Economic Benchmarking RIN Basis of Preparation

2020-21

Part of Energy Queensland

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Compliance with RIN Requirements

Table 1.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 1.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must report revenues by chargeable quantity (RIN Table 3.1.1) and by customer class (RIN Table 3.1.2).	SCS revenue figures have been reported in line with the AERs requirements. Where figures exist the ACS revenue figures have been reported in line with the AERs requirements Demonstrated in the methodology section.
The total of revenues by chargeable quantity must equal the total of revenues by customer class because they are simply two different ways of disaggregating revenue information.	Demonstrated in the methodology section.
Energex must separately provide revenues received or deducted as a result of incentive schemes (RIN Table 3.1.3).	Not applicable.
Total revenues for Direct Control Services will equal those reported in the Regulatory Accounting Statements (with the exception of total revenue in RIN Table 3.1.3).	All figures for SCS revenue have been reconciled to schedule 8.1 (Income) of the Regulatory Reporting Statement. The values reported reconcile to rows "Distribution revenue" and "Jurisdictional scheme amounts" in the "Standard Control Services" column of schedule 8.1 Income. Total revenue for ACS has been balanced to the Regulatory Accounts for 2021.
Revenues reported must be allocated to the chargeable quantity that most closely reflects the basis upon which the revenue was charged by Energex to customers… …Revenues that cannot be allocated to the specific chargeable quantities in variables DREV0101 to DREV0112 must be reported against 'Revenue from other Sources' (DREV0113).	All SCS revenue was reported in the categories defined by the AER. No SCS revenue was reported against "Revenue from other sources" Where possible, Energex has stated ACS revenues in line with those categories which most closely reflect how customers were charged. All other revenue was stated in "Revenue from Other Sources".
Energex must allocate revenues to the customer type that most closely reflects the customers from which Energex received its revenue. Revenues that Energex cannot allocate to the customer types DREV0201-DREV0205 must be reported against 'Revenue from other Customers' (DREV0206).	All SCS revenue was reported in the categories defined by the AER. Where possible, Energex has stated ACS revenues in line with the AERs customer categories. All other revenue was stated in "Revenue from Other Customers".
Energex must report the penalties or rewards of incentive schemes in this table. The penalties or rewards from the schemes applied by previous jurisdictional regulators that are equivalent to the service target performance incentive scheme (STPIS) or efficiency benefit sharing scheme (EBSS) must be reported against the line items for those schemes.	Energex recognises revenues and penalties from incentive schemes.
ACS are defined in the NER. By way of context, ACS are intended to capture distribution services provided at the	ACS has been reported for the year 2021.

Requirements (instructions and definitions)	Consistency with requirements
request of, or for the benefit of, specific customers with regulatory oversight of prices. Where an AER determination was not in effect at the time ACS are for DNSPs located in Queensland, excluded distribution services as determined by the Queensland Competition Authority.	

Sources

Standard Control Services

Table 1.2: Data Sources - RIN Table 3.1.1: Revenue grouping

Variable Code	Variable	Unit	Source
DREV0101	Revenue from Fixed Customer Charges	$0's	PEACE/Regulatory Accounts
DREV0102	Revenue from Energy Delivery charges where time of use is not a determinant	$0's	PEACE/Regulatory Accounts
DREV0103	Revenue from On- Peak Energy Delivery charges	$0's	PEACE/Regulatory Accounts
DREV0104	Revenue from Shoulder period Energy Delivery Charges	$0's	PEACE/Regulatory Accounts
DREV0105	Revenue from Off- Peak Energy Delivery charges	$0's	PEACE/Regulatory Accounts
DREV0106	Revenue from controlled load customer charges	$0's	PEACE/Regulatory Accounts
DREV0107	Revenue from unmetered supplies	$0's	PEACE/Regulatory Accounts
DREV0108	Revenue from Contracted Maximum Demand charges	$0's	PEACE/Regulatory Accounts
DREV0109	Revenue from Measured Maximum Demand charges	$0's	PEACE/Regulatory Accounts
DREV0110	Revenue from metering charges	$0's	PEACE/Regulatory Accounts General ledger reports
DREV0111	Revenue from connection charges	$0's	PEACE/Regulatory Accounts General ledger reports
DREV0112	Revenue from public lighting charges	$0's	PEACE/Regulatory Accounts General ledger reports
DREV0113	Revenue from other Sources	$0's	PEACE/Regulatory Accounts General ledger reports
DREV01	Total revenue by chargeable quantity	$0's	PEACE/Regulatory Accounts

Table 1.3: Data Sources - RIN Table 3.1.2: Revenue grouping by Customer Type or Class

Variable Code	Variable	Unit	Source
DREV0201	Revenue from residential Customers	$0's	PEACE/Regulatory Accounts
DREV0202	Revenue from non-residential customers not on demand tariffs	$0's	PEACE/Regulatory Accounts
DREV0203	Revenue from non-residential low voltage demand tariff customers	$0's	PEACE/Regulatory Accounts
DREV0204	Revenue from non-residential high voltage demand tariff customers	$0's	PEACE/Regulatory Accounts
DREV0205	Revenue from unmetered supplies	$0's	PEACE/Regulatory Accounts
DREV0206	Revenue from Other Customers	$0's	PEACE/Regulatory Accounts
DREV02	Total revenue by customer class	$0's	PEACE/Regulatory Accounts

Alternative Control Services

Table 1.4: Data Sources - RIN Table 3.1.1: Revenue grouping by chargeable quantity

Variable Code	Variable	Unit	Source
DREV0101	Revenue from Fixed Customer Charges	$0's	PEACE reports / SAP data extract reports
DREV0102	Revenue from Energy Delivery charges where time of use is not a determinant	$0's	N/A for ACS
DREV0103	Revenue from On-Peak Energy Delivery charges	$0's	N/A for ACS
DREV0104	Revenue from Shoulder period Energy Delivery Charges	$0's	N/A for ACS
DREV0105	Revenue from Off-Peak Energy Delivery charges	$0's	N/A for ACS
DREV0106	Revenue from controlled load customer charges	$0's	N/A for ACS
DREV0107	Revenue from unmetered supplies	$0's	N/A for ACS
DREV0108	Revenue from Contracted Maximum Demand charges	$0's	N/A for ACS
DREV0109	Revenue from Measured Maximum Demand charges	$0's	N/A for ACS
DREV0110	Revenue from metering charges	$0's	General ledger reports based on SAP data extract FIR3027
DREV0111	Revenue from connection charges	$0's	General ledger reports based on SAP data extract FIR3027
DREV0112	Revenue from public lighting charges	$0's	General ledger reports based on SAP data extract FIR3027

Variable Code	Variable	Unit	Source
DREV0113	Revenue from other Sources	$0's	General ledger reports based on SAP data extract FIR3027
DREV01	Total revenue by chargeable quantity	$0's	Regulatory Accounts

Table 1.5: Data Sources - RIN Table 3.1.1: Revenue grouping by chargeable quantity

Variable Code	Variable	Unit	Source
DREV0201	Revenue from residential Customers	$0's	N/A for ACS
DREV0202	Revenue from non-residential customers not on demand tariffs	$0's	N/A for ACS
DREV0203	Revenue from non-residential low voltage demand tariff customers	$0's	N/A for ACS
DREV0204	Revenue from non-residential high voltage demand tariff customers	$0's	N/A for ACS
DREV0205	Revenue from unmetered supplies	$0's	General ledger reports based on SAP data extract FIR3027
DREV0206	Revenue from Other Customers	$0's	General ledger reports based on SAP data extract FIR3027
DREV02	Total revenue by customer class	$0's	Regulatory Accounts

Methodology

Standard Control Services

Revenue data is collated by Energex in a Microsoft Excel spreadsheet in categories similar to what is required for the EB RIN. This spreadsheet is used to report on the under/over collection of revenue from customers and is used along with groupings of revenue classifications to report and reconcile the revenue figures.

1. The following reports have been used for the 2020-21 regulatory year:

   (i) FRC003B

   (ii) FRC111

   (iii) FRC123

   (iv) MSR296

2. These reports are collated in the spreadsheet, classified by network tariff code and charge category (fixed, demand, volume). The classifications of both network tariff code and charge category are used to derive the classification of revenue into prescribed categories. The tariff category informs "RIN Table 3.1.1 - Revenue by chargeable quantity"; and the network tariff code informs "RIN Table 3.1.2 - Revenue by customer type".

3. For RIN Table 3.1 charge category codes were contained in the source data from PEACE and these categories were used to classify most revenue transactions into chargeable quantities.

Network tariff codes were used to calculate controlled load customer charges and customer types were used to classify unmetered revenue and public lighting. The mapping of these charge categories can be seen Table 1.6 below:

Table 1.6: Categorisations used to classify revenue transactions

Variable Code	Variable	Source
DREV0101	Revenue from Fixed Customer Charges	FIXED
DREV0102	Revenue from Energy Delivery charges where time of use is not a determinant	VOLUME
DREV0103	Revenue from On-Peak Energy Delivery charges	VOLUME peak VOLUME evening
DREV0104	Revenue from Shoulder period Energy Delivery Charges	VOLUME shoulder VOLUME overnight
DREV0105	Revenue from Off-Peak Energy Delivery charges	VOLUME off peak Volume day
DREV0106	Revenue from controlled load customer charges	NTC's 9000/9020/9050/9070 - Controlled Load 1 (super economy) NTC's 9100/9120/9150/9170 - Controlled Load 2 (economy) NTC 7300/7350 - Smart Control
DREV0107	Revenue from unmetered supplies	UMS & WML (Customer Type)
DREV0108	Revenue from Contracted Maximum Demand charges	CAPACITY
DREV0109	Revenue from Measured Maximum Demand charges	DEMAND PEAK DEMAND EXCESS DEMAND
DREV0110	Revenue from metering charges	-
DREV0111	Revenue from connection charges	-
DREV0112	Revenue from public lighting charges	Streetlights (Customer Type)
DREV0113	Revenue from other Sources	-
DREV01	Total revenue by chargeable quantity	Calculated as sum of variables above

Note: Most SAC non-demand tariffs are replicated with ‘XX20’, 'XX50' and "XX70' NTC's to deal with differences in metering service charges (MSC) as follows;

- The original XX00 NTC's are for customers subject to the full MSC
- The new XX20 NTC's are for customers that are subject to only operating costs
- The new XX50 NTC's are for customers that are NOT subject to a MSC
- The new XX70 NTC's are for customers that are subject to only a residual capital MSC

4. The customer classification was mapped to the revenue data via the network tariff code. The classification of network tariff codes to the customer types can be seen in Table 1.7.

Table 1.7: Classification of network tariff codes to the customer types

Variable Code	Variable	Source
DREV0201	Revenue from residential Customers	8400/8420/8450/8470 - Residential Flat 8900/8920/8950/8970 - Residential TOU 7000/7050 - Residential Demand (retired in 1 July 2020) 9000/9020/9050/9070 - Controlled Load 1 (super economy) 9100/9120/9150/9170 - Controlled Load 2 (economy) 7300/7350 - Smart Control 3750/3770 – Residential Demand 3950/3970 – Residential Transitional Demand 6950/6970 – Residential Time of Use Energy
DREV0202	Revenue from non-residential customers not on demand tariffs	8500/8520/8550/8570 - Business Flat 8800/8820/8850/8870 - Business - TOU 6000/6020 Small Business Wide Inclining Fixed 6850/6870 - Small Business Time of Use Energy 5700/5720/5750/5770 - Small Business Primary Load Control 5800/5820/5850/5870 – Large Business Primary Load Control
DREV0203	Revenue from non-residential low voltage demand tariff customers	7100/7150 - Business Demand 8100/8170 - Demand Large 8300/8370 - Demand Small 7200/7250- LV ToU Demand 3650/3670 – Small Business Demand

Variable Code	Variable	Source
		3850/3870 – Small Business Transitional Demand
DREV0204	Revenue from non-residential high voltage demand tariff customers	1000 - (> 40 GWh pa) - ICC 3000 - (>4 GWh pa) - 11kV EG 4000 - (>4 GWh pa) - 11kV Bus 4500 - (>4 GWh pa) - 11kV Line 8000 - HV Demand (retired on 1 July 2021) 7400 - 11kV ToU Demand
DREV0205	Revenue from unmetered supplies	9500 - Watchman Lights 9600 - Unmetered Supply
DREV0206	Revenue from Other Customers	-
DREV02	Total revenue by customer class	Calculated as sum of variables above

5. Once all data was categorised, the figures were compared to the Regulatory Account totals. The key variances seen in the data were individually addressed:

   (i) For the 2020-21 regulatory year, all unmetered supplies (being public lighting, watchman lights and other unmetered supplies) were billed in a similar manner. An additional Peace report was requested which breaks down the unmetered supplies into these three areas. This allowed Unmetered Supplies (DREV0107) and Revenue from Public Lighting (DREV0112) to have the correct allocation of unmetered supplies. This does not affect RIN Table 3.1.2 as both line items from RIN Table 3.1.1 are already aggregated into Revenue from Unmetered Supplies (DREV0205).

Alternative Control Services

Figures for ACS revenue have been sourced from the general ledger based on SAP data extract FIR3027 and balanced back to the Regulatory Accounts for 2021.

All numbers are sourced from the general ledger based on SAP data extract FIR3027 and balance to the Regulatory Accounts submitted to the AER. The reported ACS revenue and its method of calculation from the source documentation is provided in

Table 1.8:

Table 1.8: ACS revenue figures and methodology

Variable Code	Variable	Source
DREV0101	Revenue from Fixed Customer Charges	Calculated as the sum of ACS revenue charged via fixed fees, using the similar information to that used for CA RIN BoP 4.3 Fee Based Services.
DREV0110	Revenue from metering charges	Sourced from the general ledger accounts based on SAP data extract FIR3027 specifically for metering as ACS. This includes: • Metering Services Charge • Special meter read • Meter alteration • Meter inspect and investigate • Meter reconfigure • Non-standard data services
DREV0111	Revenue from connection charges	Sourced from the general ledger accounts based on SAP data extract FIR3027 specifically for connections as ACS. This includes: • Real Estate Developments (or sub-divisions) • Large Customer Connections (LCCs) • Re-energisations • Customer initiated supply enhancement • Supply abolishment • Temporary connections • Connection asset rearrangements
DREV0112	Revenue from public lighting charges	Sourced from the general ledger accounts based on SAP data extract FIR3027 specifically for public lighting. This includes street lighting fixed charges, recoverable streetlighting construction and capital contributions revenue.
DREV0113	Revenue from other Sources	Calculated as the balance of ACS Revenue. It is typically for Rearrangement of Network Assets, and sale of inventory for connection assets which are Ancillary Services.
DREV01	Total revenue by chargeable quantity	Calculated as the sum of variables above.
DREV0205	Revenue from unmetered supplies	Calculated as the value for street lighting revenue stated in DREV0112.
DREV0206	Revenue from Other Customers	Calculated as the total revenue stated in DREV01 minus that stated for street lighting in DREV0112
DREV02	Total revenue by customer class	Calculated as the total revenue stated in DREV01.

Assumptions

Standard Control Services

The following assumptions were applied:

- All network tariff codes (NTCs) are assumed to be 100% attributable to each applicable line item.
- It has been assumed that all controlled load NTCs can be grouped into "Residential Customers" (DREV0201). This has been assumed because 99.4% of all instances of the controlled load NTCs also are accompanied by the residential NTC.

Alternative Control Services

No assumptions were applied.

Estimated Information

Energex has provided 'Actual Information' (as per the AER's defined term) in relation to all variables contained in this Template.

Explanatory Notes

Standard Control Services

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 and Energy Queensland. No new standards have been implemented this financial year that may impact the reported revenue figures.

The new Classification of Services applicable from this Determination period reclassified several services from ACS to SCS. The main contributors are:

- Major customer connection extensions likely to be shared in the future
- Major customer connection augmentation to the shared network

Generally, major customers are those customers who connect under the Individually Calculated Customer (ICC) and Connection Asset customer (CAC) tariff classes as per Energex's pricing proposal.

Alternative Control Services

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 and Energy Queensland.

The new Classification of Services applicable from this Determination period had a significant effect on ACS Revenue. The main contributors are:

- Some services have been reclassified from ACS to unregulated, the most significant of which is Type 6 meter data management to other electricity distributors.
- Some services have been reclassified from Unregulated to ACS, the most significant of these are sale of materials for connection assets that are gifted back to become part of the shared network, high load escorts, training to third parties for network access and security lights.

Table 3.1.3 - Revenue (penalties) Allowed (deducted) Through Incentive Schemes

Compliance with RIN Requirements

Table 1.9 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 1.9: Demonstration of Compliance (SCS)

Requirements (instructions and definitions)	Consistency with requirements
Energex must separately provide revenues received or deducted as a result of incentive schemes (RIN Table 3.1.3).	STPIS reported in RIN table 3.1.3 as per 2020-21 Pricing Proposal EBSS & CESS reported in RIN table 3.1.3 included within the smoothed revenue of the Final Decision PTRM
Total revenues for Direct Control Services will equal those reported in the Regulatory Accounting Statements (with the exception of total revenue in RIN Table 3.1.3).	All figures for SCS revenue have been reconciled to schedule 8.1 (Income) of the Regulatory Reporting Statement. The values reported reconcile to rows "Distribution revenue' and "Jurisdictional scheme amounts' in the 'Standard Control Services' column of schedule 8.1 Income.
Energex must report the penalties or rewards of incentive schemes in this table. The penalties or rewards from the schemes applied by previous jurisdictional regulators that are equivalent to the service target performance incentive scheme (STPIS) or efficiency benefit sharing scheme (EBSS) must be reported against the line items for those schemes."	Energex recognises revenues and penalties from incentive schemes.

Table 1.10: Demonstration of Compliance (ACS)

Requirements (instructions and definitions)	Consistency with requirements
Energex must separately provide revenues received or deducted as a result of incentive schemes (RIN Table 3.1.3).	Not applicable to ACS.
Total revenues for Direct Control Services will equal those reported in the Regulatory Accounting Statements (with the exception of total revenue in RIN Table 3.1.3).	Total revenue for ACS has been balanced to the Regulatory Accounts for 2021.
ACS are defined in the NER. By way of context, ACS are intended to capture distribution services provided at the request of, or for the benefit of, specific customers with regulatory oversight of prices. Where an AER determination was not in effect at the time ACS are for DNSPs located in Queensland, excluded distribution services as determined by the Queensland Competition Authority.	ACS has been reported for the year 2021.

Sources

Table 1.11: Data Sources - RIN Table 3.1.3: Revenue (penalties) allowed (deducted) through incentive schemes (SCS)

Variable Code	Variable	Unit	Source
DREV0301	EBSS	$0's	AER Final Decision Energex distribution determination 2020-25 PTRM Public June 2020

Variable Code	Variable	Unit	Source
DREV0302	STPIS	$0's	2020-21 Pricing Proposal
DREV0303	F-Factor		Not applicable
DREV0304	S-Factor True up		Not applicable
DREV0305	Other		AER Final Decision Energex distribution determination 2020-25 PTRM Public June 2020
DREV03	Total revenue of incentive schemes	$0's	

Table 1.12: Data Sources - RIN Table 3.1.3: Revenue (penalties) allowed (deducted) through incentive schemes (ACS)

Variable Code	Variable	Unit	Source
DREV0301	EBSS	$0's	Not Applicable
DREV0302	STPIS	$0's	Not Applicable
DREV0303	S-Factor	$0's	Not Applicable
DREV0304	S-Factor True up	$0's	Not Applicable
DREV0305	Other	$0's	Not Applicable
DREV03	Total revenue of incentive schemes	$0's	Not Applicable

Methodology

Revenue (penalties) allowed (deducted) through incentive schemes

- Incentive schemes do not apply to ACS and therefore no revenue or penalties have been reported.

Assumptions

The following assumptions were applied:

Standard Control Services

- STPIS as per the 2020-21 Pricing Proposal has been fully recovered in revenues collected. The STPIS reward has been calculated based on data in the TAR formula and in accordance with advice received from the AER on 16 February 2018 , to reflect underlying performance results data has been based on STPIS reward implicitly included in revenues for pricing (i.e. s factor prior to removing prior years factor impact).
- EBSS included within the smoothed revenue of the Final Decision Energex distribution determination 2020-25 PTRM has been fully recovered in revenues collected. The EBSS

penalty per the EBSS model been smoothed applying the X Factor within the Final Decision PTRM.

- Energex has populated the variable 'DREV0305 Other' with the CESS reward included in the approved 2020-21 TAR 2020-21. The CESS reward per the CESS model has been smoothed applying the X Factor within the Final Decision PTRM.

Alternative Control Services

- No assumptions were applied.

Estimated Information

Energex has provided ‘Actual Information’ (as per the AER’s defined term) in relation to all variables contained in this Template.

Explanatory Notes

Not applicable.

BoP – 3.2 Opex

Table 3.2.1 - Current OPEX Categories and Cost Allocations

Table 3.2.2 - OPEX Consistency - Current Cost Allocation Approach

Compliance with RIN Requirements

Table 1.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 2.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must report opex in accordance with the categories that they reported in response to their Annual Reporting Requirements.	Energex has reported opex in accordance with the categories reported in response to the Annual Reporting Requirements as detailed in RIN tables 3.2.1 and 3.2.2.
Opex in table 3.2.1 must be prepared for all Regulatory Years in accordance with Energex's Cost Allocation Approach and directions within the Annual Reporting Requirements for the most recent completed Regulatory Year. For years where the Cost Allocation Approach and Regulatory Accounting Statements are consistent with those that applied in the most recent completed Regulatory year, total opex should equal that reported in the Regulatory Accounting Statements.	The opex amounts in RIN table 3.2.1 have been prepared in accordance with Energex's Cost Allocation Approach and directions within the Annual Reporting Requirements. Total opex equals that reported in the Annual Reporting RIN.
For table 3.2.2 Energex must report opex in accordance with the AER Variables and the Cost Allocation Approaches and reporting framework applied in the relevant Regulatory Years.	Energex has reported opex in the categories as defined in the AER EB RIN in accordance with its current Cost Allocation Approach. Total opex for SCS in this table aligns with that in the Annual Reporting RIN.

