SUBMISSION TO NERSA
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NERJD/ESK

Standard tariffs

Cost-to-serve (CTS) Study Report

2024/25 Financial year

Executive summary

The standard tariffs cost-of-supply (CoS) report describes how the 2024/25 financial year study was performed using allowable revenues and forecasted sales volumes. From this point onwards, it is referred to as the cost-to-serve (CTS) study. Conducting the study is a significant function in establishing and designing electricity rates that determine the price of electricity for our customers.

This 2024/25 CTS study is an embedded cost-of-supply (CoS) study allocating approved allowable revenues to costing categories. It is not a marginal CoS study because it does not provide a view of incremental (changes in) unit costs from the provision of additional units of electricity sales, network capacity and retail services. It also does not provide the actual costs of the standard tariffs nor tariff charges and rates.

This CTS study answers the question:

"How much does it cost to supply electricity to standard tariff customers using the NERSA-approved allowable costs, returns, and forecasted sales?"

To this end, in this CTS study, the 2024/25 approved allowable standard tariff revenues that are the sum of allowed costs and returns (referred to as costs from this point forward) are treated as follows:

- A cost causation principle guides the costing. That is, the cost allocation tracks how each costing category contributes to the costs to supply electricity based on electricity consumption, use of networks and the related network demand.
- The costs to supply electricity to standard tariff customers are for energy purchases (energy and distribution and transmission network electrical losses), transmission network capacity, distribution network capacity and retail.
- The costing is done as follows:
  - The cost drivers are the 2024/25 National Energy Regulator of South Africa (NERSA) revenue decision forecasted sales volume (kWh), demand (kVA), and number of customers' points of delivery (PoDs).
  - Flat rate variable generation legacy charge across time-of-use and seasonality periods.
  - Time-of-use and seasonally differentiated energy purchase unit costs are used to allocate variable energy purchase costs.
  - Fixed generation capacity costs are allocated using maximum demands adjusted for technical losses and contribution to the system demand.
  - Transmission network capacity costs are allocated based on the utilised capacity demands.

- Distribution network capacity costs are allocated using maximum demands adjusted for technical losses, contribution to the system demand and use of networks.
- Retail costs are allocated by the number of PoDs grouped by demand size.

- For practical reasons, customers' PoDs are grouped into 15 customer costing categories (from this point forward referred to as costing categories) made up of all customers on standard tariffs grouped by the voltage of the supply and their location (rural/urban). The geographic location is not applicable in the costing category. However, in the detailed customer data, it is possible to identify the transmission zone for each PoD. For retail costing, customers are grouped by PoD demand size.

The results from the CTS study are the average unit costs of the 15 costing categories for variable energy purchases, retail services and provision of generation, transmission, and distribution network capacity. See the table below.

Allocated costs 2024/25

					Allocated costs (R'million)								
	Voltage	Costing category	No of PoDS	Sales volumes (GWh)	Energy ToU	Energy capacity	Legacy charge	Tx network capacity	Tx ancillary services	Dx network capacity	Retail	**Total allocated costs**
	>132kV	C01 : 275 LPU	128	36 085	46 221	3 262	6 149	1 527	109	0	20	**57 288**
Urban	≥66kV - ≤132kV	C02 : 132 LPU*	281	19 324	26 856	1 860	3 531	547	63	512	88	**33 456**
Urban	≥66kV - ≤132kV	C03 : Blank - no customers	0	0	0	0	0	0	0	0	0	**0**
Urban	≥66kV - ≤132kV	C04 : 88 LPU	248	8 094	11 074	875	1 479	316	26	730	81	**14 581**
Urban	≥66kV - ≤132kV	C05 : 66 LPU	74	7 581	10 702	756	1 385	198	25	1 122	23	**14 211**
Urban	≥500V - <66kV	C06 : 44 LPU	42	1 666	2 441	189	328	90	6	328	15	**3 398**
Urban	≥500V - <66kV	C07 : 33 LPU	92	28 128	39 075	2 936	5 539	654	98	2 806	31	**51 138**
Urban	≥500V - <66kV	C08 : 6.6 3.3 2.2 LPU	195	15 240	21 347	1 619	3 001	394	53	2 417	58	**28 889**
Urban	≥500V - <66kV	C09 : 2211 U LPU	1 607	33 275	48 293	3 593	6 552	1 041	116	5 895	172	**65 663**
Urban	≥500V - <66kV	C10 : Blank - no customers	0	0	0	0	0	0	0	0	0	**0**
Urban	<500V	C11 : 500 U ELEC	7 556 410	7 230	12 929	1 605	1 461	1 031	26	5 944	2 630	**25 627**
Urban	<500V	C12 : 500 U RES	113 225	1 409	2 572	181	285	81	5	1 009	382	**4 514**
Urban	<500V	C13 : 500 R RES	0	0	0	0	0	0	0	0	0	**0**
Urban	<500V	C14 : 500 U OTHER SPU*	37 367	1 142	1 902	159	231	61	4	403	176	**2 936**
Urban	<500V	C15 : 500 U OTHER LPU	3 503	1 395	2 100	168	282	115	5	441	90	**3 200**
Rural	≥500V - <66kV	C16 : 2211 R LPU	1 789	3 434	5 068	416	688	176	12	2 213	88	**8 663**
Rural	≥500V - <66kV	C17 : 500 R ELEC	0	0	0	0	0	0	0	0	0	**0**
Rural	<500V	C18 : 500 R OTHER LPU	13 180	3 447	5 126	471	703	309	12	2 885	326	**9 832**
Rural	<500V	C19 : 500 R OTHER SPU	139 614	3 498	5 893	962	714	684	13	4 775	1 105	**14 145**
		Total	**7 867 753**	**170 947**	**241 601**	**19 050**	**32 329**	**7 221**	**574**	**31 480**	**5 285**	**337 541**

Notes:

1. *Costing categories C17, C13, C10 and C03 are not used in the 2024/25 CTS study.*
2. *The detail per transmission zone for energy and transmission networks underlies the above summary.*
3. *The allocated allowable revenues are higher than the MYPD decision in the ERTSA decision due to the rounding and nature of the ERTSA methodology. After the ERTSA decision, a few of the high-voltage points of supply voltage was corrected from >66 kV to below 66 kV.*

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Abbreviations

CoS	Cost of supply
CPD	Coincident peak demand
CS	Customer services/retail services such as billing and administration.
CTS	Cost-to-serve
Dx	Distribution
Gx	Generation
NCPD	Non-coincident peak demand
PoD	Point of Delivery/Point of Supply
Tx	Transmission

Key definitions

Allowable revenue	The regulated revenues for Eskom in a given financial year are approved by the NERSA. The allowable revenues (AR) for Eskom for the Multi-year Price Determination (MYPD) period must be determined by applying the AR formula that is: $AR=(RAB\times WACC)+E+PE+D+R\&D+IDM\pm SQI+L\&T\pm RCA$; MYPD Methodology (2016).
Annualised utilised capacity or UC	The higher of the notified maximum demand (NMD) or the maximum demand, per PoD measured in kVA, and registered during a rolling 12-month period. The monthly values are annualised by summating the forecasted UC per month for each PoD.
Distribution	The regulated Eskom division that constructs, owns, operates, and maintains the distribution system in accordance with its NERSA license and the Distribution Grid Code.
Excess maximum demand	This is the demand used in the allocation of the distribution network costs; it is the difference resulting from the sales maximum demand less the average demand.
Generation	The regulated Eskom division produces electricity in accordance with its NERSA license.
High-demand season	The time-of-use (ToU) period is from 1 June to 31 August of each year.
Key customer	A customer identified by Eskom as requiring special services, or a customer that consumes more than 100GWh per annum at a contiguous site.
Loss factors	The factor indicating the technical energy losses cost on the transmission and the distribution system. The distribution loss factors differ per voltage category and for the rural and urban categories. The transmission loss factors differ for generators and loads and are based on the transmission zones.
Low-demand season	The ToU period is from 1 September to 31 May of each year.
Maximum demand	The highest average demand measured in kVA or kW at the PoD during a 30-minute integrating period in a billing month.
Peak period	The ToU periods of relatively high system demand.
Standard period	The ToU periods of relatively mid-system demand.
Standard tariff	The Eskom schedule of prices and charges available to South African customers.
Transmission	The regulated division, through which Eskom constructs, owns, operates, and maintains the transmission system in accordance with its NERSA license and the Transmission Grid Code.
Voltage of supply/supply voltage	The secondary supply voltage is recorded in the customer billing system. This is not the primary voltage of each PoD.

1. Introduction

The objective of the 2024/25 CTS study is to assign NERSA allowable revenues (AR) to determine standard tariffs' average units of AR (referred to as unit costs from this point forward) separately for energy purchases, transportation, and retail.

This CTS study is an embedded CoS study because it allocates a revenue requirement (approved AR) and answers the question- "How much does it cost to supply electricity to standard tariff customers using the NERSA-allowed costs and returns?"

The cost allocation is according to cost drivers, which are the volumes, sales kilowatt-hour, demand, and number of PoDs. The costing methodology follows the nature of costs to supply electricity on a justifiable cost allocation basis.

The approach used complies with the applicable government policies, guidelines and rules as contained in the Electricity Pricing Policy (EPP), the Codes (Distribution and South African Grid Code), the NERSA Cost to supply framework and the MYPD methodology (October 2016).

Three main steps in the CTS study's costing process are revenue mapping (or cost functionalisation), cost classification and cost allocation as shown in Figure 1.

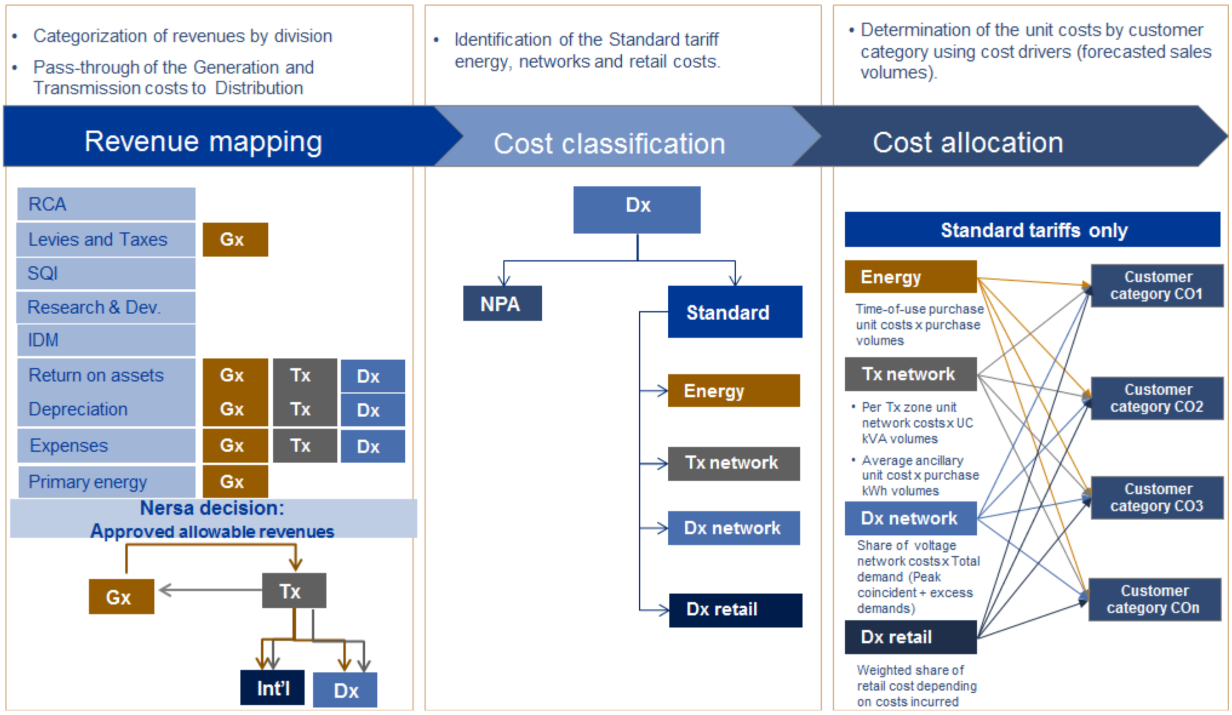


Figure 1: The CTS costing process

Revenue mapping

- The revenue mapping separates the NERSA 2024/25 AR decision into Generation, Transmission and Distribution Divisions. The pass-through of Generation and Transmission costs to Distribution provides a basis for conducting the cost classification.
- The revenue mapping includes the liquidated and implemented Regulatory Clearing Account (RCA) amounts applicable for 2024/25 implemented as part of the ERTSA tariff increase. The 2024/25 allowable revenue decision for standard tariffs was lower than the ERTSA revenues and this revenue difference is included during revenue mapping as part of the Distribution division revenues.

Cost classification

- The revenues mapped (or functionalised) by division are classified into energy purchases, transmission networks, distribution networks and retail. The exports are separated from the Eskom total. The NPA revenues from the MYPD decision, are subtracted from the Distribution energy purchase costs.
- The Distribution costs are further classified into detailed network and retail costs including separation of metering, billing, and customer services. The ERTSA revenue difference is classified as distribution costs when calculating revenue recovery for the ERTSA application.

Cost allocation

- A cost causation principle guides the CTS study, that is, it is informed by how a customer's electricity consumption affects the cost of supplying electricity. The cause of electricity costs or cost drivers is kilowatt-hours (kWh) for electricity consumed and electrical losses by time-of-use (ToU) and season. Maximum demand in kilovolt-ampere (kVA) is the cost driver providing generation and network capacity. The retail cost driver is the number of PoDs.
- The cost allocation applies detailed electricity volumes from the NERSA 2024/25 revenue decision, which are forecasted sales volumes (kilowatt-hour, kVA, and number of PoDs) grouped into CTS costing categories.
- The results of the CTS study are unit costs by cost category. For energy variable purchases (c/kWh), for generation capacity (kVA), ancillary services (c/kWh), Legacy charge (c/kWh), and for transmission network capacity (R/kVA) are differentiated by transmission zone. The distribution network capacity (R/kVA) is differentiated by voltage and the retail unit costs (R/PoD) are differentiated by PoD capacity size.

2. Regulatory compliance

The CTS study complies with the applicable government policies, guidelines and rules as contained in the EPP, the MYPD methodology (October 2016), the CoS framework (2023) and the Grid Code according to the Eskom license requirements.

2.1. Electricity Pricing Policy (EPP)

Compliance with the requirements of the EPP in this CTS study is as follows:

- Position 23 of the Electricity Pricing Policy, ("the EPP") requires electricity distributors to undertake CoS studies at least every five years following the NERSA standard to reflect changing costs and customer behaviour. The cost allocation methods applied in these studies should align with the principles contained in the NERSA Distribution Tariff Code and the CoS framework. The following lists the record of CTS submissions by Eskom:
  - This 2024/25 CTS study is submitted eighteen months after the 2021/22 study of August 2022.
  - Before that, the 2019/20 CTS study was submitted in August 2020 and the 2018/19 CTS study in May 2019.
  - The 2012/13 CTS study submission was included in the 2013 MYPD3 application which contained proposed tariff structural changes.

- Position 26 specifies that the number of consumer categories for tariff purposes needs to be justifiable to NERSA based on cost drivers and the customer base, including consumption patterns, for example, the load factor, ToU, position on the network (not geographic location), the voltage of the supply and the system from which the supply is taken. It, furthermore, specifies that a new costing category has to be created when costs differ by at least 10%.

In summary, the 2024/25 CTS study uses:

- Costing categories based on the voltage and supply location density (rural/urban).
- Cost drivers which are the volume detail from the NERSA MYPD decision forecasted sales volumes are kWh, kVA, and number of PoDs.
- The transmission network's transmission zones and distribution network's voltages to cost network capacity and electrical losses.
- 15 costing categories that are based on practical considerations. No further separation of categories was implemented in the 2024/25 study given that the inter-category differences did not surpass the EPP threshold.

2.2. Distribution Tariff Code

The Distribution Tariff Code v6 of 2014, *section 4.1 (Principles for the allocation and recovery of costs in tariffs)*, guides how to enable tariffing, accordingly, in this CTS study:

- The allocation of costs is based on the NERSA-approved allowable revenue decision for 2024/25; the revenue mapping follows the NERSA MYPD methodology AR formula; and
- Unit cost information is provided with capacity, voltage, load factor, load profile, density, and geographic location differentiation. This is captured through the costing categories and underlying per PoD customer details.

2.3. South African Grid Code

Compliance with the requirements of the South African Grid Code is through allocating the transmission costs to generators and loads. In the pass-through, the Generation and Distribution Divisions each share ±50% of the Transmission Division's electrical losses, and ancillary and network costs. The cost-sharing refers to all generators including imports and IPPs, and all loads including pumping and exports.

2.4. MYPD methodology

Compliance with the requirements of the MYPD methodology in this CTS study is as follows:

- The CTS study uses the 2024/25 Eskom AR and forecasted sales volumes as determined in the MYPD decision and the 2024/25 ERTSA NERSA decision.
- As required in the MYPD methodology (Rules 5.6, 5.7 and 5.8), the generation and transmission costs are passed through to the Distribution level.

2.5. CoS framework

The CoS framework of October 2023 follows a four-step process. The steps cover revenue requirement, cost functionalisation, cost classification and cost allocation. It also includes cost drivers relating to electricity generation, distribution, and transmission.

The allocation of the generation capacity costs is not included in the CTS framework but provided for in the EPP. Following that generation capacity costs are driven by maximum demand; its volume drivers are demand volumes.

3. The nature of costs to supply electricity

The nature of the costs to supply electricity informs the cost allocation in the CTS study. The costs to supply electricity are energy purchases, transportation and retail costs as shown in Figure 2.

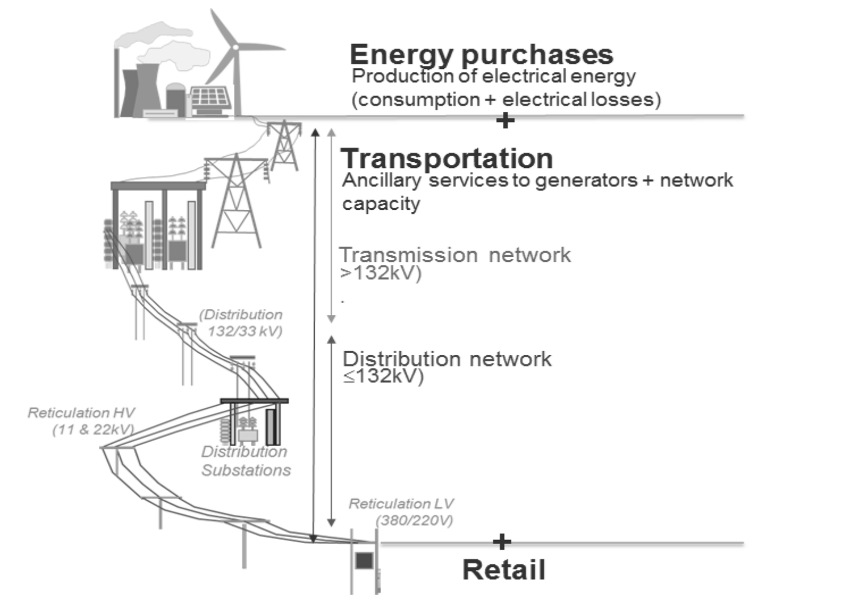


Figure 2: The costs to supply electricity

- Electricity produced by generators is first transported at high voltages in the transmission network. Some large industrial, mining and metro customers take supply at these high voltages (275 kV).
- Electricity is then transmitted in the distribution network from high-voltage to medium voltage to low-voltage networks and eventually to reticulation networks.
- Consequently, a customer taking supply in a reticulation network uses the transmission network and the distribution network (upstream networks) to receive electricity supply.

3.1. Energy purchase costs

- The variable cost of a unit of electricity (in c/kWh) depends on the time-of-day or ToU and season. This is because there are varying levels of customer electricity demand during a day. Production requirements and/or seasonal temperature changes increase or decrease customers' hourly use of electricity for heating or cooling.
- Generally, electricity (in kWh) is mainly produced using base-load generators. To meet increased electricity demand during different times of the day and/or seasons, more expensive power stations are used to supplement baseload electricity generation resulting in a mix of generators producing electricity at different times at different costs. See Figure 3.
- During transportation electrical (line) losses (in kWh) occur and generators need to produce more volumes of electricity than consumed to meet demand. Consequently, the cost to supply electrical energy is the sum of the electricity consumed (sales) or active energy, distribution network electrical losses and transmission network electrical losses. See Figure 4.

