RIN Supporting Information

Schedule 1

2010-11

energex
positive energy

Schedule 1 – Provide Information

Item No.	Requirement	ENERGEX Response
1.1	Complete the templates in accordance with the instruction provided in the templates.	Please see Attachment "RIN templates 2010–11". The Templates are completed in accordance with the instructions provided in the Templates, unless stated otherwise.
1.1(a)-(c)	Provide assumptions, methodologies and justifications for any non-provision of information required by the templates.	These Items are addressed in ENERGEX's response to Item 1.2 below.
1.2	Describe processes, procedures, and systems used to provide the information in the templates.	**<u>Template 1 – RAB</u>** The information provided in this template is automatically drawn from Template 2 (Capital expenditure) through cell-links embedded in the spreadsheet. Please refer to ENERGEX's response to Template 2 below. **<u>Template 2 – Capital Expenditure</u>** **<u>Certain information is confidential</u>** <u>Table 2.1 Capex by Asset Category</u> Forecast figures have been determined based on the AER's Final Decision, which is a combination of:

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		• 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 informed the Forecast totals included in the Final Decision. The information was sourced from the Proposal at the detailed level and updated based on AER advice. Forecast figures 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. However, actuals have been separately reported for Distribution Substation Switchgear. While preparing the actuals, it was determined that 5% of 110kV Circuit Breakers were previously included as UG Sub-transmission Cables, with the remaining 95% included as Substation Bays. The Proposal was prepared on this basis, however 110kV Circuit Breakers should be reclassified as 100% Distribution Substation Switchgear. Accordingly, the actuals have been updated to reflect this change – refer to the table below. Similarly, UG Sub-transmission Cables previously included 5% of 33kV Capacitor Banks, Circuit Breakers, Regulators and Terminators. The remaining 95% of 33kV Capacitor Banks, Circuit Breakers, Regulators and Terminators were included as Substation Bays. The Proposal was prepared on this basis, however 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 the 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. It should be noted that continual improvements in capturing costs will occur over the regulatory period where warranted.

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Category	Proposal	Actuals
UG Sub-Transmission Cables:		
110KV Circuit Breaker	5%	-
33KV Capacitor Banks, Circuit Breakers, Regulators & Terminators	5%	-
110KV UG Cable	100%	100%
UG Cable solid insulated	100%	100%
Substation Bays:		
110KV Circuit Breaker	95%	-
66KV Capacitor Banks & Circuit Breakers	100%	100%
33KV Capacitor Banks, Circuit Breakers, Regulators & Terminators	95%	100%
11KV Capacitor Banks & Circuit Breakers	75%	75%
LV Circuit Breaker	100%	100%
Distribution Substation Switchgear:		
110KV Circuit Breaker	-	100%
11KV Capacitor Banks & Circuit Breakers	25%	25%

Capex projects which do not have an assigned asset category are allocated to regulatory asset categories based on the account used for the project.

Capital Contribution balances that do not have an assigned project or asset category are allocated to regulatory asset categories based on the proportions of projects or asset categories identified. 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 2010/11, this manual adjustment was for only $447.

As this data has not been reported in the past, further improvements are expected in the future which will enable specific identification by regulatory asset category in more cases.

Capital Contributions reported in Table 2.1 are reconciled to Capital Contributions reported in Table 7a.1 for Standard Control Services.

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		Actuals (direct and overhead) have been sourced from ENERGEX's Enterprise Resource Planning (ERP) system Ellipse. This data has been extracted via a software package (CorVu) which allows a cross reference of the Ellipse projects against the regulatory asset categories and is reconciled to the general ledger. Direct and overhead components are specifically identified via a segment of the account code. Overhead is applied via system entries in accordance with the Cost Allocation Method (CAM) approved by the AER in February 2009. Regulatory asset categories for system assets and buildings attract overhead. Other non-system asset categories do not attract overhead as they are typically purchases which do not require additional work. Disposal data is sourced from the Ellipse Fixed Asset Register (FAR) developed specifically for regulatory assets. Disposals are identified via advice from the relevant areas of the business and updated to regulatory FAR progressively throughout the year. Data is extracted based on the relevant regulatory asset categories. Capital contributions data is sourced from a combination of the general ledger and the project ledger. Data is extracted via CorVu which cross references the projects that have Capital Contributions revenue against the regulatory asset categories. <u>Table 2.2 Explanation of significant variations by asset category</u> As highlighted in ENERGEX's response to the Draft RIN, explanations by asset category are relatively meaningless. As this level would not allow proper explanation of underlying reasons for variances, ENERGEX has instead provided explanations for system capex by purpose (refer Table 2.4) in an Attachment. Non-system capex explanations are included in Table 2.2. <u>Table 2.3 Related Party Transactions</u> The related party capex number reported in Table 2.3 for SPARQ differs from the IT Systems capex figure reported in Table 2.1. This is because the SPARQ transactions also include IT expenditure reported against different asset categories in Table 2.1. Transactions for Ergon may not reconcile to the transactions included in its RIN if it regards the services as non-regulated in nature. Related party transactions are sourced via different methods depending on the party. SPARQ transactions are sourced via a manual review of invoices and compilation into a spreadsheet to identify those related to

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		capex. This process also ensures that invoices received reconcile to the amount processed in the ledger. Ergon transactions are sourced via a CorVu report run for the relevant supplier numbers. The report includes the account numbers that the transactions have been charged to and the capex transactions are extracted. A manual review of these transactions is then performed to provide the related party description. <u>Table 2.4 Capex by purpose</u> Refer to explanation of Forecast figures included with Table 2.1 information above. The same methodology applied to derive the Forecast figures by purpose has been used for the Actuals. Explanations for variances by purpose have been provided separately as an Attachment. Data is sourced from Ellipse and extracted via the same CorVu query used for Table 2.1 above. The data for capex by purpose is identified via a segment of the account number and is reconciled to the general ledger. <u>Table 2.5 Effects on capex from capitalisation policy changes</u> The version of the capitalisation policy submitted to the AER as part of ENERGEX's regulatory proposal is the capitalisation policy applied in preparing the 2010/11 RIN. ENERGEX has refined its approach to categorising overheads, however this is not considered a change to the capitalisation policy. <u>Table 2.6 Non-network Alternative Capex</u> The reduction in peak demand (in megawatts) has been confirmed by an internal audit review completed by PWC. Financial data has been sourced from Ellipse, wherein separate work orders exist to capture costs for each separate project. Governance requirements involve regular reporting to internal reference groups and the Energy Conservation & Demand Management Steering Committee. The Demand Management Plan for 2010/11 was reviewed by the Network Technical Committee and ENERGEX Board prior to submission to the technical regulator. <u>Table 2.7 Capex by Cost Category</u>