Sources

Table 2. and Table 2. below demonstrate the sources from which Energex obtained the required information:

Table 2.2: Data Sources - RIN Table 3.2.1 Current Opex categories and cost allocations

Variable Code	Variable	Unit	Source
DOPEX0101-14	Individual opex categories	$0's	Annual Reporting RIN
DOPEX01	Total opex	$0's	Annual Reporting RIN

Table 2.3: Data Sources - RIN table 3.2.2: Opex consistency - current cost allocation approach

Variable Code	Variable	Unit	Source
DOPEX0201	Opex for network services	$0's	Annual Reporting RIN
DOPEX0202	Opex for metering	$0's	Annual Reporting RIN Annual Reporting RIN, Ellipse POW022, FIN077

Variable Code	Variable	Unit	Source
DOPEX0203	Opex for connection services	$0's	Annual Reporting RIN Ellipse POW022
DOPEX0204	Opex for public lighting	$0's	Annual Reporting RIN
DOPEX0205	Opex for amounts payable for easement levy or similar direct charges on DNSP	$0's	Not applicable
DOPEX0206	Opex for transmission connection point planning	$0's	Not applicable

Methodology

Separate methodologies were applied for each table within the opex worksheet. The methodologies stated in this basis of preparation relate to both SCS and ACS.

RIN Table 3.2.1 Current Opex categories and cost allocations

- RIN Table 3.2.1 requires opex be stated on the basis of the current Cost Allocation Approach. The opex amounts in RIN table 3.2.1 have been prepared in accordance with Energex's Cost Allocation Approach and directions within the Annual Reporting Requirements. Total opex equals that reported in the Annual Reporting RIN.

RIN Table 3.2.2 Opex consistency - current cost allocation approach

- The opex consistency table based on the current CAM (table 3.2.2) has been based on the values stated in RIN Table 3.2.1 Current opex categories and cost allocations.
- RIN Table 3.2.1 balances to RIN Table 3.2.2 for SCS only. ACS will not balance between the two tables as RIN Table 3.2.2 does not include Ancillary Network Services which are reported in RIN Table 3.2.1.

$$\begin{aligned}\text{SCS Opex for Metering} \\ &= \text{Data retrieval communication costs for network meters} \\ &+ \text{Meter data provision services for meters located at substation}\end{aligned}$$

DOPEX0201 - Opex for network services

- Network services are defined in the EB RIN Instructions and Definitions as "a subset of Standard Control Services that excludes Connection Services, Metering services, Fee Based and Quoted Services and Public Lighting Services". Based on this definition the value for "DOPEX0201 - Opex for network services" has been calculated as the total opex value stated in RIN Table 3.2.1 minus the values for:
  - DOPEX0202 - Opex for metering
  - DOPEX0203 - Opex for connection services
  - DOPEX0204 - Opex for public lighting

DOPEX0202 - Opex for metering

- The formula used for calculating SCS Opex for Metering is stated below:
    - The data retrieval communication costs associated with Network meters for power quality purposes were extracted from Ellipse report FIN077.
    - Expenditure for meter data provision services for meters that are attached to Energex's network and used for network monitoring purposes, were extracted from Ellipse report POW022.
- ACS pex for Metering - Total ACS Opex for Metering is taken directly from the Annual Reporting RIN.

DOPEX0203 - Opex for connection services

- The amount for SCS "DOPEX0203 - Opex for connection services" is extracted from the POW022 report. This is for opex incurred on overhead service line inspection program.
- The amount for ACS "DOPEX0203 - Opex for connection services" is taken directly from the Annual Reporting RIN.

DOPEX0204 - Opex for public lighting

- The amount for ACS "DOPEX0204 - Opex for public lighting"" is taken directly from the Annual Reporting RIN.

DOPEX0205 - Opex for amounts payable for easement levy or similar direct charges on DNSP

- The amount for DOPEX0205 is zero as Energex does not pay any easement levies.

DOPEX0206 - Opex for transmission connection point planning

- The amount for DOPEX0206 is zero as Energex does not have any opex attributable to opex for transmission connection point planning.

Assumptions

No assumptions were applied.

Estimated Information

Energex has provided 'Actual Information' (as per the AER's defined term) for 2020-21 in relation to all variables.

Explanatory Notes

RIN Table 3.2.1 Current Opex categories and cost allocations

The following explanations are provided in relation to RIN Table 3.2.1 Current Opex categories and cost allocations:

- Other network maintenance costs (DOPEX0106) represent maintenance costs for Public Lighting.

The following explanations are provided for the material variances for SCS:

- DOPEX0104 Vegetation - Variability of vegetation growth as relates to rainfall/weather. Also reflective of ongoing improvements to vegetation program including efficiencies realised through Energy Queensland Limited (EQL) vegetation management contract.
- DOPEX0105 Emergency response/storms - Attributed to variability of the impact of major events including severe thunderstorms.
- DOPEX0108 Network billing and other energy market services – Customer Market Transaction team has undergone a restructure and also impacted by changes to functional mix as well as FTE numbers.
- DOPEX0109 Customer services (incl call centre) - Customer Operations team has undergone a restructure and also impacted by changes to functional mix as well as FTE numbers.
- DOPEX0112 Debt Raising - Following the transfer of ownership of Ergon and Energex from the state to Energy Queensland Limited (EQL) on the 30 June 2016, transfers of debt for both DNSPs were made in order to comply with the Government Owned Corporations Regulation 2016 (Regulation).
    - The share of the State Government debt pool held by the DNSPs prior to the formation of the group was a liability held by each DNSP. In accordance with the Regulation, all DNSP debt (Queensland Treasury Corporation Loans) was transferred back to the Government debt pool. It was then transferred to the parent entity (EQL) at the carrying amount, such that: A share of Queensland debt is held in the EQL parent entity. In 2021 a portion of QTC admin fees were representative of debt raising costs and these costs were allocated between the DNSPs based on their underlying PPE balances. Energex has therefore recognised its share of Debt raising costs this year.
- DOPEX0114 Corporate allocations – 2021 included an allocation of SCS costs from EQLD to Energex as a result of the new Cost Allocation Method being adopted in SAP. Part of this allocation includes corporate restructuring costs. This was previously included in Other operating costs in 2020.

Table 3.2.4 - OPEX for High Voltage Customers

Compliance with the RIN Requirements

Table 2. below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 2.4: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must report the amount of opex that it would have incurred had it been responsible for operating and maintaining the electricity Distribution Transformers that are owned by its high voltage customers. Where Actual Information is unavailable, this must be estimated based on the opex Energex incurred for operating similar MVA capacity Distribution Transformers within its own network. Where the MVA capacity of high voltage customer-owned Distribution Transformers is not known, it must be approximated by the observed Maximum Demand for that customer.	Energex is not required to, and as a result does not, keep any records relating to electricity distribution transformers which are owned by its high voltage customers. As such, for reporting purposes, Energex has estimated the opex which would otherwise have been expensed, had the company been responsible for their maintenance. The estimate of this avoided cost is derived applying a formula using reported information in the Category Analysis and Economic Benchmarking RINs.

Sources

Table 2. below demonstrates the sources from which Energex obtained the required information. Because the reported figure is derived from figures reported in alternate templates in the Category Analysis (CA) and Economic Benchmarking (EB) RINs, the underlying data sources for each input field should also be considered when reviewing this figure.

Table 2.5: Data Sources - RIN Table 3.2.1 Current Opex categories and cost allocations

Variable Code	Variable	Unit	Source
DOPEX0401	Opex for high voltage customers	$000's	Category Analysis Maintenance template 2.8: Table 2.8.2 - Routine and Non-Routine Maintenance for distribution substation equipment and property maintenance, (all subcategories) Economic Benchmarking Analysis: Template 3.5, table 3.5.2.1, variables DPA0501, DPA0502, DPA0503

Methodology

Opex in RIN table 3.2.4 was estimated by first establishing a per MVA maintenance unit rate cost for distribution transformers and then multiplying this by the EB RIN reported distribution transformer capacity owned by High Voltage Customers to approximate the maintenance costs incurred by HV customers.

$$\left[\frac{\text{CA RIN Table 2.8.2 combined sum of routine and non-routine maintenance for Distribution substation equipment \& property maintenance (all subcategories)}}{\text{(EB RIN template 3.5 Physical Assets variable DPA0501 - variable DPA0503)}}\right] \times \text{EB RIN template 3.5 Physical assets, table 3.5.2, variable DPA0502}$$

Assumptions

No assumptions were applied.

Estimated Information

Opex for High voltage customers where Energex does not own the distribution transformer is not measured by Energex and is, therefore, inherently estimated.

Explanatory Notes

The method utilised to calculate the estimated Opex for HV Customers has been updated this year. The approach used is considered a best estimate as it uses known per MVA maintenance operating costs for distribution transformers owned by Energex to approximate the costs that might have been incurred if transformers owned by HV customers where operated by Energex.

BoP – 3.2.3 Provisions

Table 3.2.3 - Provisions

Compliance with RIN Requirements

Table 1.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 3.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must report, for all Regulatory Years, financial information on provisions for Standard Control Services in accordance with the requirements of the Cost Allocation Approach and the Regulatory Accounting Statements that were in effect for the relevant Regulatory Year. Provisions must be reported in accordance with the principles and policies within the Annual Reporting Requirements for each Regulatory Year.	Energex has reported financial information on provisions for Standard Control Services. Provisions are allocated to services based on Property, Plant & Equipment (PP&E) balances, consistent with the methodology applied in previous year RINs to apportion balance sheet items among services. The provision amount attributed to SCS is based on the proportion of SCS PP&E to total PP&E.
Financial information on provisions should reconcile to the reported amounts for provisions in the Regulatory Accounting Statements for each Regulatory Year.	Provisions which are charged to indirect expenditure are apportioned to opex and capex components for the EB RIN based on the overhead allocation ratio, sourced from the supporting workings for the AR RIN.

Sources

Reporting for all provisions is based on the 2021 Financial Statements and AR RIN workings. Data extracted from the FIC3018 SAP Regulatory model was used to determine capex/opex splits.

Methodology

Methodology for the provisions reporting is detailed below.

- Provisions are allocated to services based on PP&E balances. Allocation of opening balances is based on the closing PP&E balances of the prior regulatory year. The current regulatory year movements and the closing balances are allocated based on the closing PP&E balances of the current regulatory year.
- Provisions typically relate to opex, capex or indirect expenditure. When provisions are charged to indirect expenditure, they are allocated to opex and capex through the overhead allocation process. Therefore, provisions that are charged to indirect expenditure are apportioned to opex and capex components for the EB RIN based on the overhead allocation ratio for the relevant year, sourced from the supporting workings for the AP RIN. This is

reported as actual information since the overhead allocation to capex and opex is based on the AER approved CAM (Cost Allocation Method) and sourced from the General Ledger.

- The Provision for Employee Benefits is allocated to opex and capex based on labour deployment balances sourced from the General Ledger. Therefore, it is also reported as actual information.
- Table 3. provides background on each of the provisions

Table 3.2: Capex and Opex apportionment for each of the Provisions (SCS)

Variable Code	Variable	Capex and Opex Components
DOPEX03A	Provision for Site Restoration	Charged to indirect expenditure and allocated to opex and capex through overhead allocations.
DOPEX03B	Provision for Public Liability Insurance	Charged to indirect expenditure and allocated to opex and capex through overhead allocations.
DOPEX03C	Provision for Employee Benefits	Charged to indirect expenditure and allocated to opex and capex through Energex labour costing processes. Energex uses a standard costing method to apply labour costs to activities. Labour costing entries are processed to standard indirect expense accounts. At the end of the month the wages paid/wages costed balances in the corporate Income statement are transferred to the Labour costing over/under recoveries balance sheet account. The balance of this account represents the total year-to-date variance between labour costed and wages paid. At the end of the financial year, the balance of the Labour Costing Over/Under Recoveries Account in the balance sheet is cleared and distributed across the divisions and spread over operating and capital costs based on labour deployment balances from the General Ledger. The "increase during the period in the discounted amount arising from the passage of time and the effect of any change in the discount rate" is disclosed as part of finance charges in the statutory financial statements. For the EB RIN reporting purposes, this amount is multiplied by the PP&E allocation rate and the opex/capex allocation rate based on labour deployment balance from the General Ledger. The amount for leave entitlements is the accrued leave balance per payroll records plus on-costs such as payroll tax, superannuation and workers' compensation. As discussed with the AER, on 1 July 2018, employees of the distribution network service providers Ergon Energy and Energex were transferred to Energy Queensland Limited (EQL) as the parent entity of the Energy Queensland Limited corporate group. EQL has entered into the Service agreement with Ergon Energy and Energex which effectively provides Energex and Ergon with a labour resource and this is subject to the direction and management of the DNSPs, although paid from EQL. Therefore, employee related provisions no longer reside with the DNSPs - they reside with EQL. Balance sheet balances were transferred to EQL on 30 June 2019 but movements associated with each DNSP's labour resource can be determined and have been reported in this template.

Variable Code	Variable	Capex and Opex Components
		The closing balance of employee related provisions is therefore zero. The transfer to EQLD is reflected in 'unused amounts reversed during the period - other component'. It is noted that movement in provisions is reflective of EQL employees whose payroll was processed in the Energex/Ergon ERP system. The movement in the EQL provisions (which represents employees whose payroll was processed in the EQL ERP system) has been apportioned between the two DNSPs on a 50/50 basis in line with how EQL costs were allocated to the DNSPs.
DOPEX03D	Provision for Redundancy	Charged to other support cost directly, therefore 100% allocated to opex. As noted in provisions for employee benefits, the redundancy provision has also been transferred to EQL and movements are reported on the same basis as noted above.
DOPEX030E	Provision for Environmental Offsets	Charged to capital projects directly, therefore 100% allocated to Capex.
DOPEX03F	Provision for Overpaid Network Charges to be Refunded	Neither opex nor capex. This is related to revenue billings and has been reported in the EB RIN under Other Component.

Assumptions

The difference in PP&E allocation percentages between the current regulatory year and prior regulatory year is treated as follows:

- adjustments that resulted in increased provisions are assumed to be additions to provisions; and
- adjustments that resulted in decreased provisions are assumed to be unused amounts reversed.

Estimated Information

Energex has provided 'Actual Information' (as per the AER's defined term) in relation to all variables contained in this BoP.

Explanatory Notes

The following explanations are provided in relation to provisions:

- Provision for Site Restoration (DOPEX0301A - DOPEX0314A) - The demolition and remedial work required on the ex-depot site at Banyo was substantially completed in previous years along with further earth works, soil testing and certifications required for compliance with environmental regulations. Minor costs have been incurred in 2020-21 and a small provision balance remains to cover unforeseen costs remaining due to disputes with a contractor. This provision also includes costs anticipated to "make-good" leased premises on expiration of property leases in the future, showing movements in the current year for utilisation for premises exited, reversals where no longer required and increases for new estimates as applicable.

- Provision for Employee Benefits (DOPEX0301C - DOPEX0314C) - Overall, the employee benefit provisions increased slightly from the prior year. The balance of these provisions have been transferred to EQL as noted above but movements have been reflected within the DNSPs.
- Provision for Redundancy (DOPEX0301D - DOPEX0314D) - The redundancy provision was utilised during the current year and is now raised at the parent EQL level as noted above. The amounts disclosed represent Energex's share.
- Provision for Overpaid Network Charges to be Refunded (DOPEX0301F -DOPEX0314F) - Provision was raised for refunds to customers for overpaid network charges. No changes to this estimate have been made during 2020-21.

BoP – 3.3 Assets (RAB)

Table 3.3.1 - Regulatory Asset Base Values

Table 3.3.2 - Asset Value Roll Forward

Table 3.3.3 - Total Disaggregated RAB Asset Values

Compliance with RIN Requirements

Energex confirms, as required by the AER in Box 7, *Assets (RAB) Financial Reporting Framework* in Appendix B, Instructions and Definitions, that:

RAB financial information (capex, disposals, and inflation) for SCS and ACS reconciles to decisions the AER has made in relation to RAB values for these services in the 2020-25 Energex Final Determination; and

Where forecast values (additions and disposals) were used in relation to a decision on RAB values these amounts have been replaced with actual values which reconcile to amounts reported in the Annual Performance RIN for 2020-21.

A reconciliation between the opening balance for 2020-21 and the opening balance provided in the Final Decision – Energex Distribution Determination 2020-2025 PTRM is detailed in the table below.

Table 4.1: Reconciliation of EB RIN Opening Balance to Final Decision PTRM Opening Balance

Table: Reconciliation EB RIN Opening Balance to Final Decision Distribution Determination PTRM Opening Balance							
Asset Class ($M)	EB RIN 2019-20 CB (A)	Less Actual 19-20 (B)	Plus Forecast 19-20 (C)	Plus FY Rev Adj (D)	Plus FY Adj (E)	AER PTRM OB (F)	EB RIN 2020-21 OB (G)
Overhead Network Assets less than 33kV	2,785.18	(121.07)	145.18	0.00	-	2,809.29	2,785.18
Underground Network Assets less than 33kV	2,418.06	(15.66)	60.25	0.00	-	2,462.65	2,418.07
Distribution Substations and Transformers	1,923.88	(118.48)	95.23	0.00	-	1,900.64	1,923.88
Overhead Network Assets 33kV and Above	653.43	(37.94)	16.80	0.00	-	632.30	653.43
Underground Network Assets 33kV and Above	850.45	(12.76)	10.59	0.00	-	848.27	850.45
Zone Substations and Transformers	3,020.70	(58.25)	73.18	0.00	-	3,035.64	3,020.71

Easements	182.01	(0.35)	1.08	0.00	-	182.75	182.01
Meters	72.35	(1.63)	9.54	0.00	-	80.25	72.35
Other Assets with Long Lives	740.39	(74.13)	32.44	0.00	-	698.69	740.39
Other Assets with Short Lives	115.42	(37.12)	24.81	(0.00)	120.95	224.06	236.36
Total	12,761.87	(477.39)	469.09	0.01	120.95	12,874.54	12,882.83
Notes							
(G) EB RIN 2020-21 OB = A + D + E							
(F) AER PTRM 20-21 OB = A - B + C + D + E							

Energex has adopted the *Standard Approach*, with *Direct Attribution to the AER's economic benchmarking RAB Asset Classes*, as described in section 4.1.1 of Appendix B, Instructions and Definitions. The mapping of the 27 disaggregated asset classes in the SCS RFM to the specified 10 asset categories of the EB RIN is detailed in the table below.

Table 4.2: RAB EB RIN Asset category definitions and mapping of EB RIN asset categories to annual RIN categories

EB RIN Asset Category	Definition	Mapped Energex Annual RIN Categories
Overhead network assets less than 33 kV (wires and poles)	Assets used to conduct electricity from one point to another above ground. These include poles, pole-top structures and overhead conductors. This does not include pole top substations and transformers.	Overhead Distribution Lines Low Voltage Services
Underground network assets less than 33 kV (cables)	Assets used to conduct electricity from one point to another below ground. This includes cables, cable joints and other assets used to connect the underground network to the overhead system. This does not include underground substations and transformers.	Underground Distribution Cables
Distribution substations including transformers	Overhead and underground distribution substations. This includes ground mounted substations and pole mounted substations. This does not include zone substations.	Distribution Equipment Distribution Transformers
Overhead network assets 33 kV and above (wires and poles)	Assets used to conduct electricity from one point to another above ground. These include poles, pole-top structures and overhead conductors. This does not include pole top substations and transformers.	Overhead Sub-Transmission Lines

Underground network assets 33 kV and above (cables)	Assets used to conduct electricity from one point to another below ground. This includes cables, cable joints and other assets used to connect the underground network to the overhead system. This does not include underground substations and transformers.	Underground Sub-Transmission Cables
Zone substations and transformers	Sites housing transformers involved in transforming power from high voltage input supply either directly from a TNSP or from Energex's own higher voltage lines - to distribution level voltages (e.g. 66 kV to 22 kV). This transformation can involve one step or multiple steps.	Substation Bays Substation Establishment Zone Transformers Distribution Substation Switchgear Buildings (System) Land (System)
Easements	An electricity easement is the right held by Energex to control the use of land near aboveground and underground power lines and substations. It holds this right to ensure the landowner's safety and to allow staff access to work on the power lines at all times.	Easements (System)
Meters	An electricity meter is a device that measures the amount of electric energy consumed by a residence, business, or an electrically powered device	Metering
Other assets with long lives	Assets with expected asset lives greater than or equal to 10 years that are not: 1. Overhead Distribution Assets (Wires and Poles) 2. Underground Distribution Assets (Cables) 3. Distribution Substations Including Transformers 4. Zone Substations and Transformers 5. Easements 6. Meters	Communications Pilot Wires Street Lighting Control Centre - SCADA Buildings Land Buildings – Capital Works Equity Raising Costs
Other assets with short lives	Assets with expected asset lives less than 10 years that are not: 1. Overhead Distribution Assets (Wires And Poles) 2. Underground Distribution Assets (Cables) 3. Distribution Substations Including Transformers 4. Zone Substations and Transformers 5. Easements 6. Meters	Communications IT Systems Office Equipment & Furniture Motor Vehicles Plant & Equipment In-house software

RAB values for each of the RAB Asset categories are exclusive of Capital Contributions.

Energex currently does not own, control or operate any Dual Function Assets.

In accordance with the instructions and definitions, Energex has only included RAB values for those services where the AER has approved a RAB or RAB equivalent. Therefore, for ACS, Energex has only reported RAB assets that provide ACS Street lighting Services and Type 5-6 Metering Services, consistent with the classification of service, and the RAB that was approved for these categories of service in Energex's 2020-25 Distribution Determination. No RABs have been approved for any of Energex's other categories of ACS (Quoted and Fee Based Services).

Asset Value Roll Forward - Network Services

Energex has prepared the information for the Network Services RAB in accordance with the definition of Network Services set out in Appendix B, Instructions and Definitions. Further detail on how the information provided by Energex is consistent with the requirements and definitions of Network Services is discussed below.

Total disaggregated RAB asset values

The value reported for the total disaggregated RAB asset values in table 3.3.3 for each respective asset category is derived as the average of the opening value and closing value reported in table 3.3.2. As the RAB values for each of the asset categories in template 3.3 are exclusive of capital contributions a zero value has been reported in line item DRAB13.

For the purposes of the EB RIN, data has been treated as actual information for the following reasons:

- The AER has determined the closing RAB values for 2019-20 in its Final Decision; and
- 2020-21 values are based on actual information from the AR RIN, with the exception of forecast depreciation for SCS which has been determined from the SCS RFM approved in the Final Decision.