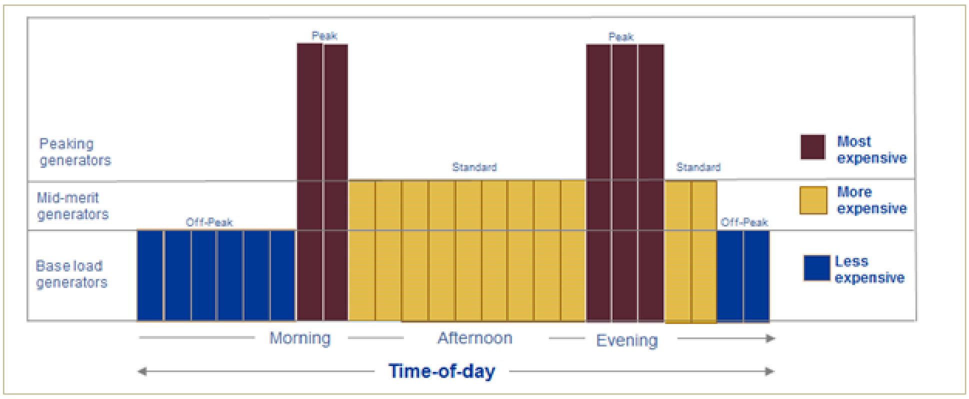


Figure 3: Varying costs of electricity production

Figure 4: The cost of ToU energy purchases

- Although generators have fixed and variable costs, traditionally, the total costs were expressed in c/kWh. The separation of fixed and variable costs better informs costing based on cost causation.
- Unpacking energy purchase costs into variable, fixed and legacy charges enable a more cost-reflective way to allocate generator costs and create a comparable basis for the growing number of different electricity-generating technologies.
- Generation capacity costs do not vary with different levels of electricity production and are in varying proportions relative to the total generating costs for different technologies. Primarily, capital is the fixed generating cost incurred to establish the power plant or to make the capacity to produce electricity available.
- Generation capacity costs are informed by the maximum output of the generating plant. The total generation capacity costs associated with the total energy supplied are related to the maximum demand. Consequently, a customer's maximum demand is the cost driver for allocating generation capacity costs.
- Legacy charge is a wholesale energy purchase cost passed through from Generation that is separately identified. The legacy costs are the ring-fenced costs of the Section 34 independent

power producers above the base energy cost. The cost is allocated to all energy purchased at the >132 kV level similar to active energy but not on a time-of-use basis; as a flat c/kWh.

3.2. Transportation costs

Costs incurred in the transportation of electricity (excluding electrical losses) are for providing network capacity and ancillary services:

- Ancillary services are procured by the System Operator from generators and loads (customers). This includes providing generating power plants with, for example, the power to restore a generating power plant to restart production. In this CTS study, the cost driver used for ancillary services is the energy purchase volumes (kWh).
- Costs incurred to provide capacity in the transmission and distribution networks are for building, refurbishing, and maintaining the networks to ensure the network capacity to supply the electricity demand. As the transmission and distribution networks are designed to meet maximum demand, a customer's maximum demand is a cost driver for transportation costs.

3.2.1. Transmission network costs

- In the transmission network (transmission grid/ transmission electricity system), electricity is transmitted over long distances and uses assets (lines and substation equipment) where the nominal voltage is above 132 kV.
- The transmission network costs and electrical losses are organised into transmission zones. This is to reflect the relative distance to the main region in South Africa where most electricity; see Figure 5[1].
- Electricity from generators to all customer supply points is first transported in the transmission network; therefore, all customers contribute to the costs of the transmission network.

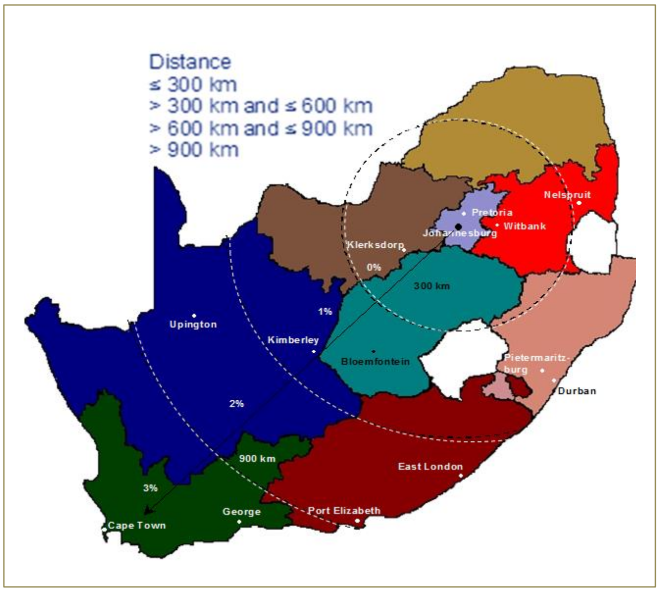


Figure 5: Transmission zones

- Customers taking supply from the transmission network (>132 kV / 275 kV supply voltage) or who are connected to the

[1] The transmission zones which are concentric zones centered in Johannesburg were introduced in 1986.

transmission network at a nominal voltage lower than or equal to 132 kV but do not use distribution network assets, incur transmission network costs and not distribution network costs.

3.2.2. Distribution network costs

- The distribution network connects customers to the transmission network and consists of assets operated at a nominal voltage of 132 kV or lower that are not recognised as transmission network transformation equipment. The assets used in distribution networks include substations, conductors, poles, and lines; From this point forward, they are referred to as transformation and lines.
- The transportation of electricity in the distribution network is through a complex distribution network system providing the capacity to transport and transform the electricity supply from high to lower voltages (step-down the voltage). During the transportation of electricity, power losses occur. Accordingly, the measured demand at a point of consumption is lower than demand measured at preceding distribution network positions.
- In the distribution network supplies connected at high-voltages* do not use medium-voltage and low-voltage reticulation networks. Customers/Loads connected in the medium-voltage networks use high-voltage* and medium-voltage* networks. Customers/Loads in the low-voltage networks use the high-voltage*, medium-voltage* and reticulation networks. See a simplified distribution network illustration in Figure 6.

For ease of reference, the distribution network is grouped into high-voltage (≤132 kV to ≥33 kV), medium-voltage (≤2 2kV to ≥2.2 kV) and reticulation/low-voltage (<500 V or 400 V).

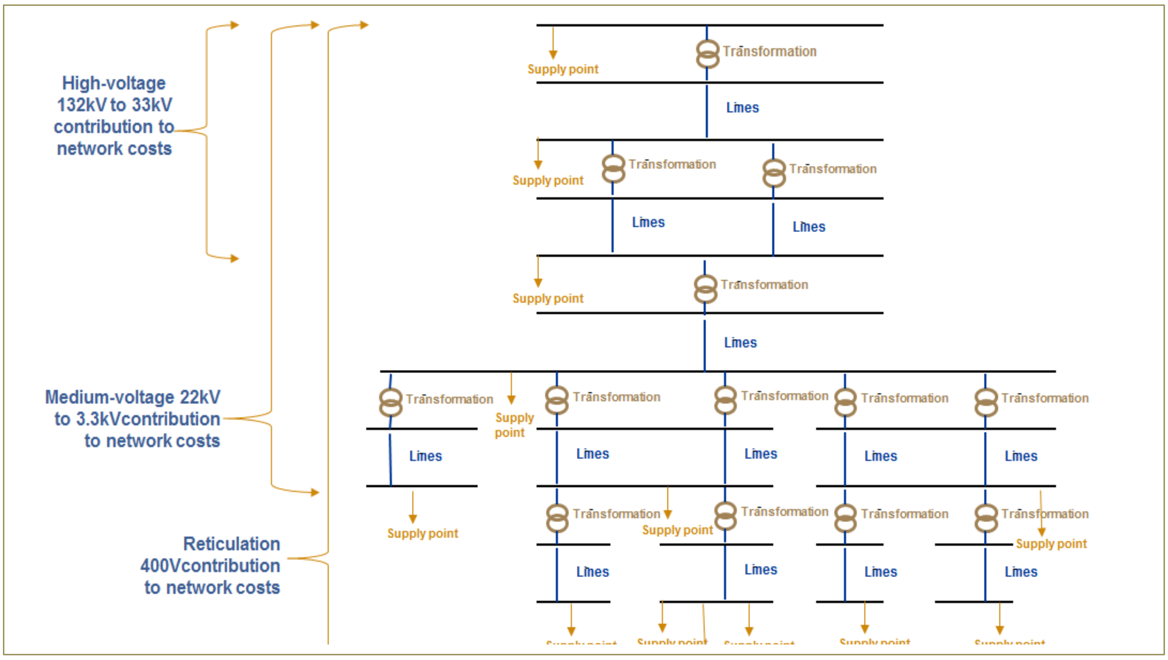


Figure 6: Use of the distribution network at different points of connection

3.3. Retail costs

- Retail costs are for providing customer services through, for example, contact centres and include meter reading, billing, and prepayment.
- Customers incur different retail costs depending on the type of services rendered: for example, prepayment customers do not incur the cost of billing. The cost driver for retail costs is the number of PoDs.

4. Customer costing categories

Eskom directly supplies electricity to 7.9 million active customer PoDs which excludes 1.9 million inactive PoDs. Since the 2021/22 study, customer PoDs for low-usage urban residential have increased by 653 thousand while other SPUs decreased by 17 thousand and LPU customers have increased by 2 hundred. See Table 1 for 2024/25 number of PoDs by costing category.

Eskom customers are broadly segmented into small power user (SPU) and large power user (LPU) customers. SPU customers are usually residential, small commercial and agricultural with supply sizes below 100 kVA. LPU customers have points of supply from 25 kVA in sizes and most have more than one PoD.

For practical reasons, customer PoDs are grouped into 15 costing categories (from this point forward referred to as costing categories). The CTS study's costing categories are informed by how electricity is supplied to a customer by considering the voltage of supply, and the density (rural/urban) of the network in which the customer is connected:

- The location of a customer's PoD is determined using the customer's tariff; rural PoDs are those on rural standard tariffs while urban PoDs are those on urban standard tariffs.
- The forecasted sales per PoD are obtained from the details by PoD contained in the NERSA 2024/25 MYPD decision.
- There are 9.75 million active and inactive PoDs at 400 V. For practical purposes, the costing categories for supplies connected at 400V are sub-categorised based on the demand size of the customer supply as follows:
  - "Other LPU" with ≥25kV Notified maximum demand (NMD).
  - "Other SPU" for commercial types of supply with a demand size of up to 100 kV. In the rural SPU category, 60 A and 20 A rural supplies are included; because the use of the network considered is similar and the only difference is the lines to supply at 400 V.

- The urban residential supplies are separated into two categories: 500U RES for residential supplies and 500U ELEC specific to 60 A and 20 A supplies.

- The size of supply provides a basis to group customers according to the type of retail services received. See Table 1 for the costing categories grouped by voltage and density.

Table 1: Number of PoDs by costing category

		Customer Categories		Description	Number of PoDs			
					Consuming (active)	Zero consumption	Total	% of total
	>132kV	C01	275 LPU	≥275kV and Tx* connected supplies	128	0	128	0.0013%
Urban	≥ 66kV & ≤ 132kV	C02	132 LPU*	132kV supplies	281	0	281	0.0029%
		C03	*Blank - no customers*	*n/a*	*0*	*0*	*0*	*0%*
		C04	88 LPU	88kV urban supplies	248	0	248	0.0025%
		C05	66 LPU	66kV urban supplies	74	0	74	0.0008%
	≥ 500V & < 66kV	C06	44 LPU	44kV urban supplies	42	0	42	0.0004%
		C07	33 LPU	33kV urban supplies	92	0	92	0.0009%
		C08	6.6 3.3 2.2 LPU	<33kV - 2.2kV urban supplies	195	0	195	0.0020%
		C09	2211 U LPU	<33kV - 11kV urban supplies	1 607	0	1 607	0.0165%
		C10	*Blank - no customers*	*n/a*	0	0	0	0%
	<500V	C11	500 U ELEC	≤500V low-usage urban residential	7 556 410	1 866 097	9 422 507	96.62%
		C12	500 U RES	≤500V other urban residential	113 225	6 468	119 692	1.23%
		C13	Blank - no customers	n/a	0	0	0	0.00%
		C14	500 U OTHER SPU*	≤500V urban small power users	37 367	1 854	39 220	0.40%
		C15	500 U OTHER LPU	≤500V urban large power users	3 503	0	3 503	0.04%
Rural	≥ 500V & < 66kV	C16	2211 R LPU	≤22kV - 11kV rural supplies	1 789	0	1 789	0.02%
		C17	Blank - no customers	n/a	0	0	0	0.00%
	<500V	C18	500 R OTHER LPU	≤500V rural other large power users	13 180	0	13 180	0.14%
		C19	500 R OTHER SPU	≤500V rural other small power users	139 614	9 960	149 573	1.53%
				Total	**7 867 753**	**1 884 378**	**9 752 132**	**100.0%**
				% of total	**81%**	**19%**	**100%**	**0.0%**
				Customers at <400V	*7 723 684*	*1 874 419*	*9 598 102*	*98.4%*

**Tx* = Transmission*
** LPU = Large power users*
** SPU = small power users*

5. Cost drivers

The cause of electricity costs or cost drivers for energy purchases is the electricity consumed in kilowatt-hours (kWh) for variable generation costs and maximum demand (kVA) for generation capacity costs. The cost driver for transmission and distribution network electrical (line) losses is electricity consumed (kWh). For networks, the cost drivers are maximum demand and utilised capacity (UC) volumes both in kilovolt-ampere (kVA). The retail cost drivers are the number of PoDs.

5.1. Forecasted sales volumes

The underlying forecasted sales volumes in (kWh), demand volumes (kVA) and customer numbers (No of PoDs) in the 2024/25 NERSA MYPD and ERTSA decisions are:

- **Electricity consumption (sales) volumes in kilowatt-hours (kWh)**
  - Kilowatt-hour volumes are used to allocate the energy purchases, ancillary services, transmission, and distribution network electrical losses costs.
  - The sales volumes are multiplied by the transmission network loss factors and distribution network loss factors to determine the respective electrical losses.
  - The sales volumes in the forecast are by month providing the winter and summer volumes and are by ToU periods:
    - The sales volume forecast for all LPUs includes the ToU detail. The actual 2022/23 ToU profiles for customers on the non-ToU Nightsave tariffs are used because this tariff's sales forecast does not include ToU volumes.
    - SPU tariffs including 60 A and 20 A supplies do not have actual or forecasted sales volumes by time-of-use. ToU representative profiles obtained from an SPU ToU research study were used; See Annexure 2.
  - For all sales volumes, to reflect the 1:6 ToU periods, all sales kWh volumes were updated from 1:8 to 1:6 ToU periods.

- **Non-coincident demands (kVA)**
  - The maximum demand measured at a customer's PoD may not occur at the same time as the distribution network's (system) maximum demand. It is not coincident with the distribution system's peak demand.
  - For different customers taking supply at the same network position on the distribution system, the demand measured at the given network position is the non-coincident demand. That is, it is the sum of all customers' maximum demand connected to different PoDs at the network position.

- **Utilised capacity (UC) in kVA**
  - The UC in the forecasted sales volumes is a non-coincident demand. It is the higher of the NMD or the maximum demand, per PoD measured in kVA as registered over a rolling 12-month period. The annualised UC is used to allocate transmission network costs.
  - The UC for SPUs is not metered. For rural SPU supplies, the NMD according to each connection was assumed because there are fewer diversity considerations when rural networks are constructed. For the other urban SPU supplies, to incorporate a view of the diversity (maximum demand coincidence) of shared assets used close to the point of connection, the average diversified maximum demand (ADMD) was assumed for the UC. See Annexure 3.

- **Maximum demand in kilovolt-ampere (kVA)**
  - The maximum demand in the forecasted sales volumes is a non-coincident demand that is the highest average demand measured in kVA at the PoD during 30-minute integrating periods in a billing month.
  - An annualised maximum demand is used to allocate distribution network capacity costs. To express the allocated costs in sales volume terms, the annualised UC is applied to the allocated distribution network capacity costs.
  - The maximum demands for SPUs are not metered. For rural SPU supplies, the NMD according to connections' data was assumed. For other SPU supplies, the ADMD from the connections' data was assumed. See Annexure 3.

- **Points of delivery (PoDs)**
  - The number of PoDs is used to allocate retail costs and this number is according to connections' data in the billing/vending system. Some PoDs that are non-consuming (zero consumption PoDs) are included in the CTS study recognising their contribution to retail and network costs, for example, maintenance and refurbishment.
  - See Table 2 for the CTS cost drivers that is the 2024/25 NERSA MYPD decision forecasted energy sales volumes summarised by costing category. The underlying maximum demands and UC are shown in Table 3. The numbers of PoDs from the customer data system are contained in Table 1.

Table 2: Cost drivers – 2024/25 forecasted sales volumes

(Forecasted sales after an adjustment to match the proposed time-use periods)

			Winter sales (GWh) [3 months : Jun - Aug]				Summer sales (GWh) [9 months : Apr - May & Sep-Mar]				Annual forecasted sales (GWh) [12 months: Apr - Mar]			
			Peak	Standard	Off-peak	Total	Peak	Standard	Off-peak	Total	Peak	Standard	Off-peak	Total
	>132kV	C01 : 275 LPU	1 630	4 025	3 923	9 578	4 418	11 040	11 049	26 507	6 047	15 066	14 971	36 085
Urban	≥66kV - ≤132kV	C02 : 132 LPU*	881	2 214	2 048	5 143	2 394	6 046	5 742	14 181	3 275	8 260	7 790	19 324
Urban	≥66kV - ≤132kV	C03 : Blank - no customers	0	0	0	0	0	0	0	0	0	0	0	0
Urban	≥66kV - ≤132kV	C04 : 88 LPU	375	929	926	2 231	979	2 415	2 469	5 863	1 354	3 344	3 395	8 094
Urban	≥66kV - ≤132kV	C05 : 66 LPU	352	874	789	2 015	956	2 388	2 222	5 565	1 308	3 262	3 011	7 581
Urban	≥500V - <66kV	C06 : 44 LPU	72	194	190	456	196	509	505	1 210	268	703	694	1 666
Urban	≥500V - <66kV	C07 : 33 LPU	896	2 633	3 095	6 623	3 222	8 370	9 912	21 505	4 118	11 003	13 007	28 128
Urban	≥500V - <66kV	C08 : 6.6 3.3 2.2 LPU	564	1 529	1 825	3 918	1 630	4 395	5 297	11 322	2 194	5 924	7 122	15 240
Urban	≥500V - <66kV	C09 : 2211 U LPU	1 398	3 554	3 784	8 737	3 884	9 905	10 750	24 539	5 282	13 459	14 534	33 275
Urban	≥500V - <66kV	C10 : Blank - no customers	0	0	0	0	0	0	0	0	0	0	0	0
Urban	<500V	C11 : 500 U ELEC	536	963	398	1 897	1 420	2 686	1 227	5 333	1 956	3 649	1 625	7 230
Urban	<500V	C12 : 500 U RES	115	190	91	396	288	486	239	1 014	403	675	331	1 409
Urban	<500V	C13 : Blank - no customers	0	0	0	0	0	0	0	0	0	0	0	0
Urban	<500V	C14 : 500 U OTHER SPU*	65	148	75	288	191	437	226	854	256	585	301	1 142
Urban	<500V	C15 : 500 U OTHER LPU	56	158	143	357	165	453	419	1 038	221	611	563	1 395
Rural	≥500V - <66kV	C16 : 2211 R LPU	135	363	378	876	402	1 045	1 111	2 558	537	1 408	1 489	3 434
Rural	≥500V - <66kV	C17 : Blank - no customers	0	0	0	0	0	0	0	0	0	0	0	0
Rural	<500V	C18 : 500 R OTHER LPU	117	347	332	796	403	1 126	1 121	2 650	521	1 473	1 454	3 447
Rural	<500V	C19 : 500 R OTHER SPU	193	456	228	876	603	1 363	655	2 622	796	1 819	883	3 498
		Total	**7 382**	**18 577**	**18 227**	**44 186**	**21 152**	**52 664**	**52 945**	**126 761**	**28 534**	**71 242**	**71 171**	**170 947**

Table 3: Cost drivers - 2024/25 maximum demands and UC

			Annualisaed sales utilised capacity (UC kVA) Conversion of allocated costs to R/kVA	Annualised maximum demand (kVA) at sales Network allocation basis
Urban	>132kV	C01 : 275 LPU	104 713 732	7 559 374
Urban	³66kV - <132kV	C02 : 132 LPU*	65 176 029	4 668 808
Urban	³66kV - <132kV	C04 : 88 LPU	38 029 262	2 371 332
Urban	³66kV - <132kV	C05 : 66 LPU	23 341 278	1 602 014
Urban	³500V - <66kV	C06 : 44 LPU	9 817 389	544 631
Urban	³500V - <66kV	C07 : 33 LPU	71 752 799	5 263 374
Urban	³500V - <66kV	C08 : 6.6 3.3 2.2 LPU	43 328 427	2 923 872
Urban	³500V - <66kV	C09 : 2211 U LPU	113 746 798	7 491 093
Urban	<500V	C11 : 500 U ELEC	109 277 742	9 211 719
Urban	<500V	C12 : 500 U RES	8 557 198	539 232
Urban	<500V	C14 : 500 U OTHER SPU*	6 442 462	537 430
Urban	<500V	C15 : 500 U OTHER LPU	12 042 638	415 401
Rural	³500V - <66kV	C16 : 2211 R LPU	18 660 483	1 029 020
Rural	³500V - <66kV	C18 : 500 R OTHER LPU	31 810 824	1 384 243
Rural	<500V	C19 : 500 R OTHER SPU	71 508 582	5 964 637
		Total	**728 205 643**	**51 506 177**

5.2. Cost allocation diagram (CAD)

The allocation of purchase costs (energy and transmission networks) and distribution network costs is guided by the location of a costing category in the distribution network. Costing categories are plotted on a summated view of the Eskom distribution network, that is, the CAD that:

- Depicts distribution network positions by voltage and density. The CAD is linked to network positions' transformation assets (substations, cables, and lines) and values from the MYPD asset valuation study.
- Consists of 22 network positions with position P0 referencing >132 kV and the distribution network. The CAD starts from position P1 which has 132 kV transformation (T1) and 132 kV lines (N1). See Annexure 4 for the distribution network model.
- Groups networks into high-voltage (≤132 kV to ≥33 kV), medium-voltage (≤22 kV to ≥2.2 kV) and reticulation/low-voltage (400 V) for ease of reference.
- Links to asset loss factors obtained from a distribution network study (see Annexure 5) to enable distribution network loss calculations.

