pty Ltd	SPARQ cost directly attributable to Energex	Control systems equipment	$ 20.2	Labour hours charged to project at standard labour rate-capitalised labour cost	Capex - Communications. Refer to Table 5.5 Related Party Transactions.	Not Allocated - Costs booked directly to Capex
SPARQ Solutions Pty Ltd	SPARQ cost directly attributable to Energex	PC Toughbooks & Accessories ($100-$999)	$ 16.7	PC Hardware ($100-$999) - purchase price	Capex - IT Systems. Refer to Table 5.5 Related Party Transactions.	Not Allocated - Costs booked directly to Capex
SPARQ Solutions Pty Ltd	SPARQ cost directly attributable to Energex	Geebung Redevelopment	$ 20.4	Redevelopment of Geebung office - ICT Fitout including hardware, software, capitalised labour	Capex - Non System Buildings. Refer to Table 5.5 Related Party Transactions.	Not Allocated - Costs booked directly to Capex
SPARQ Solutions Pty Ltd	SPARQ cost directly attributable to Energex	Mobile Hardware ($100 plus) to be pooled	$ 13.1	PC Hardware ($100-$999) - purchase price	Capex - IT Systems. Refer to Table 5.5 Related Party Transactions.	Not Allocated - Costs booked directly to Capex
SPARQ Solutions Pty Ltd	SPARQ cost directly attributable to Energex	Matrix Stage 2 - Multi Protocol Labelled Switching Network (Telecommunications transfer method for packets of data).	$ 9.1	Finalise design, manage construction work - labour hours charged to project at standard labour rate	Capex - Communications. Refer to Table 5.5 Related Party Transactions.	Not Allocated - Costs booked directly to Capex
SPARQ Solutions Pty Ltd	SPARQ cost directly attributable to Energex	Network communications to the substation	$ 4.0	Labour hours charged to project at standard labour rate-capitalised labour cost	Capex - Non System Buildings. Refer to Table 5.5 Related Party Transactions.	Not Allocated - Costs booked directly to Capex
SPARQ Solutions Pty Ltd	SPARQ cost directly attributable to Energex	Project Support - Install Sub Security	$ 3.7	Firewall - purchase price	Capex - Distribution Equipment. Refer to Table 5.5 Related Party Transactions.	Not Allocated - Costs booked directly to Capex
SPARQ Solutions Pty Ltd	SPARQ cost directly attributable to Energex	Metering Handhelds ($1000 plus)	$ 1.0	PC Hardware ($100-$999) - purchase price	Capex - IT Systems. Refer to Table 5.5 Related Party Transactions.	Not Allocated - Costs booked directly to Capex
SPARQ Solutions Pty Ltd	SPARQ cost directly attributable to Energex	Victoria Park - Convert to 110/11kV with 2 x 60MVA	$ 0.8	Labour hours charged to project at standard labour rate-capitalised labour cost	Capex - Distribution Equipment. Refer to Table 5.5 Related Party Transactions.	Not Allocated - Costs booked directly to Capex
SPARQ Solutions Pty Ltd	SPARQ cost directly attributable to Energex	Standard Operating Equipment Licence (PCs)	$ 0.3	Standard Operating Environment Licence (PCs) - purchase price	Capex - IT Systems. Refer to Table 5.5 Related Party Transactions.	Not Allocated - Costs booked directly to Capex
		TOTAL CAPEX (REFER TO TABLE 5.5)	**$ 1,408.8**			