Therefore, the data 'is not contingent on judgements and/or assumptions for which there are valid alternatives, which could lead to a materially different presentation', as per the definition of 'Actual Information' in the AER's EB RIN Instructions and Definitions.

Sources

Asset Value Roll Forward - SCS and ACS

- For 2020-21, annual SCS and ACS (street lighting and Type 5-6 metering) financial information (additions, disposals and capital contributions) are sourced from the 2020-21 AER Annual Reporting RIN provided by Energex to the AER. Capex recognised in the SCS RAB and therefore reported in the T3.3 RIN Template is exclusive of capital contributions. Other inputs to the RFM have been sourced as follows:
    - Forecast Depreciation – From the Final Decision – Energex Distribution Determination 2020-25 PTRM
    - CPI information – From the Australian Bureau of Statistics (ABS) data series (eight capital cities December to December)

  - WACC – From AER – Energex distribution determination 2020-2025 PTRM 2021-22 ROD Update
- The closing RAB values for each year from 1 July 2020 onwards will not align with the closing RAB values calculated each year in the AER's 2020-25 RFM. This is because the AER's 2020-25 RFM recognises actual 2019-20 additions and disposals for the first time at the end of 2024-25, whereas in the T3.3 RIN template the actual 2019-20 additions and disposals is recognised in the year in which it is incurred, and rolled forward through to 1 July 2020.

Asset Value Roll Forward - Network Services

- As defined by the AER for the purposes of the Economic Benchmarking RIN, Network Services are a subset of SCS excluding Connection Services, Type 5-7 Metering Services, Fee Based and Quoted Services and Street Lighting Services. Consistent with the AER's definition of Network Services it is also necessary to exclude capital contributions (cash and in-kind.
- Network Services data is derived from SCS data. Energex has established General Ledger activities within the corporate system to specifically report capital expenditure (capex) relating to connection services, in addition to ACS public lighting, connection, metering and ancillary network services. Capex relating to NS can then be derived by deducting connection services capex from the total SCS capex and mapped to the asset categories required by the EB RIN.
- Connections expenditure includes:
  - New shared network assets for Standard Asset Customers;
  - New dedicated connection assets for Standard Asset Customers; and
  - Testing and commissioning of all new shared network assets and connection assets for Standard Asset Customers only.

It explicitly excludes metering expenditure, connection expenditure for real estate developers and design, construction, test and commission costs for large commercial and industrial customers.

- Consistent with the SCS RAB values reported in the T3.3. RIN Template, the reported actual SCS additions used in calculating the Network Services net capex for the 2020-21 regulatory year are consistent with the SCS values in the 2020-21 Annual Reporting RIN, adjusted for movements in provisions.
- Actual additions, disposals and capital contributions for 2020-21 associated with Type 5-6 Metering Services (to be removed from SCS data and hence Network Services data) are sourced from Energex's 2020-21 Annual Reporting RIN templates.
- No adjustment is necessary in relation to Street Lighting, Fee Based and Quoted Services since this expenditure is already excluded from the SCS data (and hence Network Services data).

- For 2020-21, the value of capital contributions (gifted assets and cash contributions) is sourced from the 2020-21 Annual Reporting RIN.

Total disaggregated RAB asset values

Data used to populate this table was extracted from the 2020-21 AER Annual Reporting RIN lodged by Energex to the AER.

Methodology

Asset Value

- Energex has derived the SCS RAB values for EB RIN BoP 3.3 by rolling forward the approved RFM from the AER's Final Decision, and updating for actual 2020-21 information from the AR RIN (capex and disposals), actual CPI, updated WACC and forecast depreciation. Each RAB asset category in the RFM has been rolled up into the EB RIN asset categories using the mapping provided in Table 2.
- An RFM for Network Services (NS) was constructed from the RFM for SCS using historical RAB values, actual capex, actual disposals and actual CPI and forecast depreciation that has been adjusted to remove connection assets values.
- An RFM for ACS was constructed from the Public Lighting and Metering RFMs from the AER's Final Decision, updated to include the actual capex, disposals, CPI and depreciation and updated WACC for 2020-21.

Standard Control Services (Steps 1 – 4)

1. The RFM was based on the Final Decision – Energex Distribution Determination 2020-2025. The RFM starts with the closing RAB values for the 2019-20 regulatory year adjusted for actuals and includes these values as the Opening Asset Value.
2. Data for 2020-21 was sourced from the AR RIN and depreciation from the Final Decision – Energex Distribution Determination 2020-2025 PTRM. Consistent with the Final Decision RFM, total capitalised provision movement has been deducted from the actual capex of each asset category proportionately. Capital contributions are excluded from the RAB. As a result, capital contributions have been excluded from capex in the input sheet of the RAB RFM and the variable DRAB13 is reported as nil.
3. Using the input values in step 2) above, the RFM calculates the following for each asset category for regulatory year 2020-21:
    a. Nominal Opening Regulated Asset Base – The opening balance reflects the 2019-20 closing Regulated Asset Base amended for:

i. Final year revenue adjustments for any variances between forecast and actual capex of the last year of the previous control period
ii. Asset adjustments

b. Nominal Actual Inflation on Opening RAB. Calculated as the Nominal Opening Regulated Asset Base multiplied by CPI. A manual adjustment is made to this value to reflect the fact that no adjustment is factored into the revenue adjustment for inflation on opening balance due to differences in forecast and actual capex for the last year.
c. Nominal Forecast Straight-line Depreciation Extracted from the Final Decision PTRM.
d. Nominal Actual Gross Capex. Calculated as the actual real term capex with half WACC adjustment and adjusted by actual CPI (1 year lagged). Capex is adjusted for movement in provisions relating to capex.
e. Nominal Actual Disposal. Calculated as the actual real term disposals with half WACC adjustment and adjusted by actual CPI (1 year lagged).

4. The values calculated in step 3) above then form the variables stated in EB RIN tables 3.3.1, 3.3.2 and 3.3.3. Table 3.3.1 contains the aggregated RAB values, Table 3.3.2 disaggregates these values into each asset category specified in the EB RIN and Table 3.3.3 contains the yearly average RAB value of the disaggregated asset categories.

EB RIN Table 3.3.1 - Regulatory Asset Base Values

Aggregated RAB values

- Opening value - Nominal Opening Regulated Asset Base
- Inflation addition - Nominal Actual Inflation Opening RAB
- Straight line depreciation - Nominal Forecast Straight-line Depreciation
- Actual additions (recognised in RAB) - Nominal Actual Gross Capex
- Disposals - Nominal Actual Disposal
- Closing value for asset value - Nominal Opening Regulated Asset Base (for next regulatory year).

EB RIN Table 3.3.2 - Asset Value Roll Forward

RIN Table 3.3.2 disaggregates each of the values in RIN Table 3.3.1 into the individual asset categories specified in the EB RIN. These EB RIN asset categories are made up of one or more asset categories from the RFM. For the mapping of these refer to Table 2.

EB RIN Table 3.3.3 - Total disaggregated RAB asset values

EB RIN Table 3.3.3 - Total disaggregated RAB asset values are calculated as the average of the opening and closing RAB totals for each EB RIN asset category for each year by applying the formula below.

$$Total\ Disaggreated\ RAB\ asset\ value_{y1} = \frac{Opening\ Value_{y1} + Closing\ Value_{y1}}{2}$$

Network Services (NS)

Network Services (NS) are a subset of Standard Control Services that excludes Connection Services, Metering services, Fee Based and Quoted Services and Public Lighting Services. Accordingly, the NS RFM is identical to SCS in its construction and calculation; however, the inputs are adjusted for the following:

- The RFM opening values were adjusted to include only those values relating to NS. Where a respective asset category was identified as not to incorporate connection services and the balance did not reflect the SCS balance the network asset service category was adjusted to align with the reported SCS balance.
- The capex relating to connection assets was deducted from the capex in the SCS RFM to derive the NS values. The capitalised provision movement allocated to each asset category for SCS has been allocated to NS based on the proportion of NS capex to SCS capex for that asset category.
- The value of disposals for NS is taken to be the same as the SCS asset categories as connection asset disposals are not considered material.

Alternative Control Services

- From 1 July 2015, Energex's ACS includes public lighting, connection, metering and ancillary network services. As the AER only approved a RAB for public lighting and metering services, only assets relating to these services are included and reported in the EB RIN Assets BoP for ACS, consistent with the EB RIN Instructions and Definitions.
- CPI and WACC are based on those used for the SCS.
- Capex for ACS was sourced directly from the AR RIN and/or supporting workings.

Assumptions

No assumptions were made.

Estimated Information

Energex has provided 'Actual Information' (as per the AER's defined term) in relation to all variables contained in this BoP.

Explanatory Notes

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 Committee and implemented where required and the associated Energex accounting policies are updated accordingly.

There are no material impacts from changes in accounting standards for the 2021 financial year, and subsequently no accounting policy changes that may impact the RIN.

Table 3.3.4 - Asset Lives (estimated Residual Service Life)

Table 3.3.4 - Asset Lives (estimated Service Life of New Assets)

Compliance with the RIN Requirements

The AER requires Energex to report asset life information in accordance with the asset categories defined in the EB RIN BoPs. The definitions of these asset categories can be found in BoP 3.3.1 Asset (RAB) Values.

The table below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 4.3: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
New assets are assets installed in the most recent regulatory reporting year. The expected service life of new assets is the estimated period after installation of a new asset during which the asset will be capable of delivering the same effective service as it could at its installation date. This may not align with the asset's financial or tax life.	Energex has reported the service life of new assets in the RAB based on the RAB RFM from the AER's Final Decision: Energex determination 2020-21 to 2024-25. This represents the estimated time during which the asset is capable of delivering the same effective service as it could at installation date.
Energex must report a current estimation of the weighted average remaining time expected that an asset class (as per DRAB1401 to DRAB1409) will deliver the same effective service as that asset class did at its installation date.	Energex has reported the estimated residual service life of all RAB asset categories as the weighted average of all assets contained in that category. Similar to the estimated service lives, these figures are based on the Final Decision. All weighted averages have been calculated on the assets' share of the RAB and their expected asset lives. Energex has also divided asset life data into NS, SCS and ACS. This was done in line with the methodology outlined for RAB values.

Sources

Asset life data has been sourced from the RFMs from the AER's Final Decision. Additional inputs have been sourced as follows:

- CPI information - Sourced from the Australian Bureau of Statistics (ABS) data series A2325846C (eight capital cities from December to December) in line with the AER approach and regulatory reporting;
- Capex and disposals - Sourced from the Annual Performance (AP) RIN; and
- WACC - Sourced from the Final Decision, updated for the return on debt component of the WACC every April in line with the AER guidance.

The table below demonstrate the sources from which Energex obtained the required information.

Table 4.4: Data Sources RIN Table 3.3.4.1 asset lives: estimated service life of new assets

Variable Code	Variable	Source
DRAB1501	Overhead network assets less than 33kV (wires and poles)	Final Decision, AR RIN, ABS
DRAB1502	Underground network assets less than 33kV (cables)	Final Decision, AR RIN, ABS
DRAB1503	Distribution substations including transformers	Final Decision, AR RIN, ABS
DRAB1504	Overhead network assets 33kV and above (wires and towers/poles etc.)	Final Decision, AR RIN, ABS
DRAB1505	Underground network assets 33kV and above (cables, ducts etc.)	Final Decision, AR RIN, ABS
DRAB1506	Zone substations and transformers	Final Decision, AR RIN, ABS
DRAB1507	Meters	Final Decision, AR RIN, ABS
DRAB1508	"Other" assets with long lives	Final Decision, AR RIN, ABS
DRAB1509	"Other" assets with short lives	Final Decision, AR RIN, ABS

Methodology

Asset Lives

Energex has calculated the expected service life of new assets and the residual service life of assets based on the RFMs from the Final Decision. These RFMs were updated for the 2019 actual information (capex and asset disposals) from the AR RIN.

Standard Control Services

- The estimated service life of new assets was calculated using the standard service life published in the Final Decision RFM. This service life was applied to 2021. The asset life categories in the RFM were then aggregated into the categories required for the EB RIN. The aggregation used a weighted average of each of the applicable asset categories, weighted by their 2020 closing RAB value. For the mapping of the Final Decision RFM asset categories to the EB RIN categories refer to BoP 3.3.1 Asset (RAB) Values.
- The residual service life of RAB assets was calculated applying the remaining life calculation in the AER RFM. The calculation applies estimated standard lives for additions and residual lives of existing assets. This BoP relies on information calculated in the RAB RFM for SCS, ACS and NS, as detailed in Basis of Preparation for Asset (RAB) Values. The RFM extracts the following information for each asset category and regulatory year:
    - Standard Asset Life;
    - Opening RAB Value (2020);

  - Opening RAB Residual Asset Life (2020);
  - Acquisitions (assumed average mid-year capitalisation and adjusted for half year WACC);
  - Disposals (assumed average mid-year disposal and adjusted for half year WACC);
  - Depreciation; and
  - Adjustments (adjustments made in 2019-20 for the difference between actual and forecast capex for 2015).
- The average residual life for each asset class is calculated by rolling forward the RAB values from the prior year. This is calculated as the weighted average of:
- The prior year's average residual life minus one; and
- The standard life of any new acquisitions.
- The weightings are based on the RAB value of the current year's assets (prior year RAB minus disposals, depreciation and applicable adjustments) and the newly acquired assets.
- With the residual average asset lives calculated for each regulatory year, the asset categories are then combined into the EB RIN asset categories. The EB RIN residual asset life is calculated for each year as the average of the RFM asset lives weighted by the yearly RAB value of each RFM asset category. The mapping of the RFM asset categories to the EB RIN asset categories can be found in BoP 3.3.1 Asset (RAB) Values.

Network Services

NS are defined as a subset of SCS. NS are identical to SCS with the exclusion of those assets specified by the AER in the definition of Network Services contained in the Instructions and Definitions for the EB RIN (e.g. Connection assets). For details of the construction of the NS RAB values refer to Basis of Preparation for Asset (RAB) Value.

The Asset Life calculation for NS was constructed in an identical manner to that for SCS however it draws its data from the NS RAB. The methodology for preparing the estimated service life of new assets and the residual service life of RAB assets is identical to the process outlined above for SCS.

Alternative Control Services

From 1 July 2015, Energex's ACS includes public lighting, connection, metering and ancillary network services. As the AER only developed a RAB for public lighting and metering services based on the limited building block approach, only these services are included in the RFM, consistent with the EB RIN Instructions and Definitions.

The methodology of calculating the estimated service life and residual service life was identical to SCS and NS.

Assumptions

Standard service life of RAB assets is constant and equal to those specified in the Final Decision.

Estimated Information

Energex has provided 'Actual Information' (as per the AER's defined term) in relation to all variables contained in this BoP.

Explanatory Notes

EB RIN Asset Category Definitions and Mapping

Table 4.5: RAB EB RIN Asset category definitions and mapping of EB RIN asset categories to annual RIN categories

EB RIN Asset Category	Definition	Mapped Energex Annual RIN Categories
Overhead network assets less than 33 kV (wires and poles)	Assets used to conduct electricity from one point to another above ground. These include poles, pole-top structures and overhead conductors. This does not include pole top substations and transformers.	Overhead Distribution Lines Low Voltage Services
Underground network assets less than 33 kV (cables)	Assets used to conduct electricity from one point to another below ground. This includes cables, cable joints and other assets used to connect the underground network to the overhead system. This does not include underground substations and transformers.	Underground Distribution Cables
Distribution substations including transformers	Overhead and underground distribution substations. This includes ground mounted substations and pole mounted substations. This does not include zone substations.	Distribution Equipment Distribution Transformers
Overhead network assets 33 kV and above (wires and poles)	Assets used to conduct electricity from one point to another above ground. These include poles, pole-top structures and overhead conductors. This does not include pole top substations and transformers.	Overhead Sub-Transmission Lines
Underground network assets 33 kV and above (cables)	Assets used to conduct electricity from one point to another below ground. This includes cables, cable joints and other assets used to connect the underground network to the overhead system. This does not include underground substations and transformers.	Underground Sub-Transmission Cables
Zone substations and transformers	Sites housing transformers involved in transforming power from high voltage input supply either directly from a TNSP or from Energex's own higher voltage lines - to distribution level voltages (e.g. 66 kV to 22 kV). This transformation can involve one step or multiple steps.	Substation Bays Substation Establishment Zone Transformers Distribution Substation Switchgear Buildings (System) Land (System)
Easements	An electricity easement is the right held by Energex to control the use of land near aboveground and underground power lines	Easements (System)

	and substations. It holds this right to ensure the landowner's safety and to allow staff access to work on the power lines at all times.	
Meters	An electricity meter is a device that measures the amount of electric energy consumed by a residence, business, or an electrically powered device	Metering
Other assets with long lives	Assets with expected asset lives greater than or equal to 10 years that are not: 1. Overhead Distribution Assets (Wires And Poles) 2. Underground Distribution Assets (Cables) 3. Distribution Substations Including Transformers 4. Zone Substations and Transformers 5. Easements 6. Meters	Communications Pilot Wires Street Lighting Other Equipment Control Centre - SCADA Buildings Land Buildings – capital works Equity Raising Costs
Other assets with short lives	Assets with expected asset lives less than 10 years that are not: 1. Overhead Distribution Assets(Wires And Poles) 2. Underground Distribution Assets (Cables) 3. Distribution Substations Including Transformers 4. Zone Substations And Transformers 5. Easements 6. Meters	Communications IT Systems Office Equipment & Furniture Motor Vehicles Plant & Equipment In-house software

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 Committee and implemented where required and the associated Energex accounting policies are updated accordingly.

There are no material impacts from changes in accounting standards for the 2021 financial year, and subsequently no accounting policy changes that may impact the RIN.

BoP – 3.4 Operational Data

Table 3.4.1 - Energy Delivery

Table 3.4.1 Energy Delivered

Table 1.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Compliance with RIN Requirements

Table 5.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energy delivered is the amount of electricity transported out of Energex's network in the relevant Regulatory Year (measured in GWh). It must be the energy metered or estimated at the customer charging location rather than the import location from the TNSP. Energy delivered must be actual energy delivered data, unless this is unavailable.	Energy delivered has been measured at the customer charging location.
Peak, shoulder and off-peak periods relate to Energex's own charging periods.	Energex only uses on and off-peak periods. Data for shoulder periods is reported as blank.
Energex must only report 'Energy Delivery where time of use is not a determinant' (DOPED0201) for Energy Delivery that was not charged for peak, shoulder or off-peak periods.	All data for DOPED0201 was not charged based on time of use. Data for DOPED0206 are actuals, but for DOPED0201 ~ 0205, DOPED0205 and DOPED01, they are estimation.
Energex is required to report energy received from Non-residential Embedded Generation by time of receipt. Energex is required to report back cast energy received from Residential Embedded Generation only if it records data for these variables (DOPED0405-DOPED0408)	Only solar generation has been reported in DOPED0405 and they are estimation. Other data in table 3.4.1.3 are actuals.
Energex must report energy delivered in accordance with the category breakdown as per the definitions provided in chapter 9. The category breakdown must be consistent with the customer types reported in RIN Table 5.2.1	The customer types are consistent to those used in RIN Table 3.4.2[1]. Data for DOPED0504 ~ 0505 are actuals but are estimation for DOPED0501 ~ 0503.

Sources

Table 3.4.1 Energy Delivered

Table 5.2, Table 5., Table 5., Table 5. and Table 5. specify the sources from which Energex obtained the required information.

Table 5.2: Data Sources: RIN Table 3.4.1: Energy delivery - total energy delivered

Variable Code	Variable	Unit	Source
DOPED01	Total energy delivered	GWh	PEACE

Table 5.3: Data Sources: RIN Table 3.4.1.1: Energy grouping - delivery by chargeable quantity

Variable Code	Variable	Unit	Source
DOPED0201	Energy Delivery where time of use is not a determinant	GWh	PEACE
DOPED0202	Energy Delivery at On-peak times	GWh	PEACE and NLF

Variable Code	Variable	Unit	Source
DOPED0203	Energy Delivery at Shoulder times	GWh	-
DOPED0204	Energy Delivery at Off-peak times	GWh	PEACE and NLF
DOPED0205	Controlled load energy deliveries	GWh	PEACE
DOPED0206	Energy Delivery to unmetered supplies	GWh	PEACE

Table 5.4: Data Sources: RIN Table 3.4.1.2: Energy - received from TNSP and other DNSPs by time of receipt

Variable Code	Variable	Unit	Source
DOPED0301	Energy into DNSP network at On-peak times	GWh	Network Load Forecasting (NLF) Database
DOPED0302	Energy into DNSP network at Shoulder times	GWh	-
DOPED0303	Energy into DNSP network at Off-peak times	GWh	NLF
DOPED0304	Energy received from TNSP and other DNSPs not included in the above categories	GWh	NLF

Table 5.5: Data Sources: RIN Table 3.4.1.3 Energy - received into DNSP system from embedded generation by time of receipt

Variable Code	Variable	Unit	Source
DOPED0405	Energy into DNSP network at On-peak times from residential embedded generation	GWh	PEACE
DOPED0504	Non-residential high voltage demand tariff customers energy deliveries	GWh	PEACE and NLF
DOPED0505	Other Customer Class Energy Deliveries	GWh	PEACE

Table 5.6: Data Sources: RIN Table 3.4.1.4 Energy grouping - customer type or class

Variable Code	Variable	Unit	Source
DOPED0501	Residential customers energy deliveries	GWh	PEACE
DOPED0502	Non-residential customers not on demand tariffs energy deliveries	GWh	PEACE
DOPED0503	Non-residential low voltage demand tariff customers energy deliveries	GWh	PEACE

Methodology

Table 3.4.1 Energy Delivered

Actual

Annual energy data in the Energex Network can be classified into two categories, based on both the energy flow features and the 2020-21 Economic Benchmarking RIN requirement:

- Energy Delivered (i.e. kWh conveyed by Energex to end users)
- Energy Purchased (i.e. kWh injected into the Energex Network)

Energy delivered is reported in RIN tables 3.4.1.1 and 3.4.1.4, while energy purchased is reported in RIN tables 3.4.1.2 and 3.4.1.3. Each of these figures is broken down into the categories specified by the AER.