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		The Instructions for this Table state that forecasts are to be for direct capex only, therefore actuals are included on the same basis – ie: both forecasts and actuals exclude overheads. Refer to explanation of Forecast figures included with Table 2.1 information above. Actual costs by category are specifically identified via a segment of the account code. Total costs in this table are reconciled to the Actual Direct Costs in Table 2.1. Labour costs include all employee benefits such as ordinary time, overtime, payroll tax, superannuation, leave payments and training. Labour costs are inclusive of labour oncosts. Materials costs include store issues and consumables, workwear, stationery, direct purchases, and land and easements. Materials costs are inclusive of materials oncosts. Contractor costs include contracted labour and consultants. Contributions in kind represent assets gifted to ENERGEX. Capitalised Interest is the interest cost for capex projects extending beyond 12 months. Other costs represent miscellaneous items such as stamp duty, fuels and vehicle hire. <u>Table 2.8 ACS Streetlighting Capex</u> The Instructions for this Table state that forecasts are to be for direct capex only, therefore actuals are included on the same basis – ie: both forecasts and actuals exclude overheads. Refer to explanation of Forecast figures included with Table 2.1 information above. Refer to explanation of Capital Contributions figures included with Table 2.1 information above. Actual Streetlighting capex is identified via asset category or, where no category is specified, by specific account codes. Refer to explanation for disposals included with Table 2.1 information above. Refer to explanation capital contributions included with Table 2.1 information above. Capital Contributions reported in Table 2.8 will not reconcile with Capital Contributions reported in Table 7a.1 for Alternative Control Services as ENERGEX also receives contributions for other ACS work, such as Large Customer Connections. <u>Table 2.9 Capex Unit Costs</u> The 141 items reported in Table 2.9 equate to the top 75% of assets/equipment issued from the Stores to capex projects during the year. Unit costs have been calculated by dividing the total issue value for the year by the total number of issues for the year. Total

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		issue value is calculated using issue prices relevant at the time of issue. Total number of issues and total issue value have been sourced from the Ellipse inventory module. Issue prices represent an average of each individual purchase price for the stock on hand (eg: if stock on hand is 30, acquired through three individual purchases of 5 @ $5.00, 18 @ $5.05, and 7 @ $5.10, the issue price would be $5.053. If 10 units are then used on a capex job, the total issue value would be $50.53). This method of calculating issue prices is standard across inventory systems and has been audited as part of ENERGEX's statutory audit for several years. **<u>Template 3 – Operating Expenditure</u>** **<u>Certain information is confidential</u>** <u>Table 3.1 Opex by Activity</u> Refer to explanation of Forecast figures included with Table 2.1 information above. In addition to the Forecast opex figure, $1M has been included with DSM Initiatives for DMIA. The $5M nominal amount for the regulatory control period was a revenue allowance for DMIA, as opposed to an expenditure forecast. As DMIA is a specific EBSS exclusion, it needs to be included in total opex before adjustment. Call Centre, Meter Reading, Levies and Debt Raising Costs do not attract overhead as they do not contribute to the program of work. Of the Other Operating Costs, only the NECF costs (refer Table 3.3) attract overhead. This treatment is consistent with ENERGEX's regulatory proposal (Note: NECF costs were not foreseen at the time of the proposal). Actuals (direct and overhead) have been sourced from Ellipse. Most data is available via general ledger reports with activities being identified at the source. Direct and overhead components are specifically identified via a segment of the account code. Overhead is applied in accordance with the CAM. <u>Table 3.2 Explanations of significant variations by activity</u> Not applicable. <u>Table 3.3 Other operating costs</u> Refer to explanation of Forecast figures included with Table 2.1 information above.

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		Actuals that have been provided at a lower level of detail than requested (ie: request was only for components greater than 10% of other operating costs) are typically items that were subject to review by the AER in making the revenue determination (eg: FIT administration, network insurance and self insurance) or new costs that meet the pass-through criteria but not the materiality threshold (eg: NECF). Network Insurance and Self Insurance costs are also EBSS exclusions so their separate disclosure in Table 3.3 aids transparency in Table 13.1. The amount reported for FIT payments represents actual payments made for Solar PV. It equals the figure for "Feed- in tariff payments incurred in 2010-11" included in the spreadsheet attachment to the AER's letter to ENERGEX dated 12 December 2011. It excludes the CPI applied to the base amount and is consistent with the AER's preferred methodology to verify actual FIT payments in future. The total of this Table balances to "Other operating costs (inc self insurance)" from Table 3.1. Refer to information included with Table 3.1 above for process and systems description. The figure for Self Insurance is obtained from a separate system (Figtree) used for insurance purposes. It represents all settled claims at 30 June 2011 over $100,000. <u>Table 3.4 Opex Related Party Transactions</u> Most SPARQ transactions are charged via an asset usage fee or Service Level Agreement with the costs included in the general overhead pool. The remainder are project costs booked directly to the relevant projects. Energy Impact transactions are reported as part of DSM Initiatives. Powerlink transactions are for TUOS costs but do not match the Net TUOS Expense figure in Table 7a.1. This is because Net TUOS Expense also includes other costs for Avoided TUOS and Network Support. Transactions for Ergon may not reconcile to the transactions included in its RIN if it regards the services as non-regulated in nature. Related party transactions are sourced via different methods depending on the party.

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		SPARQ transactions are sourced via a manual review of invoices and compilation into a spreadsheet to identify those related to opex. This process also ensures that invoices received reconcile to the amount processed in the ledger. Energy Impact transactions have been calculated using the contracted rates for: • Assets used to provide generator availability for network support services during the reporting period; and • Energy Impact to organise generator availability at pre-determined sites for the Network Demand Management department during the summer period 1 December 2010 to 31 March 2011 Powerlink transactions are sourced from the specific account for TUOS payments. Ergon transactions are sourced via a CorVu report run for the relevant supplier numbers. The report includes the account numbers that the transactions have been charged to and the opex transactions are extracted. A manual review of these transactions is then performed to provide the related party description. Table 3.5 Effects on opex from capitalisation policy changes The version of the capitalisation policy submitted to the AER as part of ENERGEX's regulatory proposal is the capitalisation policy applied in preparing the 2010/11 RIN. ENERGEX has refined its approach to categorising overheads, however this is not considered a change to the capitalisation policy. Table 3.6 Non-network alternatives opex Refer to information included with Table 2.6 above. Completion of the regulatory test for Bromelton resulted in opex substitution for the stand-by generation project previously forecast as capex. This regulatory test was submitted to the ENERGEX Board on 13 December 2010. The $31M reported as “deferred opex from DM project” is actually the forecast capex amount which has been deferred. Refer to information included with Table 2.6 above for process and systems description. Expenditure for Residential Targeted Initiatives has been confirmed through an external audit conducted by PWC. All of this expenditure is included with DSM Initiatives in Table 3.1. Table 3.7 Opex by Cost Category

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		The Instructions for this Table do not restrict the data to direct costs only (as for Table 2.7), therefore both direct and overhead costs are included. This table therefore reconciles to Table 3.1. Refer to explanation of Forecast figures included with Table 2.1 information above. Refer to information included with Table 2.7 above for labour, materials and contractor costs for systems and processes description. General overheads represent costs allocated to direct opex activities in accordance with the CAM. Other costs include Solar PV FIT payments and administration, National Energy Customer Framework, insurance, non-capitalisable costs, non-network alternatives, levies and debt raising costs. Table 3.8 ACS Streetlighting opex The Instructions for this Table do not restrict the data to direct costs only (as for Table 2.8), therefore both direct and overhead costs are included. Refer to explanation of Forecast figures included with Table 2.1 information above. Actual Streetlighting opex is identified via a specific account code. **Template 4 – Weighted Average Cost of Capital** **This information is confidential** A description of the methodology used to calculate the book interest rate has been provided in an Attachment. Information relating to the debt and financial instruments held in the ENERGEX Client Specific Pool (CSP) has been sourced from the Quantum portfolio management system used by Queensland Treasury Corporation. **Template 5 – Not Used** This Template is not used to collect data from ENERGEX. **Template 6 – Self-Insurance**

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<u>This information is confidential</u>

Confidential managed by external claims managers Gallagher Bassett Services (GBS). All claims 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 Figtree General Claims database. On a regular basis, GBS provided payment reports for claimants requiring payment by ENERGEX.