Plotting costing categories on the CAD enables network losses (energy and demand) allocation and determination of each category's volumes at the various network positions.

The CAD is a primary reference to allocate active energy, transmission and distribution network losses, generation capacity purchase costs and distribution network costs. The CAD is not used for retail cost allocation. See Table 8 for the network demand volumes and Annexure 6 for the active energy purchase volumes.

5.3. Electrical losses

On the 2024/25 energy wheel, which is a summary of the MYPD forecasted electricity production, supply and demand, Generators (local and imports) supply a total of 224 805 GWh. This supply volume meets 224 805 GWh of customer demand which consists of local energy purchases (including distribution network losses), export purchases, pumping purchases and transmission network losses. See Annexure 1 for the 2024/25 energy wheel.

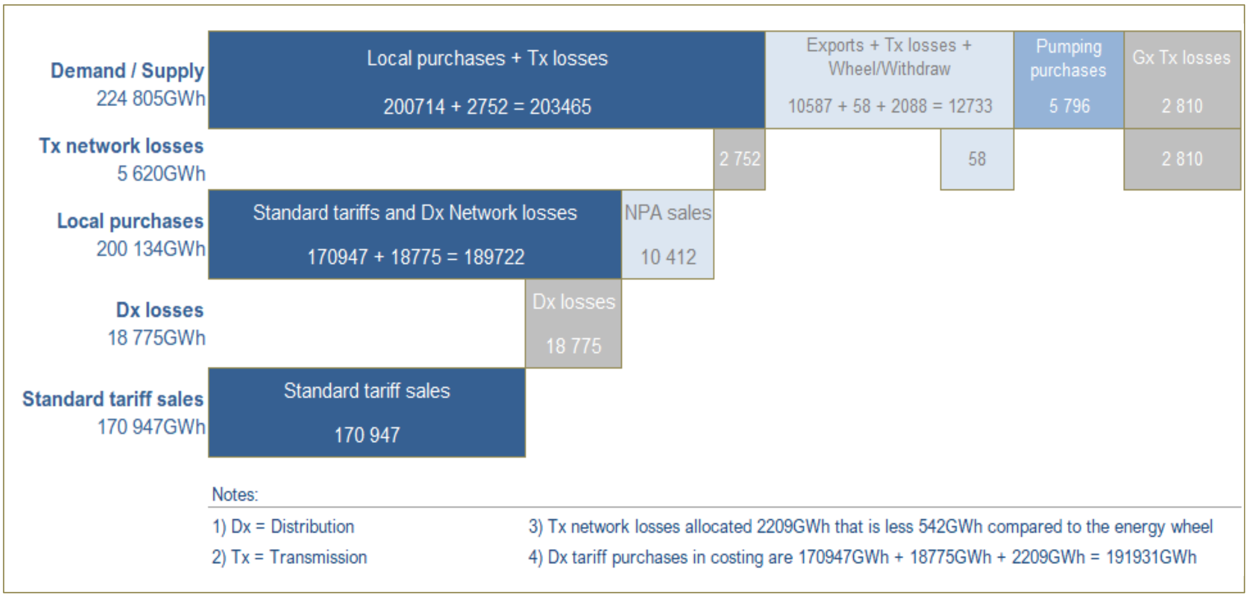
Transmission network electrical losses

- The South African Grid code requires that ±50% of the transmission network losses be for generators and ±50% for loads (local and export purchases).
- Of the total 5 620 GWh transmission network losses 2 810 GWh is for generators, the remainder 2 810 GWh is for the loads, that is, 2 752 GWh for local sales and 58 GWh for international/exports.

Distribution network electrical losses

- In the energy wheel the total distribution network losses are 18 775 GWh.
- The distribution losses are only for customers taking supply in the distribution network. The NPA sales and some large industrial, mining and metro customers take supply at >132 kV and /or are directly connected to the transmission network.
- See Table 4 for a summary of the forecasted supply, losses, and sales.

Table 4: Summary of the energy wheel



5.4. Distribution electrical losses by costing category

Distribution network electrical losses for costing, are determined using per asset unit loss factors. The derived electrical loss volumes are summarised to provide loss factors by distribution network voltage category. To calculate the distribution network electrical losses associated with each costing category's energy consumption:

- Costing categories are plotted in the network model at their voltage of supply. The corresponding consumption is multiplied by the respective per-asset unit loss factors for transformation and lines following the transfer of electricity supply in the distribution network.
- The summation of the resulting volumes is the distribution network losses volumes by costing category as shown in Table 5.
- The distribution network loss volumes summarised by voltage and then divided by the corresponding distribution purchase volumes provide the distribution loss factors as shown in Table 6.
- The difference between the CTS distribution loss factors and those in the 2024/25 schedule of standard tariffs arises from the fact that the CTS factors are calculated using 2024/25 forecasted

sales volumes, which differ from the 2012/13 volumes used for the current standard tariff distribution loss factors.

The 2024/25 distribution network losses (18 775 GWh) plus the sales (170 947 GWh) are the standard tariffs' energy purchases (189 722 GWh). This purchase volume is lower by 542 GWh compared to the energy wheel. This is because the energy wheel is calculated at a high level whilst the loss volumes in the CTS study are derived from the detailed sales volumes after the application loss factors.

Table 5: Distribution network loss volumes (GWh)

			Winter Dx network losses (GWh) [3 months : Jun - Aug]				Summer Dx network losses (GWh) [9 months : Apr - May & Sep-Mar]				Dx network losses [12 months: Apr - Mar]			
			Peak	Standard	Off-peak	Total	Peak	Standard	Off-peak	Total	Peak	Standard	Off-peak	Total
	>132kV	C01 : 275 LPU	0	0	0	0	0	0	0	0	0	0	0	0
Urban	≥66kV - ≤132kV	C02 : 132 LPU*	64	160	148	372	173	438	416	1 027	237	598	564	1 399
Urban	≥66kV - ≤132kV	C03 : Blank - no customers	0	0	0	0	0	0	0	0	0	0	0	0
Urban	≥66kV - ≤132kV	C04 : 88 LPU	27	67	67	162	71	175	179	424	98	242	246	586
Urban	≥66kV - ≤132kV	C05 : 66 LPU	25	63	57	146	69	173	161	403	95	236	218	549
Urban	≥500V - <66kV	C06 : 44 LPU	11	30	30	71	31	79	79	188	42	109	108	259
Urban	≥500V - <66kV	C07 : 33 LPU	139	410	482	1 031	501	1 302	1 542	3 346	641	1 712	2 024	4 377
Urban	≥500V - <66kV	C08 : 6.6 3.3 2.2 LPU	88	238	284	610	254	684	824	1 762	341	922	1 108	2 371
Urban	≥500V - <66kV	C09 : 2211 U LPU	218	553	589	1 359	604	1 541	1 673	3 818	822	2 094	2 262	5 178
Urban	≥500V - <66kV	C10 : Blank - no customers	0	0	0	0	0	0	0	0	0	0	0	0
Urban	<500V	C11 : 500 U ELEC	100	179	74	353	264	500	228	993	364	680	303	1 346
Urban	<500V	C12 : 500 U RES	21	35	17	74	54	90	45	189	75	126	62	262
Urban	<500V	C13 : Blank - no customers	0	0	0	0	0	0	0	0	0	0	0	0
Urban	<500V	C14 : 500 U OTHER SPU*	12	27	14	54	36	81	42	159	48	109	56	213
Urban	<500V	C15 : 500 U OTHER LPU	10	29	27	66	31	84	78	193	41	114	105	260
Rural	≥500V - <66kV	C16 : 2211 R LPU	24	64	67	154	71	184	196	451	95	248	262	605
Rural	≥500V - <66kV	C17 : Blank - no customers	0	0	0	0	0	0	0	0	0	0	0	0
Rural	<500V	C18 : 500 R OTHER LPU	23	68	66	157	80	222	221	523	103	291	287	680
Rural	<500V	C19 : 500 R OTHER SPU	38	90	45	173	119	269	129	517	157	359	174	690
		Total	**801**	**2 016**	**1 965**	**4 782**	**2 357**	**5 824**	**5 813**	**13 993**	**3 158**	**7 839**	**7 778**	**18 775**

Table 6: 2024/25 CTS study Distribution loss factors

	2024/25 Tariff book		2024/25 CTS Updated Dx loss factors	
	Urban	Rural	Urban	Rural
< 500V	1.1111	1.1527	1.1862	1.1973
≥ 500V & < 66kV	1.0957	1.1412	1.1556	1.1761
≥ 66kV & ≤ 132kV	1.0611		1.0724	
> 132kV	1.0000		1.0000	
< 500V	11.11%	15.27%	18.62%	19.73%
≥ 500V & < 66kV	9.57%	14.12%	15.56%	17.61%
≥ 66kV & ≤ 132kV	6.11%		7.24%	
> 132kV	0.00%		0.00%	

5.5. Transmission electrical losses by costing category

Detailed distribution network energy purchases by costing category are multiplied by transmission network loss factors to determine the electrical losses for the transmission network.

- The transmission loss factors are by transmission zone representing the average percentage difference between the total energy demand and load purchases in each concentric zone. Consequently, if there are changes in energy production and purchase volumes from one year to the next, the transmission loss factors will change. See the updated transmission network loss factors in Table 7.
- The calculated transmission losses by costing category are contained in Annexure 6 and they are a total of 2 209 GWh which is a 601 GWh difference from the 2 810 GWh on the energy wheel. This is because transmission loss factors on the energy wheel are calculated at a high level (at the total energy production and purchases by transmission zone). In the CTS study, the transmission loss volumes are derived from the sum of the detailed distribution sales plus distribution network losses.
- When compared to the transmission loss factors in the 2024/25 schedule of standard tariffs, the change in transmission loss factors is due to the use of different forecasted sales volumes.

Table 7: Transmission loss factors

Transmission zone	2024/25
≤ 300km	1.0060
> 300km and ≤ 600km	1.0160
> 600km and ≤ 900km	1.0261
> 900km	1.0361

5.6. Maximum demand and UC

- The allocation of distribution network capacity costs requires using the maximum demand per costing category at each of the 22 network positions considering the respective line and transformation assets.
- Like electrical losses, power losses occur during the transformation from higher to lower voltages in the distribution network. The per-asset loss factors are applied to sales maximum demands (measured at the PoDs) to determine the costing category sales non-coincident maximum demands by network position.
- See Table 8 for the sales maximum demand, the annualised UC and the cumulative adjusted non-coincident maximum demands including distribution network losses.

Table 8: Sales and network demands

					Max demand purchases /Non-coincident demand (kVA) (Cumulative: sum of identified demands at each network and transformation position)				
			Annualisaed sales utilised capacity (UC kVA) Conversion of allocated costs to R/kVA	Annualised maximum demand (kVA) at sales Network allocation basis	Tx network (L&T) >132kV	HV networks (L&T) 132kV - 33kV	MV networks (L&T) 22kV - 3.3kV	LV networks (L&T) 400V	Total
Urban	>132kV	C01 : 275 LPU	104 713 732	7 559 374	7 559 374	0	0	0	7 559 374
	³66kV - <132kV	C02 : 132 LPU*	65 176 029	4 668 808	0	4 668 808	0	0	4 668 808
		C04 : 88 LPU	38 029 262	2 371 332	0	7 383 349	0	0	7 383 349
		C05 : 66 LPU	23 341 278	1 602 014	0	6 671 668	0	0	6 671 668
	³500V - <66kV	C06 : 44 LPU	9 817 389	544 631	0	1 930 180	0	0	1 930 180
		C07 : 33 LPU	71 752 799	5 263 374	0	21 142 849	0	0	21 142 849
		C08 : 6.6 3.3 2.2 LPU	43 328 427	2 923 872	0	7 332 842	6 299 676	0	13 632 518
		C09 : 2211 U LPU	113 746 798	7 491 093	0	19 307 549	15 404 074	0	34 711 622
	<500V	C11 : 500 U ELEC	109 277 742	9 211 719	0	24 656 500	19 671 609	18 670 249	62 998 358
		C12 : 500 U RES	8 557 198	539 232	0	1 443 333	1 151 529	1 092 912	3 687 773
		C14 : 500 U OTHER SPU*	6 442 462	537 430	0	1 438 508	1 147 680	1 089 259	3 675 446
		C15 : 500 U OTHER LPU	12 042 638	415 401	0	1 111 880	887 087	841 931	2 840 899
Rural	³500V - <66kV	C16 : 2211 R LPU	18 660 483	1 029 020	0	2 721 014	2 144 197	0	4 865 211
		C18 : 500 R OTHER LPU	31 810 824	1 384 243	0	3 755 666	4 343 759	0	8 099 425
	<500V	C19 : 500 R OTHER SPU	71 508 582	5 964 637	0	16 182 990	18 717 058	5 964 637	40 864 685
		Total	**728 205 643**	**51 506 177**	**7 559 374**	**119 747 135**	**69 766 669**	**27 658 988**	**224 732 165**

5.7. Distribution network demand for cost allocation

In the distribution network, customers connected at high voltages do not use medium-voltage and low-voltage or reticulation networks. Customers connected at medium-voltage use high-voltage and medium-voltage networks. Customers connected at low-voltage and reticulation networks use high-voltage, medium-voltage, and reticulation networks. Further, networks are built, maintained, and refurbished primarily to meet maximum demand. To capture this relationship that combines the use of the distribution network and maximum demand influence on costs, there is a need to calculate customers' contribution to the different network positions' maximum demands for cost allocation.

Individual customers' maximum demands are non-coincident, that is, their occurrence may not coincide with the maximum demands of networks used; they are non-coincident peak demands (NCPD). Understanding how costing categories' NCPDs contribute to the maximum demands at various network positions is required. This is to enable cost allocation following costing categories use of networks and their contribution to network positions' maximum demand. To achieve this, the average and excess (A&E) method is applied.

The A&E methodology provides a way in which to determine the total demand for cost allocation by costing category which is the average and allocated excess demand at each network position. The process is outlined below, highlighting costing category C02 132 LPU at network position N1 and outlined in

Table 9:

1. Annualised customer maximum demands / NCPD (in kVA) and active energy (kWh) volumes are grouped by costing category and plotted on the CAD. The mapping of each costing category's volumes identifies the network position of connections and all the other network positions used to supply electricity to the costing category.

2. The NCPD and active energy for each costing category is adjusted with network per asset loss factors to determine the NCPD and active energy including losses at each network position. The result determines each costing category's contribution to the network position's maximum demand.

3. The average power factor /pf (a ratio of real to the apparent power) determined using each costing category's sum of maximum KW divided by maximum kVA is included. At N1, in column (a) the C02 NCPD is 4 669 MVA, the pf is 0.962 and the active energy (b) is 19 234 GWh.

4. To determine a costing category's average demand (d) at a network position, the active energy (b) is divided by annual hours and by the power factor (c), that is:

   $(b) \div 8\ 760 \div (c) = (d)$

   For C02 at N1, this is 19 324 054 116kWh ÷ 8 760 ÷ 0.962 = 2 293 386kVA

5. The determination of coincident peak demand (CPD) (i) at a network position is as follows:

i. The network positions excess demand (e) is determined by subtracting the average demand (d) from the NCPD (c), that is:

(a) - (d) = (e)

For C02 at N1, this is 4 668 808 kVA - 2 293 386 kVA = 2 375 422 kVA

ii. The contribution of each costing category to the excess demand (f) is determined by dividing each costing category's excess demand (e) by the total excess demand Σ(e) for the network position, which is:

(e) ÷ Σ(e) = (f)

For C02 at N1, this is 2 375 422 kVA ÷ 31 792 296 kVA = 0.07471689951 or 7.47%

iii. An average load factor /LF (g) for each costing category is calculated for use in the determination of each costing category's CPD at a network position; that is:

((b)÷(a)÷(c)÷8760 =(g)

For C02 at N1, this is 19 324 054 116 kWh ÷ 4 668 808 kVA ÷ 0.962 = 0.4912145 or 49.12%

iv. The coincident peak demand / CPD (i) is the NCPD (a) multiplied by the Barry coefficient (h), that is:

The Barry coefficient is contained in the Bary Curve (See Annexure 10), and it maps (plots) the relationship between the diversity factors of a system and the load factor. The data for the Bary Curve used in this CTS study was updated with South African system data; the original Bary Curve was conducted in the USA in the 1930s.

(a) x (h) = (i)

For C02 at N1, this is 4 668 808 kVA x 0.5947 = 2 776 661 kVA

6. The sum of the network position calculated CPD (Σ(i) or (o)) less the average demand (Σ(d)) is the network position's system's excess demand (k), that is:

Σ(i) - Σ(d) = (k) or (o) - Σ(d) = (k)

For network position 1 / N1, this is, 21 708 589 kVA - 17 982 027 kVA = 3 726 563 kVA

7. Each costing category's contribution to the network position's excess demand (f) multiplied by the system excess demand (k) is its allocated excess demand (j), that is:

(f)x (k) = (j)

For C02 at N1, this is 7.47% x 3 726 563 kVA = 278 437 kVA

8. The total demand (l) used to allocate each network position's total costs to individual costing

(j)+ (d) = (l)

For C02 at N1, this is 278 437 kVA + 2 293 386 VA = 2 571 823 kVA

categories using the network position, is the sum of the allocated excess demand (j) plus the average demand (d), that is:

9. The contribution of each costing category's total demand for allocation is the ratio (m) used to allocate the network position's costs to the costing category, which is:

The determined contribution to total demand for cost allocation by customer category at each

(l) ÷ Σ(l) = (m)

For Co2 at N1, this is 2 571 823 kVA ÷ 21 708 589 kVA = 11.85%

network position is then used to allocate distribution network costs. The generation capacity cost allocation uses the total demand for allocation at P0 that is the network position denoting the connection to the main transmission substations (MTSs).

Table 9: Determination of the coincident peak and excess demands at network 1 (N1)

			Non Coincident Peak Demand (NCPD) (MVA) Including power losses	Annual energy purchases (GWh) Including Dx electrical losses	Power factor (PF)	Average Demand (MVA)	Excess Demand (MVA)	Contri. to excess Demand %	Load factor (LF)	Bary CF	Coincident Peak Demand (CPD) (MVA)	Allocated Excess Demand (MVA)	Total demand for allocation (MVA)	Demand contribution (%)	Total Cost Portion (R'million)
		Network position for N1	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(l)	(m)	(n)
		Customer category				=(b)÷8760÷(c)	=(a)-(d)	=(e)÷Total(e)	=(b)÷(a)÷(c)÷8760		=(a)x(h)	=(f)x(k)	=(d)+(j)	=(l)÷Total(l)	=(m)x(p)
	>132kV	C01 : 275 LPU	0	0											
Urban	≥66kV - ≤132kV	C02 : 132 LPU*	4 669	19 324	0.962	2 293	2 375	7%	49.121%	0.5947	2 777	278	2 572	11.85%	157
		Blank - no customers : n/a													
		C04 : 88 LPU	2 537	8 659	0.961	1 029	1 508	5%	41%	0.5139	1 304	177	1 206	5.55%	74
		C05 : 66 LPU	1 714	8 111	0.965	959	755	2%	56%	0.6608	1 133	88	1 048	4.83%	64
	≥500V - <66kV	C06 : 44 LPU	595	1 819	0.964	215	380	1%	36%	0.4604	274	44	260	1.20%	16
		C07 : 33 LPU	5 950	31 795	0.948	3 828	2 121	7%	64%	0.7312	4 350	249	4 077	18.78%	249
		C08 : 6.6 3.3 2.2 LPU	3 340	17 406	0.945	2 102	1 237	4%	63%	0.7227	2 413	145	2 247	10.35%	137
		C09 : 2211 U LPU	8 468	37 613	0.952	4 512	3 956	12%	53%	0.6330	5 360	464	4 975	22.92%	304
		Blank - no customers : n/a													
	<500V	C11 : 500 U ELEC	10 814	8 488	0.985	984	9 830	31%	9%	0.1281	1 386	1 152	2 136	9.84%	130
		C12 : 500 U RES	633	1 654	0.956	198	435	1%	31%	0.4044	256	51	249	1.15%	15
		Blank - no customers : n/a	0	0											
		C14 : 500 U OTHER SPU*	631	1 341	0.946	162	469	1%	26%	0.3461	218	55	217	1.00%	13
		C15 : 500 U OTHER LPU	488	1 637	0.950	197	291	1%	40%	0.5034	245	34	231	1.06%	14
Rural	≥500V - <66kV	C16 : 2211 R LPU	1 193	3 983	0.925	491	702	2%	41%	0.5139	613	82	574	2.64%	35
		Blank - no customers : n/a													
	<500V	C18 : 500 R OTHER LPU	1 647	4 101	0.915	512	1 135	4%	31%	0.4044	666	133	645	2.97%	39
		C19 : 500 R OTHER SPU	7 097	4 162	0.950	500	6 597	21%	7%	0.1005	713	773	1 273	5.87%	78
		Total	49 774	150 094	n/a	17 982	31 792	100%	n/a	7	21 709	3 727	21 709	100%	1 325

Network position coincident peak demand (MVA)	21 709	(o) = total(i)
Network position excess demand (MVA)	3 727	(k) = (o) - (d)
Allocated network position costs : Capital (R'million)	1 325	(p)

6. Revenue mapping

6.1. Revenue mapping

The NERSA 2024/25 allowable revenue decision, amount R352 166 million, provides a total Eskom view by the MYPD methodology (2016) AR formula. Revenue mapping (functionalisation) is conducted to separate the approved allowable revenues for the Generation, Transmission and Distribution Divisions.