RIN table 3.4.1.1: Energy grouping - delivery by chargeable quantity

The calculation of each line item is summarised in the Table 5. below and figures were disaggregated using the network tariff codes. The data was separated into the separate time periods using data inherent in the source systems. Energex does not use a shoulder period and therefore cells for these variables have been left blank. Data in this table was sourced from the Energex billing system (PEACE).

Table 5.7: Method for calculating delivery by chargeable quantity

Variable Code	Variable	Source
DOPED0206	Energy Delivery to unmetered supplies	Sum of street lighting only based on NTC 9600. The other unmetered energy delivery accounts for very small amount of the total energy delivered. It is historically treated as energy losses so it is not included in this category.

RIN table 3.4.1.2: Energy - received from TNSP and other DNSPs by time of receipt

Data in this table was sourced from the Network Load Forecasting database (which is an extract of the TOHT metering system) and was detailed below:

Table 5.8: Method for calculating RIN Table 3.4.1.2 Energy - received from TNSP and other DNSPs by time of receipt

Variable Code	Variable	Source
DOPED0301	Energy into DNSP network at On-peak times	Sum of all energy received to Energex connection points between 7am - 9pm weekdays.
DOPED0302	Energy into DNSP network at Shoulder times	Not applicable.
DOPED0303	Energy into DNSP network at Off-peak times	Sum of all energy received to Energex connection points outside 7am - 9pm (this includes all times on weekends and public holidays).
DOPED0304	Energy received from TNSP and other DNSPs not included in the above categories	Sum of all energy received from and/or exported to other DNSPs not listed in DOPED0301 ~ DOPED0303 (For example, Kirra zone substation owned by Energex occasionally receives/exports energy from/to New South Wales) over a financial year. Because the direction of electricity conveyed can flow both (in and out) ways, the net impacts may show positive or negative values (e.g; it was positive 4.295 GWh for the 2020-21 year, indicating energy flowing-in).

RIN table 3.4.1.3: Energy - received into DNSP system from Embedded Generation by time of receipt

Data in this table was sourced from the Network Load Forecasting database as detailed in Table 5.:

Table 5.9: Method for calculating RIN Table 3.4.1.3 Energy - received into DNSP system from embedded generation by time of receipt

Variable Code	Variable	Source
DOPED0401	Energy into DNSP network at On-peak times from non-residential embedded generation	Sum of all energy received from embedded generators and Queensland Rail trains (regenerative braking) between 7am - 9pm weekdays.
DOPED0402	Energy into DNSP network at Shoulder times from non-residential embedded generation	Not applicable.
DOPED0403	Energy into DNSP network at Off-peak times from non-residential embedded generation	Sum of all energy received from embedded generators and Queensland Rail trains (regenerative braking) outside 7am - 9pm (this includes all times on weekends and public holidays).
DOPED0404	Energy received from embedded generation not included in above categories from non-residential embedded generation	Not applicable.
DOPED0406	Energy into DNSP network at Shoulder times from residential embedded generation	Not applicable.
DOPED0407	Energy into DNSP network at Off-peak times from residential embedded generation	Not applicable.
DOPED0408	Energy received from embedded generation not included in above categories from residential embedded generation	Not applicable.

RIN table 3.4.1.4: Energy grouping - customer type or class

Data in this table was sourced from the Energex billing system (PEACE) and was detailed below:

Table 5.10: Method for calculating RIN Table 3.4.1.4 Energy grouping: customer type or class

Variable Code	Variable	Source
DOPED0504	Non-residential high voltage demand tariff customers energy deliveries	Calculated as the sum of NTCs up 1000 to 4500 plus NTC7400. This includes all customers with a high voltage network connection.
DOPED0505	Other Customer Class Energy Deliveries	Same figure as DOPED0206. Please refer to DOPED0206 calculation methodology.

Estimated

Annual energy data in the Energex Network can be classified into two categories, based on both the energy flow features and the 2020-21 Economic Benchmarking RIN requirement:

- Energy Delivered (i.e. kWh conveyed by Energex to end users)

- Energy Purchased (i.e; kWh injected into the Energex Network)

Energy delivered is reported in RIN tables 3.4.1.1 and 3.4.1.4, while energy purchased is reported in RIN tables 3.4.1.2 and 3.4.1.3. Each of these figures is broken down into the categories specified by the AER.

Total Energy Delivered

The total energy delivered by Energex to customers was extracted directly from the Energex billing system (PEACE) and aggregated for the Regulatory Year. A large proportion of Energex customers (residential and small business accounting for around 95%) are quarterly read accumulation metering and Energex is required to estimate the final end of financial year total as the actual data is not fully known until October each year.

RIN table 3.4.1.1: Energy grouping - delivery by chargeable quantity

The calculation of each line item is summarised in the Table 5. below and figures were disaggregated using the network tariff codes. The data was separated into the separate time periods using data inherent in the source systems. Energex does not use a shoulder period and therefore cells for these variables have been left blank. Data in this table was sourced from the Energex billing system (PEACE).

Table 5.11: Method for calculating delivery by chargeable quantity

Variable Code	Variable	Source
DOPED0201	Energy Delivery where time of use is not a determinant	Calculated as the sum of residential and small business energy delivered where the volume charge is a flat anytime rate on NTC's 6000 and 6020, 8400 to 8470 and 800 to 8570 and excludes controlled load and solar.
DOPED0202	Energy Delivery at On-peak times	Calculate the On-peak-times usage ratios by using the peak (between either 7am - 9pm or 7am - 11pm weekdays) over the total energy delivered to half hourly metered customers sourced from monthly NRUR reports. The ratios then are applied to those half hourly metered customer groups (i.e.; the following NTCs: 1000, 3000, 4000, 4500, 3650 to 3970, 6850 to 6970, , 7100, 7150, 7200, 7250, 7400, , 8100 to 8370, and 8800 to 8970,) sourced from PEACE system to calculate the total on-peak-time energy delivery.
DOPED0203	Energy Delivery at Shoulder times	Not applicable.
DOPED0204	Energy Delivery at Off-peak times	The same methodology (described in DOPED0202) is used to calculate the off-peak time ratios (which are basically the residuals of the on-peak-time ratios) for half hourly metered customers. The ratios then are applied to those half hourly metered customer groups (i.e.; the following NTC's: 1000, 3000, 4000, 4500, 3650 to 3970, 6850 to 6970, 7100 and 7150, 7200 and 7250, 7400, , 8100 to 8370, 8800 to 8870 and 8900 to 8970) sourced from PEACE system to calculate the total off-peak-time energy delivery.

Variable Code	Variable	Source
DOPED0205	Controlled load energy deliveries	Sum of energy delivered to controlled load customers, calculated as the sum of NTCs 5700 to 5970 and NTC's 9000 to 9170.

RIN table 3.4.1.3: Energy - received into DNSP system from Embedded Generation by time of receipt

Data in this table was sourced from the Network Load Forecasting database as detailed in Table 5.:

Table 5.12: Method for calculating RIN Table 3.4.1.3 Energy - received into DNSP system from embedded generation by time of receipt

Variable Code	Variable	Source
DOPED0405	Energy into DNSP network at On-peak times from residential embedded generation	Sum of all solar photovoltaic generated injections. It is assumed that all solar power is generated inside peak periods. Due to the sunlight times there is little generation outside these times.

RIN table 3.4.1.4: Energy grouping - customer type or class

Data in this table was sourced from the Energex billing system (PEACE) and was detailed in Table 5.1:

Table 5.1: Method for calculating RIN Table 3.4.1.4 Energy grouping: customer type or class

Variable Code	Variable	Source
DOPED0501	Residential customers energy deliveries	Calculated as (1) the sum of energy delivered to all residential customers on NTC's 3750 and 3770, 3950 and 3970, 6950 and 6970, 8400 to 8470 and 8900 to 8970 plus (2) energy delivered to non-business specific controlled load NTCs 9000 9070 and 9100 to 9170.
DOPED0502	Non-residential customers not on demand tariffs energy deliveries	Calculated as (1) the sum of energy delivered to SAC Small Business NTCs 6000 and 6020, 6850 and 6870, 8500 to 8570 and 8800 to 8870 plus (2) the sum of energy delivered to SAC Small Business specific controlled tariffs 5700 to 5770, 5800 to 5870 and 5900 to 5970
DOPED0503	Non-residential low voltage demand tariff customers energy deliveries	Calculated as (1) the sum of energy delivered to 'SAC Small Business' NTC's 3650 and 3670, 3850 and 3870 plus 7100 and 7150 which are kW based demand tariffs for small business customers with volume <100 MWh per-annum plus. (2) the sum of energy delivered to 'SAC Large' NTC's 7200 and 7250, plus 8100 to 8370 which are kVA based demand tariffs for SME customers with volume >100 MWh per-annum.

Assumptions

Actual

Energex applied the following assumptions to obtain the required information:

- It is assumed that all residential solar power is generated inside peak periods and metered. Due to the sunlight times there is little generation outside these periods.
- Commercial solar PV is un-metered. All the energy generated in this group is assumed to be consumed internally so that its impacts on energy and peak demand are covered by the monthly recorded billing data.

Estimate

Energex applied the following assumptions to obtain the required information:

- It is assumed that all residential solar power is generated inside peak periods and metered. Due to the sunlight times there is little generation outside these periods.
- Commercial solar PV is un-metered. All the energy generated in this group is assumed to be consumed internally so that its impacts on energy and peak demand are covered by the monthly recorded billing data.

Estimated Information

- All energy delivered which includes variables DOPED01, DOPED0201, DOPED0202, DOPED0203, DOPED0204, DOPED0205, DOPED0501, DOPED0502 and DOPED0503 in RIN tables 3.4.1, 3.4.1.1 and 3.4.1.4.
- Energy purchased data on Residential Embedded Generation at On-peak Times (i.e. DOPED0405 in RIN table 3.4.1.3).

Justification for Estimated Information

- The energy delivered data is sourced from the PEACE Billing Software. It is quarterly billed so the data is not available for 3 to 4 months due to the meter reading processes. This means the data will not be finalised until the mid-October for a reported financial year.
- Energy purchased data on Residential Embedded Generation at On-peak Times record the total energy injected into the Energex Network system provided by domestic PV generation.

The data also comes from PEACE and therefore, is estimated due to the same reason discussed above.

Basis for Estimation

- Energex constructs a series of Monthly Energy Sales Models for different tariff groups (e.g. T4000s large non-domestic customers, T8000s medium/small non-domestic customers and domestic non-controlled customers which combine with T7000, T8400, T8420, T8450, T8470, T8900, T8920, T8950 and T8970 network tariff groups).
- These typical econometric models use key drivers such as Queensland Gross State Product (GSP), the number of new customer connections and weather variables (e.g.; temperature and relative humidity indices). They systematically analyse the underlying driving forces and try to capture the impacts of those key drivers on energy sales in both the short and long term. It therefore, provides a powerful tool for Energex to do energy forecasts.
- If the actual monthly data is available for a part of the year (for example, actual billing data are available for July ~ March), this data will be added to the estimated energy sales for the portion of the financial year that is unavailable to produce the full financial year figure. The energy sales for the unavailable portion of the financial year will be estimated based on those econometric models. If necessary, some adjustments may also be included in estimation based on the latest available information.

Energex believes the estimate supplied is its best estimate based on the available information at the time.

Explanatory Notes

Not applicable.

Table 3.4.2 – Customer Numbers

Compliance with RIN Requirements

Table 3.4.2 Customer Numbers

Table 5. below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 5.14: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Distribution Customers for a Regulatory Year are the average number of active National Meter Identifiers (NMIs) in Energex's network in that year. The average is calculated as the average of the number of NMIs on the first day of the Regulatory Year and on the last day of the Regulatory Year.	Customer numbers have been calculated as the average of the beginning and end of year figures.
Each NMI is counted as a separate customer. Both energised and de-energised NMIs must be counted. Extinct NMIs must not be counted.	Energex has calculated all customer numbers as the number of "active" NMIs inclusive of both "energised" and "deenergised" NMIs.
Energex must report Customer Numbers broken down by customer class in accordance with the categorisations specified by the AER.	Customer numbers have been broken down by customer type using the definitions specified by the AER.

Sources

Table 5. specifies the sources from which Energex obtained the required information for RIN Table 3.4.2.1 Distribution customer numbers by customer type or class.

Table 5.15: Data sources for customers by customer type or class

Variable Code	Variable	Unit	Source
DOPCN0101	Residential customer numbers	number	PEACE
DOPCN0102	Non-residential customers not on demand tariff customer numbers	number	PEACE
DOPCN0103	Low voltage demand tariff customer numbers	number	PEACE
DOPCN0104	High voltage demand tariff customer numbers	number	PEACE
DOPCN0105	Unmetered Customer Numbers	number	SLIM
DOPCN0106	Other Customer Numbers	number	Not Applicable
DOPCN01	Total customer numbers	number	PEACE and SLIM (UMS only)

All data relating to customer numbers broken down by location on the network was sourced from the Energex PoN system as detailed in Table 5. below:

Table 5.16: Data sources for customers by network location

Variable Code	Variable	Unit	Source
DOPCN0201	Customers on CBD network	number	PoN
DOPCN0202	Customers on Urban network	number	PoN
DOPCN0203	Customers on Short rural network	number	PoN
DOPCN0204	Customers on Long rural network	number	Not Applicable
DOPCN02	Total customer numbers	number	PoN

Methodology

The Energex customer numbers are reported from two separate systems as the breakdown of customers by customer type and network location are stored in Energex's PEACE and PowerOn (PoN) systems respectively. The total customer numbers in these two systems do not match and this is expected and explained in 3.4.2.5 Explanatory Notes.

The customer numbers extracted from PEACE and PoN include "active" and "de-energised" customers.

Network Tariff codes have been used to split the customers across DOPCN0102, DOPCN0103, DOPCN0104. Refer to Table 5.17: Network Tariffs used to assign Customer Types to see exactly how it was done.

RIN Table 3.4.2.1 Distribution customer numbers by customer type or class

This approach required a count of PEACE customers and a report from SLIM to generate all data required. These reports extracted the number of NMIs that were classed only as active and were energised or de-energised.

1. The total end of year customer numbers for residential vs non-residential customers was extracted from PEACE and split using the corresponding network tariff codes.
2. The Network Tariff Code was used to determine the customer voltage. This is considered the most reliable way to break the customers up into the voltages requested.
3. SLIM provided the count of UMS NMIs (not Street Lights or government lighting (rate 1, 2, 3). Government owned Rate 8 street lighting was also excluded. Rate 8 privately owned lighting was included.
4. No customers fell into the "Other customers" (DOPCN0106) classification and as such these figures are zero. The AER have advised previously they do not expect data to be provided here.

RIN Table 3.4.2.2 Distribution customer number by location on the network

1. The customer numbers broken down by their location on the network are stored on the Energex PoN system. Energex does not have any customers on long rural networks and therefore all rural flagged customers are classed as short rural.
2. Average customer figures were then calculated for each variable DOPCN0201-3 - the total from the start and end of the regulatory periods was used. De-en customers are included. UMS are excluded from these totals and have not been added in.
3. Where the customer's distribution transformer (Network Attachment Point (NAP)) or Feeder is not known, the customer is not counted in the totals in PoN. Therefore, these missing customers have been added to each total using proportional allocation (using the existing percentages of customers against each feeder category).
4. The variable "DOPCN02 - Total customer numbers" was then calculated as the sum of customers in each network location.

Assumptions

Not applicable.

Estimated Information

Not applicable. Energex has provided actual information.

Explanatory Notes

Table 3.4.2 Customer Numbers Reconciliation of total customer figures between 3.4.2.1 and 3.4.2.2

PoN feeds a corporate Energex EPM report and has done since 1-7-2015 (Customers by Feeder Category). This is considered a more appropriate solution to report customer numbers by feeder category than NFM.

Where the customer's distribution transformer (or Network Attachment Point (NAP)) or feeder category is not known, the customer is not counted in the totals in PoN as they cannot be allocated to a feeder (and therefore a feeder category).

Therefore, these missing customers have been added to each total (each feeder category) using proportional allocation (using the existing percentages of customers against each feeder category).

Table 5.17: Network Tariffs used to assign Customer Types

Network Tariff Code	Customer Type
1000	HV Demand
3000	HV Demand
4500	HV Demand
4000	HV Demand
8000	HV Demand
7400	HV Demand
7100	LV Demand - NonRes
8300	LV Demand - NonRes
8100	LV Demand - NonRes
8800	LV Demand - NonRes Non Demand
8500	LV Demand - NonRes Non Demand
8850	LV Demand - NonRes Non Demand
8870	LV Demand - NonRes Non Demand
8550	LV Demand - NonRes Non Demand
8570	LV Demand - NonRes Non Demand
All other NTCs	Residential

Table 3.4.3 – System Demand

Compliance with RIN Requirements

System Demand Annual System Maximum Demand

Table 5. specifies how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 5.18: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
RIN Tables 3.4.3.1 to 3.4.3.4 must be completed in accordance with the definitions in chapter 9.	Demonstrated in the Methodology section
Energex must provide inputs for these cells if it has calculated historical Weather Adjusted Maximum Demand.	Demonstrated in the Methodology section
For RIN Table 3.4.3.1 the coincident and noncoincident Maximum Demands must be reported raw (or unadjusted) and Weather Adjusted at the 10% and 50% Probability of Exceedance (POE) levels.	Demonstrated in the Methodology section
For RIN Table 3.4.3.2 the coincident and noncoincident Maximum Demands must be reported raw (or unadjusted) and Weather Adjusted at the 10% and 50% POE levels.	Demonstrated in the Methodology section
For RIN Table 3.4.3.3 the coincident and noncoincident Maximum Demands must be reported raw (or unadjusted) and Weather Adjusted at the 10% and 50% POE levels.	Demonstrated in the Methodology section
For RIN Table 3.4.3.4 the coincident and noncoincident Maximum Demands must be reported raw (or unadjusted) and Weather Adjusted at the 10% and 50% POE levels.	Demonstrated in the Methodology section
Coincident Raw System Annual Maximum Demand is the actual, unadjusted (i.e. not weather normalised) summation of actual raw demands for the requested asset level (either the zone substation or transmission connection point) at the time when this summation is greatest. The Maximum Demand does not include Embedded Generation.	Demonstrated in the Methodology section
Energex does not include Embedded Generation in its calculation of Maximum Demand.	Demonstrated in the Methodology section
Coincident Weather Adjusted System Annual Maximum Demand 10% POE is the summation of the Weather Adjusted annual Maximum Demands for the requested asset level (either the zone substation or transmission connection point) at the 10 per cent POE level at the time when this summation is greatest.	Demonstrated in the Methodology section
Coincident Weather Adjusted System Annual Maximum Demand 50% POE is the summation of the Weather Adjusted annual Maximum Demands for the requested asset level (either the zone substation or transmission connection point) at the 50 per cent POE level at the time when this summation is greatest.	Demonstrated in the Methodology section
Maximum Demand is as defined in the NER	Maximum Demand is defined in the Rules and applied by Energex as meaning - the highest amount of electrical power delivered, or forecast to be delivered, over a defined period (day, week, month, season or year) either at a connection point, or simultaneously at a defined set of connection points.
Non-Coincident Raw System Annual Maximum Demand is the actual unadjusted (i.e. not weather normalised)	Energex has based its calculations of the annual peaks from the data for the summer and winter seasons only

Requirements (instructions and definitions)	Consistency with requirements
summation of actual raw annual Maximum Demands for the requested asset level (either the zone substation or transmission connection points) irrespective of when they occur within the year. This Maximum Demand is not to be adjusted for Embedded Generation.	(Demonstrated in the Methodology section). This provides a more accurate representation of customer demand as it excludes anomalies that may occur due to Network configuration changes upstream of the Connection Point. On 22 July 2015 the AER confirmed that this approach was appropriate and acceptable.
Energex does not include Embedded Generation in its calculation of Maximum Demand.	
Non-Coincident Weather Adjusted System Annual Maximum Demand 10% POE This is the summation of the Weather Adjusted annual Maximum Demands for the requested asset level (either the zone substation or transmission connection point) at the 10 per cent POE level irrespective of when they occur within the year.	Demonstrated in the Methodology section

Average overall network power factor conversion between MVA and MW

Table 5. specifies how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 5.19: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must report the power factor to allow for conversion between MVA and MW measures for each voltage.	Demonstrated in the Methodology section
If both MVA and MW throughput for a network are available, then the power factor is the total MW divided by the total MVA. Energex must provide a power factor for each voltage level and for the network as a whole. The average overall power factor conversion (DOPSD0301) is the total MW divided by the total MVA.	Demonstrated in the Methodology section
If either the MW or MVA measure is unavailable the average power factor conversion can be calculated as an approximation based on best engineering estimates.	Demonstrated in the Methodology section

Average power factor conversion for other kV

Table 5. specifies how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 5.20: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must report the power factor to allow for conversion between MVA and MW measures for each voltage.	Demonstrated in Methodology section
If both MVA and MW throughput for a network are available, then the power factor is the total MW divided by the total MVA. Energex must provide a power factor for each voltage level and for the network as a whole. The average overall power factor conversion (DOPSD0301) is the total MW divided by the total MVA.	Demonstrated in Methodology section
If either the MW or MVA measure is unavailable the average power factor conversion can be calculated as an approximation based on best engineering estimates.	Demonstrated in Methodology section

Demand Supplied (For Customers Charged on this Basis)

Table 5. specifies how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 5.21: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex is only required to complete RIN table 3.4.3.6 if it charges customers for Maximum Demand supplied. If Energex does not charge customers on this basis then Energex should enter '0"	Demonstrated in the Methodology section
Energex must report Maximum Demand amounts for customers that are charged based upon their Maximum Demand as measured in MW. Where Energex cannot distinguish between contracted and measured Maximum Demand, demand supplied must be allocated to contracted Maximum Demand.	Demonstrated in the Methodology section
Energex is only required to complete RIN table 3.4.3.7 if it charges customers for demand supplied. If Energex does not charge customers on this basis then Energex must enter '0'.	Demonstrated in the Methodology section
Energex must report Maximum Demand amounts for customers that are charged based upon their Maximum Demand as measured in MVA. Where Energex cannot distinguish between contracted and measured Maximum Demand, demand supplied must be allocated to contracted Maximum Demand.	Demonstrated in the Methodology section
Maximum Demand is as defined in the NER.	Maximum Demand is defined in the Rules and applied by Energex as meaning - the highest amount of electrical power delivered, or forecast to be delivered, over a defined period (day, week, month, season or year) either at a connection point, or simultaneously at a defined set of connection points.