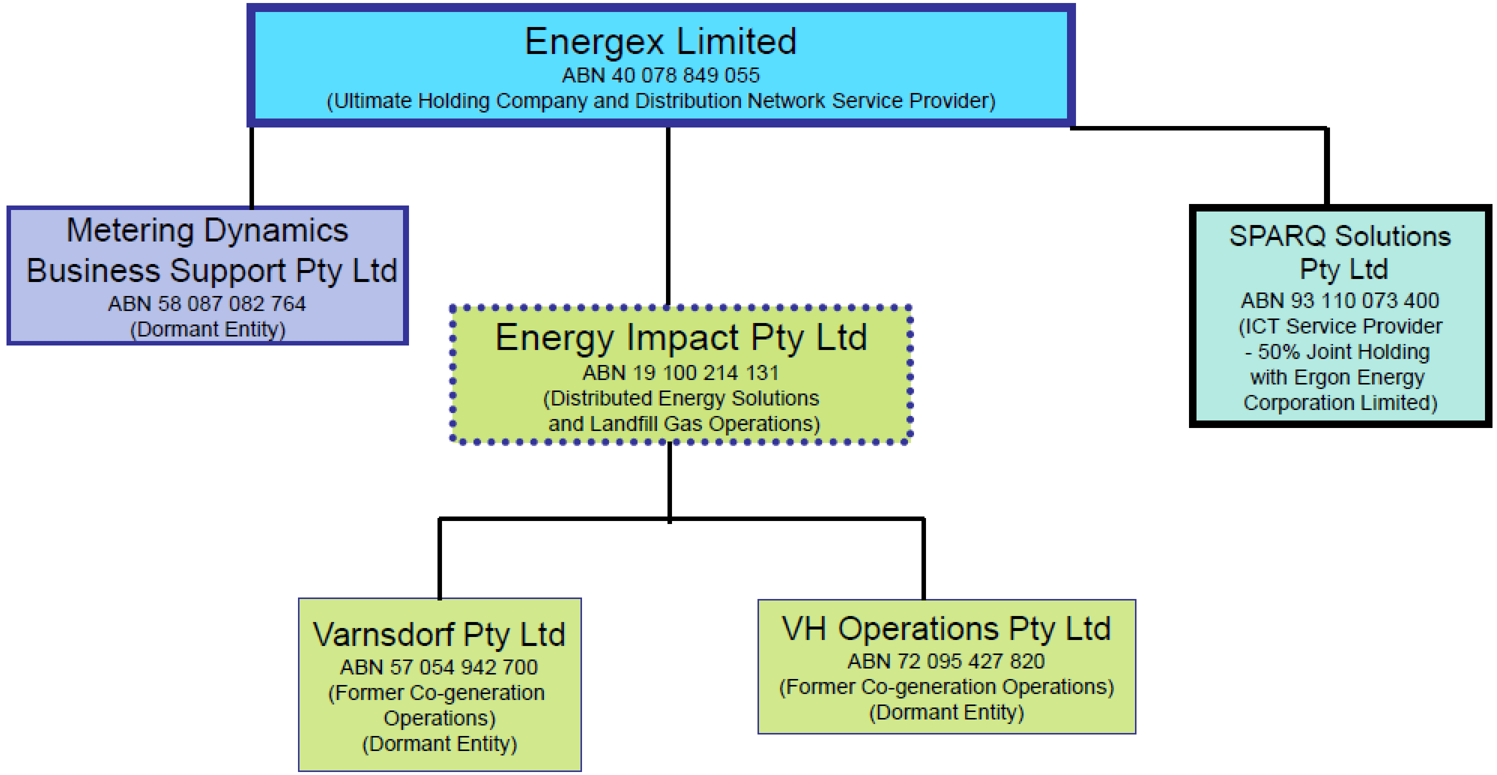
Item No.	Requirement	Energex Response
4.3	For each transaction identified in the response to paragraph 4.2:	
4.3(a)	State the name of the Related Party;	Information is provided in the table above in response to item 4.2.
4.3(b)	Identify any other parties involved;	Information is provided in the table above in response to item 4.2.
4.3(c)	Explain the nature and purpose of the transaction, including the good(s) or service(s) provided by the Related Party;	Information is provided in the table above in response to item 4.2.
4.3(d)	State the actual costs incurred by the Related Party in providing good(s) or service(s), not including any profit margin or management fee incurred by *Energex;*	Information is provided in the table above in response to item 4.2.
4.3(e)	Explain how the actual costs of the good(s) or service(s) incurred was determined.	Information is provided in the table above in response to item 4.2.
4.3(f)	Identify the actual costs of the good(s) or service(s) in the Regulatory Accounting Statements, including the Asset category, Maintenance Cost category or Operating Cost category to which the actual cost(s) is allocated to: and	Information is provided in the table above in response to item 4.2.
4.3(g)	Explain the basis upon which the actual costs of the good(s) or service(s) was or were allocated, as identified in the response	Information is provided in the table above in response to item 4.2.