The revenue mapping of the 2024/25 Eskom totals R342 832million which excludes R9 334million international sales costs. AR revenue is functionalised as R293 560 million for the Generation Division, R15 084 million for Transmission Division and R34 188 million for Distribution Division. See Table 10.

Table 10: Revenue mapping - 2024/25 AR decision

Allowable revenues (AR)		Generation	Transmission	Distribution			Eskom total
				Networks	Retail	Total	
PE	PE Total	176 275	0	14	0	14	176289
E	Expenses	32 824	4 778	21 575	2 125	23 700	61 302
D	Depreciation	59 537	6 885	6 603	19	6 622	73 044
(RAB x WACC)	Return on assets	12 113	1 706	1 797	0	1 797	15 616
IDM	IDM	0	0	0	473	473	473
R&D	Research and development	0	0	0	0	0	0
SQI	Service quality incentives	0	0	0	0	0	0
L&T	Levis & taxes	0	0	0	0	0	0
RCA	Regulatory clearing account	12 810	1 716	1 583	0	1 583	16 109
AR	**Allowable revenues**	**293 560**	**15 084**	**31 572**	**2 617**	**34 188**	**342 832**
		86%	*4%*	*9%*	*1%*	*10%*	*100%*

6.2. Pass-through to Distribution

The MYPD methodology facilitates the recognition of the Generation and Transmission costs in Distribution through the pass-through rule. The pass-through of costs from the Transmission and Generation Divisions to the Distribution Division is as follows:

- Generation costs are passed through to Distribution through the Wholesaler located in the Transmission Division by way of a wholesale pricing structure to recoup the cost of energy purchased by the Distribution Division. In 2024/25, the Generation pass-through costs are separate for ToU energy (c/kWh), generation capacity costs (R/kW) and Legacy charge (c/kWh) which are R238 051 million, R19 050 million and R32 316 million, respectively.
- The costs passed through from Transmission are the purchases for network, transmission losses and ancillary services.

- Transmission technical losses and ancillary purchase cost pass-through applies c/kWh purchase unit costs to generators and loads (Distribution). For transmission network capacity purchase costs R/kVA network unit costs differentiated by transmission zone are applicable.
- The transmission costs passed through from Transmission to Generation are R11 905 million and R11 357 million to Distribution less the costs attributable to exports.
- The total Distribution Division expenses, depreciation and return on assets plus the costs pass-through from Transmission and Generation are a total R334 962 million for recovery through standard tariffs. Including the 2024/25 ERTSA R2 577 million difference, the total revenues for allocation in the 2024/25 CTS study are R337 539 million. See Table 11.

Table 11: 2024/25 pass-through to Distribution Division

Allowable revenues (AR)		Generation	Transmission	Distribution	Eskom
PE	PE Total	176 275		14	176 289
E	Expenses	32 824	4 778	23 700	61 302
D	Depreciation	59 537	6 885	6 622	73 044
(RAB x WACC)	Return on assets	12 113	1 706	1 797	15 616
IDM	IDM			473	473
R&D	Research and dev. programme				0
SQI	Service quality incentives				0
L&T	Levis & taxes	0			0
RCA	Regulatory clearing account	12 810	1 716	1 583	16 109
AR	**Allowable revenues**	**293 560**	**15 084**	**34 188**	**342 832**
				Pass-through to Distribution	
EPPa	**Other transmission costs**				
	Transmission losses		8 167		
	Ancillary services		1 286		
AR Tx	**Transmission**		**24 537**		
	Purchases from transmission	**11 905**		**11 357**	
	Transmission network	7 314		7 221	
	Transmission losses	3 960		3 561	
	Ancillary services	630		574	
AR Gx	**Generation**	**305 465**			
	Purchases from Generation			**289 417**	
	Energy capacity			19 050	
	ToU Energy			238 051	
	Legacy charge			32 316	
AR Dx	**Distribution**			**334 962**	
	Exports & NPA				**6 763**
AR Eskom	**Total Eskom allowable revenues**				**341 725**
	ERTSA Difference			2 577	
	Distribution Standard tariffs			**337 539**	

7. Cost classification

The result of the revenue mapping informs the cost classification of the Distribution Division's costs. The classification of the passed-through standard tariff costs is as follows:

- **Energy purchase costs** are for the purchase of electrical energy which consists of energy sold and losses in the transmission and distribution networks and generation capacity:
  - The separately identified variable energy purchase costs are active energy costs, environmental levy (levies & taxes), and transmission and distribution network (technical) losses. This grouping in the classification process enables separate but equivalent cost allocation of active energy and network losses at the point of connection to the transmission network (>132 kV).
  - The generation capacity costs are separately identified because of their fixed nature.

- **Transmission purchase costs** are separately classified into transmission network capacity and ancillary services costs, excluding transmission technical losses.

- **Distribution costs** are classified into distribution network capacity and retail costs:
  - The Distribution Division allowable revenues are for the provision of network capacity in the distribution network (≤132 kV) and retail services.
  - The distribution costs are classified into network and retail costs based on the details underlying the 2024/25 MYPD5 revenue application.
  - The distribution costs are increased by the difference between the MYPD decision's revenues for standard tariffs and the NERSA-approved ERTSA revenues.

See Table 12 for the standard tariff costs after classification and the further breakdown of the distribution networks and retail costs in Table 13.

Table 12: Standard tariff costs after classification

	Standard tariff
Total	337 539
Energy purchases	**292 979**
Energy ToU costs	232 000
Energy Capacity costs	19 050
Energy Legacy charge	32 316
Transmission technical losses	3 561
Distribution technical losses	0
Environmental levy	6 051
Transmission network	**7 795**
Network capacity	7 221
Ancillary services	574
Distribution total	**36 765**
Distribution network	
Network capacity	31 572
Retail services	
Customer service and administration	5 194

Table 13: Detail of Standard tariff distribution networks and retail costs

Distribuiton networks total	**31 572**
Capital	**9 983**
Network capital	9 892
Meter capital	91
Network support : Operating and mainte	**21 575**
Repairs and maintenance	9 609
Employee benefits	10 068
Corporate overheads	2 431
Other income	-534
Other overheads	**14**
Other expenses	14
Dx returns	**0**
Tax and dividends	**0**
Retail total	**5 194**
Retail expenses	**2 308**
Marketing	520
Customer service (Employee benefits)	1 788
Billing	**832**
Prepayment	637
Account	195
Meter reading	**91**
CS Overheads (other costs)	**1 945**
Impairments (abnormal) costs	**0**
Other customers	0
Key customers	0
Depreciation	**19**

8. Cost allocation

The cost allocation involves determining standard tariff unit costs by costing category using cost drivers, namely energy sales volumes, UC volumes, maximum demand volumes and number of PoDs.

8.1. Active energy purchases (ToU) unit costs

Active energy is the electricity generated, transported, and consumed. The cost of active energy ToU purchases from the Wholesaler includes transmission and distribution network losses. The total Distribution active energy purchase costs from the Wholesaler are R238 815 million for 170 947 GWh (sales, distribution, and transmission network losses).

The cost allocation reflects the Wholesale ToU energy pricing which is applied to active energy ToU purchase volumes as follows (with reference to Table 14):

- The total energy purchase volumes are classified by ToU period and season (i) ratios.
- The ratio of 1:6 (ii) applied is proposed by the System Operator (SO); also see Annexure 9 for a summary of the SO motivation to propose the 1:6 ratio.
- The energy purchase units cost (c/kWh) rate (iii) for each ToU period and season (i) are multiplied by the applicable energy purchase volumes (i) to get the energy purchase costs (iv)

See Table 14 for the calculation of the ToU energy purchase using the applicable unit rates.

Table 14: Active energy purchase at 1:6 time-of-use (ToU) ratio

		High Demand (3mths)			**Low Demand** (9mths)			**Total**
		Peak	Standard	Off-Peak	Peak	Standard	Off-Peak	
(i)	Energy purchase volumes (GWh)	7 382	18 577	18 227	21 152	52 664	52 945	170 947
(ii)	1:6 Time-of-use ratio	*6.00*	*2.31*	*1.18*	*2.50*	*1.67*	*1.00*	
(iii)	**Energy purchase unit costs (c/kWh)**	**478.66c**	**119.66c**	**79.78c**	**198.64c**	**111.69c**	**79.78c**	
(iv)	**Energy purchase costs (R'million)**	39 169	24 642	16 108	46 698	65 323	46 874	238 815

The active energy unit costs are then applied to costing category purchase volumes expressed at >132 kV, that is, including the distribution and transmission network losses. See Table 15 for the resulting energy purchase costs by costing category. The allocated active energy costs by costing category divided by the purchase volumes are the purchase unit costs that are the same across costing categories. See Table 16. When the same costs are divided using sales volumes the resulting average unit costs are different as they reflect unit costs inclusive of network losses costs. See Table 17.

Table 15: Allocated active energy purchase costs by costing category (R'million)

			Winter Dx purchases (GWh) [3 months : Jun - Aug]				Summer Dx purchases (GWh) [9 months : Apr - May & Sep-Mar]				Dx purchases costs (R'million)			
			Peak	Standard	Off-peak	Total	Peak	Standard	Off-peak	Total	Peak	Standard	Off-peak	Total
	>132kV	C01 : 275 LPU	7 801	4 817	3 129	15 747	8 775	12 331	8 815	29 921	16 576	17 148	11 944	45 668
Urban	³66kV - £132kV	C02 : 132 LPU*	4 522	2 841	1 752	9 116	5 099	7 241	4 912	17 253	9 621	10 082	6 664	26 368
		C03 : Blank - no customers	0	0	0	0	0	0	0	0	0	0	0	0
		C04 : 88 LPU	1 927	1 193	793	3 912	2 085	2 892	2 112	7 090	4 012	4 085	2 905	11 002
		C05 : 66 LPU	1 806	1 122	675	3 603	2 036	2 860	1 901	6 797	3 842	3 982	2 576	10 400
	³500V - <66kV	C06 : 44 LPU	397	269	175	840	450	657	465	1 573	847	926	640	2 413
		C07 : 33 LPU	4 954	3 641	2 853	11 448	7 397	10 803	9 139	27 338	12 350	14 444	11 992	38 786
		C08 : 6.6 3.3 2.2 LPU	3 118	2 115	1 682	6 915	3 741	5 672	4 884	14 297	6 859	7 787	6 566	21 212
		C09 : 2211 U LPU	7 733	4 915	3 489	16 137	8 915	12 784	9 911	31 610	16 649	17 699	13 400	47 747
		C10 : Blank - no customers	0	0	0	0	0	0	0	0	0	0	0	0
	<500V	C11 : 500 U ELEC	3 042	1 367	377	4 786	3 346	3 559	1 161	8 066	6 388	4 926	1 538	12 852
		C12 : 500 U RES	651	269	87	1 006	680	643	227	1 550	1 330	913	313	2 556
		C13 : Blank - no customers	0	0	0	0	0	0	0	0	0	0	0	0
		C14 : 500 U OTHER SPU*	367	209	71	648	450	579	214	1 243	817	789	285	1 891
		C15 : 500 U OTHER LPU	318	224	136	677	389	601	397	1 387	707	824	533	2 064
Rural	³500V - <66kV	C16 : 2211 R LPU	760	511	355	1 625	939	1 373	1 043	3 355	1 699	1 884	1 397	4 980
		C17 : Blank - no customers	0	0	0	0	0	0	0	0	0	0	0	0
	<500V	C18 : 500 R OTHER LPU	671	497	317	1 486	959	1 505	1 071	3 536	1 631	2 003	1 388	5 022
		C19 : 500 R OTHER SPU	1 105	653	218	1 975	1 434	1 823	626	3 883	2 539	2 476	844	5 858
		Total	**39 169**	**24 642**	**16 109**	**79 920**	**46 698**	**65 325**	**46 877**	**158 899**	**85 867**	**89 967**	**62 986**	**238 819**

Table 16: Allocated active energy purchase costs at >132 kV level (c/kWh)

			Winter active energy purchase costs expressed at >132kV(c/kWh) [3 months : Jun - Aug]				Summer active energy purchase costs expressed at >132kV (c/kWh) [9 months : Apr - May & Sep-Mar]				Total energy active energy purchase costs expressed at >132kV (c/kWh) [12 months: Apr - Mar]			
			Peak	Standard	Off-peak	Total	Peak	Standard	Off-peak	Total	Peak	Standard	Off-peak	Total
	>132kV	C01 : 275 LPU	495.50c	136.50c	96.61c	181.23c	215.48c	128.53c	96.62c	129.72c	290.93c	130.66c	96.62c	143.39c
Urban	≥66kV - ≤132kV	C02 : 132 LPU*	495.40c	136.39c	96.52c	182.01c	215.37c	128.42c	96.51c	130.18c	290.68c	130.55c	96.51c	143.97c
Urban	≥66kV - ≤132kV	C03 : Blank - no customers												
Urban	≥66kV - ≤132kV	C04 : 88 LPU	495.59c	136.59c	96.71c	180.42c	215.57c	128.62c	96.71c	129.70c	293.17c	130.83c	96.71c	143.68c
Urban	≥66kV - ≤132kV	C05 : 66 LPU	495.22c	136.22c	96.35c	183.29c	215.20c	128.25c	96.34c	130.45c	290.50c	130.38c	96.34c	144.49c
Urban	≥500V - <66kV	C06 : 44 LPU	495.51c	136.51c	96.60c	176.33c	215.48c	128.53c	96.60c	129.29c	290.45c	130.74c	96.60c	142.16c
Urban	≥500V - <66kV	C07 : 33 LPU	495.57c	136.57c	96.69c	166.50c	215.55c	128.60c	96.70c	126.93c	276.47c	130.51c	96.70c	136.25c
Urban	≥500V - <66kV	C08 : 6.6 3.3 2.2 LPU	495.59c	136.59c	96.71c	169.67c	215.57c	128.62c	96.71c	126.21c	287.53c	130.68c	96.71c	137.38c
Urban	≥500V - <66kV	C09 : 2211 U LPU	495.51c	136.51c	96.63c	176.69c	215.49c	128.54c	96.63c	128.32c	289.60c	130.64c	96.63c	141.02c
Urban	≥500V - <66kV	C10 : Blank - no customers												
Urban	<500V	C11 : 500 U ELEC	495.60c	136.60c	96.72c	229.60c	215.58c	128.63c	96.72c	144.44c	292.29c	130.73c	96.72c	166.79c
Urban	<500V	C12 : 500 U RES	495.60c	136.59c	96.71c	231.32c	215.58c	128.62c	96.71c	145.82c	295.19c	130.86c	96.71c	169.83c
Urban	<500V	C13 : Blank - no customers												
Urban	<500V	C14 : 500 U OTHER SPU*	495.60c	136.60c	96.72c	206.73c	215.58c	128.63c	96.72c	139.64c	286.32c	130.64c	96.72c	156.54c
Urban	<500V	C15 : 500 U OTHER LPU	495.41c	136.41c	96.53c	176.70c	215.38c	128.43c	96.53c	129.38c	286.25c	130.49c	96.53c	141.48c
Rural	≥500V - <66kV	C16 : 2211 R LPU	495.40c	136.41c	96.53c	174.52c	215.38c	128.43c	96.52c	128.24c	285.72c	130.49c	96.53c	140.04c
Rural	≥500V - <66kV	C17 : Blank - no customers												
Rural	<500V	C18 : 500 R OTHER LPU	495.36c	136.37c	96.49c	172.54c	215.32c	128.38c	96.47c	128.12c	278.28c	130.26c	96.47c	138.37c
Rural	<500V	C19 : 500 R OTHER SPU	495.60c	136.60c	96.72c	205.21c	215.58c	128.63c	96.72c	140.65c	283.41c	130.63c	96.72c	156.82c
		Total	**495.50c**	**136.50c**	**96.62c**	**180.05c**	**215.48c**	**128.53c**	**96.62c**	**129.74c**	**287.79c**	**130.61c**	**96.62c**	**142.72c**

Table 17: Allocated active energy purchase costs by costing category at sales level (c/kWh)

			Winter active energy purchase costs expressed at sales(c/kWh) [3 months : Jun - Aug]				Summer active energy purchase costs expressed at sales (c/kWh) [9 months : Apr - May & Sep-Mar]				Total energy active energy purchase costs expressed at sales (c/kWh) [12 months: Apr - Mar]			
			Peak	Standard	Off-peak	Total	Peak	Standard	Off-peak	Total	Peak	Standard	Off-peak	Total
	>132kV	C01 : 275 LPU	501.43c	138.15c	97.80c	183.44c	218.10c	130.09c	97.78c	131.29c	294.45c	132.24c	97.79c	145.13c
Urban	≥66kV - ≤132kV	C02 : 132 LPU*	540.94c	148.96c	105.37c	198.75c	235.27c	140.29c	105.40c	142.20c	317.50c	142.62c	105.39c	157.25c
Urban	≥66kV - ≤132kV	C03 : Blank - no customers												
Urban	≥66kV - ≤132kV	C04 : 88 LPU	534.92c	147.43c	104.40c	194.75c	232.70c	138.84c	104.40c	140.01c	316.46c	141.23c	104.40c	155.10c
Urban	≥66kV - ≤132kV	C05 : 66 LPU	546.44c	150.31c	106.27c	202.21c	237.53c	141.55c	106.30c	143.97c	320.62c	143.90c	106.30c	159.45c
Urban	≥500V - <66kV	C06 : 44 LPU	579.22c	159.55c	113.07c	206.23c	251.91c	150.26c	113.08c	151.22c	339.54c	152.83c	113.08c	166.27c
Urban	≥500V - <66kV	C07 : 33 LPU	577.16c	159.02c	112.57c	193.85c	250.95c	149.72c	112.56c	147.76c	321.89c	151.94c	112.56c	158.61c
Urban	≥500V - <66kV	C08 : 6.6 3.3 2.2 LPU	576.38c	158.85c	112.47c	197.31c	250.71c	149.58c	112.47c	146.77c	334.40c	151.97c	112.47c	159.77c
Urban	≥500V - <66kV	C09 : 2211 U LPU	579.15c	159.54c	112.92c	206.49c	251.90c	150.25c	112.93c	149.99c	338.52c	152.70c	112.93c	164.82c
Urban	≥500V - <66kV	C10 : Blank - no customers												
Urban	<500V	C11 : 500 U ELEC	591.38c	163.00c	115.41c	273.98c	257.24c	153.49c	115.41c	172.36c	348.78c	156.00c	115.41c	199.03c
Urban	<500V	C12 : 500 U RES	591.49c	163.04c	115.47c	276.12c	257.29c	153.53c	115.47c	174.06c	352.32c	156.20c	115.47c	202.72c
Urban	<500V	C13 : Blank - no customers												
Urban	<500V	C14 : 500 U OTHER SPU*	591.38c	163.00c	115.41c	246.69c	257.24c	153.49c	115.41c	166.63c	341.66c	155.89c	115.41c	186.80c
Urban	<500V	C15 : 500 U OTHER LPU	597.88c	164.64c	116.47c	213.23c	260.01c	155.04c	116.49c	156.16c	345.53c	157.51c	116.48c	170.76c
Rural	≥500V - <66kV	C16 : 2211 R LPU	592.92c	163.24c	115.49c	208.83c	257.87c	153.75c	115.53c	153.51c	342.06c	156.20c	115.52c	167.62c
Rural	≥500V - <66kV	C17 : Blank - no customers												
Rural	<500V	C18 : 500 R OTHER LPU	605.07c	166.51c	117.82c	210.69c	263.33c	156.97c	117.92c	156.64c	340.23c	159.22c	117.90c	169.13c
Rural	<500V	C19 : 500 R OTHER SPU	596.92c	164.52c	116.49c	247.16c	259.65c	154.93c	116.49c	169.40c	341.35c	157.33c	116.49c	188.88c
		Total	**555.63c**	**153.08c**	**108.29c**	**201.86c**	**242.28c**	**144.42c**	**108.47c**	**145.73c**	**323.35c**	**146.68c**	**108.43c**	**160.24c**

8.2. Legacy charge unit costs

The Legacy charge is included in the energy purchase cost. The total Distribution legacy charge from the wholesaler is R39 392 million for 170 947 GWh (sales, distribution, and transmission network losses).