Sources

System Demand Annual System Maximum Demand

- The SIFT database was used to extract the annual maximum demand across the network at the zone substation and transmission connection point level.
- The Bureau of Meteorology (BOM) was also used to source information on the weather conditions. To calculate the weather adjusted data at the zone substation and Connection Point level the weather data was based on five weather stations (namely Maroochydore, Brisbane Airport, Archerfield, Coolangatta and Amberley).

Table 5., Table 5., Table 5. and Table 5. specify the sources for additional responses to variables relating to annual system maximum demand:

Table 5.22 Data sources for the annual system maximum demand characteristics at the zone substation level - MW measure

Variable Code	Unit	Source
DOPSD0101	Non-coincident Summated Raw System Annual Maximum Demand	SIFT
DOPSD0102	Non-coincident Summated Weather Adjusted System Annual Maximum Demand 10% POE	SIFT/BOM
DOPSD0103	Non-coincident Summated Weather Adjusted System Annual Maximum Demand 50% POE	SIFT/BOM
DOPSD0104	Coincident Raw System Annual Maximum Demand	SIFT
DOPSD0105	Coincident Weather Adjusted System Annual Maximum Demand 10% POE	SIFT/BOM
DOPSD0106	Coincident Weather Adjusted System Annual Maximum Demand 50% POE	SIFT/BOM

Table 5.23: Data sources for the annual system maximum demand characteristics at the transmission connection point - MW measure

Variable Code	Unit	Source
DOPSD0107	Non-coincident Summated Raw System Annual Maximum Demand	SIFT
DOPSD0108	Non-coincident Summated Weather Adjusted System Annual Maximum Demand 10% POE	SIFT/BOM
DOPSD0109	Non-coincident Summated Weather Adjusted System Annual Maximum Demand 50% POE	SIFT/BOM
DOPSD0110	Coincident Raw System Annual Maximum Demand	SIFT
DOPSD0111	Coincident Weather Adjusted System Annual Maximum Demand 10% POE	SIFT/BOM
DOPSD0112	Coincident Weather Adjusted System Annual Maximum Demand 50% POE	SIFT/BOM

Table 5.24: Data sources for the annual system maximum demand characteristics at the transmission connection point - MW measure

Variable Code	Unit	Source
DOPSD0201	Non-coincident Summated Raw System Annual Maximum Demand	SIFT
DOPSD0202	Non-coincident Summated Weather Adjusted System Annual Maximum Demand 10% POE	SIFT/BOM
DOPSD0203	Non-coincident Summated Weather Adjusted System Annual Maximum Demand 50% POE	SIFT/BOM
DOPSD0204	Coincident Raw System Annual Maximum Demand	SIFT
DOPSD0205	Coincident Weather Adjusted System Annual Maximum Demand 10% POE	SIFT/BOM

Variable Code	Unit	Source
DOPSD0206	Coincident Weather Adjusted System Annual Maximum Demand 50% POE	SIFT/BOM

Table 5.25: Data sources for the annual system maximum demand characteristics at the transmission connection point - MVA measure

Variable Code	Unit	Source
DOPSD0207	Non-coincident Summated Raw System Annual Maximum Demand	SIFT
DOPSD0208	Non-coincident Summated Weather Adjusted System Annual Maximum Demand 10% POE	SIFT/BOM
DOPSD0209	Non-coincident Summated Weather Adjusted System Annual Maximum Demand 50% POE	SIFT/BOM
DOPSD0210	Coincident Raw System Annual Maximum Demand	SIFT
DOPSD0211	Coincident Weather Adjusted System Annual Maximum Demand 10% POE	SIFT/BOM
DOPSD0212	Coincident Weather Adjusted System Annual Maximum Demand 50% POE	SIFT/BOM

Average overall network power factor conversion between MVA and MW

Table 5. specifies the sources from which Energex obtained the required information.

Table 5.26: Data sources for Average overall network power factor conversion between MVA and MW

Variable Code	Variable	Unit	Source
DOPSD0301	Average overall network power factor conversion between MVA and MW	Factor	SIFT/Metering data from Network Load Forecasting (NLF) Database

Average power factor conversion for other kV

Table 5. specifies the sources from which Energex obtained the required information.

Table 5.27: Data source for demand supplied (for customers charged on this basis)

Variable Code	Variable	Unit	Source
DOPSD0302	Average power factor conversion for low voltage distribution lines	Factor	SIFT/SCADA
DOPSD0303	Average power factor conversion for 3.3 kV lines	Factor	Not Applicable
DOPSD0304	Average power factor conversion for 6.6 kV lines	Factor	Not Applicable
DOPSD0305	Average power factor conversion for 7.6 kV lines	Factor	Not Applicable
DOPSD0306	Average power factor conversion for 11 kV lines	Factor	SIFT/SCADA
DOPSD0307	Average power factor conversion for SWER lines	Factor	SIFT/SCADA
DOPSD0308	Average power factor conversion for 22 kV lines	Factor	Not Applicable

Variable Code	Variable	Unit	Source
DOPSD0309	Average power factor conversion for 33 kV lines	Factor	SIFT/SCADA
DOPSD0310	Average power factor conversion for 44 kV lines	Factor	Not Applicable
DOPSD0311	Average power factor conversion for 66 kV lines	Factor	Not Applicable
DOPSD0312	Average power factor conversion for 110 kV lines	Factor	SIFT/SCADA
DOPSD0313	Average power factor conversion for 132 kV lines	Factor	SIFT/SCADA
DOPSD0314	Average power factor conversion for 220 kV lines	Factor	Not Applicable

Demand Supplied (For Customers Charged on this Basis)

Table 5. and Table 5. specifies the sources from which Energex obtained the required information.

Table 5.28: Data source for demand supplied (for customers charged on this basis)

Variable Code	Unit	Source
DOPSD0401	Summated Chargeable Contracted Maximum Demand	PEACE
DOPSD0402	Summated Chargeable Measured Maximum Demand	PEACE

Table 5.29: Data source for demand supplied (for customers charged on this basis)

Variable Code	Unit	Source
DOPSD0403	Summated Chargeable Contracted Maximum Demand	PEACE
DOPSD0404	Summated Chargeable Measured Maximum Demand	PEACE

Methodology

System Demand Annual System Maximum Demand

The weather adjustment process used by Energex was based on the following process:

1. The days that are unlikely to produce a peak demand were excluded.
2. Multiple seasons of data were used.
3. A multiple regression model was developed for daily maximum demand incorporating maximum temp, minimum temp, and variables for weekends, public holidays and the Christmas shut down period. D = f(Max Temp, Min Temp, is_workday*, error term) -> *is_workday: weekends, public holidays and Xmas time.
4. Each zone substation and connection point's load data is correlated with each of the five weather stations, the weather station with the highest statistical best fit is the weather station chosen for the modelling.

5. The model and weather station with the best fit was used in the Monte Carlo simulation to determine the 10POE and 50POE adjustments for each Zone Substation and Connection Point. The adjustments were applied to the raw peak demand to calculate the 10POE and 50POE adjusted demands before aggregation.

The following approach was applied to calculate the annual system maximum demand characteristics at the zone substation level - MW and MVA (RIN tables 3.4.3.1 and 3.4.3.3):

1. The demand data for each zone substation was aggregated to find for total non- coincident peak;
2. The POE adjustment is based on the standard weather adjustment process using the best fit of five BOM sites and is recorded in SIFT; and
3. These adjustments are then applied to the recorded demands and then aggregated to total values in the appropriate row in MW or MVA (as appropriate).

The following approach was applied to calculate the annual system maximum demand characteristics at the transmission connection point - MW and MVA (RIN tables 3.4.3.2 and Table 3.4.3.4):

1. The peak demand data for each Connection Point was aggregated to find for total non-coincident peak;
2. The Connection Point coincident MW and MVA values were calculated from as recorded system raw demand.
3. The Energex System level POE values will be different from the temperature corrected figures calculated at the individual Connection Point (or Zone Substation level) and aggregated to form a system total number - as the aggregated numbers are not only based on peaks from either the summer or the winter, but there are also differences in the methodology of temperature correction, with the POE methodology used at the Energex System level incorporating more explanatory variables - like economic and demographic drivers.
4. The non-coincident zone substation summated demands are from any half hour, and therefore diversity of load peaks & losses need to be accounted for in any comparison between aggregated zone substation and connection point demands.

Average overall network power factor conversion between MVA and MW

The methodology and justification for the low voltage distribution line power factor conversion is outlined below.

The following approach was applied to calculating the relevant power factor conversion variables:

- Average power factor was calculated using the summated MVA and summated MW at the system level. All data for these calculations was extracted from SCADA.

Average power factor conversion for other kV

The methodology and justification for the low voltage distribution line power factor conversion is outlined below in Approach.

The following approach was applied to calculating the relevant power factor conversion variables:

- Average power factor was calculated using the summated MVA and summated MW at the system level. All data for these calculations was extracted from SCADA;
- Power factor at the132 & 110 kV line level was calculated using the actual MVA and MW at the connection points;
- Power factor at the 33 kV line level was calculated using the actual MVA and MW at the Bulk Supply substations;
- Power factor at the 6.35 kV SWER line level was calculated using the actual MVA and MW at the Somerset Dam Zone Substation, which is the only Zub in Energex network with SWER network. While only part of the load supplied by Somerset is SWER, the substation's power factor is considered to be a reliable predictor of its SWER component, due to the similarities of the load supplied;
- Power factor at the 11 kV line level was calculated using the actual MVA and MW at the Zone substations; and
- Power factor at LV line level was based on the average power factor across a sample of 6472+ distribution transformers randomly scattered across the Energex network. The power factor calculated is considered to be a reliable estimate as a sample of that size with a 95% confidence interval yields a band of only + / - 1.14%.

Demand Supplied (For Customers Charged on this Basis)

Data has been sourced directly from the network billing system and Distribution Use of System charges were used to differentiate between Contracted and Actual Demand as per below.

- kw_actual_demand (for DOPSD0402)
  - NDADC - DUoS Actual Demand Charge
  - NDDCP - DUoS Demand Charge - Peak
- kva_capacity_demand (for DOPSD0403)
  - NDKVACC - DUoS kVA Capacity Charge
- kva_actual_demand (for DOPSD0404)

- NDKVAADC - DUoS kVA Actual Demand Charge
- NDKVADCP - DUoS kVA Actual Demand Charge Peak
- NDMEKVADC - DUoS Monthly Excess kVA Demand Charge

Assumptions

Table 3.4.3 - System Demand Annual System Maximum Demand

The following assumptions apply to the calculation of the weather adjusted data at the zone substation level:

- Where the zone substation has insignificant variables or contribution to demand, these values were excluded from the calculation;
- The duration of the summer period is November, December, January, February and March;
- Refer to CA RIN BoP 5.4.1 Maximum Demand and Utilisation Spatial section 22.5 Assumptions for an explanation of summer and winter peaks.
- The temperature threshold is based on the average for each day;
- Any day where the average temperature at Amberley was above 17.0 degrees Celsius during the winter period was disregarded;
- Any day where the average temperature at Amberley was below 24.5 degrees Celsius during the summer period was disregarded;
- The temperature data is based on the daily minimum and maximum temperatures, with the weekday, weekend and Friday temperatures all identified separately in the model, allowing both the day and temperature affects to be adjusted for; and
- The weather data sourced from the Bureau of Meteorology was based on the best fit across five weather stations, including Maroochydore, Brisbane Airport, Archerfield, Coolangatta and Amberley.

The following assumptions apply to calculation of the weather adjusted data at the transmission connection point level:

- The duration of the winter period is June, July and August;
- The duration of the summer period is November, December, January, February and March;

- The temperature is based on the average for each day;
- Any day where the average temperature at Amberley was above 17.0 degrees Celsius during the winter period was disregarded;
- Any day where the average temperature at Amberley was below 24.5 degrees Celsius during the summer period was disregarded;
- The temperature data is based on the daily minimum and maximum temperatures, with the weekday, weekend and Friday temperatures all identified separately in the model, allowing both the day and temperature affects to be adjusted for;
- The raw data excluded embedded generation; and
- The weather data sourced from the Bureau of Meteorology was based on the best fit across all 5 weather stations.

Average overall network power factor conversion between MVA and MW, Average power factor conversion for other kV and Demand Supplied (For Customers Charged on this Basis)

Not applicable.

Estimated Information

Not applicable. Energex has provided actual information.

Explanatory Notes

Not applicable.

BoP – 3.5 Physical Assets

Table 3.5.1 - Network Capacities

Compliance with RIN Requirements

Circuit Length

Overhead network length of circuit at each voltage

Table 6. below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 6.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex is required to report against the capacity variables for the whole network.	Demonstrated in Methodology section.
The network includes overhead power lines and towers, underground cables and pilot cables that transfer electricity from the regional bulk supply points supplying areas of consumption to individual zone substations, to distribution substations and to customers.	Demonstrated in Methodology section. Energex's figures do not include pilot cables as they are a secondary system, as per the definition below.
The network also includes distribution feeders and the low voltage distribution system but excludes the final connection from the mains to the customer and also wires or cables for public lighting, communication, protection or control and for connection to unmetered loads.	Demonstrated in Methodology section.
Specify the voltage for each 'other' voltage level, where applicable.	Energex does not have any other voltage levels to those specified in the AER's RIN Instructions and Definitions.
Circuit length is calculated from the Route length (measured in kilometres) of lines in service (the total length of feeders including all spurs), where each SWER line, single-phase line, and three-phase line counts as one line. A double circuit line counts as two lines. The length does not take into account vertical components such as sag.	Demonstrated in Methodology section.

Circuit Capacity (33kV, 110kV, 132kV)

Table 6. below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 6.2: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
The estimated typical or weighted average capacities for each of the listed voltage classes under normal circumstances must be provided taking account of limits imposed by thermal or by voltage drop considerations as relevant.	Demonstrated in Methodology section.
The summer Maximum Demands are to be provided for summer peaking assets and the winter Maximum Demands are to be provided for winter peaking assets.	As this requirement is inconsistent with the remaining AER Instructions and Definitions and with the Data BoP itself it has not been addressed in the methodology. That is, this refers to Maximum Demand when the remainder of the report relate to capacity.

Requirements (instructions and definitions)	Consistency with requirements
Where Energex's peak has changed from winter to summer (or vice versa) over the time period, winter ratings should be applied for those years where there is a winter peak and summer ratings for those years where there is a summer peak.	Demonstrated in Methodology section.
Where circuits travel both overhead and underground and the capacity of the overhead and underground components is not available separately, Energex may split the circuit capacity by the ratio of the network that is overhead and underground to form estimates of the overhead capacity and underground capacity components.	Demonstrated in Methodology section.

Circuit Capacity (Low voltage, 11kV and SWER)

Table 6. below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 6.3: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
The estimated typical or weighted average capacities for each of the listed voltage classes under normal circumstances must be provided taking account of limits imposed by thermal or by voltage drop considerations as relevant.	Demonstrated in Methodology section.
The summer Maximum Demands are to be provided for summer peaking assets and the winter Maximum Demands are to be provided for winter peaking assets.	There is some variation in the terminology used in the AER's Instructions and Definitions document. Both Maximum Demand and Capacity has been referred to. For the basis of this variable it has been inferred that the requirement is for capacity figures.
Where the peak has changed from winter to summer (or vice versa) over the time period, winter ratings should be applied for those years where there was a winter peak and summer ratings for those years where there was a summer peak.	Demonstrated in Methodology section.
Where circuits travel both overhead and underground and the capacity of the overhead and underground components is not available separately, Energex may split the circuit capacity by the ratio of the network that is overhead and underground to form estimates of the overhead capacity and underground capacity components.	Demonstrated in Methodology section.

Circuit Length

Underground network length of circuit at each voltage

Table 6. below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 6.4: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex is required to report against the capacity variables for the whole network.	Demonstrated in Methodology section.

Requirements (instructions and definitions)	Consistency with requirements
The network includes overhead power lines and towers, underground cables and pilot cables that transfer electricity from the regional bulk supply points supplying areas of consumption to individual zone substations, to distribution substations and to customers.	Demonstrated in section 9.4 (Methodology). Energex's figures do not include pilot cables as they are a secondary system, as per the definition below.
The network also includes distribution feeders and the low voltage distribution system but excludes the final connection from the mains to the customer and also wires or cables for public lighting, communication, protection or control and for connection to unmetered loads.	Demonstrated in Methodology section.
Specify the voltage for each 'other' voltage level, where applicable.	Energex does not have any other voltage levels to those specified in the AER's RIN Instructions and Definitions.
Circuit length is calculated from the Route length (measured in kilometres) of lines in service (the total length of feeders including all spurs), where each SWER line, single-phase line, and three-phase line counts as one line. A double circuit line counts as two lines. The length does not take into account vertical components such as sag.	Demonstrated in Methodology section.

Distribution Transformer Total Installed Capacity

Table 6.2 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 6.2: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must report total installed Distribution Transformer Capacity.	Demonstrated in the Methodology section
The total installed Distribution Transformer Capacity is the transformer capacity involved in the final level of transformation, stepping down the voltage used in the distribution lines to the level used by the customer. It does not include intermediate transformation capacity (e.g. 132 kV or 66 kV to the 22 kV or 11 kV distribution level).	Demonstrated in the Methodology section
The capacity measure is the normal nameplate continuous capacity/rating (including forced cooling and other factors used to improve capacity).	Demonstrated in the Methodology section
The measure includes Cold Spare Capacity of Distribution Transformers and excludes the capacity of all zone substation transformers, voltage transformers (potential transformers) and current transformers.	Demonstrated in the Methodology section
The transformer capacity owned by Energex is to be reported using the nameplate continuous rating including forced cooling.	Demonstrated in the Methodology section The data does not include forced cooling as it is not applicable for Energex.
The transformation capacity from high voltage to customer utilisation voltage that is owned by customers connected at high voltage is to be provided.	Demonstrated in the Methodology section
Where the transformer capacity owned by customers connected at high voltage is not available, the summation of individual Maximum Demands of high voltage customers whenever they occur is required to be provided (i.e. the summation of single annual Maximum Demand for each customer) as a proxy for delivery capacity within the high voltage customers.	Demonstrated in the Methodology section

Energex must report the total capacity of spare transformers owned by Energex but not currently in use.	Demonstrated in the Methodology section
A Distribution Transformer is a transformer that provides the final voltage transformation in the electricity distribution system, stepping down the voltage used in the distribution lines to the level used by the customer.	Demonstrated in the Methodology section
The Cold Spare Capacity is the capacity of spare transformers owned by Energex but not currently in use. Cold Spare Capacity incorporates both spare capacity and cold capacity. Cold capacity is equipment which is already on site, with connections already in place so that the device can be brought into service merely by switching operations but which is not normally load carrying. Spare capacity also includes spare assets, on site, or in the store, where physical movement and/or making of connections would require manual intervention at the site of use.	Demonstrated in the Methodology section

Sources

Circuit Length

Overhead network length of circuit at each voltage

The circuit lengths at each voltage level were extracted from the Network Facilities Management (NFM) database. This is outlined in Table 6. below:

Table 6.6: Data Source for overhead network length of circuit at each voltage

Variable Code	Variable	Source
DPA0101	Overhead low voltage distribution	DMA
DPA0102	Overhead 2.2 kV	Not Applicable
DPA0103	Overhead 6.6 kV	Not Applicable
DPA0104	Overhead 7.6 kV	Not Applicable
DPA0105	Overhead 11 kV	DMA
DPA0106	Overhead SWER	DMA
DPA0107	Overhead 22 kV	Not Applicable
DPA0108	Overhead 33 kV	DMA
DPA0109	Overhead 44 kV	Not Applicable
DPA0110	Overhead 66 kV	Not Applicable
DPA0111	Overhead 110 kV	DMA
DPA0112	Overhead 132 kV	DMA
DPA0113	Overhead 220 kV	Not Applicable
DPA0114	Other	Not Applicable
DPA01	Total overhead circuit km	DMA

The NFM database is the master electronic record of all network assets and their connectivity. NFM is populated from completed field work orders and reflects the "as constructed" state of the network. This information is then stored in DMA.

Because practical completion is required before capture can occur, there is a delay in the capture of data. Energex currently captures approximately 50% of all records within 20 days of commissioning.

Circuit Capacity (33kV, 110kV, 132kV)

Table 6. below demonstrates the sources from which Energex obtained the required information.

Table 6.7: Data Sources

Variable Code	Variable	Source
DPA0307	Overhead 33kV	Powerfactory, GIS/NFM, ERAT2, DMA
DPA0409	Underground 33kV	Powerfactory, GIS/NFM, ERAT2, DMA
DPA0310	Overhead 110kV	PSS/E, GIS/NFM, DMA, MS
DPA0311	Overhead 132kV	PSS/E, GIS/NFM, DMA, MS
DPA0411	Underground 110kV	PSS/E, GIS/NFM, DMA, MS

Energex also used SIFT or Mailbot to investigate the commissioning date of feeders.

Circuit Capacity (Low voltage, 11kV and SWER)

The primary information sources used to extract the necessary data to calculate the circuit capacities for 11kV was Powerfactory and for SWER the NFM database. This is outlined in Table 6. and Table 6.:

Table 6.8: Data source for estimated overhead network weighted average MVA capacity by voltage class

Variable Code	Variable	Source
DPA0301	Overhead low voltage distribution	NFM
DPA0304	Overhead 11kV	Powerfactory
DPA0305	Overhead SWER	NFM

Table 6.9: Data source for estimated underground network weighted average MVA capacity by voltage class

Variable Code	Variable	Source
DPA0401	Underground low voltage distribution	NFM
DPA0405	Underground 11kV	Powerfactory

Energex also used the Plant Rating Manual and the ERAT corporate ratings tool to validate the datasets and to develop estimation methods.