GBS payments reports are filed on Hummingbird electronic document records management system. Individual payments are recorded against the appropriate claimant in Figtree. Regular payments reports are run out of Figtree to capture payments to be made in electronic format, with the electronic files passed to Accounts Payable for payment through Ellipse.

<u>Template 7a – Statement of Financial Performance</u>

Adjustments relate to:

- Under/over recovery of revenue, consistent with ENERGEX's response to the Purpose and Issues correspondence. These include:
  - Distribution Revenue;
  - Capital Contributions; and
  - Net TUOS Expense.

- Reclassification of revenue and expense items from the statutory view to the regulatory view. These include:
  - Reclassification of minor amount for the portion of assets funded via government grant from Government Grant Revenue to Capital Contributions;
  - Reclassification of Streetlighting, Quoted Services and Fee Based Services from Other Revenue to Distribution Revenue;
  - Reclassification of Debt Raising Costs from Interest Expense to Other Operating Costs;
  - Reclassification of TUOS Revenue from Distribution Revenue to Net TUOS Expense;
  - Reclassification of minor amount from Other Operating Costs to Meter Reading and recognition of entry eliminated in the statutory accounts for Meter Reading;
  - Reclassification of minor amount from Other Operating Costs to Customer Services; and
  - Recognition of Self Insurance as this cost is not recognised in statutory accounts;

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Elimination of non-regulated services. These include:

Gross Proceeds From Sale of Assets consistent with the Purpose & Issues correspondence;
Interest Income consistent with the Purpose & Issues correspondence;
Sale of Goods revenue consistent with the Purpose & Issues correspondence;
Government Grant Revenue for DSM Initiatives funded by the State government and grants received for the legacy businesses, both of which are non-regulated;
Other revenue for provision of support to Ergon for the January 2011 storm events, work for Powerlink, training provided to external parties, shared asset provision, rentals and hire, testing and calibration of equipment and metering services;
DSM Initiatives for the expenditure related to State government funded activities;
Other Operating Costs for provision of support to Ergon for the January 2011 storm events, work for Powerlink, cost of sales, shared asset provision, rentals and hire, testing and calibration of equipment and metering services
Depreciation & Amortisation for non-regulated assets;
Book Value of Assets Disposed for the non-regulated proportion of disposed assets;
Interest Expense for the proportion related to non-regulated Borrowings; and
Taxation Expense for the proportion related to non-regulated tax assets and liabilities, consistent with the Purpose & Issues correspondence.

Most Statement of Financial Performance line items are allocated among services based on the account code. Exceptions relate to:

Other Operating Costs – balances for Alternative Control Services and Non-Regulated Services are specifically identified with the remaining balance reported as Standard Control Services;
Depreciation & Amortisation – balances are sourced from the Regulatory FAR where services are specifically identified. This is consistent with the Purpose & Issues correspondence for Property, Plant & Equipment (PP&E);
Book Value of Assets Disposed – balances are determined by allocating the total value of assets disposed in proportion to the services identified from the Regulatory FAR;
Interest Expense – adjustment is made for Debt Raising Costs (refer to the Assumptions & Methodologies above) with remaining balances allocated in proportion to the underlying Borrowings; and
Taxation Expense – allocation between services is on the same basis as the underlying tax assets and liabilities. This is

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		consistent with the Purpose & Issues correspondence. Non-regulated services are included in Adjustments as detailed above. Statutory account figures are sourced from the audited year-end workpapers and mapped to the regulatory line items by staff who prepare the statutory accounts. All figures that can be reconciled to other disclosures in the RIN financial templates have been, ie: • SCS capital contributions; • Network operations; • Network maintenance including Inspections, Planned Maintenance, Corrective Repair, Vegetation, Emergency Response/Storms; and • Other costs including Meter Reading, Customer Services (inc Call Centre), DSM Initiatives, Levies, Other Operating Costs **<u>Template 7b – Statement of Financial Position</u>** Adjustments are made for: • Under/over recovery of revenue, consistent with ENERGEX's response to the Purpose and Issues correspondence. These include: o Non Current Receivables – for under recoveries due to be recovered from customers more than 12 months from balance date; o Other Current Liabilities – for over recoveries due to be returned to customers within 12 months; and o Non Current Provisions – for over recoveries due to be returned to customers more than 12 months from balance date. • Reclassification of items from the statutory view to the regulatory view. These include: o Reclassification of Accrued Revenue from Current Receivables, consistent with ENERGEX's proposal in the Purpose & Issues correspondence.

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		Balances for Statement of Financial Performance line items, adjusted for the items listed above, are allocated to services based on PP&E balances. PP&E balances are sourced from the Regulatory FAR and this methodology is consistent with ENERGEX's proposal in the Purpose & Issues correspondence. Statutory account figures are sourced from the audited year-end workpapers and mapped to the regulatory line items by staff who prepare the statutory accounts. **<u>Template 7c – Provisions</u>** The detail and format of this Table had not been previously issued for comment, and so ENERGEX had no opportunity to provide comment. The disclosures requested are at a lower level of detail than indicated by the AER's previous advice that "the RIN will be amended to include a requirement for DNSPs to report increases or decreases in provisions" and are considerably more extensive than ENERGEX's suggestion that movements in provisions "should be a separate table (of one row) in template 7b." Difficulties in completion of this table related to the following: • Liabilities paid from a provision are not charged to opex or capex. When liabilities are paid from a provision, they reduce the balance of that provision with the opposing entry being the Cash at Bank account; • Almost 66% of ENERGEX's provisions do not relate to opex or capex. Provision for Dividends (54%) is related to Net Operating Profit After Tax (NOPAT) and Regulated Revenue Recoveries (12%) are related to revenue; • Over 32% of ENERGEX's provisions relate to Employee Benefits with increases in the provision allocated via labour oncosts; and • Movements in other provisions (less than 2%) are typically charged to indirect expenditure and are allocated to services as part of general overhead. Due to these complications, all movements have been reported as "Other adjustments". Other adjustments also include an amount for the change in the allocation rate, as the proportions of PP&E for individual services may vary from the start of the year to the end of the year. For example, the proportion of PP&E at the start of the year could be 95% / 3% / 2% (SCS / ACS / Non-Regulated) and 96% / 3% / 1% at the end of the year, resulting in an "Other adjustment" between the services.