The cost allocation reflects the wholesale Legacy charge unit cost rates which are applied to active energy ToU purchase volumes as follows (with reference to Table 18):

- The total energy purchase volumes are classified by ToU period and season (i) ratios.
- The ratio of 1:6 (ii) applied is proposed by the System Operator (SO); also see Annexure 9 for a summary of the SO motivation to propose the 1:6 ratio.
- The flat rate unit cost across ToU period and season for 2024/25 is 17.04 c/kWh (v).
- Legacy charge unit costs (c/kWh) rate (v) is multiplied by the applicable total energy purchase volumes (i) to get the Legacy charge (vi).

See Table 18 for the calculation of the ToU Legacy charge using the applicable unit rates.

Table 18: Legacy charge at 1:6 time-of-use (ToU) ratio

		High Demand (3mths)			Low Demand (9mths)			Total
		Peak	Standard	Off-Peak	Peak	Standard	Off-Peak	
(i)	Energy purchase volumes (GWh)	7 382	18 577	18 227	21 152	52 664	52 945	170 947
(ii)	1:6 Time-of-use ratio	***6.00***	***2.31***	***1.18***	***2.50***	***1.67***	***1.00***	
(v)	**Legacy charge unit costs (c/kWh)**	**17.04c**	**17.04c**	**17.04c**	**17.04c**	**17.04c**	**17.04c**	
(vi)	**Legacy charge (R'million)**	1 394	3 509	3 441	4 006	9 966	10 012	**32 329**

The Legacy charge unit costs are then applied to costing category purchase volumes expressed at >132kV, that is, including the distribution and transmission network losses. See Table 19 for the resulting energy purchase costs by costing category. The Legacy charges are divided by sales volumes the results reflect average unit costs inclusive of network loss costs. See Table 20.

Table 19: Allocated Legacy charge by costing category (R'million)

			Winter Legacy charge (R'million) [3 months : Jun - Aug]				Summer Legacy charge (R'million) [9 months : Apr - May & Sep-Mar]				Legacy charge (R'million) [12 months: Apr - Mar]			
			Peak	Standard	Off-peak	Total	Peak	Standard	Off-peak	Total	Peak	Standard	Off-peak	Total
	>132kV	C01 : 275 LPU	278	686	668	1 632	753	1 881	1 883	4 517	1 030	2 567	2 551	6 149
Urban	³66kV - £132kV	C02 : 132 LPU*	161	405	374	940	437	1 105	1 049	2 591	598	1 509	1 423	3 531
		C03 : Blank - no customers	0	0	0	0	0	0	0	0	0	0	0	0
		C04 : 88 LPU	69	170	169	408	179	441	451	1 071	247	611	620	1 479
		C05 : 66 LPU	64	160	144	368	175	436	406	1 017	239	596	550	1 385
	³500V - <66kV	C06 : 44 LPU	14	38	37	90	39	100	99	238	53	139	137	328
		C07 : 33 LPU	176	518	609	1 304	635	1 648	1 952	4 235	811	2 167	2 561	5 539
		C08 : 6.6 3.3 2.2 LPU	111	301	359	771	321	865	1 043	2 229	432	1 167	1 402	3 001
		C09 : 2211 U LPU	275	700	745	1 720	765	1 950	2 117	4 832	1 040	2 650	2 862	6 552
		C10 : Blank - no customers	0	0	0	0	0	0	0	0	0	0	0	0
	<500V	C11 : 500 U ELEC	108	195	81	384	287	543	248	1 078	395	738	328	1 461
		C12 : 500 U RES	23	38	18	80	58	98	48	205	81	137	67	285
		C13 : Blank - no customers	0	0	0	0	0	0	0	0	0	0	0	0
		C14 : 500 U OTHER SPU*	13	30	15	58	39	88	46	173	52	118	61	231
		C15 : 500 U OTHER LPU	11	32	29	72	33	92	85	210	45	124	114	282
Rural	³500V - <66kV	C16 : 2211 R LPU	27	73	76	176	81	209	223	513	108	282	298	688
		C17 : Blank - no customers	0	0	0	0	0	0	0	0	0	0	0	0
	<500V	C18 : 500 R OTHER LPU	24	71	68	162	82	230	229	541	106	300	297	703
		C19 : 500 R OTHER SPU	39	93	46	179	123	278	134	535	162	371	180	714
		Total	**1 394**	**3 509**	**3 441**	**8 344**	**4 006**	**9 966**	**10 012**	**23 984**	**5 400**	**13 475**	**13 453**	**32 329**

Table 20: Allocated Legacy charge by costing category at sales level (c/kWh)

			Winter legacy charge expressed at sales(c/kWh) [3 months : Jun - Aug]				Summer legacy charge expressed at sales (c/kWh) [9 months : Apr - May & Sep-Mar]				Total legacy charge expressed at sales (c/kWh) [12 months: Apr - Mar]			
			Peak	Standard	Off-peak	Total	Peak	Standard	Off-peak	Total	Peak	Standard	Off-peak	Total
	>132kV	C01 : 275 LPU	17.04c	17.04c	17.04c	17.04c	17.04c	17.04c	17.04c	17.04c	17.04c	17.04c	17.04c	17.04c
Urban	≥66kV - ≤132kV	C02 : 132 LPU*	18.27c	18.27c	18.27c	18.27c	18.27c	18.27c	18.27c	18.27c	18.27c	18.27c	18.27c	18.27c
		C03 : Blank - no customers												
		C04 : 88 LPU	18.27c	18.27c	18.27c	18.27c	18.27c	18.27c	18.27c	18.27c	18.27c	18.27c	18.27c	18.27c
		C05 : 66 LPU	18.27c	18.27c	18.27c	18.27c	18.27c	18.27c	18.27c	18.27c	18.27c	18.27c	18.27c	18.27c
	≥500V - <66kV	C06 : 44 LPU	19.69c	19.69c	19.69c	19.69c	19.69c	19.69c	19.69c	19.69c	19.69c	19.69c	19.69c	19.69c
		C07 : 33 LPU	19.69c	19.69c	19.69c	19.69c	19.69c	19.69c	19.69c	19.69c	19.69c	19.69c	19.69c	19.69c
		C08 : 6.6 3.3 2.2 LPU	19.69c	19.69c	19.69c	19.69c	19.69c	19.69c	19.69c	19.69c	19.69c	19.69c	19.69c	19.69c
		C09 : 2211 U LPU	19.69c	19.69c	19.69c	19.69c	19.69c	19.69c	19.69c	19.69c	19.69c	19.69c	19.69c	19.69c
		C10 : Blank - no customers												
	<500V	C11 : 500 U ELEC	20.21c	20.21c	20.21c	20.21c	20.21c	20.21c	20.21c	20.21c	20.21c	20.21c	20.21c	20.21c
		C12 : 500 U RES	20.21c	20.21c	20.21c	20.21c	20.21c	20.21c	20.21c	20.21c	20.21c	20.21c	20.21c	20.21c
		C13 : Blank - no customers												
		C14 : 500 U OTHER SPU*	20.21c	20.21c	20.21c	20.21c	20.21c	20.21c	20.21c	20.21c	20.21c	20.21c	20.21c	20.21c
		C15 : 500 U OTHER LPU	20.21c	20.21c	20.21c	20.21c	20.21c	20.21c	20.21c	20.21c	20.21c	20.21c	20.21c	20.21c
Rural	≥500V - <66kV	C16 : 2211 R LPU	20.04c	20.04c	20.04c	20.04c	20.04c	20.04c	20.04c	20.04c	20.04c	20.04c	20.04c	20.04c
		C17 : Blank - no customers												
	<500V	C18 : 500 R OTHER LPU	20.40c	20.40c	20.40c	20.40c	20.40c	20.40c	20.40c	20.40c	20.40c	20.40c	20.40c	20.40c
		C19 : 500 R OTHER SPU	20.40c	20.40c	20.40c	20.40c	20.40c	20.40c	20.40c	20.40c	20.40c	20.40c	20.40c	20.40c
		Total	**18.89c**	**18.89c**	**18.88c**	**18.88c**	**18.94c**	**18.92c**	**18.91c**	**18.92c**	**18.93c**	**18.92c**	**18.90c**	**18.91c**

8.3. Generation capacity unit costs

Generation capacity costs are generally incurred to establish power plants availing the infrastructure (capacity) to produce electricity. These costs do not vary with different amounts of electricity produced. They are instead driven by the costs incurred to provide each generating plant's maximum output.

The allocation of generation capacity costs recognises that:

- The total capacity made available is to meet customers' maximum demand as reflected in the transmission network >132kV.
- Not all customers are connected at >132 kV and therefore their maximum demand as recorded at their connection to the distribution network (≤132 kV) requires an adjustment to include asset losses. This reflects the maximum demand measured at the point of connection to the transmission network (>132 kV).
- Additionally, customers do not contribute equally to the maximum demand in the distribution network but allocating generation capacity costs needs to exclude further differentiation by distribution network voltage.

To determine the demand for use to allocate generation capacity costs, the Average and Excess (A&E) method is used. This is because it enables the expression of customer demand at >132 kV as discussed in section 5.7 Distribution network demand for cost allocation.

The total demand for allocation used to allocated generation capacity is the amount at network position P0. The network position P0 is the connection to the main transmission sub-station (MTS) on the CAD. The use of the P0 demand excludes voltage differentiation in the allocation of generation capacity costs.

The contribution of each costing category to the total demand for allocation at P0 is used to allocate the total generation capacity costs. To express the generation capacity unit costs at a sales level, the allocated costs are divided by the sales demand UC to arrive at the R/kVA unit cost. See **Table 21**.

Table 21: Allocated generation capacity purchase costs (R'million)

	Allocation at netowrk position 0 (P0)					Coincident Peak demand (MVA)	Excess demand (MVA)	Demand for allocation used (MVA)	Annualized Sales UC (MVA)	Total Generation capacity costs (R'million)	Generation capacity R/kVA based on allocation demand (monthly)	Generation capacity R/kVA based on sales demand UC (monthly)
	Voltage	Costing category	Avg PF	Avg LF	Bary CF							
	>132kV	C01 : 275 LPU	0.959	56.8%	0.67	5 064	417	4 713	104 714	3 262	57.68	31.15
Urban	≥66kV - ≤132kV	C02 : 132 LPU*	0.962	49.1%	0.59	2 873	314	2 687	65 176	1 860	57.68	28.54
		C03 : Blank - no customers										
		C04 : 88 LPU	0.961	40.6%	0.51	1 349	200	1 264	38 029	875	57.68	23.00
		C05 : 66 LPU	0.965	56.0%	0.66	1 172	100	1 092	23 341	756	57.68	32
	≥500V - <66kV	C06 : 44 LPU	0.964	36.2%	0.46	283	50	273	9 817	189	57.68	19.25
		C07 : 33 LPU	0.948	64.3%	0.73	4 501	281	4 242	71 753	2 936	57.68	40.91
		C08 : 6.6 3.3 2.2 LPU	0.945	62.9%	0.72	2 497	164	2 339	43 328	1 619	57.68	37.36
		C09 : 2211 U LPU	0.952	53.3%	0.63	5 546	523	5 192	113 747	3 593	57.68	31.59
		C10 : Blank - no customers										
	<500V	C11 : 500 U ELEC	0.985	9.1%	0.13	1 434	1 301	2 319	109 278	1 605	57.68	14.68
		C12 : 500 U RES	0.956	31.2%	0.40	265	58	262	8 557	181	57.68	21.19
		C13 : 500 R RES										
		C14 : 500 U OTHER SPU*	0.946	25.6%	0.35	226	62	229	6 442	159	57.68	24.65
		C15 : 500 U OTHER LPU	0.950	40.4%	0.50	254	38	242	12 043	168	57.68	13.91
Rural	≥500V - <66kV	C16 : 2211 R LPU	0.925	41.2%	0.51	635	93	601	18 660	416	57.68	22.31
		C17 : 500 R ELEC										
	<500V	C18 : 500 R OTHER LPU	0.915	31.1%	0.40	689	150	680	31 811	471	57.68	14.79
		C19 : 500 R OTHER SPU	0.950	7.0%	0.10	738	873	1 390	71 509	962	57.68	13.46
			Total			27 525	4 624	27 525	728 206	19 050	57.68	26.16

8.4. Ancillary service unit costs

The ancillary costs are not specific by time of day and transmission zone. Consequently, the ancillary cost allocation is not differentiated by ToU. The purchase cost is at the same unit cost for all purchase volumes.

The cost allocation of ancillary service costs is as follows:

- The R574 million is the total purchase cost. At the purchase volumes including transmission network losses, the unit cost is 0.3024c/kWh.
- The R574 million is divided by the distribution energy purchase volumes excluding transmission losses to determine the average c/kWh for allocation, that is, the ancillary service unit cost. This approach ensures ancillary service unit costs incurred are the same for all energy purchases.
- The allocated ancillary service costs by costing category divided by the purchase volumes are the purchase unit costs that are the same across costing categories. See Table 22.
- When the allocated ancillary service costs are divided by sales volumes the resulting average unit costs differ because they are inclusive of distribution network losses costs. See Table 22.

Table 22: Allocated ancillary costs by costing category

			Annual energy purchase volumes	Ancillary purchase costs	Distribution purchase volumes (Excld Tx losses)	Ancillary purchase unit cost at distribution purchase volumes	Distribution sales volumes (Excld Dx losses)	Ancillary purchase unit cost at sales level
			GWh	R'million	GWh	c/kWh	GWh	c/kWh
	>132kV	C01 : 275 LPU	36 523	109	36 085	0.3024	36 085	0.3024
Urban	≥66kV - ≤132kV	C02 : 132 LPU*	21 106	63	20 723	0.3024	19 324	0.3243
		C03 : Blank - no customers	0	0	0		0	
		C04 : 88 LPU	8 737	26	8 680	0.3024	8 094	0.3243
		C05 : 66 LPU	8 365	25	8 129	0.3024	7 581	0.3243
	≥500V - <66kV	C06 : 44 LPU	1 948	6	1 925	0.3024	1 666	0.3494
		C07 : 33 LPU	32 745	98	32 505	0.3024	28 128	0.3494
		C08 : 6.6 3.3 2.2 LPU	17 722	53	17 611	0.3024	15 240	0.3494
		C09 : 2211 U LPU	38 892	116	38 453	0.3024	33 275	0.3494
		C10 : Blank - no customers	0	0	0		0	
	<500V	C11 : 500 U ELEC	8 628	26	8 577	0.3024	7 230	0.3587
		C12 : 500 U RES	1 682	5	1 672	0.3024	1 409	0.3587
		C13 : Blank - no customers	0	0	0		0	
		C14 : 500 U OTHER SPU*	1 363	4	1 355	0.3024	1 142	0.3587
		C15 : 500 U OTHER LPU	1 683	5	1 655	0.3024	1 395	0.3587
Rural	≥500V - <66kV	C16 : 2211 R LPU	4 111	12	4 039	0.3024	3 434	0.3556
		C17 : Blank - no customers	0	0	0		0	
	<500V	C18 : 500 R OTHER LPU	4 213	12	4 127	0.3024	3 447	0.3620
		C19 : 500 R OTHER SPU	4 213	13	4 188	0.3024	3 498	0.3620
		Total	**191 931**	**574**	**189 722**	**0.3024**	**170 947**	**0.3356**

8.5. Transmission network capacity unit costs

The capacity provided in the transmission network is for transmission network-connected customers and the diversified distribution network demand as measured at the various distribution network points connected to MTS points.

The distribution network demand measured at the transmission MTS points is not the maximum demand of individual customers (non-coincident demand) but the maximum demand from all the distribution network demands (diversified demand).

- For the cost allocation, as outlined consequentially in Table 23, the annualised transmission network maximum demand is grouped into four transmission zones which are the concentric zones differentiated by the distance from the South African region with the most electricity production; see (i) and (iv). See Figure 5 for the concentric zones drawn on the South African map.
- The total transmission network capacity costs divided by diversified maximum demands differentiated by transmission zone are used to determine transmission network R/kVA capacity unit costs (or purchase rates) by transmission zone at >132 kV. The zonal R/kVA purchases unit costs (ii) apply to the costing category at >132 kV.
- To determine the costs for supplies connected to the distribution network, the allocated >132 kV supplies costs are subtracted from the total transmission capacity costs, that is, (iv) - (iii) = (v). The average transmission network R/kVA unit cost for supplies connected to the distribution network is (vi) = (v) ÷ (total vii) where (vii) is the sum of the non-diversified distribution network annualised UC. Consequently, because of using an undiversified UC (a higher value than the diversified demand at >132 kV), the average unit cost for supplies connected to the distribution network appears lower than for >132 kV supplies.
- To calculate the zone-differentiated transmission capacity unit cost for supplies connected to the distribution network, the average (vi) R/kVA transmission capacity unit cost is differentiated by transmission zone (viii). This zone-differentiated transmission capacity R/kVA unit cost is used to allocate the transmission network costs to the costing categories supplied from the distribution network (≤132 kV).
- The cost for transmission network capacity is therefore dependent on the transmission zone and voltage of the supply. See Table 23 (ii) for >132 kV unit costs and (viii) for ≤132 kV connected supplies. See Table 24 for the total allocated costs mapped to costing categories.

Table 23: Allocation of the transmission network capacity costs

Transmission zone	(i) >132kV / Tx connected Annulised UC volumes (kVA)	(ii) Tx network >132kV R/kVA purchase unit rate	(iii) Tx network >132kV Allocated purchase costs R'million
≤ 300km	60 190 245	14.49	872
> 300km and ≤ 600km	34 400 149	14.64	504
> 600km and ≤ 900km	2 363 421	14.78	35
> 900km	7 759 917	14.93	116
Total	**104 713 732**		**1 527**

(iv) Total transmission network capacity costs (R'million)	**7 221**
(v) Total transmission network capacity costs less allocated >132kV costs (R'million)	**5 695**
(vi) Average Tx network unit cost for Dx connected supplies (R/kVA)	**7.81**

Transmission zone	(vii) £132kV / Tx connected Annulised UC volumes (kVA)	(viii) Per Transmission zone differentiated R/kVA unit cost	(ix) Dx network £132kV Allocated purchase costs R'million
≤ 300km	532 893 668	7.77	**4 139**
> 300km and ≤ 600km	101 349 632	7.84	**795**
> 600km and ≤ 900km	26 879 447	7.92	**213**
> 900km	68 492 895	8.00	**548**
Total	**729 615 642**		**5 695**

Table 24: Allocated transmission network costs by costing category

	Voltage	Costing category	UC (MVA)	Allocated Tx nework capacity costs (R'million)	R/kVA unit cost (Rands) Total Tx zones
	>132kV	C01 : 275 LPU	104 714	1 527	14.58
Urban	≥66kV - ≤132kV	C02 : 132 LPU*	65 176	547	8.39
		C03 : Blank - no customers	0	0	
		C04 : 88 LPU	38 029	316	8.31
		C05 : 66 LPU	23 341	198	8.48
	≥500V - <66kV	C06 : 44 LPU	9 817	90	9.17
		C07 : 33 LPU	71 753	654	9.11
		C08 : 6.6 3.3 2.2 LPU	43 328	394	9.09
		C09 : 2211 U LPU	113 747	1 041	9.15
		C10 : Blank - no customers	0	0	
	<500V	C11 : 500 U ELEC	109 278	1 031	9.43
		C12 : 500 U RES	8 557	81	9.44
		C13 : 500 R RES	0.00	0.00	
		C14 : 500 U OTHER SPU*	6 442	61	9.43
		C15 : 500 U OTHER LPU	12 043	115	9.53
Rural	≥500V - <66kV	C16 : 2211 R LPU	18 660	176	9.44
		C17 : 500 R ELEC	0.00	0.00	
	<500V	C18 : 500 R OTHER LPU	31 811	309	9.70
		C19 : 500 R OTHER SPU	71 509	684	9.56
		Total	**728 206**	**7 221**	**9.92**

8.6. Distribution network capacity unit costs

Distribution network capacity costs include network capital (capital) and network support operating and maintenance (O&M) costs. The meter capital costs classified as distribution network costs are allocated separately.