Circuit Length

Underground network length of circuit at each voltage

Table 6.10: Data Source for underground network length of circuit at each voltage

Variable Code	Variable	Source
DPA0201	Underground low voltage distribution	DMA
DPA0202	Underground 5 kV	Not Applicable
DPA0203	Underground 6.6 kV	Not Applicable
DPA0204	Underground 7.6 kV	Not Applicable
DPA0205	Underground 11 kV	DMA
DPA0206	Underground SWER	DMA
DPA0207	Underground 22 kV	Not Applicable
DPA0208	Underground 33 kV	DMA
DPA0209	Underground 66 kV	Not Applicable
DPA0210	Underground 110 kV	DMA
DPA0211	Underground 132 kV	DMA
DPA0212	Other	Not Applicable
DPA02	Total underground circuit km	DMA

The NFM database is the master electronic record of all network assets and their connectivity. NFM is populated from completed field work orders and reflects the "as constructed" state of the network. This information is then stored in DMA.

Because practical completion is required before capture can occur, there is a delay in the capture of data. Energex currently captures approximately 50% of all records within 20 days of commissioning.

Distribution Transformer Total Installed Capacity

The input data for the distribution transformer total installed capacity variables were extracted from the NFM database, PEACE and Ellipse. NFM and Ellipse information is then stored in DMA for reporting purposes. The information for Distribution Transformer Capacity owned by High Voltage Customers was retrieved directly from Peace.

Table 6. demonstrates the sources from which Energex obtained the required information.

Table 6.11: Data sources for Distribution Transformer Total Installed Capacity

Variable Code	Variable	Source
DPA0501	Distribution Transformer Capacity owned by utility	DMA
DPA0503	Cold Spare Capacity included in DPA0501	DMA

- The NFM database is the master electronic record of distribution transformer installed capacity and their connectivity. It is populated from completed field work orders and reflects "as constructed" state of the network.

- PEACE is Energex's billing system and was used to source the input data used to calculate the distribution transformer capacity owned by high voltage customers.
- Ellipse is an Enterprise Resource Planning system used by Energex to manage internal and external resources including assets, financial resources, materials, and human resources. It is grouped into sub-systems providing:
  - Maintenance and repair scheduling;
  - Workforce management, resource allocation, skills, training and payroll;
  - Materials management and resource management; and
  - Financial management.

Methodology

Circuit Length

Overhead network length of circuit at each voltage

The following approach was applied to calculate the variables:

- The data for the current year was obtained by running DMA Reports. In particular the DMA Reports were run to extract data for each of the voltage levels. The SWER lines were separated from the 11kV overhead lines by identifying the feeders and the conductor count. The reports extracted data for the overhead and underground circuit length of each voltage level.

Circuit Capacity (33kV, 110kV, 132kV)

The following approach is applied to calculating the values for 33kV, 110kV and 132kV feeders:

1. The feeder rating data for 2020-21 is obtained from the DMA system. If the feeders were identified in DMS to be thermally limited by its circuit breaker, the circuit breaker rating is then used to represent the thermal limit rating of the feeder.
2. The 33kV network is modelled in Powerfactory and the 110kV and 132kV network is modelled in PSSE. Both models use 2020 summer and winter forecasts to identify the highest utilised feeder section and its seasonal maximum demand to determine whether the summer or winter rating is to be applied in the calculation.
3. For feeders which are the limiting element (not limited by circuit breaker rating capacity) with multiple tee-off points, the rating of the entire feeder is represented by the feeder rating section of the lowest rate section.

4. The current basis of preparation requires Energex to segregate the 33kV, 110kV and 132kV feeders as a separate category. This separation is done based on the allocated voltage level for each feeder as per the DMA report and verified through Energex's PSS/E models, Powerfactory models and DMS system.

5. Line length data is extracted from DMA and is subsequently matched to each corresponding feeder name and rating.

6. To obtain the weighted average MVA, each feeder is then segregated into its respective voltage levels and UG and OH components based on the DMA feeder length report.

7. Each feeder length component is then multiplied by its corresponding rating and aggregated.

8. The total is then divided by the total feeder UG/OH section length to obtain the weighted average MVA. The formula below is applied:

$$\text{UG weighted average MVA} = \frac{\sum_{N}(MVA_N \times UG\_Length_N)}{Total\_UG\_Length}$$

$$\text{OH weighted average MVA} = \frac{\sum_{N}(MVA_N \times OH\_Length_N)}{Total\_OH\_Length}$$

Where:

- MVA is the constrained feeder rating of feeder N
- UG_length is the total length of UG component of feeder N (km)
- OH_length is the total length of OH component of feeder N (km)
- Total_UG_Length is the aggregated UG feeder length of all 33kV, 110kV or 132kV energised circuits in the Energex network (km)
- Total_OH_Length is the aggregated OH feeder length of all 33kV, 110kV or 132kV energised circuits in the Energex network (km)

Circuit Capacity (Low voltage, 11kV and SWER)

The following approach was applied to calculating LV:

1. Low voltage (LV) circuit line lengths were obtained by conductor description for overhead and underground for Regulatory Year ending 30 June 2021 (this data is covered in the Basis of Preparation for circuit lengths). The circuit line length and conductor data was cross checked

for consistency with the total lengths data for overhead and underground conductors provided in the RIN;

2. A conductor rating table was created by:

   (ii) Assigning a thermal rating to the unique list of conductor types/sizes installed on the network (based on its description) using the Energex Plant Rating Manual or Conductor Catalogues (if necessary);

   (iii) For all overhead conductors types/sizes listed in the Plant Rating Manual, the summer day thermal ratings for Category A sub-circuits for 55 degrees and 75 degrees conductor temperature stringing were extracted;

   (iv) All overhead conductors types/sizes installed on the network were classified with ratings extracted from the Plant Rating Manual as either "imperial" or "metric" conductor;

   (v) A 55 degree rating was assigned to overhead conductors with an "imperial" type/size and a 75 degree rating was assigned to overhead conductors with a "metric" type/size; and

   (vi) For overhead conductors installed on the network not listed in the Plant Rating Manual, a summer day thermal rating with reference to the Olex Aerial Catalogue and Nexan's Handbook was assigned for the nearest stringing conductor temperature of 75 degrees;

3. The overhead and underground average thermal de-rating factors were determined. This involved estimating the thermal de-rating factors for LV overhead and underground designed networks to account for contingency load and voltage limitations.

4. The average thermal de-rating factors for conductors were applied. This involved:

   (vii) Assigning the overhead and underground average thermal estimated de-rating factors to the thermal rating of each conductor type (0.8 for UG and 0.7 for OH) to determine the voltage limited rating of each conductor; and

   (viii) Summating the voltage limited conductor rating multiplied by the length of conductor (amps multiplied by km's) for overhead and underground categories;

5. The weighted average voltage limited circuit rating (Amps) for overhead and underground was obtained by using the following formulas:

$$underground\ Rating\ MVA =$$

$$\frac{\sum^{UG\ conductor\ types} Conductor\ type\ rating\ \times conductor\ type\ length}{System\ Total\ UG\ circuit\ length}$$

$$overhead\ Rating\ MVA =$$

$$\frac{\sum^{OH\ conductor\ types} Conductor\ type\ rating\ \times conductor\ type\ length}{System\ Total\ OH\ circuit\ length}$$

6. The weighted average voltage limited circuit rating in Amps was converted to MVA by multiplying by sqrt(3) * 415V and dividing by 1,000,000.

The following approach was applied to calculating the variables for 11kV and SWER:

- The Powerfactory length data was compared to the length data obtained from NFM. Discrepancies were investigated to ensure validity of both source data sets where possible;
- The Powerfactory constrained feeder capacity was cross-checked against the ERAT corporate operational ratings tool; and
- Each cable segment was categorised as overhead or underground.

Different approaches were applied for feeder capacity and are set out below:

- For 11kV conductors, the constrained rating (capacity) of a feeder was determined by finding the highest thermal utilisation of each cable segment in the feeder or the highest voltage drop on the feeder. These values were scaled until the thermal or voltage limited segment reached 100% capacity or would exceed the voltage drop threshold. The capacity of all conductor segments in that circuit were then calculated at the loading where no thermal or voltage limitations were exceeded along the circuit;
- For the SWER conductors, capacity was taken as the rating of the SWER isolation transformer as this was the limiting factor for the capacity of the SWER feeders. The nameplate rating of these transformers was used to represent the constraint rating for these feeders;
- For 11kV, each segment length was then multiplied by the segment demand at the feeder's thermal or voltage limited capacity;
- For SWER, the length of conductor off each isolation transformer was multiplied by the capacity;

- The total was then divided by the total feeder UG/OH length section to obtain the weighted average MVA; and
- The formula below was applied:

$$\text{UG weighted average MVA} = \frac{\sum_{N}(MVA_N \times UG\_SegmentLength_N)}{Total\_UG\_SegmentLength}$$

$$\text{OH weighted average MVA} = \frac{\sum_{N}(MVA_N \times OH\_SegmentLength_N)}{Total\_OH\_SegmentLength}$$

Where:

- MVAN is the capacity of the segment at the constrained rating of the segment in the feeder
- UG_SegmentLengthN is the total UG length (km) of segment
- OH_SegmentLengthN is the total OH length (km) of segment
- Total_UG_SegmentLength is the total UG feeder length in the Energex network
- Total_OH_SegmentLength is the total OH feeder length in the Energex network

Circuit Length

Underground network length of circuit at each voltage

The following approach was applied to calculate the variables:

- The data for the current year was obtained by running DMA Reports. In particular the DMA Reports were run to extract data for each of the voltage levels. The SWER lines were separated from the 11kV overhead lines by identifying the feeders and the conductor count. The reports extracted data for the overhead and underground circuit length of each voltage level.

Distribution Transformer Total Installed Capacity

The following approach was applied to calculating the distribution transformer capacity owned by utility (DPA0501):

- The data was obtained by running the DMA Report for the current period;

- The data was then combined into a master document and arranged into the AER BoP format; and
- Cold spare capacity was added to the distribution transformer installed capacity to give total distribution transformer capacity owned by Energex.

The following approach was applied to calculating the Cold spare capacity included in DPA0501 (DPA0503):

- The data was obtained through the DMA report, this report is generated from a database containing daily snapshots of inventory held in Ellipse;
- Distribution transformer assets were extracted from the report as at the 30th of June; and
- Distribution transformer capacity was extracted from the stock code description.

Assumptions

Circuit Length

Overhead network length of circuit at each voltage

The following assumptions and limitations apply to the data:

- Customer owned conductors were generally not captured in the NFM database. However, there were a limited number of instances where:
    - Energex operated the network through these customer assets and therefore required them to be captured; or
    - Selected assets had been sold to customers and the assets may not have been removed from the NFM (this had an immaterial impact on the data).
- Energex limited the impact customer owned conductors would have on reported lengths by assuming that where two customer-owned assets are joined together, the conductor facilitating this connection was also customer-owned. All other instances were unable to be identified and have been included in the overall figure.
- The conductor data does not include conductors that are in store or held for spares.
- The circuit length data only includes those lines that are in service. Conductors that are in the field but de-energised have not been included.
- The length of each conductor category was the total conductor route length and not each individual phase conductor length, however:

  - Routes 11 kV and above predominately consist of 3 conductors. However there are some 11 kV routes that are one or two conductors, these are included in the total length; and
  - LV routes predominately consist of 4 conductors: 3 phases plus neutral, however lengths provided include all variations.
- All lengths stated exclude any vertical components to the conductor, such as sag and vertical tails.

Circuit Capacity (33kV, 110kV, 132kV)

The following criteria underpin the calculation of these values:

- All values are based on energised operating voltage.
- 'Energex's peak' (as set out in the AER's Instructions and Definitions) is deemed to be Energex system peak.

Circuit Capacity (Low voltage, 11kV and SWER)

In relation to the LV circuit line lengths used to calculate the weighted average circuit ratings, the following assumptions were made:

- Customer owned conductors were generally not captured in the NFM database. However, there were a limited number of instances where:
- Energex operated the network through these customer assets and therefore required them to be captured; or
- Selected assets had been sold to customers and the assets may not have been removed from the NFM (which had an immaterial impact on the data.

In these few instances Energex was unable to exclude the conductors;

- The conductor data does not include conductors that are in store or held for spares;
- The length of each conductor category was the total conductor route length and not each individual phase conductor length. In particular, LV routes predominately consist of 4 conductors (namely 3 phases plus neutral). However, it should also be noted that lengths provided include all variations;
- All lengths stated exclude any vertical components to the conductor, such as sag and vertical tails; and
- As a single line diagram was used, where multiple conductors were present within the single line the conductor with the highest count was chosen. Where multiple different conductors were found with the same count then the last installed conductor was chosen.

In addition, the following assumptions and limitations also underpin the calculation of these variables:

- Energex's LV asset level has a thermal summer voltage limiting rating (as set out in the AER's RIN Instructions and Definitions);
- Where an individual conductor was not included in the Energex Plant Rating Manual or Conductor Catalogues, the rating associated with the nearest listed conductor was used for that conductor. The impact of this assumption was immaterial on the overall data, as there was a small number of instances where this occurred and it did not relate to current standard conductors;
- Overhead (aerial) metric conductors are assumed to be strung to a conductor temperature design of 75 degrees. Conductor stringing to 75 degrees was introduced around the 1980's and is closely aligned to the introduction of metric conductors. Prior to the metric conductors, imperial conductors were used and strung to a more conservative conductor temperature of 55 degrees;
- The underground conductors were assigned a thermal summer day (inducts) rating from the Plant Rating Manual;
- A single average thermal de-rating factor for overhead conductors and a single average thermal de-rating factor for underground conductors to account for contingency loading and voltage limitations were derived from the experience of Energex planning and design staff; and
- The average thermal de-rating factors are applied globally to the conductors in the overhead and underground categories rather than identify individual LV circuits and their individual limiting conductors. Values are therefore based on estimated data.

The following assumptions underpin the calculation of 11kV and SWER:

- 'Energex's peak' (as set out in the AER's Instructions and Definitions) was interpreted as being the system peak season, rather than the peak associated with individual assets. Therefore, network capacities have been calculated based on summer day loads and ratings; and
- The circuit constraint was identified by assuming any increase in load was applied in proportion to the Powerfactory load flow allocated load.
- All of the results are based on feeder's the energised operating voltage.

Circuit Length

Underground network length of circuit at each voltage

The following assumptions and limitations apply to the data:

- Customer owned conductors were generally not captured in the NFM database. However, there were a limited number of instances where:
  - Energex operated the network through these customer assets and therefore required them to be captured; or
  - Selected assets had been sold to customers and the assets may not have been removed from the NFM (this had an immaterial impact on the data).
- Energex limited the impact customer owned conductors would have on reported lengths by assuming that where two customer-owned assets are joined together, the conductor facilitating this connection was also customer-owned. All other instances were unable to be identified and have been included in the overall figure.
- The conductor data does not include conductors that are in store or held for spares.
- The circuit length data only includes those lines that are in service. Conductors that are in the field but de-energised have not been included.
- The length of each conductor category was the total conductor route length and not each individual phase conductor length, however:
  - Routes 11 kV and above predominately consist of 3 conductors. However there are some 11 kV routes that are one or two conductors, these are included in the total length; and
  - LV routes predominately consist of 4 conductors: 3 phases plus neutral, however lengths provided include all variations.
- All lengths stated exclude any vertical components to the conductor, such as sag and vertical tails.

Distribution Transformer Total Installed Capacity

The following assumptions and limitations apply to "Distribution transformer capacity owned by utility" (DPA0501):

- Total installed transformer capacity (MVA) was reported using the recorded nameplate rating from NFM;
- Only the normal state of the network was taken into account;
- Only transformers recorded in DMA as connected to the network and with a nameplate rating at the time specified were included in the data;

- Non-Energex owned assets were excluded from the data; and
- The capacity data includes assets that are in store or held for spares.

The following assumptions and limitations apply to Cold Spare Capacity included in DPA0501 (DPA0503):

- The number and mix of assets held in stores varies each day. Stock levels are as of 30th of June;
- Actual Information was available for the current year.
- Energex does not have store transformer assets that are only for cold capacity. Energex stores all distribution transformers at store locations, these assets can be used for any situation whether it is for replacement of failed equipment or for future works; and
- The capacity includes strategic spares as well as normal stock holding owned by Energex.

Estimated Information

Energex has provided actual information for all categories except Circuit Capacity (Low voltage, 11kV and SWER).

Circuit Capacity (Low voltage, 11kV and SWER)

For the 11kV capacities, the Powerfactory network model and ERAT database only provide the current state of the network. No historical values are available for the Powerfactory network model. However, ERAT circuit ratings are published annually in the Distribution Annual Planning Report (DAPR) and historically in the Network Management Plan (NMP). The ERAT rating is based on the feeder backbone conductors and this is used to provider operational ratings. Furthermore, these ratings are not separated into overhead or underground components.

For the 2020-21 year capacities, load flow analysis was undertaken to identify the capacity limitation for each feeder by determining the thermal or voltage limit. This has been used to determine the weighted average capacity for the network in 2020-21.

Energex believes the estimate supplied is its best estimate based on the available information at the time.

Explanatory Notes

Circuit Length

Overhead network length of circuit at each voltage

The figures stated for circuit length in RIN tables 3.5.1.1 and 3.5.1.2 may differ from those used in the calculation of circuit capacity in RIN tables 3.5.1.3 and 3.5.1.4. Data for circuit length has been reported previously on an "as constructed" basis and the same methodology has been used in these variables to ensure consistency. The circuit length used for the calculation of circuit capacities in RIN tables 3.5.1.3 and 3.5.1.4 is on an "as operated basis".

Circuit Capacity (33kV, 110kV, 132kV)

The figures stated for circuit length in RIN tables 3.5.1.1 and 3.5.1.2 may differ from those used in the calculation of circuit capacity in RIN tables 3.5.1.3 and 3.5.1.4. Data for circuit length has been reported previously on an "as constructed" basis and the same methodology has been used in these variables to ensure consistency. This aligns with the table requirement for circuit length by "voltage".

The circuit length used for the calculation of circuit capacities in RIN tables 3.5.1.3 and 3.5.1.4 is on an "as operated basis". This aligns with the table requirement for circuit length by "voltage" class.

The Energex network does not comprise 22kV, 44kV, 66kV or 220kV voltage classes, therefore zero values have been provided for these voltage classes.

Rating Conversion

Energex line ratings are expressed in current capacity (A), the conversion from A to MVA is done assuming nominal voltage. The equation below shows the example of calculating the rating of a 33kV feeder. The same equation applies for 110kV and 132kV feeders.

$$\text{Rating (A)} \times 33000\ \text{(V)} \times \sqrt{3} / 1000000 = \text{Rating (MVA)}$$

Circuit Capacity (Low voltage, 11kV and SWER)

Rating Conversion

Energex line ratings are expressed in current capacity (A), the conversion from A to MVA was done assuming nominal voltage of 11kV.

$$Rating(A) * 11000(V) * \sqrt{3}/1000000 = Rating(MVA)$$

Circuit Length

Underground network length of circuit at each voltage

The figures stated for circuit length in RIN tables 3.5.1.1 and 3.5.1.2 may differ from those used in the calculation of circuit capacity in RIN tables 3.5.1.3 and 3.5.1.4. Data for circuit length has been reported previously on an "as constructed" basis and the same methodology has been used in these variables to ensure consistency. The circuit length used for the calculation of circuit capacities in RIN tables 3.5.1.3 and 3.5.1.4 is on an "as operated basis".

Note: 132kV underground has been reported as nil for 2019-20 because two now operate at voltage 110kV.

Table 3.5.2 - Transformer Capacities

Compliance with the RIN Requirements

Table 6.12: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must report total installed Distribution Transformer Capacity.	Demonstrated in Methodology section.
The total installed Distribution Transformer Capacity is the transformer capacity involved in the final level of transformation, stepping down the voltage used in the distribution lines to the level used by the customer. It does not include intermediate transformation capacity (e.g. 132 kV or 66 kV to the 22 kV or 11 kV distribution level).	Demonstrated in Methodology section.
The capacity measure is the normal nameplate continuous capacity/rating (including forced cooling and other factors used to improve capacity).	Demonstrated in Methodology section.
The measure includes Cold Spare Capacity of Distribution Transformers and excludes the capacity of all zone substation transformers, voltage transformers (potential transformers) and current transformers.	Demonstrated in Methodology section.
The transformer capacity owned by Energex is to be reported using the nameplate continuous rating including forced cooling.	Demonstrated in Methodology section. The data does not include forced cooling as it is not applicable for Energex.
The transformation capacity from high voltage to customer utilisation voltage that is owned by customers connected at high voltage is to be provided.	Demonstrated in Methodology section.
Where the transformer capacity owned by customers connected at high voltage is not available, the summation of individual Maximum Demands of high voltage customers whenever they occur is required to be provided (i.e. the summation of single annual Maximum Demand for each customer) as a proxy for delivery capacity within the high voltage customers.	Demonstrated in Methodology section.
Energex must report the total capacity of spare transformers owned by Energex but not currently in use.	Demonstrated in Methodology section.
Energex must report the transformer capacity used for intermediate level transformation capacity in either one or two steps.(For example, high voltages such as 132 kV, 66 kV or 33 kV at the zone substation level to the distribution level of 22 kV, 11 kV or 6 kV.)	Demonstrated in Methodology section.
These measures are required to be the summation of normal assigned continuous capacity/rating (with forced cooling or other capacity improving factors included) and include both energised transformers and Cold Spare Capacity.	Demonstrated in Methodology section.
Where available, the assigned rating must be determined from results of temperature rise calculations from testing. Otherwise the nameplate rating is to be provided. For those zone substations where the thermal capacity of exit feeders is a constraint, thermal capacity of exit feeders should be reported instead of transformer capacity.	Demonstrated in Methodology section.
The total installed capacity for first step transformation where there are two steps to reach distribution voltage (DPA0601) includes, for example, 66 kV or 33 kV to 22 kV or 11 kV where there will be a second step transformation before reaching the distribution voltage.	Demonstrated in Methodology section.