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		Balances are allocated to services based on PP&E balances, consistent with ENERGEX's proposal in the Purpose & Issues correspondence. Statutory account figures are sourced from the audited year-end workpapers with all movements included as other adjustments – refer Assumptions & Methodologies above. Explanations for movements in the provision have been supplied by staff who prepare the statutory accounts, therefore any figures quoted reconcile to the "Audited statutory account figures". This reflects the underlying nature of the transactions and applies to the different services, which are an apportionment of the statutory account amount – refer Disaggregation of Services above. **<u>Template 8 – Overheads Allocation</u>** **<u>This information is confidential</u>** Overhead costs are those costs which are not directly attributable to distribution services and are allocated in accordance with the CAM. This allocation is based on total direct spend, which reflects a strong correlation with the consumption of the overhead costs (refer ENERGEX CAM s7.6). As such, there is no direct link between the source of the overhead costs and the services they are costed to. Source costs are identified by the specific group incurring the costs, with these groups being included in the "Description" column. Application of the overhead is identified by the specific service costed to and proportions of the total service costs are determined. Source costs by group are then allocated to the services in these proportions. For example: • Groups A, B & C incur $100, $150 and $200 respectively • These costs are combined into a pool of $450 and allocated as general overhead to: o SCS $300 (67%) o ACS $100 (22%) o Non-Regulated $50 (11%) • Therefore for the purpose of Table 8.1, these are reported as: **Cost SCS ACS Non-Reg**

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	100%	67%	22%	11%
Group A	100	67	22	11
Group B	150	100	33	17
Group C	200	133	44	22
	450	**300**	**100**	**50**

General overheads exclude other corporate support costs which are not allocated, such as financial control (including end of month and end of year reporting, financial systems and assets), tax & treasury, secretariat & governance, risk & compliance, internal audit, strategy & regulation, corporate communications and government liaison.

Overheads allocated to services are specifically identified via the account code.

Balances for each area contributing to the general overhead pool are sourced via an Ellipse report to determine the total for each group.

Overheads allocated to services are specifically identified via the account code.

The total overheads reported in Table 8.1 for SCS equals the overheads for capex in Table 2.1 and the overheads for opex in Table 3.1.

Template 9 – Asset Condition

Certain information is confidential

The data in Template 9 should not be considered true and accurate in all material respects, unless otherwise indicated below. The data provided is the best information currently available to ENERGEX. The data should only be reviewed and applied with close reference to the descriptions and qualifications set out below.

Please also note that:

- Some of the data is sourced from the Condition Based Risk Management (CBRM) analysis as detailed below. CBRM data was most recently updated in 2008 (it was used for determining maintenance and refurbishment programs for the most recent AER Regulatory Proposal); and is based on samples of various asset classes;

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		• The definition of asset failure across asset types may differ from the RIN definition (and amongst themselves) depending on the type of failure data available to ENERGEX. The inclusions in the failure statistics should be reviewed extremely carefully prior to using the data; • The data presented in the spreadsheets does not include assets that are in store or held for spares; • Unless otherwise specified the age profile data is to December 2011 and reflect assets currently in service. An asset is assumed to be installed in 1910/11 in circumstances where the installation date is unknown or the asset was installed prior to 1910/11; and • Replacement costs are based on strategic planning estimates or budgeting estimates. There are usually many estimates available for the categories given depending on the actual work requirements. For instance, different estimates are available for replacement of LV mains by: o Single phase or 3 phase; o Rural, urban or CBD; o Replacement of open wire with bundle ABC; and • Line length data is to June 2011. The following systems and documents have been used to prepare the data in Template 9: • Network Facilities Management (NFM). The NFM database is the master electronic record of all network assets and their connectivity. It is populated from completed field work orders and reflects the normal state of the network. The NFM data is used by other engineering systems and processes, including CBRM. In certain instances, the CBRM data has been directly used to prepare the Template 9 data. It should be noted that NFM categorises assets as plant and non-plant. Plant items are defined as assets of high value, requiring a detailed history for asset management purposes. Since the inception of NFM, certain assets, such as cross-arms, pillars, 11kV airbreak switches, metal clad switches, remote controlled load break switches and services, have been considered low value non-plant assets not requiring detailed historical records. The NFM data includes a small number of customer assets. Where possible these assets have been excluded from ENERGEX assets.

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		• Service Call Management (SCM). The SCM application is part of the Distribution Management System, and is the application used to manage customer trouble calls and network faults. The SCM application has three types of data records – service requests, incidents and service orders. • Ellipse: The ENERGEX corporate estimating tool is the Ellipse enterprise system. All replacement unit cost data are standard estimates sourced from Ellipse. The Ellipse modules used for estimating are: Work Request Module MSQ541, Job Packaging Module MSQ695, Job Estimating Module MSQ655 and Compatible Units Database MSQ635. Standard estimates represent the most common Network Building Block constructions. • Network Outage (NO) System: The Network Outage recording system records any network incidents, including Powerlink, from low voltage circuits and upward, either planned or unplanned, that affects customers; and • Program of Work Network Operations Steering Committee Monthly Performance Reports: Also used as a source of data in some instances. The following assumptions and methodologies have been used to prepare the Template 9 data. • Poles: o **Materially true and accurate, but should only be used with close reference to the following explanations.** o The pole data has been categorised by the highest voltage on the pole and material type. These two characteristics usually determine the cost of replacement. o The replacement life has been calculated using pole data up to 2004. Only poles which had been replaced are included in the data set. Active poles still in service are not included the replacement calculations. The replacement age includes any life extension actions. The same life is assumed for all wood pole types. The same life is assumed for all concrete and steel pole types. o The replacement cost for "steel poles" is an estimate for streetlight poles which do not have mains on them. These include Rate 1 and Rate 2 streetlight poles. o There is no standard replacement cost estimate for the 'other' poles as these poles vary in material and function and are individually cost estimated at time of replacement. o Pole failures include all poles which are identified as unserviceable (no longer meets design criteria e.g. rotted) or in service pole failure (pole falling to ground). The pole strength is assessed during its regular 5 year inspection cycle. There is no failure data available for concrete poles, although it is unlikely that there were any failures given the pole type, and so zero failures has been assumed. All steel poles are assumed to be streetlight poles. There is no failure data available for 'other poles' which are typically wooden stay poles with no conductors attached to them. o Towers include 110kV and 132kV towers and poles. There is no failure data available for towers, although it is