To allocate the costs to costing categories first, the total distribution network capacity costs are assigned to each network position separately for transformation and lines and separately for capital and O&M. The basis for assigning the distribution cost to transformation and lines is the asset repayment costs obtained from the replacement values in the MYPD4 asset valuation study. The use of capital repayments follows that:

- Capital costs would be incurred if the distribution network were to be fully replaced recognising that the lifetime of existing network assets is diverse. Old assets reach their end of life and are replaced, new assets are installed at different times and different network positions. Consequently, the distribution network assets' age is diverse across the network. Using asset replacement values as a basis to apportion the total distribution costs creates an equitable base due to the varying ages of assets.
- The process to separately allocate the capital and O&M is as follows:
  - The network asset replacement values are summarised to correspond to network positions on the CAD grouped by transformation and lines.
  - The annuity for each network position's asset values is calculated and its contribution to the sum of all distribution network assets' annuity is determined. The derived contribution is then used to allocate the total capital costs to each network position.
  - The assignment of the O&M costs to network positions pools the network replacement values by high-voltage (HV: ≥33 kV), medium and low-voltage (MV& LV: ≤22 kV). This is so that the allocation of HV costs by network positions is limited to the contribution of HV network assets and similarly for the LV network.
  - The distribution capital and O&M costs assigned to each network position are then allocated by cost category based on the demand calculated using the A&E method as discussed 5.7 Distribution network demand for cost allocation.
  - See Table 25 for the allocated distribution network capacity costs by network position. See Table 26 and Table 27 for the summary of the allocated distribution network costs by customer category.

Table 25: Distribution network capacity costs by network position (R'million)

			Assets Networks (N) Transformation (T)	% of Total Annuity by lines and transformation assets	Distribution Capital (R'million)	% of Total annuity by HV and LV	Dx O&M (R'million)	Total Dx network capacity costs (R'Million)	
Transformation Tx - Dx		MTS - 132 kV	T1	0.0%	0	0.0%	0	0	
Lines Dx		132 kV	N1	20.1%	1 325	35.7%	2 995	4 320	Dx HV
		88 kV	N2	11.9%	788	21.2%	1 781	2 570	Dx HV
		66 kV	N3	7.2%	472	12.7%	1 068	1 540	Dx HV
		44 kV	N4	1.9%	127	3.4%	287	414	Dx HV
		33 kV	N5	0.4%	26	0.7%	59	85	Dx HV
Transformation Dx - Dx		88 kV Secondary	T2	4.1%	134	3.6%	303	437	Dx HV
		66 kV Secondary	T3 / T4 / T5	7.6%	250	6.7%	566	816	Dx HV
		44 kV Secondary	T6 / T7 / T8	4.1%	136	3.7%	307	443	Dx HV
		33 kV Secondary	T9 / T10 / T11 / T12	13.9%	458	12.3%	1 035	1 493	Dx HV
					3 718	100%	8 400	12 118	Dx HV
Transformation Dx - Rx	High Density (urban)	22 kV Secondary 11 kV Secondary	T13 / T14 / T15 / T16 / T17	37.6%	1 236	20.0%	2 637	3 873	Dx LV
		6.6 kV Secondary 3.3 kV Secondary	T18 / T19 / T20 / T21 / T22 / T23	9.9%	326	5.3%	696	1 022	Dx LV
	Low Density (rural)	22 kV Secondary 11 kV Secondary		0.0%	0	0.0%	0	0	Dx LV
		6.6 kV Secondary 3.3 kV Secondary		0.0%	0	0.0%	0	0	Dx LV
Lines Rx	High Density (urban)	22 kV 11 kV	N6	10.1%	666	10.8%	1 421	2 087	Dx LV
		6.6 kV	N7	0.3%	20	0.3%	43	62	Dx LV
	Low Density (rural)	22 kV 11 kV	N11	30.6%	2 021	32.7%	4 312	6 333	Dx LV
		6.6 kV		0.0%	0	0.0%	0	0	Dx LV
Transformation Rx - LV	High Density (urban)	Residential Low-usage residential Other	T24	11.8%	387	6.3%	825	1 212	Dx LV
	Low Density (rural)	Low-usage residential Other	T25	11.0%	363	5.9%	775	1 138	Dx LV
Lines LV	High Density (urban)	Residential	N9	2.9%	189	3.1%	403	592	Dx LV
		Low-usage residential	N8	13.2%	869	14.1%	1 854	2 722	Dx LV
		Other	N10	0.5%	30	0.5%	63	93	Dx LV
	Low Density (rural)	Residential	N13	0.0%	0	0.0%	0	0	Dx LV
		Low-usage residential	N12	1.0%	68	1.1%	145	213	Dx LV
					6 174	100%	13 174	19 348	Dx LV

Transformation	33.3%	**3 290**	**39%**	**8 400**	**12 118**
Lines	66.7%	**6 602**	**61%**	**13 174**	**19 348**
Total	**100.0%**	**9 892**	**100%**	**21 575**	**31 466**

Table 26: Summary of the allocated distribution network capacity costs (R'million)

Based on cumulative max demand purchases /Non-coincident peak demand (NCPD) from each network and transformation position						Average demand (MVA)	Excess demand (MVA)	Total demand for cost allocation (MVA)	Capital costs (R'million)	O&M costs (R'million)	Total costs (R'million)
	Voltage	Costing category	Avg PF	Avg LF	Bary CF						
	>132kV	C01 : 275 LPU	0.959	56.8%	0.67	4 295	417	4 713	0	0	0
Urban	≥66kV - ≤132kV	C02 : 132 LPU*	0.962	49.1%	0.59	2 293	278	2 572	157	355	512
Urban	≥66kV - ≤132kV	C03 : Blank - no customers				0	0	0	0	0	0
Urban	≥66kV - ≤132kV	C04 : 88 LPU	0.961	40.6%	0.51	2 994	507	3 501	224	506	729
Urban	≥66kV - ≤132kV	C05 : 66 LPU	0.965	56.0%	0.66	3 734	323	4 057	344	778	1 122
Urban	≥500V - <66kV	C06 : 44 LPU	0.964	36.2%	0.46	699	161	860	101	227	328
Urban	≥500V - <66kV	C07 : 33 LPU	0.948	64.3%	0.73	13 604	1 135	14 739	860	1 944	2 805
Urban	≥500V - <66kV	C08 : 6.6 3.3 2.2 LPU	0.945	62.9%	0.72	8 581	895	9 477	756	1 661	2 416
Urban	≥500V - <66kV	C09 : 2211 U LPU	0.952	53.3%	0.63	18 495	1 698	20 193	1 848	4 044	5 892
Urban	≥500V - <66kV	C10 : Blank - no customers				0	0	0	0	0	0
Urban	<500V	C11 : 500 U ELEC	0.985	9.1%	0.13	5 731	5 003	10 734	1 882	4 059	5 942
Urban	<500V	C12 : 500 U RES	0.956	31.2%	0.40	1 151	256	1 407	320	688	1 008
Urban	<500V	C13 : 500 R RES				0	0	0	0	0	0
Urban	<500V	C14 : 500 U OTHER SPU*	0.946	25.6%	0.35	942	278	1 220	127	276	403
Urban	<500V	C15 : 500 U OTHER LPU	0.950	40.4%	0.50	1 146	172	1 319	139	301	441
Rural	≥500V - <66kV	C16 : 2211 R LPU	0.925	41.2%	0.51	2 004	277	2 281	702	1 510	2 212
Rural	≥500V - <66kV	C17 : 500 R ELEC				0	0	0	0	0	0
Rural	<500V	C18 : 500 R OTHER LPU	0.915	31.1%	0.40	2 517	494	3 011	916	1 968	2 884
Rural	<500V	C19 : 500 R OTHER SPU	0.950	7.0%	0.10	2 878	3 134	6 013	1 515	3 258	4 773
			Total			71 066	15 031	86 097	9 892	21 575	31 466

Table 27: Distribution network capacity unit costs (R/kVA)

Based on cumulative max demand purchases /Non-coincident peak demand (NCPD) from each network and transformation position			Total demand for cost allocation (MVA)	Annualized Sales demand UC (MVA)	Distribution network capacity R/kVA based on allocation	Distribution network capacity R/kVA based on sales
	Voltage	Costing category				
	>132kV	C01 : 275 LPU	4 713	104 714	0.00	0.00
Urban	≥66kV - ≤132kV	C02 : 132 LPU*	2 572	65 176	16.58	0.65
Urban	≥66kV - ≤132kV	C03 : Blank - no customers	0	0	0	0
Urban	≥66kV - ≤132kV	C04 : 88 LPU	3 501	38 029	17.36	1.60
Urban	≥66kV - ≤132kV	C05 : 66 LPU	4 057	23 341	23.04	4.00
Urban	≥500V - <66kV	C06 : 44 LPU	860	9 817	31.77	2.78
Urban	≥500V - <66kV	C07 : 33 LPU	14 739	71 753	15.86	3.26
Urban	≥500V - <66kV	C08 : 6.6 3.3 2.2 LPU	9 477	43 328	21.25	4.65
Urban	≥500V - <66kV	C09 : 2211 U LPU	20 193	113 747	24.32	4.32
Urban	≥500V - <66kV	C10 : Blank - no customers	0	0	0.00	0.00
Urban	<500V	C11 : 500 U ELEC	10 734	109 278	46.13	4.53
Urban	<500V	C12 : 500 U RES	1 407	8 557	59.70	9.82
Urban	<500V	C13 : 500 R RES	0	0	0.00	0.00
Urban	<500V	C14 : 500 U OTHER SPU*	1 220	6 442	27.53	5.21
Urban	<500V	C15 : 500 U OTHER LPU	1 319	12 043	27.85	3.05
Rural	≥500V - <66kV	C16 : 2211 R LPU	2 281	18 660	80.82	9.88
Rural	≥500V - <66kV	C17 : 500 R ELEC	0	0	0.00	0.00
Rural	<500V	C18 : 500 R OTHER LPU	3 011	31 811	79.81	7.55
Rural	<500V	C19 : 500 R OTHER SPU	6 013	71 509	66.15	5.56
			86 097	728 206	30.46	3.60

8.7. Retail unit costs

The allocated retail costs are metering costs (meter capital and meter reading costs), customer service (employee benefits, returns, billing and other costs), marketing and billing.

Metering costs are allocated based on per meter type unit cost. After cost allocation, the metering unit costs are applied to detailed PoD data and then summarised by costing category.

For customer service, marketing and billing costs, customer groups based on connection capacity size are used in the allocation. The capacity size of a PoD indicates the extent of retail services provided. This is because larger-sized supply points involve more complexity to service than for example, a residential supply. The customer groups used are as shown is Table 28.

Table 28: Customer groups by capacity size

Point of delivery (PoD) capacity size	Customer group
≤ 100 kVA	Low Usage
≤ 100 kVA	Small Other
≤ 100 kVA	Small Residential
≤ 100 kVA	Small Rural
> 100 kVA & ≤ 500 kVA	Medium
> 500 kVA & ≤ 1 MVA	Large
> 1 MVA	Very Large
>1 MVA and Key customers	Key

8.7.1. Meter capital unit costs

The allocated meter capital costs are R91 million, and the cost allocation following on Table 29 is as follows:

1. The meter replacement costs from a metering study are used to identify capital repayment costs by meter type. The use of capital repayments follows the principle that capital costs would be incurred if all the meters were to be replaced.
2. The percentage contribution of each meter type (a) to the total capital repayments multiplied by the total categorised meter capital costs allocates the meter capital costs by meter type (b).
3. The unit cost per meter for each meter type (c) is the allocated meter capital costs (b) divided by the number of PoDs per meter type. The resulting unit cost is applied to each PoD by meter type and then summarised by costing category.

Table 29: Meter capital cost allocation

					Meter capital allocation		
Meter Description		No. of Pods	Replacement Cost/meter - 2023/24	Annualised Replacement Cost	(a) % of annual capital repayment costs	(b) = (a) * meter capital Allocated meter capital costs (R'million)	(c) Unit cost per meter (Rands)
Prepayment - ECU	1	7 562 481	2 168	2 668 408 494	88%	80.78	10.68
Prepayment - ED	1A	85 364	2 168	30 120 512	1%	0.91	10.68
Split meter (Wired interface)	1B	0	2 168	0	0%	0.00	0.00
Split meter (Wireless interface)	1C	163 975	3 400	90 735 575	3%	2.75	16.75
Single Phase - Conventional	2	0	3 400	0	0%	0.00	0.00
3 Phase < 50 kVA - Conventional	3	26 854	17 391	76 003 600	3%	2.30	85.68
3 Phase 75 & 100 kVA - Conventional	4	0	3 708	0	0%	0.00	0.00
Ruraflex < 50 kVA - Conventional	5	0	16 005	0	0%	0.00	0.00
100 kVA - Urban	100	0	16 005	0	0%	0.00	0.00
100 kVA - Rural	101	64	14 971	155 934	0%	0.00	73.76
150 kVA - Urban	150	199	14 971	484 856	0%	0.01	73.76
150 kVA - Rural	151	9	15 158	22 202	0%	0.001	74.68
200 kVA - Urban	200	14	15 158	34 537	0%	0.00	74.68
200 kVA - Rural	201	41	15 158	101 143	0%	0.00	74.68
300 kVA - Urban	300	53	15 158	130 745	0%	0.00	74.68
300 kVA - Rural	301	30	15 158	74 007	0%	0.00	74.68
500 kVA - Urban	500	33	15 158	81 408	0%	0.00	74.68
500 kVA - Rural	501	90	15 158	222 021	0%	0.01	74.68
1000 kVA - Urban	1000	257	15 158	633 992	0%	0.02	74.68
1000 kVA - Rural	1001	224	15 158	552 584	0%	0.02	74.68
1 Feeder Point 10 - 50 MVA - Urban	10000	203	15 158	500 780	0%	0.0	74.68
1 Feeder Point 10 - 50 MVA - Rural	10001	3 960	36 443	23 486 484	1%	0.7	179.55
1 Feeder Point 10 - 50 MVA - Urban	20000	8 794	36 443	52 153 637	2%	1.6	179.55
1 Feeder Point 10 - 50 MVA - Rural	20001	0	36 443	0	0%	0.0	0.00
1 Feeder Point > 50 MVA - Urban	30000	0	36 443	0	0%	0.0	0.00
1 Feeder Point > 50 MVA - Rural	30001	2 694	58 168	25 502 951	1%	0.8	286.58
1 Feeder Point > 50 MVA - Urban	40000	5 416	58 168	51 270 965	2%	1.55	286.58
1 Feeder Point > 50 MVA - Rural	40001	0	58 168	0	0%	0.00	0.00
No Meter	0	0	58 168	0	0%	0.00	0.00
Total		7 860 754	626 380	3 020 676 425	100%	91	11.63

Table 30: Meter capital costs by costing category

			Meter capital costs (Rands)								
	Voltage	Costing category	Low usage residential	Small Other	Small Residential	Small Rural	Medium	Large	Very Large	Key	Total
	>132kV	C01 : 275 LPU	0	295	0	0	821	1 483	2 782	8 972	**14 354**
Urban	>132kV	C02 : 132 LPU*	0	0	0	0	373	892	3 950	43 264	**48 479**
Urban	≥66kV - ≤132kV	C03 : Blank - no customer	0	0	0	0	0	0	0	0	**0**
Urban	≥66kV - ≤132kV	C04 : 88 LPU	0	0	0	0	224	0	5 251	37 918	**43 393**
Urban	≥66kV - ≤132kV	C05 : 66 LPU	0	0	0	0	299	148	1 436	11 878	**13 760**
Urban	≥500V - <66kV	C06 : 44 LPU	0	0	0	0	0	0	0	8 183	**8 183**
Urban	≥500V - <66kV	C07 : 33 LPU	0	0	0	0	75	0	1 511	19 146	**20 731**
Urban	≥500V - <66kV	C08 : 6.6 3.3 2.2 LPU	0	0	0	0	0	583	7 361	27 731	**35 675**
Urban	≥500V - <66kV	C09 : 2211 U LPU	0	518	0	0	18 323	48 210	210 641	40 408	**318 100**
Urban	≥500V - <66kV	C10 : Blank - no customer	0	0	0	0	0	0	0	0	**0**
Urban	<500V	C11 : 500 U ELEC	80 715 054	0	0	0	0	0	0	0	**80 715 054**
Urban	<500V	C12 : 500 U RES	128	521	1 538 372	0	253 945	224	0	0	**1 793 190**
Urban	<500V	C13 : 500 R RES	0	0	0	0	0	0	0	0	**0**
Urban	<500V	C14 : 500 U OTHER SPU*	0	831 304	0	0	0	0	0	0	**831 304**
Urban	<500V	C15 : 500 U OTHER LPU	0	1 261	0	0	750 517	3 764	4 130	148	**759 820**
Rural	≥500V - <66kV	C16 : 2211 R LPU	0	0	0	51 796	47 672	73 475	99 233	2 587	**274 763**
Rural	≥500V - <66kV	C17 : 500 R ELEC	0	0	0	0	0	0	0	0	**0**
Rural	<500V	C18 : 500 R OTHER LPU	0	0	0	101 123	2 797 866	12 851	539	298	**2 912 677**
Rural	<500V	C19 : 500 R OTHER SPU	0	0	0	3 654 516	0	0	0	0	**3 654 516**
		Total	**80 715 182**	**833 900**	**1 538 372**	**3 807 435**	**3 870 116**	**141 630**	**336 834**	**200 530**	**91 444 000**

8.7.2. Meter reading unit costs

The allocated meter reading costs are R91.04 million and the cost allocation following on Table 31 is as follows:

- Weightings representing how much more costly it is to read different types of meters (based on operational data) are used to weight the allocation of meter reading costs. The number of PoDs by meter type is multiplied by the corresponding weighting. The result by meter type is then divided by the total weighted PoDs to derive the contribution to the total meter reading costs.
- The meter reading costs are therefore contribution multiplied by the total R91.4 million. To determine the R/PoD meter reading unit costs, the cost allocated by meter type is divided by the corresponding number of PoDs.
- The meter reading unit costs are applied PoD detail per meter type and then summarised by costing category; see Table 32.

Table 31: Meter reading cost allocation

Meter Description		(a) No. of Pods	(b) Meter reading weighting	(b) x (a) = (c) Weighted number of PoDs	(d) = (c) ÷ total(c) Contribution to meter reading costs	(e)=(d) x total meter reading Reading costs per meter type (R'million)	(e)÷(a) = (f) R/PoD meter reading cost (Rands)
			Meter reading cost allocation				
Prepayment - ECU	1	7 562 481	0.0	0	0.00%	0.00	
Prepayment - ED	1A	85 364	1.0	85 364	0.00%	8.24	96.55
Split meter (Wired interface)	1B	0	1.0	0	0.00%	0.00	
Split meter (Wireless interface)	1C	163 975	1.0	163 975	17.39%	15.83	96.55
Single Phase - Conventional	2	0	1.0	0	0.00%	0.00	
3 Phase < 50 kVA - Conventional	3	26 854	1.0	26 854	2.85%	2.59	96.55
3 Phase 75 & 100 kVA - Conventional	4	0	1.0	0	0.00%	0.00	
Ruraflex < 50 kVA - Conventional	5	0	1.0	0	0.00%	0.00	
100 kVA - Urban	100	0	1.0	0	0.00%	0.00	
100 kVA - Rural	101	64	1.0	64	0.01%	0.01	96.55
150 kVA - Urban	150	199	11.1	2 203	0.23%	0.21	1 068.65
150 kVA - Rural	151	9	2.7	24	0.00%	0.00	259.38
200 kVA - Urban	200	14	11.1	155	0.02%	0.01	1 068.65
200 kVA - Rural	201	41	2.7	110	0.01%	0.01	259.38
300 kVA - Urban	300	53	11.1	587	0.06%	0.06	1 068.65
300 kVA - Rural	301	30	2.7	81	0.01%	0.01	259.38
500 kVA - Urban	500	33	11.1	365	0.04%	0.04	1 068.65
500 kVA - Rural	501	90	2.7	242	0.03%	0.02	259.38
1000 kVA - Urban	1000	257	11.1	2 845	0.30%	0.27	1 068.65
1000 kVA - Rural	1001	224	2.7	602	0.06%	0.06	259.38
1 Feeder Point 10 - 50 MVA - Urban	10000	203	11.1	2 247	0.24%	0.22	1 068.65
1 Feeder Point 10 - 50 MVA - Rural	10001	3 960	31.5	124 740	13.23%	12.04	3 041.27
1 Feeder Point 10 - 50 MVA - Urban	20000	8 794	31.5	276 995	29.38%	26.74	3 041.27
1 Feeder Point 10 - 50 MVA - Rural	20001	0	31.5	0	0.00%	0.00	
1 Feeder Point > 50 MVA - Urban	30000	0	31.5	0	0.00%	0.00	
1 Feeder Point > 50 MVA - Rural	30001	2 694	31.5	84 861	9.00%	8.19	3 041.27
1 Feeder Point > 50 MVA - Urban	40000	5 416	31.5	170 604	18.09%	16.47	3 041.27
1 Feeder Point > 50 MVA - Rural	40001	0	31.5	0	0.00%	0.00	
No Meter	0	0	31.5	0	0.00%	0.00	
Total		7 860 754		942 916	0.00%	91	2 621.69

Table 32: Meter reading costs by costing category

	Voltage	Costing category	Low usage residential	Small Other	Small Residential	Small Rural	Medium	Large	Very Large	Key	Total
			Meter reading costs (Rands)								
	>132kV	C01 : 275 LPU	0	386	0	0	2 853	3 396	41 093	112 913	**160 642**
Urban	≥66kV - ≤132kV	C02 : 132 LPU*	0	0	0	0	1 297	2 298	66 908	681 891	**752 394**
		C03 : Blank - no custom	0	0	0	0	0	0	0	0	**0**
		C04 : 88 LPU	0	0	0	0	778	0	85 934	611 886	**698 598**
		C05 : 66 LPU	0	0	0	0	1 038	193	24 330	179 435	**204 996**
	≥500V - <66kV	C06 : 44 LPU	0	0	0	0	0	0	0	127 733	**127 733**
		C07 : 33 LPU	0	0	0	0	259	0	24 590	246 343	**271 192**
		C08 : 6.6 3.3 2.2 LPU	0	0	0	0	0	6 861	124 692	433 677	**565 229**
		C09 : 2211 U LPU	0	1 001	0	0	269 143	780 096	2 886 433	643 784	**4 580 457**
		C10 : Blank - no custom	0	0	0	0	0	0	0	0	**0**
	<500V	C11 : 500 U ELEC	0	0	0	0	0	0	0	0	**0**
		C12 : 500 U RES	0	1 490	10 834 522	0	2 861 864	778	0	0	**13 698 654**
		C13 : 500 R RES	0	0	0	0	0	0	0	0	**0**
		C14 : 500 U OTHER SPU	0	3 049 585	0	0	0	0	0	0	**3 049 585**
		C15 : 500 U OTHER LPU	0	2 944	0	0	9 995 589	50 959	69 949	193	**10 119 634**
Rural	≥500V - <66kV	C16 : 2211 R LPU	0	0	0	814 187	788 849	1 239 280	1 630 123	41 264	**4 513 704**
		C17 : 500 R ELEC	0	0	0	0	0	0	0	0	**0**
	<500V	C18 : 500 R OTHER LPU	0	0	0	1 702 584	37 580 875	215 520	9 124	4 275	**39 512 378**
		C19 : 500 R OTHER SPU	0	0	0	12 781 806	0	0	0	0	**12 781 806**
		Total	**0**	**3 055 407**	**10 834 522**	**15 298 577**	**51 502 546**	**2 299 383**	**4 963 176**	**3 083 394**	**91 037 004**

8.7.3. Marketing unit costs

The allocated marketing costs is R519.9 million and the cost allocation following on Table 33 is as follows:

- The total marketing costs include R473 million for IDM and R46.9 million for marketing.
- An average R/PoD (c) is the marketing unit cost, and it is calculated by dividing the R519.9million (b) by the sum of the PoDs (a) in the agriculture, commercial, industrial, and residential (including prepayment) sectors. There are therefore fewer PoDs used in the allocation of marketing costs.
- The R/PoD (c) is applied to the number of PoDs (a) by customer group to determine the marketing costs by customer group.
- To provide the costs by costing category, the marketing R/PoD unit cost is applied to each respective PoD (b) in the forecast detail and then summarised by costing category as shown in Table 34.