Requirements (instructions and definitions)	Consistency with requirements
This variable is only relevant where Energex has more than one step of transformation, if this is not the case Energex must enter '0' for this variable.	
The total installed capacity for second step transformation is required to be reported where there are two steps to reach distribution voltage (DPA0602). (e.g. 66 kV or 33 kV to 22 kV or 11 kV where there has already been a step of transformation above this at higher voltages within Energex's system.) This variable is only relevant where Energex has more than one step of transformation, if this is not the case Energex must enter '0' for this variable.	Demonstrated in Methodology section.
The total zone substation transformer capacity where there is only a single transformation to reach distribution voltage is to be reported (DPA0603). This variable is only relevant where there is only a single step of transformation to reach distribution voltage. If there is more than one step of transformation to reach distribution voltage, the relevant capacities must be reported in DPA0601 and DPA0602.	Demonstrated in Methodology section.
The total zone substation transformer capacity (DPA0604) is the overall total zone substation capacity regardless of whether one or two steps are used to reach the distribution	Demonstrated in Methodology section.
voltage (for example DPA0604 will be the sum of DPA0601, DPA0602, DPA0603 and DPA0605.)	Demonstrated in Methodology section.
The total Cold Spare Capacity included in total zone substation transformer capacity is to be provided.	Demonstrated in Methodology section.
A Distribution Transformer is a transformer that provides the final voltage transformation in the electricity distribution system, stepping down the voltage used in the distribution lines to the level used by the customer.	Demonstrated in Methodology section.
Cold spare capacity is the capacity of spare transformers owned by Energex but not currently in use. Cold Spare Capacity incorporates both spare capacity and cold capacity. Cold capacity is equipment which is already on site, with connections already in place so that the device can be brought into service merely by switching operations but which is not normally load carrying. Spare capacity also includes spare assets, on site, or in the store, where physical movement and/or making of connections would require manual intervention at the site of use.	Demonstrated in Methodology section.

Sources

Zone Substation Transformer Capacity

The zone substation transformer total installed capacities were extracted from the Substation Investment Forecasting Tool (SIFT). This is outlined in Table 6.3 below:

Table 6.3: Data sources for Zone Substation Transformer Capacity

Variable Code	Variable	Source
DPA0601	Total installed capacity for first step transformation where there are two steps to reach distribution voltage	SIFT

Variable Code	Variable	Source
DPA0602	Total installed capacity for second step transformation where there are two steps to reach distribution voltage	SIFT
DPA0603	Total zone substation transformer capacity where there is only a single step transformation to reach distribution voltage	SIFT
DPA0604	Total zone substation transformer capacity	SIFT
DPA0605	Cold spare capacity of zone substation transformers included in DPA0604	SIFT/DMA/Ellipse

Distribution Transformer Capacity owned by High Voltage Customers

Energex also used the Plant Rating Manual and the ERAT corporate ratings tool to validate the datasets and to develop estimation methods.

The input data for the distribution transformer total installed capacity variables were extracted from the NFM database, PEACE and Ellipse. NFM and Ellipse information is then stored in DMA for reporting purposes. The information for Distribution Transformer Capacity owned by High Voltage Customers was retrieved directly from Peace.

Table 6. demonstrates the sources from which Energex obtained the required information.

Table 6.14: Data sources for Distribution Transformer Capacity owned by High Voltage Customers

Variable Code	Variable	Source
DPA0502	Distribution Transformer Capacity owned by High Voltage Customers	PEACE

- The NFM database is the master electronic record of distribution transformer installed capacity and their connectivity. It is populated from completed field work orders and reflects "as constructed" state of the network.
- PEACE is Energex's billing system and was used to source the input data used to calculate the distribution transformer capacity owned by high voltage customers.
- Ellipse is an Enterprise Resource Planning system used by Energex to manage internal and external resources including assets, financial resources, materials, and human resources. It is grouped into sub-systems providing:
    - Maintenance and repair scheduling;
    - Workforce management, resource allocation, skills, training;
    - Materials management and resource management; and

Methodology

Zone Substation Transformer Capacity

The following approach was applied to calculating the variables:

- The data was extracted from SIFT as at June and based on Normal Cyclic NCC rating which Energex uses to operate the network;
- The rating includes fans and allows for the load temperature rise test determined by the load profile;
- The following assets meet the definitions presented by the AER:
    - For DPA0601: 110 kV-33 kV or 132 kV-33 kV substations are a first step transformation where there are two steps to reach distribution voltage. These are referred to as bulk supply substations;
    - For DPA0602: 33 kV-11 kV substations are a second step transformation where there are two steps to reach distribution voltage. These are referred to as zone substations;
    - For DPA0603: 110 kV-11 kV or 132 kV-11 kV substations are a single step transformation to reach distribution voltage. These are referred to as direct transformation substations;
    - For DPA0604: the total capacities were the summation of all zone, bulk and direct transformation substation capacities; this also includes Cold Spare Capacity.
    - Cold capacity calculated for DPA0605 was subtracted from the SIFT extract to provide the final capacity value for DPA0601, DPA0602 and DPA0603.

Cold Spare Capacity of zone substation transformers included in DPA0604 (DPA0605) incorporates both cold capacity and spare capacity:

- The approach for calculating spare capacity was as follows:
    - The data was obtained via the DMA report, generated from a database containing daily snapshots of inventory held in Ellipse;
    - Power transformer assets were extracted from the report as at 30 June 2020;
    - Power transformer assets not yet logged by the warehouse as stock on hand have been included; and
    - Power transformer capacity was extracted from the stock code description.
- The approach for calculating cold capacity was as follows:

- The data was extracted from DMA and SIFT as at June each year and based on

Normal Cyclic rating which Energex uses to operate the network;

- The extract provided the standby capacity available at each substation.

Distribution Transformer Capacity owned by High Voltage Customers

The following approach was applied to calculating Distribution Transformer Capacity owned by High Voltage Customers (DPA0502):

- As the transformer capacity owned by customers at high voltage was largely not available, the calculation was based on the recorded annual peak demands; with each customers capacity estimated to be the standard transformer capacity greater than their historical peak demands and
- Where capacities were available these values were used.

Assumptions

Zone Substation Transformer Capacity

The following assumptions and limitations apply to the data:

- Active and hot standby substation transformer capacities have been included;
- No data has been excluded; and
- A snapshot of the data was taken at the end of the 2020-21 financial year.
- The following assumptions and limitations apply to the Cold Spare Capacity of zone substation transformers included in DPA0604 (DPA0605):
    - The number and mix of assets held in stores varies each day. Stock levels are as at 30 June 2021;
    - Spare capacity includes strategic spares as well as normal stock holding owned by Energex; and
    - Cold capacity includes transformers that are in service but do not carry load under normal conditions or are not connected.

Distribution Transformer Capacity owned by High Voltage Customers

The following assumptions and limitations apply to Distribution Transformer Capacity owned by High Voltage Customers (DPA0502):

- Transformer capacity for each high voltage customer is estimated from their individual annual peak demands recorded between 2018 and 2021.

Estimated Information

Zone Substation Transformer Capacity

Energex has provided actual information with the exception of Distribution Transformer Capacity owned by High Voltage Customers, which has been provided as Estimated information.

Justification

Energex is not able to directly find out what the capacity of each transformer is, as the transformers are owned by customers and located on the customer's sites.

Basis for Estimation

High voltage transformers are available in standard sizes. Customers tend to size their transformers to be slightly greater than their expected peak loads.

Energex believes the estimate supplied is its best estimate based on the available information at the time.

Explanatory Notes

Zone Substation Transformer Capacity

Energex utilises a number of transformers in standby configurations where a transformer is in service but does not carry load under normal conditions. In this configuration the transformers are commissioned, connected to the network and only require switching (manual, remote or automatic) in order to carry load. The calculation of these variables required inputs to be disaggregated in order to separate standby (cold) capacity from total installed capacity. An example of this calculation is shown in Table 6.:

Table 6.15: Calculation of total zone substation transformer capacity for 2020-21

Variable Code	Variable	Breakdown	Units	Value
DPA0601	Total installed capacity for first step transformation where there are two steps to reach distribution voltage. i.e. 132/33 kV	In service	MVA	8,254
DPA0602	Total installed capacity for second step transformation where there are two steps to reach distribution voltage. i.e. 33/11 kV	In service	MVA	8,597
DPA0603	Total zone substation transformer capacity where there is only a single step transformation to reach distribution voltage. i.e. 110/11 kV	In service	MVA	3,904

Variable Code	Variable	Breakdown	Units	Value
DPA0604	Total zone substation transformer capacity	**Total**	**MVA**	**21,302**
DPA0605	Cold spare capacity of zone substation transformers included in DPA0604	Total standby capacity for first step transformation where there are two steps to reach distribution voltage (Energex definition cold spare)	MVA	260
Total standby capacity for second step transformation where there are two steps to reach distribution voltage (Energex definition cold + hot spare)			MVA	286
Total standby zone substation transformer capacity where there is only a single step transformation to reach distribution voltage			MVA	
Total			**MVA**	546

Distribution Transformer Capacity owned by High Voltage Customers

The RIN includes a requirement to report information in RIN tables 3.5.1.3 and 3.5.1.4 as Actual Information from the 2016 regulatory year. On 21 July 2016, the AER advised that information in these tables is not required to be reported as Actual Information as the average values are inherently estimated.

Table 3.5.3 - Public Lighting

Compliance with the RIN Requirements

Public Lighting

Table 6. below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 6.16: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must report the number of public lighting luminaires and public lighting poles.	Demonstrated in Methodology section
For both variables the numbers provided must include both assets owned by Energex and assets operated and maintained by Energex but not owned by Energex.	Demonstrated in Methodology section
Only poles that are used exclusively for public lighting are to be included in the data.	Demonstrated in Methodology section

Sources

Public Lighting

The number of public lighting poles was sourced from the NFM database. The Data is then Stored in DMA.

Table 6.174 below demonstrates the sources from which Energex obtained the required information.

Table 6.174: Demonstration of Compliance

Variable Code	Variable	Source
DPA0701	Public lighting luminaires	NFM/SLIM
DPA0702	Public lighting poles	DMA

The NFM database is the master electronic record of the public lighting assets and their connectivity. It is populated from completed field work orders and reflects the normal, as constructed state of the network.

The SLIM program is a feeder system that captures inventory numbers for unmetered supply. Data entered into NFM feeds to SLIM in preparation for end of month billing.

Methodology

Public Lighting

The following approach was applied to calculating the variables:

- Public Lighting - Luminaires.

  - The EB RIN 3-5-3.sql script was run to extract the data for the Public lighting luminaires. This script reports the number of luminaires entered into NFM and stored in SLIM.

- Public Lighting Poles: The data was obtained by running Reports through the RIN Configuration Solution for the current year.

Note: Numbers may vary from CA 5.2 Asset age tables as methodologies differ between BoPs which results in the exclusion of some data.

- The Reports ensured that for both variables the data extracted included both assets owned by Energex, and assets operated and maintained by Energex but not owned by Energex. Further, only poles that are used exclusively for public lighting were included in the data.

- Luminaires reported in this RIN will not equal the figure reported for luminaires in CA RIN 5.2. This is because CA RIN 5.2 excludes non-spatial streetlights. Equipment are consider non spatial when they do not have a Latitude and longitude.

Assumptions

Public Lighting

The following assumptions and limitations apply to the data relating to public lighting luminaires:

- Only Rate 1, 2 and 4 streetlights have been included in this count;

- Streetlights data does not include assets that are in store or held for spares;

- Rating 3 & 8 have been excluded from this count because they are supplied, installed, owned and maintained by a Public Body; and

- Rating 9 watchman security lighting has also been excluded.

The following assumptions and limitations apply to the data relating to public lighting poles:

- The pole data does not include assets that are in store or held for spares;

- Only poles with a material type of 'steel' have been included;

Estimated Information

Not applicable. Energex has provided actual information.

Explanatory Notes

Public Lighting

Not applicable.

BoP – 3.6 Quality of Services

Table 3.6.1 - Reliability

Compliance with RIN Requirements

Energex has prepared the information provided in Template 3.6.1 Reliability, 3.6.2 System Losses and 3.6.3 Capacity Utilisation Network Feeders reported in accordance with the RIN requirements, including the Principles and Requirements set out in Appendix A and definitions in Appendix F to the RIN and with Economic Benchmarking RIN instructions and definitions (November 2013).

All entry fields which are shaded yellow indicating mandatory data fields have been populated.

Sources

Energex has used outage data from the corporate reporting system EPM (Energex Performance Management) which sources its data from PON (Power On). These combined sources were queried to retrieve all sustained transformer interruptions with their customer counts and durations.

Methodology

Table 3.6.1 Reliability

For the regulatory (financial) year 2020-21, Major Event Day Threshold (tMed 3.43) was calculated utilising 5 years of Daily SAIDI sustained data using the required STPIS methodology.

Table 3.6.1 DQS0101 to DQS0108: As relevant, Energex has applied definitions and methodology as set out in the AER's Electricity DNSPs, STPIS (December 2018), which remains applicable for the current regulatory control period. The following comments are made across all variables.

- Energex notes that Average number of customers (the number of distribution customers is calculated as the average of the number of customers at the beginning of the reporting period (1 July) and the number of customers at the end of the reporting period (30 June), rounded up to nearest whole number) was used as the denominator for the calculation as per the formula outlined in Appendix A of the AER's STPIS scheme.
- Only completed unplanned sustained (> 3 min) interruptions are included.
- In the absence of specification, Whole of Network statistics were assumed to encompass the Summation of CBD, Urban & Short Rural (Customer Minutes, Customer Interruptions and Customer Numbers).
- An event caused by a customer's electrical installation, failure or request of that electrical installation which only affects supply to that customer is not deemed an interruption as defined in STPIS 2018 [Appendix A]. These following events have been confirmed through

site inspection to have resulted from faults and failures within the customer's installation or request and as such are considered to be an event beyond the boundary of the DNSPs electricity supply network and therefore handled as an exclusion from reported reliability performance under the STPIS.

Inclusive of MEDs

The following comments are made in relation to specific Reliability variables, provided in Template 3.6 Table 3.6.1 (Reliability performance inclusive of MEDs).

DQS0101 - Whole of network unplanned SAIDI

- Relevant Financial Year (Between 1 July and 30 June)
- Completed unplanned sustained (> 3 min) interruptions
- Feeder Classification: Whole of network (summation of CBD, UR & SR)
- SAIDI calculation - Customer minutes divided by average number of customers
- Inclusive of the exclusions in accordance with clauses 3.3(a) & (b) of the AER's STPIS scheme and Customer Installation Faults/Failures which reside beyond the electricity supply network.

DQS0102 - Whole of network unplanned SAIDI excluding excluded outages

- Relevant Financial Year (Between 1 July and 30 June)
- Completed unplanned sustained (> 3 min) interruptions
- Feeder Classification: Whole of network (summation of CBD, UR & SR)
- SAIDI calculation - Customer minutes divided by average number of customers
- Inclusive of the exclusions in clause 3.3(b) and exclusive of exclusions in clauses 3.3(a) in accordance of the AER's STPIS scheme and exclusive customer installation faults/failures which reside beyond the electricity supply network.

DQS0103 - Whole of network unplanned SAIFI

- Relevant Financial Year (Between 1 July and 30 June)
- Completed unplanned sustained (> 3 min) interruptions
- Feeder Classification: Whole of network (summation of CBD, UR & SR)
- SAIFI calculation - Customers interrupted divided by average number of customers

- Inclusive of the exclusions in accordance with clauses 3.3(a) & (b) of the AER's STPIS scheme and Customer Installation Faults/Failures which reside beyond the electricity supply network.

DQS0104 - Whole of network unplanned SAIFI excluding excluded outages

- Relevant Financial Year (Between 1 July and 30 June)
- Completed unplanned sustained (> 3 min) interruptions
- Feeder Classification: Whole of network (summation of CBD, UR & SR)
- SAIFI calculation - Customers Interrupted divided by average number of customers
- Inclusive of the exclusions in clause 3.3(b) and exclusive of exclusions in clauses 3.3(a) in accordance of the AER's STPIS scheme and exclusive customer installation faults/failures which reside beyond the electricity supply network.

Exclusive of MEDs

The following comments are made in relation to specific Reliability variables, provided in Template 3.6 Table 3.6.1 (Reliability performance exclusive of MEDs).

DQS0105 - Whole of network unplanned SAIDI

- Relevant Financial Year (Between 1 July and 30 June)
- Completed unplanned sustained (> 3 min) interruptions
- Feeder Classification: Whole of network (summation of CBD, UR & SR)
- SAIDI calculation - Customer minutes divided by average number of customers
- Exclusive of the exclusions in clause 3.3(b) and Inclusive of exclusions in clauses 3.3(a) in accordance of the AER's STPIS scheme and Customer Installation Faults/Failures which reside beyond the electricity supply network.

DQS0106 - Whole of network unplanned SAIDI excluding excluded outages

- Relevant Financial Year (Between 1 July and 30 June)
- Completed unplanned sustained (> 3 min) interruptions
- Feeder Classification: Whole of network (summation of CBD, UR & SR)
- SAIDI calculation - Customers minutes divided by average number of customers

- Exclusive of the exclusions in accordance with clauses 3.3(a) & (b) of the AER's STPIS scheme and exclusive customer installation faults/failures which reside beyond the electricity supply network.

DQS0107 - Whole of network unplanned SAIFI

- Relevant Financial Year (Between 1 July and 30 June)
- Completed unplanned sustained (> 3 min) interruptions
- Feeder Classification: Whole of network (summation of CBD, UR & SR)
- SAIFI calculation - Customers Interrupted divided by average number of customers
- Exclusive of the exclusions in clause 3.3(b) and Inclusive of exclusions in clauses 3.3(a) in accordance of the AER's STPIS scheme and Customer Installation Faults/Failures which reside beyond the electricity supply network.

DQS0108 - Whole of network unplanned SAIFI excluding excluded outages

- Relevant Financial Year (Between 1 July and 30 June)
- Completed unplanned sustained (> 3 min) interruptions
- Feeder Classification: Whole of network (summation of CBD, UR & SR)
- SAIFI calculation - Customers Interrupted divided by average number of customers

Exclusive of the exclusions in accordance with clauses 3.3(a) & (b) of the AER's STPIS scheme and exclusive customer installation faults/failures which reside beyond the electricity supply network.

Assumptions

No assumptions were applied.

Estimated Information

Energex as provided 'Actual Information' (as per the AER's defined term) in relation to all Reliability statistics.

Data represents Actual performance only in relation to unplanned interruptions, as defined in the AER's STPIS scheme for Electricity DNSPs (December 2018).

Explanatory Notes

The information in this template is a non-financial data set, and accordingly is not impacted by any changes in accounting policy.

Table 3.6.2 – Energy Not Supplied

Compliance with the RIN Requirements

Energex has prepared the information provided in Template 3.6.2 Energy Not Supplied in accordance with the RIN requirements, including the Principles and Requirements set out in Appendix A and definitions in Appendix F to the RIN and with Economic Benchmarking RIN instructions and definitions (November 2013).

All entry fields which are shaded yellow indicating mandatory data fields have been populated.

Sources

Energex has sourced data from its internal outage management and asset management systems (PON/EPM/NFM) for the relevant regulatory year.

Consumption for the "Energy Not Supplied" was sourced from the Network billing system Peace.

Methodology

Refer to Table 3.6.2: As relevant, Energex has applied definitions and methodology as set out in the AER's Electricity DNSPs, STPIS (December 2018) and Economic Benchmarking RIN instructions and definitions (November 2013), which remains applicable for the current regulatory control period. The following comments are made across all variables.

- The Average number of customers (the number of distribution customers is calculated as the average of the number of customers at the beginning of the reporting period (1 July) and the number of customers at the end of the reporting period(30 June) was used as the denominator for the calculation as per the formula outlined in Appendix A of the AER's STPIS scheme.
- Only completed unplanned sustained (> 3 min) interruptions are included.
- In the absence of specification, Whole of Network statistics were assumed to encompass the Summation of CBD, Urban & Short Rural (Customer Minutes, Customer Interruptions and Customer Numbers).
- An event caused by a customer's electrical installation, failure or request of that electrical installation which only affects supply to that customer is not deemed an interruption as defined in STPIS 2018 [Appendix A]. These following events have been confirmed through site inspection to have resulted from faults and failures within the customer's installation or request and as such are considered to be an event beyond the boundary of the electricity

supply network and therefore handles as an exclusion from reported reliability performance under the STPIS.

The most recently updated meter consumption data sourced from Peace for each NMI was extracted, standardised and loaded into a table. The most recently updated feeder data from NFM linking each NMI to the relevant Feeder was joined to the meter data table. A query was then run to consolidate all NMIs' annual consumption data relating to each feeder to give their annual consumption. The total is then used to calculate the average customer consumption per minute per feeder.

Energex has estimated the Energy Not Supplied using data reported for unplanned/planned customer minutes off supply (Mins) multiplied by the average consumption by feeder (in minutes) sourced from Peace. This is in accordance with methodology Chapter 7, Table 7.2 approach three *"average consumption of customers on the feeder based on their billing history"* as defined in the Economic Benchmarking RIN instructions and definitions (November 2013) for energy not supplied, inclusive of the exclusions under clause 3.3(b) (Major Event Days) and exclusive of the exclusions in accordance with clauses 3.3(a) of the AER's STPIS scheme and exclusive of Customer Installation Faults/Failures or requests which reside beyond the electricity supply network.

The calculations are based on current connectivity by feeder and not connectivity at the time of the outage. For some feeders that are no longer active or have changed connectivity in the system the average consumption per minute over all feeders is used. The methodology adopted is irrespective of the time of day the outages occurred.

In any given year, there tend to be large individual energy not supplied figures, due to lengthy planned outages of large customers. The methodology outlined above can overstate the energy loss associated with these interruptions, as these large customers may have multiple points of connection to the Energex network. So, a customer may have been partially interrupted (e.g. an interruption to one transformer where the customer has multiple transformers supplying their load), but the customer's entire energy consumption for the interruption period is attributed to the interruption. A review of feeders with the highest planned energy not supplied figure was carried out, and where it was determined that a customer had multiple connection points, the feeder's energy not supplied figure was manually reduced by a factor of the number of points of supply to account for this.

This calculation was performed for both Planned and Unplanned interruptions, with Total Energy Not supplied being the sum of DQS0201 and DQS0202.

Assumptions

The following assumptions have been applied to calculating the required variables:

- Using a 12 month total for customer energy consumption, assumes that there is no load variation for outages which occur at differing times, days, or months. The materiality of this assumption will be low as outages are relatively evenly spread over time in a 12 month period.
- Where feeder customer energy consumption information cannot be determined, the "system" customer average (i.e. total system energy consumption divided by total number of customers) is used.
- The energy consumption data used is the most up to date that resides in the source system at the end of the financial year, data was only available for the current network configurations and as such all calculations were based on these figures.