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		unlikely that there were any failures given the pole type, and so zero failures has been assumed. o There is no standard replacement cost for towers as each high voltage (110kV and 132kV) feeder is custom designed. • Pole Top Structures: o **Materially true and accurate, but should only be used with close reference to the following explanations.** o The replacement unit cost and asset failure data can be considered true and accurate in all material respects. o Pole top structures have been defined as crossarms for this analysis. o The mean age of all crossarms is based on the pole age less the difference between the pole in service date and the crossarm replacement date. The assumption is that only 1 crossarm has been replaced in the life of the pole. A standard deviation was not calculated at the time of the audit in 2008 and cannot be replicated today. o The number of crossarms in service has been calculated by multiplying the number of wooden poles by 1.5. The 1.5 factor is an estimate of the number of crossarms per pole based on field audits. o Crossarm failures are defined as those replaced as a result of Inspection Programs and those replaced due to in service failures. • Overhead Conductors: o ENERGEX does not have complete installation records for overhead cables. In the late 1990's when ENERGEX conducted its network data capture, the business case was based on operational and planning benefits which did not require the installation date or any history, only the conductor type. Hence, no age nor age profile has been provided. o ENERGEX does record the conductor type by material and ENERGEX changed over to installing aluminium conductors in the mid- 1970's. o The length of each conductor type is a 'three phase length' not individual phase conductor lengths and includes an estimate of the sag of each span. o For HV it consists of 3 phases but not an earth and for LV it is 3 phases plus neutral. o If an overhead line is re-conductored it is constructed with the latest design standard ie MOON for 11kV. The replacement cost for current constructions has been provided. o The 2010/11 failure data is sourced from the NO database. o Costs are in $ per km. • Underground Cables: o ENERGEX does not have complete installation records for underground cables. In the late 1990's when ENERGEX conducted its network data capture the business case was based on operational and planning benefits which did not require the installation date or any history only the conductor type. Hence, no age nor age profile has been provided. o If an underground line is replaced it is constructed with the latest design standard ie 240sqmm 3 phase cable. The

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		replacement cost for current constructions has been provided. o The 2010/11 failure data is sourced from the NO database. o Costs are in $ per km. • Services and Pillars: o ENERGEX does not have an age profile for overhead services. The number of overhead services is based on the number of property addresses with an overhead connection. The number of National Metering Identifiers (NMIs) was not used as the number of NMIs will overstate the number of services ie usually only one service for unit developments with multiple NMIs. The number of services is estimated to be understated by (5-10%) due to the quality of the connection point data. o The customer owns all underground services, therefore ENERGEX does not have any underground services. o For overheads services, failure data is sourced from SCM. o For pillars, failure data is sourced from SCM. o The age of individual LV pillars is not recorded in NFM. The age profile given for LV pillars is based on the age of the distribution transformer which supplies the LV pillar. This profile was derived in 2008 for the CBRM analysis and has not been updated since. The total number of pillars as at December 2011 is 250,141 whereas the total of the age profile data is 190,330. • Distribution Transformers: o **Materially true and accurate, but should only be used with close reference to the following explanations.** o Please note that certain transformer sizes are no longer purchased, so the replacement cost is based on the next standard size up. o Distribution transformers which do not have a rating attributed have been excluded from the data. There are only a small number of these (approximately 500 of 46,000). o Asset failures are sourced from NO and are actual asset failures. o The average replacement life has been calculated from distribution transformers with an NFM event code of ‘scrapped’ or ‘unavailable’. o The life of distribution transformers which have only been purchased in recent years (e.g. 315KVA) will have life data which is biased downwards. • Distribution Switchgear: o The age profile of air break/metal clad switches has been derived from the initial slot creation date and not from actual installation dates. The age profile was derived in 2008 for the CBRM analysis and has not been updated. The total number of air breaks/metalclad switches shown as connected in NFM as at December 2011 is 14,758 whereas the total of the CBRM age profile data is 17,226.

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		- Not all of the 11kV reclosers have detailed history. The age profile is based on those reclosers in NFM that had historic installation dates. The total number of reclosers shown as connected in NFM is 768 whereas the age profile is based on 682 reclosers. - Not all of the 33kV reclosers had detailed history. The age profile is based on those reclosers in NFM that had historic installation dates. The total number of reclosers shown as connected in NFM is 78 whereas the age profile is based on 62 reclosers. - ENERGEX has very little historic data on load break switches and sectionalisers. Hence there is no age profile for this switchgear. - Ring-main (RM) isolators have not been included as a failed RM would more than likely require the replacement of the whole padmount including the transformer. These replacements are included in the padmount transformer and ground transformer data. - Asset replacement age data is sourced from NFM and is based on scrapped or unserviceable equipment. - Failure data is sourced from NO. • Distribution Other Assets: - Asset failures for regulators are sourced from NO - Asset failures information for streetlights is sourced from contract replacement data and is based on 68,197 lamp and PE cell replacements and 120 full luminaire replacements. - The average unit rate is for lamp/PE cell and full luminaire replacement - The average age is based on the life expectancy that is provided to Local Government Authorities for high pressure sodium luminaire or a mercury vapour luminaire with an expectation of 4,200 hours of "burning time" every year. A standard deviation is not available. The age of the streetlight pole is known and is included in the pole data. - Rate 1 and 2 streetlights (ENERGEX assets) are included in the streetlights numbers. - Not all of the 11kV regulators have detailed history. The age profile is based on those reclosers in NFM that had historic installation dates. The total number of regulators shown as connected in NFM is 406 whereas the age profile is based on 378. - Not all of the 33kV reclosers had detailed history. The age profile is based on those reclosers in NFM that had historic installation dates. The total number of reclosers in shown as connected in NFM is 768 whereas the age profile is based on 682. - A custom estimate would be produced for each replacement regulator or new regulator. - Asset replacement age data is sourced from NFM and is based on scrapped or unserviceable equipment for both 11and 33 kV regulators together. • Zone Transformers: - **Materially true and accurate, but should only be used with close reference to the following explanations.**

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		o Zone substation transformers are generally replaced with the current transformer standards. Current replacement costs of the next size up have been used for those transformers which are not current standards o Asset failure data is sourced from NO and Ellipse. This data only includes catastrophic failure, and does not include transformers replaced based on end of life condition. o Replacement costs for current zone substation transformer rating are detailed separately. o Asset replacement age data is sourced from NFM and is based on scrapped or unserviceable equipment. Some zone transformer categories have no replacement age data as there are no recorded scrapping/unavailable for service transformers for these categories. • Zone Switchgear: o Not all of the 11kV circuit breakers have detailed history. The age profile is based on those circuit breakers in NFM that had historic installation dates. The total number of circuit breakers in connectivity is 4,365 whereas the age profile is based on 3,498. o Not all of the 33kV circuit breakers have detailed history. The age profile is based on those circuit breakers in NFM that had historic installation dates. The total number of circuit breakers in connectivity is 1,477 whereas the age profile is based on 1,300. o Not all of the 110kV circuit breakers have detailed history. The age profile is based on those circuit breakers in NFM that had historic installation dates. The total number of circuit breakers in connectivity is 420 whereas the age profile is based on 164. o Not all of the 132kV circuit breakers have detailed history. The age profile is based on those circuit breakers in NFM that had historic installation dates. The total number of circuit breakers in connectivity is 55 whereas the age profile is based on 35. o Replacement unit cost for 66kV is not provided because they are rarely used. o Replacement ages for 110kV and 132kV switchgear is not provided because they could not be discerned from the plant records. o Failure data is sourced from NO and Ellipse. • Zone Other Assets: o Not all of the 11kV capacitor banks have detailed history. The age profile is based on those capacitor banks in NFM that had historic installation dates. The total number of capacitor banks in connectivity is 396 whereas the age profile is based on 341. o Not all of the 33kV capacitor banks have detailed history. The age profile is based on those capacitor banks in NFM that had historic installation dates. The total number of capacitor banks in connectivity is 47 whereas the age profile is based on 30. o The age profile given for AFLC is based on the nameplate manufactured date of the equipment or the contract date