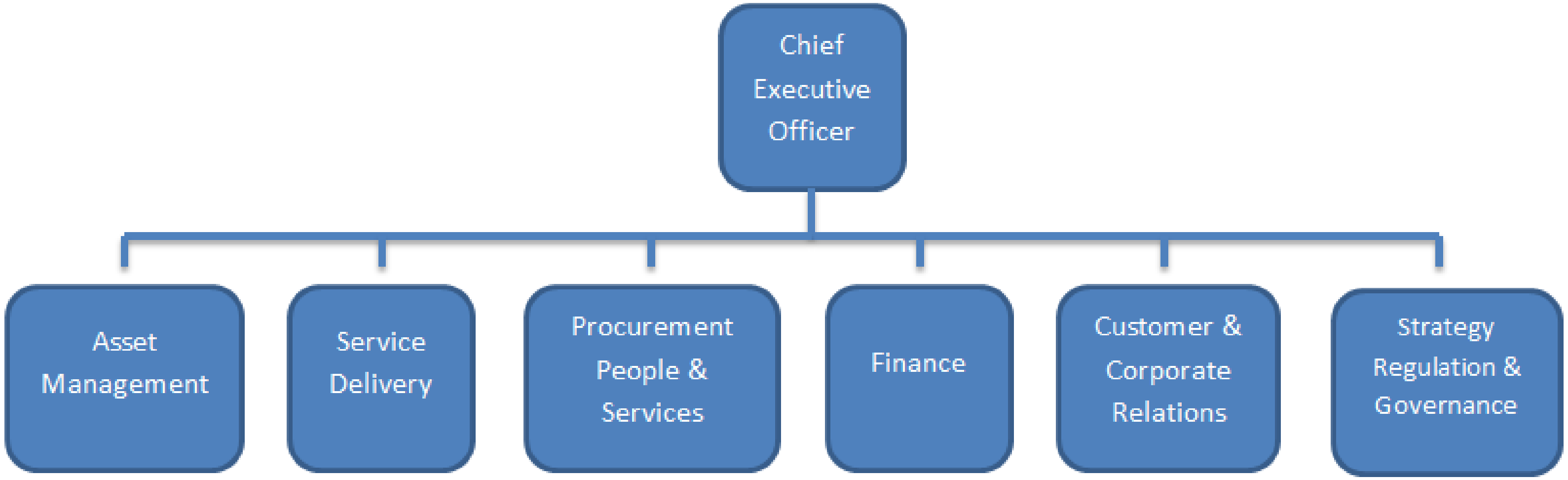
Item No.	Requirement	Energex Response
	to paragraph (f) and state the amount of any allocator applied.	
5	Efficiency Benefit Sharing Scheme	
5.1	Identify all changes between the Capitalisation Policy for the Relevant Regulatory Year and the Previous Regulatory Year;	Not applicable.
5.2	For each change identified in the response to paragraph 5.1:	
5.2(a)	State, if any, the financial impact of the change;	Not applicable.
5.2(b)	State the reasons for the change;	Not applicable.
5.2(c)	Explain the effect of the change (excluding changes in accounting policies) if any, on: (i)Forecast Operating and Maintenance Expenditure incurred for the Relevant Regulatory Year; (ii)Forecast Capital Expenditure incurred for the Relevant Regulatory Year; (iii)Actual Operating and Maintenance Expenditure incurred for the Relevant Regulatory Year; (iv)Actual Capital Expenditure incurred for the Relevant Regulatory Year; and	Not applicable.