Estimated Information

By definition, Energex has provided 'Estimated Information' in relation to all variables contained in Template 3.6 Table 3.6.2.

Historical feeder connectivity is not captured by Energex, and therefore current connectivity is assumed. Consumption is identified for all feeders and was multiplied by the customer minutes. Where there is no current connectivity an average consumption across all feeders was used.

This is consistent with the Instructions and Definition document issued by the AER in November 2013, which states

"When completing the templates for Regulatory Years subsequent to the 2013 Regulatory Year, if Energex can provide Actual Information for energy not supplied it must do so; otherwise Energex must provide Estimated Information."

Energex believes the estimates supplied are its best estimate based on the available information at the time.

Explanatory Notes

Energy Not Supplied is a non-financial data set, and accordingly is not impacted by any changes in accounting policy.

Table 3.6.3 - System Losses

Compliance with the RIN Requirements

Table 7. below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 7.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
System losses are the proportion of energy that is lost in distribution of electricity from the transmission network to Energex customers. Energex must report distribution losses calculated via the following equation: $$system\ losses = \frac{electricity\ imported - electricity\ delivered}{electricity\ imported} \times 100$$ This is a system wide figure inclusive of inflows from Embedded Generation and outflows to other DNSPs.	Energex has calculated system losses in line with the guidance provided by the AER. Refer to section 11.4 (Methodology) for details.

Sources

EB RIN Template 3.4 [variable DOPED01 - Total energy delivered and Tables 3.4.1.2 & 3.4.1.3]

Methodology

DQS03 - System losses is estimated, as it relies on DOPED01 - Total energy delivered, and DOPE0405 - Residential Embedded Generation at On-peak Times.

Justification for Estimated Information

- The energy delivered data is sourced from the PEACE Billing Software. It is quarterly billed so the data is not available for 3 to 4 months due to the meter reading processes. This means the data will not be finalised until the mid-October for a reported financial year.
- Energy purchased data on Residential Embedded Generation at On-peak Times record the total energy injected into the Energex Network system provided by domestic PV generation.

The data also comes from PEACE and therefore, is estimated due to the same reason discussed above.

Basis for Estimation

- Energex constructs a series of Monthly Energy Sales Models for different tariff groups (e.g. T4000s large non-domestic customers, T8000s medium/small non-domestic customers and T8400 domestic customers).
- These typical econometric models use key drivers such as Queensland Gross State Product (GSP), the number of new customer connections and weather variables (e.g.; temperature and relative humidity indices). They systematically analyse the underlying driving forces and try to capture the impacts of those key drivers on energy sales in both the short and long term. It therefore, provides a powerful tool for Energex to do energy forecasts.
- If the actual monthly data is available for a part of the year (for example, actual billing data are available for July ~ March), this data will be added to the estimated energy sales for the portion of the financial year that is unavailable to produce the full financial year figure. The energy sales for the unavailable portion of the financial year will be estimated based on those econometric models. If necessary, some adjustments may also be included in estimation based on the latest available information.

Assumptions

System loss figures are reported by Energex in the DLF reports each year. The DLF reports are calculated in the same manner to that specified by the AER for the EB RIN.

Two figures are required for the calculation of system losses, the electricity imported into the system and the electricity delivered from the system. The system loss percentage is then calculated as the energy loss divided by the total energy imported into the system.

- Electricity imported into the Energex network was obtained from metering data at system input points and summated for each Regulatory Year.
- Electricity sold to customers and exported from the system was obtained from the Energex billing system (PEACE) and was summated for each Regulatory Year. The difference

between these two figures was then calculated as the energy lost from the distribution system.

- The percentage system losses was then calculated using the following equation:

$$system\ losses = \frac{electricity\ imported - electricity\ delivered}{electricity\ imported} \times 100$$

Estimated Information

Justification

Customer meter data is manually read on a quarterly basis, leading to delays in the financial year's data being available for the Energy Not Supplied calculation. At the time of calculation, customer energy consumption data was only available up to April 2020 and not the complete financial year, so all values are considered "Estimated".

Basis for Estimation

The latest available 12 months of energy consumption was used in the calculation. For details and assumptions please see the methodology section above.

Energex believes the estimate supplied is its best estimate based on the available information at the time.

Explanatory Notes

Not applicable.

Table 3.6.4 - Capacity Utilisation

Compliance with the RIN Requirements

Table 7. below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 7.2: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Capacity utilisation is a measure of the capacity of zone substation transformers that is utilized each year. Energex must report the sum of non-coincident Maximum Demand at the zone substation level divided by summation of zone substation thermal capacity. For this measure, thermal capacity is the rated continuous load capacity of the zone substation (with forced cooling or other capacity improving factors included if relevant). This must be the lowest of either the transformer capacity or feeder exit capacity of the zone substation. Feeder exit capacity should similarly be the continuous rating.	Energex has calculated capacity utilisation in line with the guidance provided by the AER. Refer to section 10.4 (Methodology) for details.

Sources

Table 7. specifies the sources from which Energex obtained the required information.

Table 7.3: Sources

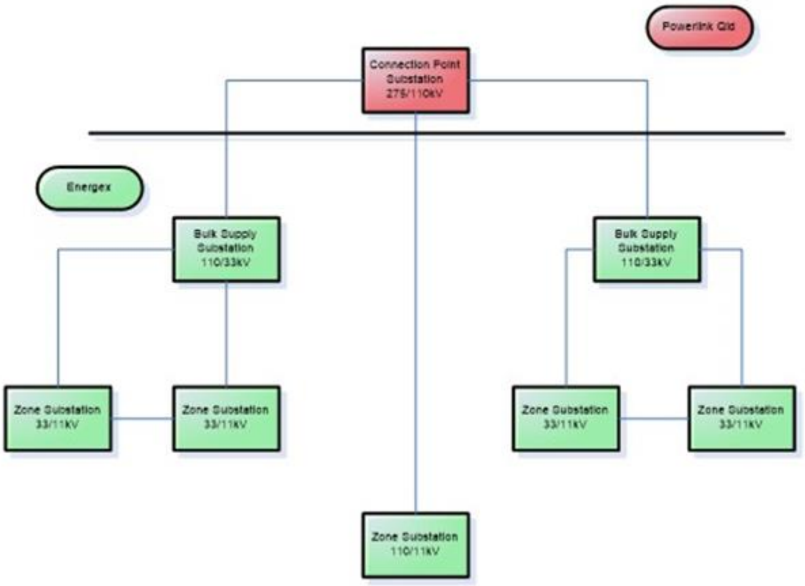
Variable Code	Variable	Source
DQS04	Overall capacity utilisation	SIFT (for ratings), SCADA (for load)

Methodology

The network capacity utilisation is calculated as the percentage utilisation of zone sub-station thermal capacity. This is calculated using the total network non-coincident maximum demand (DOPSD0201) divided by the total network zone sub-station thermal capacity (DPA0604) excluding cold spare capacity of zone substation transformers included in DPA0604 (DPA0605), i.e.: DOPSD0201/ DPA0604-DPA0605).

1. The total network non-coincident maximum demand was obtained from the Energex Metering system and summated for each Regulatory Year (DOPSD020.
2. The zone substation thermal capacity was extracted from the Energex SIFT and ERAT systems for each Regulatory Year. The thermal capacities included the nameplate capacities as well as any extra capacity added for cooling upgrades (DPA0604).
3. The calculation specified by the AER is not correct for estimating overall system utilisation. DPA0604 is a summation of the Energex bulk supply and zone substation capacities. The

correct calculation should only include the final step of transformation (DPA0602 and DPA0603).



The diagram of the Energex supply network shows the zone substation load being supplied via bulk supply substations except in the case where direct transformation substations (110/11kV) are employed. DPA0601 is the 110/33kV bulk supply substation capacity to a meshed network supplying the 33/11kV zone substations.

Assumptions

Not applicable.

Estimated Information

Not applicable. Energex has provided actual information.

Explanatory Notes

Not applicable.

BoP – 3.7 Operating Environment

Table 3.7.1 - Density Factors

Compliance with RIN Requirements

Table 1.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 8.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must input the route Line Length of lines for DNSP's network.	Demonstrated in the Methodology section
Line Length is based on the distance between line segments and does not include vertical components such as line sag. The route Line Length does not necessarily equate to the circuit length (as reported in EB RIN BoP 3.5) as the circuit length may include multiple circuits.	Demonstrated in the Methodology section
Customer density (DOEF0101) is the total number of customers divided by the route Line Length of the network.	Demonstrated in the Methodology section
Demand Density (DOEF0103) is the kVA non-coincident Maximum Demand (at zone substation level) divided by the total number of customers of the network	Demonstrated in the Methodology section Energy and Demand Densities
Energex must input a variable code for each weather station (for example, DEF03001 for the first weather station). Energex must add (or remove) rows from the Weather Stations table such that all weather stations within its network will be included.	Rows have been added to the Weather Stations Regulatory BoP 3.7.4 and appropriately coded.
Energex must input the weather station number, post code, suburb/locality for all weather stations in its service area.	This information is no longer contained within RIN BoP 3.7. Energex has, instead, provided this information in the explanatory notes of this basis of preparation (BoP)

Sources

Table 3.7.1 Density Factors - Energy Density

While the customer numbers are actuals rather estimated values, the energy delivered data is sourced from the PEACE Billing Software. It is quarterly billed, so the data is not available for 3 to 4 months due to the meter reading processes. This means the data will not be finalised until the mid-October for a reported financial year.

Table 3.7.1 Density Factors - Customer Density & Demand Density

Economic Benchmarking RIN.

Methodology

Table 3.7.1 Density Factors - Energy Density

Energy Density

- "DOEF0102 - Energy density" was calculated by dividing the total energy delivered to customers (DOPED01) by the total number of customers (DOPCN01) from RIN Table 3.4.2. The energy delivered was multiplied by 1000 to convert the figures to MWh.

Further information on the methodology employed to determine each numerator or denominator input is available in the relevant sections of the BoP for EB RIN Template 3.4 Operational data for DOPCN01 and DOPED01.

Table 3.7.1 Density Factors - Customer Density

DOEF0101 - Customer density was calculated by dividing the total number of customers.

(DOPCN01 from RIN Table 3.4.2.1) divided by the route Line Length (DOEF0301 from RIN Table 3.7).

Table 3.7.1 Density Factors - Demand Density

DOEF0103 - Demand density was calculated by dividing the total non-coincident system annual maximum demand (DOPSD0201 from RIN Table 3.4.3.3) by the total number of customers (DOPCN01 from RIN Table 3.4.2.1) from RIN Table 3.4.2. The total noncoincident system annual maximum demand was multiplied by 1000 to convert the figures to kVA.

Further information on the methodology employed to determine each numerator or denominator input is available in the relevant sections of the EB RIN Template 3.7 BoP for Route Line Length DOEF0301 and EB RIN Template 3.4 Operational data for DOPCN01 and DOPSD0201.

Assumptions

Not applicable.

Estimated Information

Table 3.7.1 Density Factors - Energy Density

Energex believes the estimates supplied are its best estimates based on the available information at the time.

Table 3.7.1 Density Factors - Customer Density & Demand Density

Not applicable. Energex has provided actual information.

Explanatory Notes

Not applicable.

Table 3.7.2 - Terrain Factors

Compliance with the RIN Requirements

Table 2. below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 8.2: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
DNSP must report the average number of vegetation related Defects that are recorded per Maintenance Span (DOEF0210 & DOEF0211) in the relevant year.	Demonstrated in the Methodology section.
Standard vehicle access is Distribution route Line Length that does not have Standard Vehicle Access. Areas with Standard Vehicle Access are serviced through made roads, gravel roads and open paddocks (including gated and fenced paddocks). An area with no Standard Vehicle Access would not be accessible by a two wheel drive vehicle.	Energex does not have data regarding line length serviced through the areas specified; or that cannot be accessed by a two wheel drive vehicle. It has therefore used line length on road reserve as a proxy.
Rural Proportion (DOEF0201) is Distribution line route length classified as short rural or long rural in km/total network Line Length.	Demonstrated in the Methodology section.
Total network Line Length is the aggregate length in kilometres of lines, measured as the length of each span between poles and/or towers, and where the length of each span is considered only once irrespective of how many circuits it contains. This is the distance between line segments and does not include vertical components such as line sag.	This definition of Line Length was applied.
A vegetation maintenance span (DOEF0202 to DOEF0204) is a span in DNSP's network that is subject to active vegetation management practices in the relevant year. Active vegetation management practices do not include Inspection of vegetation Maintenance Spans	Demonstrated in the Methodology section.
If Energex has Actual Information, Energex must report all years of available data. If Energex does not have Actual Information on these variables, then it must estimate data for the most recent Regulatory Year.	Energex has provided Actual Information where possible. In the absence of Actual Information, Energex has estimated standard vehicle access (DOEF0213) using its GIS as the distribution route line length that does not fall within the road reserve.
If DNSP records poles rather than spans, the number of spans is the number of poles less one	Energex records spans.
The tropical proportion (DOEF0212) is the approximate total number of urban and Rural Maintenance Spans in the Hot Humid Summer and Warm Humid Summer regions as defined by the Australian Bureau of Meteorology Australian Climatic Zones map (based on temperature and humidity).	Demonstrated in the Methodology section.
The bushfire risk variable (DOEF0214) is the number of Maintenance Spans in high bushfire risk areas as classified by a person or organisation with appropriate expertise on fire risk. This includes but is not limited to: • DNSP's jurisdictional fire authority • local councils • insurance companies • DNSP's consultants • Local fire experts	Demonstrated in the Methodology section.

Requirements (instructions and definitions)	Consistency with requirements
Maintenance span cycle (DOEF0206 & DOEF0207) is the planned number of years (including fractions of years) between which cyclic vegetation maintenance is performed for the relevant area.	Demonstrated in the Methodology section.
CBD and Urban Maintenance Spans (DOEF0202) refer to CBD and urban areas that are subject to vegetation management practices in the relevant year. CBD and urban areas are consistent with CBD and urban customer classifications.	Demonstrated in the Methodology and Assumption sections.
Rural Maintenance Spans (DOEF0203) are spans in rural areas that are subject to vegetation management practices in the relevant year. Rural spans include spans in short rural and long rural feeders. Rural areas must be consistent with rural short and rural long feeders.	Demonstrated in the Methodology and Assumption sections.
Route line length (DOEF0301) is "the aggregate length in kilometres of lines, measured as the length of each span between poles and/or towers, and where the length of each span is considered only once irrespective of how many circuits it contains. This is the distance between line segments and does not include vertical components such as line sag."	Route line length is based on GIS system distance and does not include vertical components.
Defects (DOEF0210 & DOEF0211)	Defects are considered as the number of trees per maintenance span.

Sources

Table 2. specifies the sources from which Energex obtained the required information.

Table 8.3: Data Sources – Table 3.7.2 Terrain Factors

Variable Code	Variable	Source
DOEF0201	Rural proportion	ArcGIS
DOEF0202	Urban and CBD vegetation maintenance spans	Contractors Data system
DOEF0203	Rural vegetation maintenance spans	Contractors Data system
DOEF0204	Total vegetation maintenance spans	Contractors Data system
DOEF0208	Average number of trees per urban and CBD vegetation maintenance span	Contractors Data system
DOEF02010 and DOEF02011	Average number of defects per vegetation maintenance span	Contractors Data system
DOEF0209	Average number of trees per rural vegetation maintenance span	Contractors Data system
DOEF0205	Total number of spans	ArcGIS
DOEF0206	Average urban and CBD vegetation maintenance span cycle	Ellipse
DOEF0207	Average rural vegetation maintenance span cycle	Ellipse
DOEF0212	Tropical proportion	ArcGIS/BOM
DOEF0213	Standard vehicle access	ArcGIS
DOEF0214	Bushfire risk	ArcGIS/Queensland Government

Methodology

Table 3.7.2 Terrain Factors

Standard vehicle access:

- The distribution route line length with standard vehicle access was estimated by identifying the line length that falls within the known road reserve boundaries. This was subtracted from total route line length to find the distribution route line length that does not have standard vehicle access.

Approach

- The distribution route line length with standard vehicle access was estimated by identifying the line length that falls within the known road reserve boundaries. This was calculated within ArcGIS by overlaying the distribution line segments with the known road reserve boundaries and counting the line segments within those boundaries. This was subtracted from total route line length to find the distribution route Line Length that does not have Standard Vehicle Access.

Proportion:

- All data to calculate the rural proportion variable was obtained through ArcGIS.
- These figures were then used to calculate the proportion of rural overhead line length for each individual year.
- Rural proportion, expressed as a percentage, was then calculated by dividing total rural overhead line length, by route line length (which included underground circuit lengths in accordance with direction provided by the AER 9 April 2014).

Maintenance Spans and Tree Numbers:

These numbers are determined by the information reported from the contractors' databases.

Span numbers, tropical proportion and bushfire risk:

Energex has calculated the total number of overhead spans, the tropical proportion spans and the bushfire risk spans using ArcGIS. This incorporated shapefiles from the Bureau of Meteorology and the Queensland Government to obtain the number of spans within tropical and bushfire risk areas.

Maintenance Span Cycles:

The average maintenance span cycle was calculated based on data sourced from the Program Progress vs Plan – Vegetation report for the respective financial year (B-WK-WK-0635 Progress vs Plan – Vegetation). This report sources data taken from the Ellipse database.

A methodology was employed whereby:

- Average urban vegetation maintenance span cycle = (Sum of treated Urban vegetation zones cycle duration [Maintenance Schedule Task]/total number of Urban Vegetation Zones treated during regulatory (financial) year;
- Average rural vegetation maintenance span cycle = (Sum or treated Rural vegetation zones cycle duration [Maintenance Schedule Task]/total number of Rural Vegetation Zones treated during regulatory (financial) year.

Maintenance Spans and Tree Numbers:

- This information has been exported from the vegetation contractors' database.

Span numbers, tropical proportion and bushfire risk:

- The total number of overhead spans was obtained by extracting the figures directly from ArcGIS.
- The tropical proportion variable was calculated by overlaying the Australian Bureau of Meteorology Australian Climatic Zones GIS shapefile on the Energex maps. From here the total number of overhead spans that fell within the tropical regions was calculated by the GIS system. This figure was then multiplied by the total proportion of maintenance spans to non-maintenance spans from the calculated variables DOEF0204 and total number of maintenance to give the number of maintenance spans in a tropical area.
- The bushfire risk variable was calculated by overlaying the Queensland Government Department Queensland Spatial Catalogue - Qspatial Bushfire Risk Maps (Wide Bay and South East Queensland) on the Energex maps. From here the number of overhead spans that fell within the bushfire risk regions was counted by the GIS system. This figure was then multiplied by the total proportion of maintenance spans to non-maintenance spans from the calculated variables DOEF0204 and total number of maintenance to give the number of maintenance spans in a bushfire risk area. Variation in figures from previous years can be attributed to a change in the area covered by the Bushfire Risk Shapefile.

Defects:

- Energex does not record specific information on defects. Each tree is seen as one defect as Energex does not record more specific information than this on defects. Therefore the number of trees per maintenance spans is replicated here as the number of defects.

Assumptions

Standard vehicle access:

- It is assumed that the route line length that does not fall within road reserve boundaries is an appropriate proxy for standard vehicle access, as this line cannot typically be accessed by standard vehicles.

Route line length includes only horizontal components of line length.

Route line length does not take into account multiple circuits within a line segment.

Total underground circuit length, which is the aggregate of each circuit length provided at each voltage level (variables DPA0201 to DPA0206), does not include multiple circuits with each segment.

Rural Proportion:

The calculation of this variable assumed that:

- Vegetation Zones are allocated as urban or rural dependent upon the type of vegetation growing within that zone, typically an urban Vegetation Zone is an area where more than five adjacent properties have a road frontage of < 40 metres per property. Rural Vegetation Zones are areas that do not fit into the Urban category.

Maintenance Spans and Tree Numbers:

- This information has been exported form the contractors' database.

Estimated Information

Table 3.7.2 Terrain Factors

Justification

The figures were estimated as Energex does not measure the distribution route line length with standard vehicle access.

Defects were estimated as Energex does not record the number of defects.

Basis for Estimation

As stated in the methodology section, the estimate for this variable was based on calculating the route line length that does not fall within the known road reserve boundaries. This was considered the most representative figure Energex could produce based on the available information.

There are two opposing situations that may affect the accuracy of this estimate:

- Line length may be accessible by a standard vehicle but is not on a road reserve (e.g. across open paddocks off the road reserve); and
- Line length may be within a road reserve but may not be accessible by a standard vehicle (e.g. line that falls in a section of undeveloped road reserve).

Given the lack of data held by Energex systems the effects of each these situations on the estimate are unknown and may or may not have a balancing effect on the figure reported.

For defects given that Energex does not record this information it can only estimate the number as one per maintenance span.

Energex believes the estimates supplied are its best estimates based on the available information at the time.

Explanatory Notes

Not applicable.

Table 3.7.3 - Service Area Factors

Compliance with the RIN Requirements

Table 8. below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 8.4: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must input the route Line Length of lines for DNSP's network.	Demonstrated in the Methodology section.
Line Length is based on the distance between line segments and does not include vertical components such as line sag. The route Line Length does not necessarily equate to the circuit length (as reported in EB RIN BoP 3.5) as the circuit length may include multiple circuits.	Demonstrated in the Methodology section.

Sources

The source from which Energex obtained the required information for DOEF0301 Route Line Length is ArcGIS.

Methodology

Energex has extracted figures for the distribution route line length from ArcGIS.

Assumptions

Route line length includes only horizontal components of line length.

Route line length does not take into account multiple circuits within a line segment.

Estimated Information

Not applicable. Energex has provided actual information.

Explanatory Notes

The Route line length (DOEF0301) reported in the EB RIN will not align with the route line length reported in BoP 2.7 Vegetation Management of the Category Analysis (CA) RIN. The CA RIN route line length is that which is trimmed in the regulatory year (not all lines are trimmed every line every year). The EB RIN figure is the total length of lines overhead and underground of the Energex network.

Weather Station ID	Postcode	Suburb	Materiality
040004 Amberley	4306	Amberley	Yes

040842 Brisbane Airport	4008	Brisbane Airport	Yes
040211 Archerfield Airport	4108	Archerfield	Yes
040717 Coolangatta	4225	Coolangatta	Yes
040861 Maroochydore	4564	Marcoola	Yes