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		where the name plate age was not available. This profile was derived in 2008 and has not been updated because of the significant resourcing requirements necessary to manually vet the data. The total number of AFLC injection units as at December 2011 is 329 whereas the total of the age profile data is 200. o Capacitor bank and AFLC failures are sourced from Ellipse Report Explorer report - ELL00471. Failures reflect corrective and demand driven preventative work (excluding routine maintenance). Entire capacitor banks are not replaced, it is generally incremental replacement of capacitor cans (this is what the failure numbers reflect). o Because capacitor banks and AFLC are generally changed incrementally as described above, the age of the banks and AFLC would be inaccurate. o Capacitor bank ages profiles are sourced from NFM. o Asset replacement age data is sourced from NFM and is based on scrapped or unserviceable equipment. • SCADA and Protection: o There are no accurate electronic records of protection equipment, only manual paper records which do not always record the age of the asset. o The replacement cost and quantity is an approximation only and is not sourced from a corporate system. **<u>Template 10 – Demand</u>** Regarding Table 10.4: • ENERGEX does not prepare a 90POE system demand forecast in MW because it is not used in the ENERGEX planning processes. • ENERGEX prepares a 50POE and 10POE system demand forecast in MW not MVA. Some of the substation demand forecasts and recorded actual demands are not available due to the substation commissioning dates being changed since the substation demand forecasts were prepared for the Regulatory Proposal. The main reason for this deferment has been the impact of the Global Financial Crisis and the slowing down of Queensland economic activity. Substations in this category include: Eumundi, Cooran, Lomandra Drive, Pacific Paradise, Merrimac, Springfield Central Tennyson and Wamuran. Some smaller customer substations have there own transformers and where the size is not known have been left blank. ENERGEX has developed and published formal procedure documents that define how the demand and energy forecasts are to be prepared and documented. Annual audits are conducted for each of the BMS documents and the findings are used to improve the procedure documentation.

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		Energy Sales Data is extracted from the PEACE billing system and the monthly estimates are used to prepare the forecasts. The monthly energy sales data is estimated from quarterly billing data for a large proportion of the customer base. The accuracy of this estimate is dependent on the seasonality factor and daily usage figures used within the reporting process. Customer Numbers are sourced from PEACE and include all registered NMIs. The monthly customer numbers are tracked to identify trend changes. Embedded generation energy is metered by the Meter Data Agency (MDA) and is made available to the forecasting process via a copy held in an Oracle database managed by the Forecasting department. Embedded generators are also counted as customers in the number count. <u>Customer Number Forecast</u> The customer number forecast developed for the ENERGEX Regulatory Proposal was based on the broad customer categories of Commercial, Industrial, Domestic, Rural and others. The Proposal forecasts developed for the 2010/11 financial year are shown below. The AER have now modified the forecast categories by consumption levels. The closest forecast that ENERGEX has developed on this basis is the forecast prepared in 2009 for the 2010/11 Distribution Loss Factor Assessment. This forecast is shown below in comparison with the Proposal forecast. Customer number forecasts are prepared annually based on segment trends and population trends.

AER Proposal Customer Numbers for 2010/11 and the DLF Customer Numbers for 2010/11

AER Customer Class	AER Customer Numbers	DLF Customer Class	DLF Customer Numbers
Domestic	1,232,615	ICC	30
Commercial	118,265	CAC	475
Industrial	3,880	SAC	129,562
Rural	7,910	Domestic	1,232,615
Traction	12	Public Lighting	456
Public Lighting	456		
Total	1,363,138	Total	1,363,138

ENERGEX has changed the billing system used to monitor customer consumption from a very old mainframe system FACOM to a system called PEACE. This occurred at the time of the sale of the ENERGEX Retail group. In the transition process the customer details in FACOM were cleansed before converting to the PEACE system. This process identified a large number (approx 10,000 customers) that were not genuine customers. The resulting step change in customer numbers is evident between

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		the two systems. The public lighting category originally included unmetered supply sites. These have now been removed from this category. The New Connections numbers are based on gross connections to the ENERGEX network. <u>Customer Energy Forecasts</u> The customer energy forecasts developed for the ENERGEX Regulatory Proposal were based on the broad customer categories of Commercial, Industrial, Domestic, Rural and others. The Proposal forecasts developed for the 2010/11 financial year are shown below. The AER have now modified the forecast categories by consumption levels. The closest forecast that ENERGEX has developed on this basis is the forecast prepared in 2009 for the 2010/11 Distribution Loss Factor Assessment. This forecast is shown below in comparison with the Proposal forecast.

AER Proposal Energy Sales for 2010/11 and the DLF Energy Sales for 2010/11

AER Customer Class	AER Energy Sales GWh	DLF Customer Class	DLF Energy Sales GWh
Domestic	8,451	ICC	1,860
Commercial	10,065	CAC	4,145
Industrial	3,340	SAC	7,783
Rural	202	Domestic	8,700
Traction	224	Public Lighting	162
Public Lighting	134		
Total	22,416	Total	22,650

Customer energy forecast are developed using long term trends in average consumption by customer class, economic conditions, appliance information and technology trends. The energy forecasts now also include the increasing impact of solar PV. It is essential to note that residential customers are normally billed quarterly and to identify the monthly energy sales figures, ENERGEX is required to estimate the consumption at the end of each month. The process used for this estimation includes average daily consumption applied to the days of unread consumption in the month with a weighting applied to capture seasonality. The end result is a monthly energy sales figure that is estimated for 1.2 million domestic customers.

<u>System Demand Forecasts</u>

ENERGEX has developed a detailed econometric modelling methodology that is used to prepare 10 year system demand forecast for both summer and winter. The methodology includes ten years of historical daily peak demand figures, maximum and