Table 33: Marketing costs by customer group

Customer group		Low Usage	Small Other	Small Residential	Small Rural	Medium	Large	Very Large	Key	Total
Point of delivery (PoD) capacity size		≤ 100 kVA	≤ 100 kVA	≤ 100 kVA	≤ 100 kVA	> 100 kVA & ≤ 500 kVA	> 500 kVA & ≤ 1 MVA	> 1 MVA	Key customers	
(a) No of PoDS		7 556 422	33 395	118 676	150 243	17 103	729	1 055	103	7 877 726
(b) Total marketing costs (Rands)		519 828 208								
(c) R/PoD marketing unit cost		65.99								
(d) Marketing cost by customer group (Rands)		44 918 256	49 360 078	175 411 996	222 069 298	25 279 459	1 077 514	1 559 366	152 241	519 828 208

Table 34: Marketing costs by costing category

	Voltage	Costing category	No of PoDS (active)	Allocated marketing costs (Rands)	R/PoD unit cost
	>132kV	C01 : 275 LPU	128	194 714	1 521.21
Urban	≥66kV - ≤132kV	C02 : 132 LPU*	281	427 459	1 521.21
		C03 : Blank - no customers	0	0	
		C04 : 88 LPU	248	377 259	1 521.21
		C05 : 66 LPU	74	112 569	1 521.21
	≥500V - <66kV	C06 : 44 LPU	42	63 891	1 521.21
		C07 : 33 LPU	92	139 951	1 521.21
		C08 : 6.6 3.3 2.2 LPU	195	296 635	1 521.21
		C09 : 2211 U LPU	1 607	2 444 579	1 521.21
		C10 : Blank - no customers	0	0	
	<500V	C11 : 500 U ELEC	7 556 410	46 229 050	6.12
		C12 : 500 U RES	113 225	172 219 824	1 521.05
		C13 : 500 R RES	0.00	0.00	
		C14 : 500 U OTHER SPU*	37 367	56 842 173	1 521.21
		C15 : 500 U OTHER LPU	3 503	5 328 787	1 521.21
Rural	≥500V - <66kV	C16 : 2211 R LPU	1 789	2 721 439	1 521.21
		C17 : 500 R ELEC	0.00	0.00	
	<500V	C18 : 500 R OTHER LPU	13 180	20 048 745	1 521.21
		C19 : 500 R OTHER SPU	139 614	212 381 131	1 521.21
		Total	7 867 753	519 828 208	66.07

8.7.4. Customer service weightings

Customer service weightings are used to allocate billing and customer service (employee benefits, returns, billing and other expenses) costs. The customer service weightings are determined as follows:

- The retail costs based on historical budgets set aside to provide retail services to customer groups were determined. The analysis of the grouped retail costs demonstrated that it costs 270 times more to serve a very large/key customer's point of delivery than a low-usage urban PoD.
- The weightings are not applied to the key customer group because the key customers' cost detail contained in the 2024/25 revenue application is used.
- The determined customer service weightings by customer group are in Table 35.

Table 35: Customer service cost allocation weightings

	Small				Medium	Large	Very Large	Key
	Low Usage (Small Electrification)	Small Other	Small Residential	Small Rural				
Customer service cost weighting: Billing	1	12	6	24	83	270	270	270
Customer service cost weighting: customer service	1	12	6	24	83	270	270	n/a

8.7.5. Billing unit costs

The allocated billing costs are R832 million made up of R637 million for prepayment and R195 million for accounts (post-payment). The prepayment costs are mainly vendor commission costs.

The billing cost allocation following on Table 36 is as follows:

- The prepayment costs (b) are directly allocated to the low-usage group.
- The customer service weightings (c) are multiplied by the number of PoDs (a) to provide the weighted number of PoDs (d).
- A weighted R/PoD (f) for account billing is determined by dividing the account billing costs (e) by the weighted number of PoDs (d).
- The allocation of the weighted R/PoD (g) is determined by multiplying the weighted R/PoD (f) with the customer service weightings (c).
- The allocated account costs (h) are determined by multiplying the allocation weighted R/PoD (g) by the number of PoDs (a) in each customer group.
- The sum of the prepayment and account billing costs for each customer group are the allocated billing costs (i) and the per unit costs per billing month and per day is in Table 36 and by costing category in Table 37.

Table 36: Billing cost allocation

	Customer group								
	Low Usage	Small Other	Small Residential	Small Rural	Medium	Large	Very Large	Key	Total
Point of delivery (PoD) capacity size	≤ 100 kVA	≤ 100 kVA	≤ 100 kVA	≤ 100 kVA	> 100 kVA & ≤ 500 kVA	> 500 kVA & ≤ 1 MVA	> 1 MVA	Key customers	
(a) No of PoDS (active)	9 422 522	39 255	118 683	150 654	17 387	862	1 654	1 062	9 752 080
(b) Prepayment costs (R'million)	637								
(c) Customer service weighting	1	12	6	24	83	270	270	270	
(d) Weighted number of PoDs (d) = (c) x (a)	9 422 522	471 063	712 100	3 615 694	1 443 121	232 740	446 580	286 740	16 630 560
(e) Account costs (R'million)	195								
(f) Average weighted R/PoD (f) = (e)÷total(d)	12								
(g) Allocation weighted R/PoD (g) = (f) x (c)	11.72	140.6	70.3	281.2	972.5	3 163.5	3 163.5	3 163.5	
(h) Allocated account costs (R'million) (h) = (g) x (a)	110	6	8	42	17	3	5	3	195
(i) Total allocated billing costs (R'million) (b) + (h)	747	6	8	42	17	3	5	3	832
(j) Active number of PoDs	7 556 422	37 402	112 219	140 694	17 387	862	1 654	1 062	7 867 701
(k) Allocated billing costs (R/PoD/annum) (k) = (i)÷(j)	99	148	74	301	972	3 163	3 163	3 163	
(l) Allocated billing costs (R/PoD/month) (l) = (k)÷12.0033	8.24	12.29	6.19	25.09	81.02	263.55	263.55	263.55	
(m) Allocated billing costs (R/PoD/day) (m) = (l)÷(365÷12)	0.27	0.40	0.20	0.82	2.66	8.66	8.66	8.66	

Table 37: Billing cost allocation by costing category

		Allocated billing costs			
	Voltage	Costing category	No of PoDS	Allocated billing costs (Rands)	R/PoD/day unit cost (Rands)
	>132kV	C01 : 275 LPU	128	368 689	239.97
Urban	≥66kV - ≤132kV	C02 : 132 LPU*	281	877 813	260.25
		C03 : Blank - no customers	0	0	
		C04 : 88 LPU	248	777 819	261.29
		C05 : 66 LPU	74	225 290	253.63
	≥500V - <66kV	C06 : 44 LPU	42	132 840	263.50
		C07 : 33 LPU	92	285 630	258.65
		C08 : 6.6 3.3 2.2 LPU	195	616 759	263.50
		C09 : 2211 U LPU	1 607	4 785 606	248.10
		C10 : Blank - no customers	0	0	
	<500V	C11 : 500 U ELEC	7 556 410	747 315 691	8.24
		C12 : 500 U RES	113 225	9 310 245	6.85
		C13 : 500 R RES	0.00	0.00	
		C14 : 500 U OTHER SPU*	37 367	5 513 093	12.29
		C15 : 500 U OTHER LPU	3 503	3 508 007	83.43
Rural	≥500V - <66kV	C16 : 2211 R LPU	1 789	3 567 210	166.12
	<500V	C17 : 500 R ELEC	0	0	
		C18 : 500 R OTHER LPU	13 180	12 600 601	79.65
		C19 : 500 R OTHER SPU	139 614	42 030 292	25.08
		Total	7 867 753	831 915 585	8.81

8.7.6. Customer service unit costs

The allocated customer services costs are a total of R3 751 million made up of R1 788 million employee benefits (EB) and R1 963 million other expenses and returns.

- The cost allocation methodology followed is the same as for billing except that the key customer costs used are specific to this group; that is, the weighted number of customers is used to allocate the costs to each customer group as described in Section 8.7.5.
- The allocated customer service costs are shown in Table 38 by customer group and in Table 39 by costing category.

Table 38: Customer service allocation (EB, returns, billing, other expenses)

	Customer group								
	Low Usage	Small Other	Small Residential	Small Rural	Medium	Large	Very Large	Key	Total
Point of delivery (PoD) capacity size	≤ 100 kVA	≤ 100 kVA	≤ 100 kVA	≤ 100 kVA	> 100 kVA & ≤ 500 kVA	> 500 kVA & ≤ 1 MVA	> 1 MVA	Key accounts	
(a) No of PoDS	7 556 422	39 255	118 683	150 654	17 387	862	1 654	1 062	7 885 979
(b) Total allocated costs (R'million)	**1 758**	**110**	**166**	**841**	**336**	**54**	**104**	**383**	**3 751**
Employee benefits (R'million)	733	46	69	351	140	23	43	383	1 788
Other expenses and returns (R'million)	1 025	64	97	490	196	32	61	0	1 963
Impairments (R'million)	0	0	0	0	0	0	0	0	0
(c) Allocation weighted R/PoD/annum (c) = (b) ÷(a)	232.6	2 791.4	1 395.7	5 582.8	19 307.2	62 806.7	62 806.7	360 898.1	475.7
(d) Allocation weighted R/PoD/month (d) = (c)÷11.99	19.4	232.4	116.2	464.8	1 607.5	5 229.3	5 229.3	30 048.7	39.6
(e) Allocation weighted R/PoD/day (e) = (d)÷(365÷12)	0.6	7.6	3.8	15.3	52.9	171.9	171.9	987.9	1.3

Table 39: Customer service cost allocation by costing category

	Allocated customer service costs					
	Voltage	Costing category	No of PoDS	Allocated customer service costs (R'million)	R/PoD/day unit cost (Rands)
	>132kV	C01 : 275 LPU	128	20	417.56
Urban	≥66kV - ≤132kV	C02 : 132 LPU*	281	86	834.06
Urban	≥66kV - ≤132kV	C03 : Blank - no customers	0	0	
Urban	≥66kV - ≤132kV	C04 : 88 LPU	248	79	873.83
Urban	≥66kV - ≤132kV	C05 : 66 LPU	74	22	815.35
Urban	≥500V - <66kV	C06 : 44 LPU	42	15	987.04
Urban	≥500V - <66kV	C07 : 33 LPU	92	30	888.27
Urban	≥500V - <66kV	C08 : 6.6 3.3 2.2 LPU	195	57	794.72
Urban	≥500V - <66kV	C09 : 2211 U LPU	1 607	160	272.83
Urban	≥500V - <66kV	C10 : Blank - no customers	0	0	
Urban	<500V	C11 : 500 U ELEC	7 556 410	1 756	0.64
Urban	<500V	C12 : 500 U RES	113 225	185	4.47
Urban	<500V	C13 : 500 R RES	0.00	0.00	
Urban	<500V	C14 : 500 U OTHER SPU*	37 367	109	8.01
Urban	<500V	C15 : 500 U OTHER LPU	3 503	70	54.85
Rural	≥500V - <66kV	C16 : 2211 R LPU	1 789	77	118.02
Rural	≥500V - <66kV	C17 : 500 R ELEC	0.00	0.00	
Rural	<500V	C18 : 500 R OTHER LPU	13 180	251	52.12
Rural	<500V	C19 : 500 R OTHER SPU	139 614	834	16.36
		Total	**7 867 753**	**3 751**	**1.31**

8.7.7. Summary of the retail cost allocation

The retail costs (including metering costs) allocated by costing categories are shown in Table 40.

Table 40: Allocated retail costs by costing category

				Allocated retail costs (R'million)					Average unit costs (Rands)		
	Voltage	Costing category	No of PoDS	Metering costs	Marketing costs	Billing	Customer service	**Total retail**	Annual R/PoD	Month R/PoD	Day R/PoD
	>132kV	C01 : 275 LPU	128	0.2	0.1947	0.37	19.53	**20**	158 311	13 193	434
Urban	≥66kV - ≤132kV	C02 : 132 LPU*	281	0.8	0.4275	0.88	85.62	**88**	312 191	26 016	855
		C03 : Blank - no customers	0	0.0	0.0000	0.00	0.00	**0**			
		C04 : 88 LPU	248	0.7	0.3773	0.78	79.17	**81**	326 876	27 240	896
		C05 : 66 LPU	74	0.2	0.1126	0.23	22.04	**23**	305 385	25 449	837
	≥500V - <66kV	C06 : 44 LPU	42	0.1	0.0639	0.13	15.14	**15**	368 504	30 709	1 010
		C07 : 33 LPU	92	0.3	0.1400	0.29	29.85	**31**	332 300	27 692	910
		C08 : 6.6 3.3 2.2 LPU	195	0.6	0.2966	0.62	56.61	**58**	298 092	24 841	817
		C09 : 2211 U LPU	1 607	4.9	2.4446	4.79	160.17	**172**	107 219	8 935	294
		C10 : Blank - no customers	0	0.0	0.0000	0.00	0.00	**0**			
	<500V	C11 : 500 U ELEC	7 556 410	81	46.229	747	1 756	**2 630**	348	29	0.95
		C12 : 500 U RES	113 225	15	172.22	9	185	**382**	3 371	281	9
		C13 : 500 R RES	0	0	0	0	0	**0**			
		C14 : 500 U OTHER SPU*	37 367	3.9	56.842	5.51	109.38	**176**	4 700	392	13
		C15 : 500 U OTHER LPU	3 503	10.9	5.3288	3.51	70.19	**90**	25 666	2 139	70
Rural	≥500V - <66kV	C16 : 2211 R LPU	1 789	4.8	2.7214	3.57	77.14	**88**	49 308	4 109	135
		C17 : 500 R ELEC	0	0	0	0	0	**0**			
	<500V	C18 : 500 R OTHER LPU	13 180	42.4	20.049	12.60	250.96	**326**	24 738	2 061	68
		C19 : 500 R OTHER SPU	139 614	16.4	212.38	42.03	834.31	**1 105**	7 916	660	22
		Total	**7 867 753**	**182**	**519.83**	**832**	**3 751**	**5 285**	672	56	1.84

9. Conclusion

The CTS study results are average unit costs separately for energy purchases (c/kWh), transmission network capacity (R/kVA) on UC, transmission ancillary (c/kWh), distribution network capacity (R/kVA) on maximum demands, and retail (R/PoD) and are as consolidated in Table 41 and Table 42.

Considerations for future developments from previous CTS studies were as follows:

1. The development of the network allocation from the A&E method was investigated including a detailed study of the current methodology and models by international experts. The A&E approach was found sufficient and recommendations to cater for the distribution of embedded generators separately are in progress and the results will be included in future CTS study reports.

2. The impact (benefit or cost) from the introduction of IPPs into the transmission grid and distribution networks will be incorporated with the separation of generators in the distribution network cost allocation.

3. Work is currently underway to implement the update to the concentric transmission zones based on more current energy purchase costs.

4. The differentiation of energy considering the nature of the costs and supply load factors amongst others was implemented by the separate allocation of active energy and generation capacity costs in this 2024/25 CTS study.