Item No.	Requirement	Energex Response
5.2(d)	Explain the estimated effected of the change, if any, for the previous *regulatory year* on; (i)Actual Operating and Maintenance Expenditure incurred; and (ii)Actual Capital Expenditure incurred.	Not applicable.
6	Demand Management Incentive Scheme	
6.1	In respect of the Demand Management Innovation Allowance:	
6.1(a)	Provide an explanation of each demand management project or program for which approval is sought;	Energex did not undertake any new DMIA projects in 2013/2014
6.1(b)	Explain, for each demand management project or program identified in the response to paragraph 6.1(a), how it complies with the Demand Management Innovation. Allowance criteria detailed at section3.1.3 of the *demand management incentive scheme*, with particular reference to: (i)the nature and scope of each demand management project or program; (ii)the aims and expectations of each demand management project or program;	Energex did not undertake any new DMIA projects in 2013/2014

Item No.	Requirement	Energex Response
	(iii)the process by which each demand management project or program was selected, including the business case for the demand management project and consideration of any alternatives; (iv)how each demand management project or program was/is to be implemented; (v)the implementation costs of the demand management project or program; and (vi)any identifiable benefits that have arisen from the demand management project or program, including any off-peak or peak demand reductions;	
6.1(c)	Provide an overview of developments in relation to the demand management projects or programs completed in previous years, and any results to date;	Energex did not undertake any new DMIA projects in 2013/2014
6.1(d)	State whether the costs associated with each demand management project or program identified in the response to paragraph 6.1(a) are: (i)not recoverable under	Energex did not undertake any new DMIA projects in 2013/2014

Item No.	Requirement	Energex Response
	any jurisdictional incentive scheme; (ii)not recoverable under any other Commonwealth or State Government scheme; (iii)not included as part of: (1)the forecast Capital Expenditure or the forecast Operating Expenditure; or (2)any other incentive scheme applied by the 2010-15 Distribution Determination; and	
6.1(e)	Provide the total amount of the Demand Management Innovation Allowance spent in the Current Regulatory Control Period and how this amount has been calculated.	Energex did not undertake any new DMIA projects in 2013/2014
7	Non-Financial Performance Monitoring Information	
7.1	Explain all Material differences between the target performance measure specified in the *service target performance incentive* scheme and actual performance reported in the response to paragraph 1.1(b) of Schedule 1.	Energex performance under the AER STPIS (Service Target Performance Incentive Scheme) for the financial year 2013/14 was favourable for all three categories in SAIDI and SAIFI. The six measured SAIDI and SAIFI values ranged from 16% (Urban SAIDI) to 63% (CBD SAIFI) favourable to target. The performance of the CBD network is by design highly reliable with outcomes variable around the target levels. Performance outcomes for the CBD are managed through operational response and use of generators. For the Urban and Rural networks, the performance outcomes are a result of improvements to network resilience through investment in capacity and reliability and maintaining effective operational capability to restore supply as quickly as possible once a fault occurs. Additionally the seasonal weather storm patterns that regularly impact the network have been less severe than past years, making up around 20% of the whole of network performance after removal of exclusion events. Where weather events have been severe they have exceeded the MED (Major Event Day) threshold thereby excluding the impact to reportable data. This year there were three major event days that contributed around 40% of the total whole of network performance.
8	Charts	
8.1	Provide charts that set out:	

Item No.	Requirement	Energex Response
8.1(a)	The group corporate structure of *Energex* is a part; and	Energex Group Structure as at 8 May 2014 **100% owned by the State of Queensland via 2 nominated shareholding Ministers as non-beneficial shareholders**  ***NB All subsidiary companies 100% owned except as marked*** 39

Item No.	Requirement	Energex Response
8.1(b)	The organisational structure of *Energex*.	
9	Audit Reports	
9.1	Provide Audit Report(s) in the form of:	
9.1(a)	Special Purpose Financial Report in accordance with the requirements set out at Appendix E of this Notice; and	Please refer to the attached QAO Audit Report.
9.1(b)	Audit Report(s) for Non-Financial Regulatory Templates information in accordance with the requirements set out at Appendix E of this Notice.	Please refer to the attached PB Audit Report.