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		minimum daily temperatures, Queensland GSP, air conditioning load and other variables that capture the key drivers of daily peak demand. Historical data is used to develop a multiple regression model that is tested by backcasting and out of sample testing before being used in a 50 year Monte Carlo simulation of weather conditions to produce the 10POE and 50POE seasonal peak demands. In the simulation process the model is calibrated to account for the standard error of the regression using a normally distributed process of applying the standard error. The resulting annual demands are used as the base case which is then modified to take account of Network Demand initiatives that are starting to be implemented in ENERGEX. The model is assessed using a range of statistical tests including statistical significance tests, direct structure tests, residual tests, out of sampling tests, sensitivity tests and other tests for cause and affect. At the end of the process the forecast is compared with an independently produced demand forecast by an independent consulting firm. <u>Substation 10 year Summer and Winter Demand Forecasts</u> ENERGEX develops the 10 year substation demand forecasts in a dedicated forecasting tool SIFT (Substation Investment Forecasting Tool). SIFT uses the historical peak and coincident substation demand as the starting point of the 10 year forecast. Zone substation forecasts are developed from the set of coincident starting demand values. Substation peak demand forecasts are derived from their coincident forecast using coincidence factors derived from historical demand readings. The starting demand is validated to ensure no embedded generation is operating, capacitors are removed and that the network is configured in a normal manner. The coincident substation starting demand is then modified for temperature using a process similar to the approach used to temperature correction the demand at system level. Loss factors are calculated at the system and bulk supply level by comparing their coincident demand with the aggregate coincident demand of substations supplied from that level. Temperature adjustment of the historical substation daily peak demands uses the relationship between daily peak demand and the maximum and minimum temperature at five BOM weather stations. The strongest demand – temperature relationship is then used to adjust the recorded substation peak demand using a 50 year Monte Carlo simulation process. SIFT takes into account the proposed block loads and transfers identified in the forecasting period in addition to the calculated base line growth rate. Only larger block loads are incorporated to avoid double counting as part of the base line growth. The resulting 10 year substation demand forecasts incorporate compensation by reinstating the capacitors. The final step is the aggregation of all the substation demands is compared with the independently prepared system demand forecast. The substation demand forecasts are adjusted to reconcile with the system demand for each year of the forecast. **<u>Template 11 – Feeder Performance</u>** **<u>Certain information is confidential</u>**

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		The following processes and systems are used to provide the network reliability and feeder performance related data in Templates 11 and 12a, b, c and d. • To provide the category reliability and performance data the NFM (Network Facilities Management) Outage data is queried for the regulatory year and this data is entered into a spreadsheet to produce required regulatory figures. For data below category level such as individual feeder data a MS Access database is used to extract NFM data. • During the regulatory period network operations staff respond to network outages and document these outages in NFM in accordance with BMS 763. For planned events personnel develop a planned workflow in A4S (Application for switching) and this is then used as a basis for an outage report generated using BMS763. At the end of the regulatory period Reliability and Network Performance staff use the above process to supply the required regulatory data. • Reliability and Network Performance staff apply the AER specified SAIDI and SAIFI calculations in determining reliability measures. • For internal daily reporting Reliability and Network Performance use a Business Objects STPIS reporting application that utilises EDW (Enterprise Data Warehouse) information which is populated from the NFM database. For external regulatory reporting NFM data is extracted and applied to a spreadsheet to gain applicable reliability indices. • Spreadsheet functionality, accuracy and transposed results are checked independently by a second Reliability and Network Performance member to eliminate errors prior to Group and Executive manager sign off. Independent audit results for previous reporting periods that highlight procedural or functional deficiencies are communicated at the Executive management level for business unit corrective action. <u>Tables 11.1 &11.2</u> In determining the 15% of customers a system customer base at the end of the reporting period was used as this complies with the “Number of Customers” definition for template 11. In the absence of a feeder definition Energex has selected feeders energised at 11KV having greater than 0 customers and greater than 1 transformer. This criteria has been applied in previous submissions for worst performing feeder analysis to the QCA. Feeder performance is inclusive of MED and excludable outages as per template instructions. Note - The following is cross referenced to the template instructions: • (c) Geographical Location of Feeder – The suburbs serviced by the associated feeder have been used as a location description.

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		• (d) Feeder Categorisation – ENERGEX owns three feeders that meet the requirement for long-rural, however ENERGEX received approval (in 2008/09) from the QCA to include these in the short rural classification therefore ENERGEX only has three (3) feeder categories. • (e) Feeder Customers – For feeder SAIDI calculations feeder customers at the end of the year have been used, but when unavailable, averaged feeder customers at the time of the outage have been used. • (f) Feeder Maximum Demand – A 50 POE maximum demand figure is used which has been corrected for abnormal network configuration and temperature variations. Total number of momentary interruptions (MAIFIe) - is not reported as ENERGEX is unable to reliably record momentary customer interruptions. Audit commentary for 2010/11 by Parsons Brinckerhoff Australia Pty Limited (PB) on ENERGEX ability to report MAIFIe states *“MAIFI events differ from other outage events in that the interruption to supply is very short and the event is unlikely to result in a customer calling to report a fault. This means that MAIFI measurement relies on automatic recording of the event by the device that autorecloses”*. PB also added that *“Approximately 40% of in-line reclosers are not connected to a communications network (decreased from 41% in the 2009-10 review) and all zone substation circuit breakers are connected to a communications network”.* And PB summarised ENERGEX’s MAIFIe recording capability as *“ENERGEX already has a number of the elements necessary to report MAIFIe and as these elements are integrated with existing outage reporting processes, the reporting of MAIFIe is likely to be reliable for those devices which are connected to communications. However, the reporting of total MAIFIe is limited due to the significant number of in-line reclosers that are not connected to a communications network and for which the number of reclose operations are not readily available”.* The Single Loss of Supply component for each feeder is unavailable for the current reporting year. Energex is developing the capability to report on single loss events at the feeder and category level. A manually entered correction is added to category figures in template 12a to account for the single loss component. <u>Table 11.3</u> Planned SAIDI & SAIFI is inclusive of MED and excluded outages as per template instructions. **<u>Template 12a – STPIS reliability</u>** SAIDI and SAIFI is calculated using a monthly averaged customer base for each category and system values. Figures include an added component for Single Loss of Supply events for each category SAIDI and SAIFI.

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		Single Loss of Supply outage data is a manually processed addition to the listed figures for SAIDI and SAIFI. Energex uses service call management system data to quantify the SAIDI and SAIFI values of single loss events for each category. **<u>Template 12b – STPIS customer service</u>** <u>Table 12b.1: Telephone Answering</u> The methods and formula used to complete this table are consistent with the latest national STPIS. Calls that are received on MED days are deducted from the total call count to report the 'Total number of calls' and 'Number of calls answered within 30 seconds With exclusions'. ENERGEX utilises a hosted telephone service provided by Telstra. This Genesys system is provided and supported by Telstra and has been in place at ENERGEX since 2005. All phone calls received by ENERGEX are handled by the Genesys system. The Genesys system incorporates a reporting tool named CCA. CCA is used to provide daily statistics on phone calls including total number of calls and number of calls answered in 30 seconds. ENERGEX has a number of phone numbers including a Loss of Supply line, Emergency line and General Enquiry Line. In accordance with the specification, calls reported are calls to the Loss of Supply line. The Loss of Supply line uses an IVR which has the capability to identify the location of a caller and to provide specific outage advice to those callers. This IVR information satisfies a large proportion of the callers to the Loss of Supply line. Calls that proceed through the IVR are recorded and timed. This includes calls which relate to a loss of supply where the customer has incorrectly called the Emergency or General Enquiry Line lines, i.e. all loss of supply calls are recorded and timed. <u>Table 12b.5: GSL reporting (relating to the planned interruptions parameter only)</u> Cell C62 is derived data supplied by the Reliability and Network Performance department. ENERGEX electronically processes Network Outage Reports (Form 1160) which classify the outage by cause: 'forced' or 'planned'. ENERGEX's network outage systems don't record planned events as per the AER definition. The total of 7,093 planned interruption events for the 2010/11 year is sourced from the Network Facilities Management system (NFM) which produces a Network Outage (NO) report. ENERGEX makes the assumption that this figure (7,093) is inclusive of 515 events where no or insufficient notice was provided (refer to C63 explanation below). Therefore the total of 6,578 planned events aligns to the RIN definition of total planned interruptions to supply. Planned interruptions where customers were interrupted for greater than 1 minute have been included. No planned Single Loss of Supply events are included in the total planned interruptions figure used to derive the number in cell C62.

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		The processes used to collect and report planned outage data is described in detail in the section on template 12a (STPIS – reliability). Cell C63 applies a 2 business day notice period as the relevant threshold, consistent with the current jurisdictional requirement. As GSL data is identified at a customer level, the source system ID taken from NFM is used to determine the total number of planned outages which involved at least one customer not being provided the requisite notice. This information is based on the occurrence date within the regulatory year. There were a total of 275 instances where a source system ID was not recorded (these instances reflect customer initiated GSL's). In such cases, ENERGEX has consolidated instances of GSL's by date and customer suburb and counted this as a single outage. ENERGEX therefore determined that there were 218 planned events where a source system ID was not identified and at least one customer was not provided with the requisite notice. This equates to 42.3% of the total 515 events reported in this cell. ENERGEX's Reliability and Network Performance department makes the assumption that these 218 events are included within the total figure of 7,093 derived from NO Reports. Cell C63 is identified by the volume of outages identified within the extracted data from IT management software called Cherwell. Cell C64 refers to instances where the recorded restoration time was greater than the planned restoration time. Where the duration of the planned interruption to supply exceeds the time specified in the notification this is considered as a single instance. Where there was insufficient data (17 per cent of occasions) ENERGEX adopted an apportionment approach. That is, of the total planned interruptions where all information was supplied, the percentage that exceeded duration was applied to the instances where insufficient information was supplied. Completing Cell C64 involves a manual process to derive the number of occasions when the duration of the planned interruption to supply exceeded the time specified in the notification. This process involved identifying all the planned outages from the system used to plan network switching (A4S). The planned outage times for the planned works in A4S were compared with the actual times recorded in the outage database (NFM). Notices of interruptions are provided to customers based on the planned times recorded in A4S. **Template 12c – STPIS unplanned outages** **Certain information is confidential** The table includes all outages with SAIDI and SAIFI calculated using a monthly averaged system customer base. Only outages where a customer was interrupted are included. Single losses of Supply outages are not included in this outage list as ENERGEX currently doesn't report on individual events.

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		ENERGEX is currently developing a capability to report these single loss unplanned events and will be including these in subsequent submissions. A manually processed SAIDI and SAIFI component is added to figures in tables 12.a to account for this regulatory requirement. **<u>Template 12d – STPIS exclusions</u>** **<u>This information is confidential</u>** Outage SAIDI and SAIFI is calculated using a monthly averaged system customer base. For the Transmission/Generation outage listed, further information detailing the cause of the outage is unavailable to ENERGEX. **<u>Template 13 – EBSS</u>** **<u>This information is confidential</u>** As noted for Table 3.3, Network Insurance and Self Insurance were separately disclosed in that table to aid transparency for this table. The amount for DMIA equals the figure reported in Table 14.1. Con-network alternative costs are only that portion of DSM Initiatives costed to the appropriate account. This account is the same as that used for the Proposal. Confidential : All EBSS exclusions, except Self Insurance and Specific Uncontrollable Costs, are individually identified via a segment of the account code. Refer to information included with Table 6.1 above for Self Insurance costs.

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		Confidential **<u>Template 14 – DMIA</u>** Only external contractor costs and associated overhead have been captured. Costs associated with existing staff who provide input to the project have absorbed into business-as-usual costs. DMIA costs are specifically identified via the account code. **<u>Template 15 – General Information</u>** A detailed description of the systems used to prepare this information is found in ENERGEX's response relating to Templates 9 and 10. All data is considered true and accurate in all material respects except for the line length data. • Customer numbers: Customer numbers are based on PEACE data at 30 June 2011. • Installed capacity: As required by the template instructions, total installed transformer capacity (MVA) is reported using nameplate rating. Installed MVA is given for each voltage transformation level – 33kV, 11kV, LV.. Installed MVA is at 30 June 2011. • Line Length: All line lengths are at 30 June 2011.Sub-transmission line lengths are all 33kv, 110kV and 132kV overhead and underground 3 phase lengths. HV is 11kV 3 phase lengths. There are known data quality issues with line lengths, as such the data is not considered materially true and accurate.
1.3	Describe the procedures and processes used to ensure compliance with the classification of services specified in the	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 to current regulatory period a review of all services provided by ENERGEX was undertaken. ENERGEX systems were changed to reflect the new classification of services as approved by the Australian Energy Regulator (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

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	distribution determination.	control period, any proposed CoA changes are required to be approved by a number of key staff including the Regulatory Accounting and 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 Regulatory Affairs Group to ensure that the new service is classified in accordance with the AER determined guidelines. As an example, during the 2011 financial year ENERGEX undertook a review in relation to "customer requested rearrangement of network assets" (rearrangement) due to uncertainty of the classification. An internal consultation was undertaken within the organisation followed by a discussion with officers of the AER. The AER confirmed ENERGEX's view that the classification of a rearrangement involving capital expenditure is a standard control service with any revenue received recorded as a capital contribution.
1.4	Describe the procedures and processes used to ensure compliance with the negotiated distribution service criteria specified in the distribution determination.	ENERGEX does not have any negotiated services under the current classification of services.

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1.5(a)-(e)	Provide the Demand Management Innovation Allowance annual report.	Please see Attachment “ENERGEX DMIA report 2010-11”.
1.6	Identify all debt instruments	**This information is confidential** Confidential

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1.7 (a)-(l)	Describe each debt instrument	**This information is confidential** Confidential

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		Confidential

Item No.	Requirement	ENERGEX Response
		Confidential

Item No.	Requirement	ENERGEX Response
		Confidential

Item No.	Requirement	ENERGEX Response
		Confidential
1.8	Identify all financial instruments	**<u>This information is confidential</u>** Confidential
1.9 (a)-(h)	Describe each financial instrument	**<u>This information is confidential</u>** Confidential

Item No.	Requirement	ENERGEX Response
		Confidential
1.10	Describe the processes in place to identify negative change events and the	The National Electricity Rules define the following events as pass through events: ▪ A regulatory change event; ▪ A service standard event; ▪ A tax change event; and

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	materiality threshold applied to such events	▪ A terrorism event. In addition, 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 the terrorism 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 Regulatory Governance Steering Committee. ENERGEX recently participated in the electricity distribution for service delivery (EDSD2) review announced by the Queensland government. Once finalised, ENERGEX will assess the outcomes of the review to determine whether a negative pass through is applicable. 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.

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1.11	Provide the audit reports including reports to ENERGEX management.	Please see attached documents: • “QAO Audit Report - Confidential”; • “PB Audit Report – Confidential”; and • “QAO Management Report – Confidential”.
1.12	Provide an extract from the ENERGEX Board Meeting or signed resolution confirming the financial information is true and fair.	Please see attached document “ENERGEX Board Confirmation”.