Table 41: Summary of the CTS study allocated costs

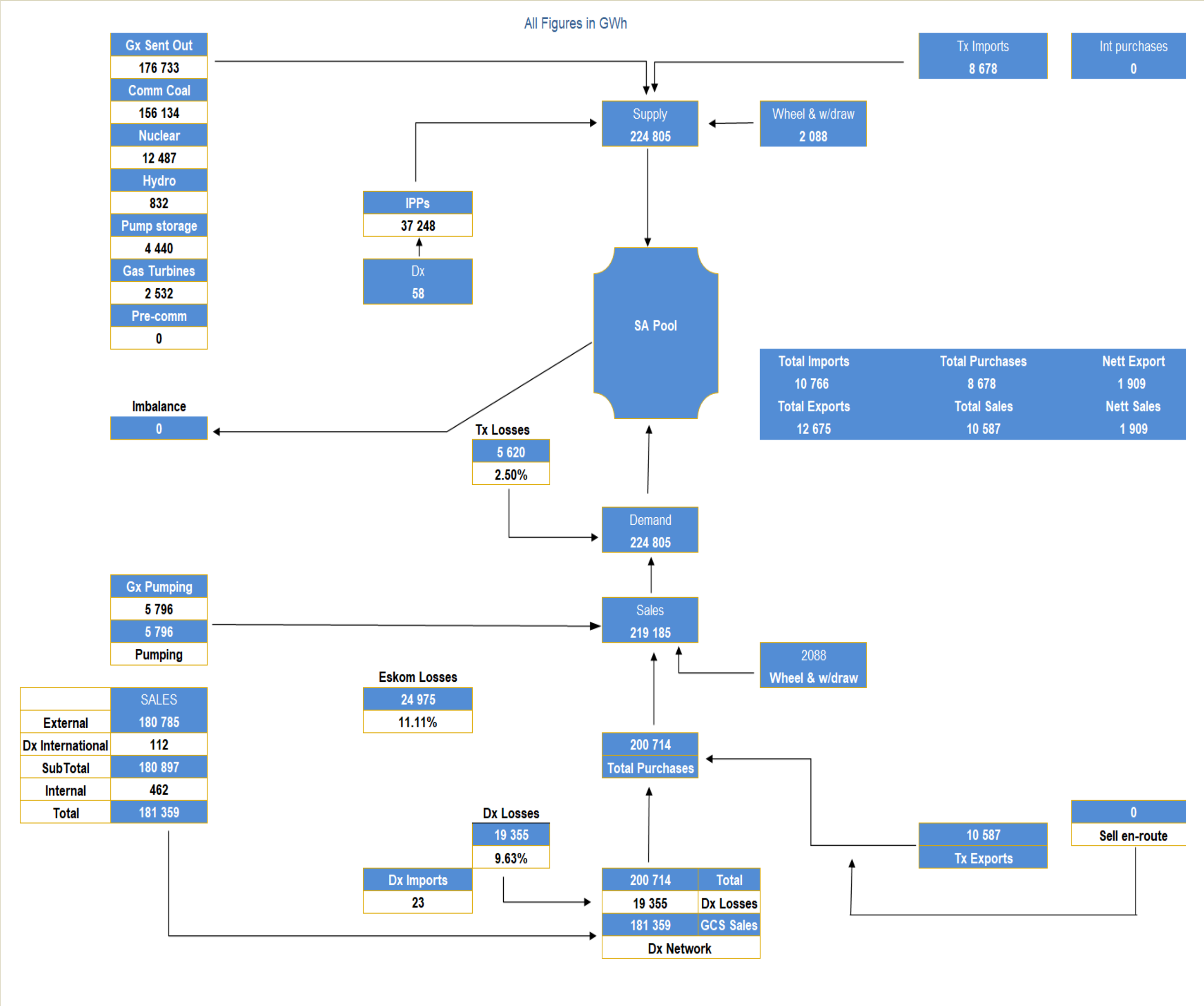
					Allocated costs (R'million)							
	Voltage	Costing category	No of PoDS	Sales volumes (GWh)	Energy ToU	Energy capacity	Legacy charge	Tx network capacity	Tx ancillary services	Dx network capacity	Retail	**Total allocated costs**
	>132kV	C01 : 275 LPU	128	36 085	46 221	3 262	6 149	1 527	109	0	20	**57 288**
Urban	≥66kV - ≤132kV	C02 : 132 LPU*	281	19 324	26 856	1 860	3 531	547	63	512	88	**33 456**
Urban	≥66kV - ≤132kV	C03 : Blank - no customers	0	0	0	0	0	0	0	0	0	**0**
Urban	≥66kV - ≤132kV	C04 : 88 LPU	248	8 094	11 074	875	1 479	316	26	730	81	**14 581**
Urban	≥66kV - ≤132kV	C05 : 66 LPU	74	7 581	10 702	756	1 385	198	25	1 122	23	**14 211**
Urban	≥500V - <66kV	C06 : 44 LPU	42	1 666	2 441	189	328	90	6	328	15	**3 398**
Urban	≥500V - <66kV	C07 : 33 LPU	92	28 128	39 075	2 936	5 539	654	98	2 806	31	**51 138**
Urban	≥500V - <66kV	C08 : 6.6 3.3 2.2 LPU	195	15 240	21 347	1 619	3 001	394	53	2 417	58	**28 889**
Urban	≥500V - <66kV	C09 : 2211 U LPU	1 607	33 275	48 293	3 593	6 552	1 041	116	5 895	172	**65 663**
Urban	≥500V - <66kV	C10 : Blank - no customers	0	0	0	0	0	0	0	0	0	**0**
Urban	<500V	C11 : 500 U ELEC	7 556 410	7 230	12 929	1 605	1 461	1 031	26	5 944	2 630	**25 627**
Urban	<500V	C12 : 500 U RES	113 225	1 409	2 572	181	285	81	5	1 009	382	**4 514**
Urban	<500V	C13 : 500 R RES	0	0	0	0	0	0	0	0	0	**0**
Urban	<500V	C14 : 500 U OTHER SPU*	37 367	1 142	1 902	159	231	61	4	403	176	**2 936**
Urban	<500V	C15 : 500 U OTHER LPU	3 503	1 395	2 100	168	282	115	5	441	90	**3 200**
Rural	≥500V - <66kV	C16 : 2211 R LPU	1 789	3 434	5 068	416	688	176	12	2 213	88	**8 663**
Rural	≥500V - <66kV	C17 : 500 R ELEC	0	0	0	0	0	0	0	0	0	**0**
Rural	<500V	C18 : 500 R OTHER LPU	13 180	3 447	5 126	471	703	309	12	2 885	326	**9 832**
Rural	<500V	C19 : 500 R OTHER SPU	139 614	3 498	5 893	962	714	684	13	4 775	1 105	**14 145**
		Total	**7 867 753**	**170 947**	**241 601**	**19 050**	**32 329**	**7 221**	**574**	**31 480**	**5 285**	**337 541**

Table 42: Summary of the CTS study's unit costs

	Voltage	Costing category	Average unit costs (allocated costs divided by sales volumes)							
			Energy ToU unit costs (c/kWh)	Legacy unit charge (c/kWh)	Energy Capacity unit costs (R/kVA)	Tx network capacity unit costs (R/kVA)	Tx ancillary services unit costs (c/kWh)	Dx network capacity unit cost (R/kVA)	Retail unit costs (R/PoD/Day)	**Total Avg. unit cost (c/kWh)**
	>132kV	C01 : 275 LPU	128.09c	17.04c	R 31.15	R 14.58	0.3024c	R 0.00	R 433.73	158.76c
Urban	≥66kV - ≤132kV	C02 : 132 LPU*	138.98c	18.27c	R 28.54	R 8.39	0.3243c	R 16.58	R 855.32	173.13c
Urban	≥66kV - ≤132kV	C03 : Blank - no customers								
Urban	≥66kV - ≤132kV	C04 : 88 LPU	136.83c	18.27c	R 23.00	R 8.31	0.3243c	R 17.36	R 895.55	180.15c
Urban	≥66kV - ≤132kV	C05 : 66 LPU	141.18c	18.27c	R 32.39	R 8.48	0.3243c	R 23.04	R 836.67	187.46c
Urban	≥500V - <66kV	C06 : 44 LPU	146.58c	19.69c	R 19.25	R 9.17	0.3494c	R 31.77	R 1 009.60	203.99c
Urban	≥500V - <66kV	C07 : 33 LPU	138.92c	19.69c	R 40.91	R 9.11	0.3494c	R 15.86	R 910.41	181.81c
Urban	≥500V - <66kV	C08 : 6.6 3.3 2.2 LPU	140.07c	19.69c	R 37.36	R 9.09	0.3494c	R 21.25	R 816.69	189.57c
Urban	≥500V - <66kV	C09 : 2211 U LPU	145.13c	19.69c	R 31.59	R 9.15	0.3494c	R 24.32	R 293.75	197.33c
Urban	≥500V - <66kV	C10 : Blank - no customers								
Urban	<500V	C11 : 500 U ELEC	178.81c	20.21c	R 14.68	R 9.43	0.3587c	R 46.13	R 0.95	354.43c
Urban	<500V	**C12 : 500 U RES**	**182.51c**	**20.21c**	**R 21.19**	**R 9.44**	**0.3587c**	**R 59.70**	**R 9.24**	**320.33c**
Urban	<500V	C13 : 500 R RES								
Urban	<500V	C14 : 500 U OTHER SPU*	166.58c	20.21c	R 24.65	R 9.43	0.3587c	R 27.53	R 12.88	257.07c
Urban	<500V	C15 : 500 U OTHER LPU	150.55c	20.21c	R 13.91	R 9.53	0.3587c	R 27.85	R 70.32	229.40c
Rural	≥500V - <66kV	C16 : 2211 R LPU	147.58c	20.04c	R 22.31	R 9.44	0.3556c	R 80.82	R 135.09	252.24c
Rural	≥500V - <66kV	C17 : 500 R ELEC								
Rural	<500V	C18 : 500 R OTHER LPU	148.73c	20.40c	R 14.79	R 9.70	0.3620c	R 79.81	R 67.77	285.25c
Rural	<500V	C19 : 500 R OTHER SPU	168.48c	20.40c	R 13.46	R 9.56	0.3620c	R 66.15	R 21.69	404.39c
		Total	**141.33c**	**18.91c**	**R 26.16**	**R 9.92**	**0.3356c**	**R 30.46**	**R 1.84**	**197.45c**

Annexure 1: 2024/25 NERSA decision energy wheel

This energy is populated with the energy volumes in GWh as provided for in the 2024/25 NERSA AR decision supply side and demand side volumes.



Annexure 2: ToU profile for small power users (SPUs)

- The SPU's ToU profiles were derived from customer and feeder metering data.
  - Customer and feeder metering data were sourced from Eskom Research Testing and Development, Energy Trading, and Data Acquisition System (DAS).
  - Data samples were sourced from the following Distribution Operating Units across the country: Gauteng, Mpumalanga, KwaZulu Natal, Eastern Cape, and Western Cape.

- Conclusions were drawn by comparing the resulting and prevailing profiles from previous research studies based on correlation and mean square error statistical calculations.

- The resulting ToU profiles show a positive correlation and meaningfully small mean square error between the latest and the previous ToU results. This means the ToU profiles from this updated study can be accepted for use.

- The following SPU categories were considered in the study with their respective Tariff mapping as follows:
  - Urban – Homepower
  - Low-usage (electrification) - Homelight 20 A
  - Township residential – Homelight 60 A
  - Commercial – Business rate
  - Agricultural – Landrate

Homelight 20A	Low demand season [9 months: Apr -May & Sep - Mar]	High demand season [3 months: Jun -Aug]
Peak	27%	29%
Standard	50%	50%
Off peak	23%	21%

Homelight 60A	Low demand season [9 months: Apr -May & Sep - Mar]	High demand season [3 months: Jun -Aug]
Peak	26%	27%
Standard	51%	52%
Off peak	23%	21%

Businessrate	Low demand season [9 months: Apr -May & Sep - Mar]	High demand season [3 months: Jun -Aug]
Peak	23%	23%
Standard	53%	53%
Off peak	24%	24%

Homepower	Low demand season [9 months: Apr -May & Sep - Mar]	High demand season [3 months: Jun -Aug]
Peak	30%	31%
Standard	49%	49%
Off peak	21%	20%

Landrate	Low demand season [9 months: Apr -May & Sep - Mar]	High demand season [3 months: Jun -Aug]
Peak	23%	22%
Standard	52%	52%
Off peak	25%	26%

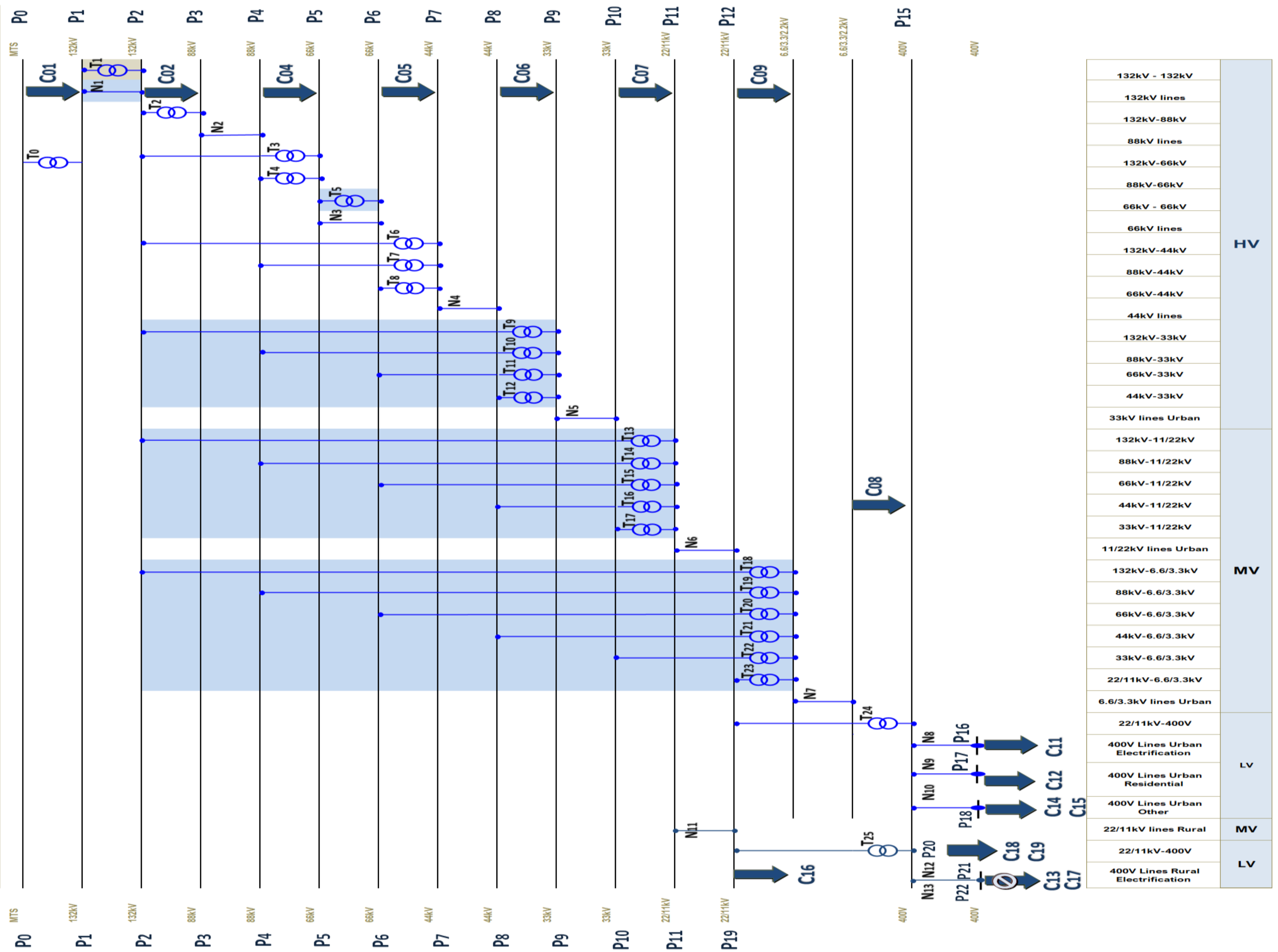
Annexure 3: Demand assumptions for small power users (SPUs)

Tariff	UC	CMD / Maximum demand
Urban 20A supplies	• ADMD as per NRSA 034 / NMD	• ADMD as per NRSA 034 / NMD
Urban 60A supplies	• ADMD as per NRSA 034 / NMD	• ADMD as per NRSA 034 / NMD
NMD of up to 100 kVA	• ADMD as per NRSA 034 / NMD	• ADMD as per NRSA 034 / NMD
Residential bulk supplies to sectional title developments*	• NMD from billing system	• NMD from billing system

	Related tariff	ADMD
NMD of up to 100 kVA	Businessrate 1	10.14
	Businessrate 2	15.36
	Businessrate 3	37.48
	Businessrate 4	5.14
Urban 20A and 60A supplies	Homelight 20A	0.67
	Homelight 60A	1.69
	Landlight 20A	4.00
	Landlight 60A	16.00
NMD of up to 100 kVA	Homepower 1	4.40
	Homepower 2	7.63
	Homepower 3	18.83
	Homepower 4	2.82
	Homepower Bulk	41.47
NMD of up to 100 kVA and <500V supply voltage	Landrate 1	25.00
	Landrate 2	50.00
	Landrate 3	100.00
	Landrate 4	16.00
	Landrate Dx	16.00
Public lighting	Public Lighting 24 Hours	0.28
	Public Lighting All Night	10.37
	Public Lighting Urban Fixed	1.53

Annexure 4: Cost allocation diagram (CAD)/Distribution network summary

	Urban/ Rural/ Shared	
132kV - 132kV		
132kV lines	Shared	N1
132kV-88kV	Shared	T2
88kV lines	Shared	N2
132kV-66kV	Shared	T3
88kV-66kV	Shared	T4
66kV - 66kV	Shared	T5
66kV lines	Shared	N3
132kV-44kV	Shared	T6
88kV-44kV	Shared	T7
66kV-44kV	Shared	T8
44kV lines	Shared	N4
132kV-33kV	Shared	T9
88kV-33kV	Shared	T10
66kV-33kV	Shared	T11
44kV-33kV	Shared	T12
33kV lines Urban	Shared	N5
132kV-11/22kV	Shared	T13
88kV-11/22kV	Shared	T14
66kV-11/22kV	Shared	T15
44kV-11/22kV	Shared	T16
33kV-11/22kV	Shared	T17
11/22kV lines Urban	Urban	N6
132kV-6.6/3.3kV	Urban	T18
88kV-6.6/3.3kV	Urban	T19
66kV-6.6/3.3kV	Urban	T20
44kV-6.6/3.3kV	Urban	T21
33kV-6.6/3.3kV	Urban	T22
22/11kV-6.6/3.3kV	Urban	T23
6.6/3.3kV lines Urban	Urban	N7
22/11kV-400V	Urban	T24
400V Lines Urban Electrification	Urban	N8
400V Lines Urban Residential	Urban	N9
400V Lines Urban Other	Urban	N10
22/11kV lines Rural	Rural	N11
22/11kV-400V	Rural	T25
400V Lines Rural	Rural	N12
MTS	Urban/ Rural/ Shared	



Annexure 5: Asset loss factors

		Tech. asset (pu) loss factor		Loss factors applied	Energy	Demand	
	MTS > 132kV	1.000000000	0%	T0	1.000000000	1.000000000	0.0%
HV	132kV - 132kV	1.000000000	0%	T1	1.000000000	1.000000000	0.0%
HV	132kV lines	1.010786141	1%	N1	1.034656748	1.034656748	3.5%
HV	132kV-88kV	1.001276621	0%	T2	1.024922653	1.024922653	2.5%
HV	88kV lines	1.019705209	2%	N2	1.043786448	1.043786448	4.4%
HV	132kV-66kV	1.009000030	1%	T3	1.032828457	1.032828457	3.3%
HV	88kV-66kV	1.009000030	1%	T4	1.032828457	1.032828457	3.3%
HV	66kV - 66kV	1.000000000	0%	T5	1.000000000	1.000000000	0.0%
HV	66kV lines	1.011249292	1%	N3	1.035130837	1.035130837	3.5%
MV	132kV-44kV	1.010347219	1%	T6	1.030003217	1.030003217	3.0%
MV	88kV-44kV	1.010347219	1%	T7	1.030003217	1.030003217	3.0%
MV	66kV-44kV	1.009806710	1%	T8	1.029452192	1.029452192	2.9%
MV	44kV lines	1.027095405	3%	N4	1.047077234	1.047077234	4.7%
MV	132kV-33kV	1.017613412	2%	T9	1.037410772	1.037410772	3.7%
MV	88kV-33kV	1.006806600	1%	T10	1.026393716	1.026393716	2.6%
MV	66kV-33kV	1.037228879	4%	T11	1.057407851	1.057407851	5.7%
MV	44kV-33kV	1.008012023	1%	T12	1.027622590	1.027622590	2.8%
MV	33kV lines Urban	1.046418373	5%	N5	1.066776124	1.066776124	6.7%
MV	132kV-11/22kV	1.007125788	1%	T13	1.026719113	1.026719113	2.7%
MV	88kV-11/22kV	1.007507602	1%	T14	1.027108356	1.027108356	2.7%
MV	66kV-11/22kV	1.009806710	1%	T15	1.029452192	1.029452192	2.9%
MV	44kV-11/22kV	1.008012023	1%	T16	1.027622590	1.027622590	2.8%
MV	33kV-11/22kV	1.003677877	0%	T17	1.023204124	1.023204124	2.3%
MV	11/22kV lines Urban	1.036160433	4%	N6	1.056318619	1.056318619	5.6%
MV	132kV-6.6/3.3kV	1.017613412	2%	T18	1.037410772	1.037410772	3.7%
MV	88kV-6.6/3.3kV	1.017613412	2%	T19	1.037410772	1.037410772	3.7%
MV	66kV-6.6/3.3kV	1.009806710	1%	T20	1.029452192	1.029452192	2.9%
MV	44kV-6.6/3.3kV	1.008012023	1%	T21	1.027622590	1.027622590	2.8%
MV	33kV-6.6/3.3kV	1.003677877	0%	T22	1.023204124	1.023204124	2.3%
MV	22/11kV-6.6/3.3kV	1.008012023	1%	T23	1.027622590	1.027622590	2.8%
MV	6.6/3.3kV lines Urban	1.033328993	3%	N7	1.053432094	1.053432094	5.3%
LV	22/11kV-400V Urban	1.012577056	1%	T24	1.011406648	1.011406648	1.1%
LV	400V Lines Urban Electrification	1.027981463	3%	N8	1.026793251	1.026793251	2.7%
LV	400V Lines Urban Residential	1.027981463	3%	N9	1.026793251	1.026793251	2.7%
LV	400V Lines Urban Other	1.027981463	3%	N10	1.026793251	1.026793251	2.7%
MV	22/11kV lines Rural	1.050833688	5%	N11	1.083727233	1.083727233	8.4%
LV	22/11kV-400V Rural	1.012577056	1%	T25	1.026048157	1.026048157	2.6%
LV	400V Lines Rural	1.027981463	3%	N12	1.041657501	1.041657501	4.2%
LV	400V Lines Rural Residential	1.027981463	3%	N13	1.041657501	1.041657501	4.2%

Annexure 6: Standard tariff energy purchase volumes

			Winter total purchase (GWh) [3 months : Jun - Aug]				Summer total purchase (GWh) [9 months : Apr - May & Sep-Mar]				Energy purchases total (sales + Dx losses + Tx losses) [12 months: Apr - Mar]			
			Peak	Standard	Off-peak	Total	Peak	Standard	Off-peak	Total	Peak	Standard	Off-peak	Total
	>132kV	C01 : 275 LPU	1 649	4 074	3 971	9 694	4 471	11 175	11 182	26 828	6 121	15 249	15 153	36 523
Urban	≥66kV - ≤132kV	C02 : 132 LPU*	962	2 418	2 236	5 616	2 615	6 605	6 270	15 490	3 577	9 023	8 506	21 106
Urban	≥66kV - ≤132kV	C03 : Blank - no customers	0	0	0	0	0	0	0	0	0	0	0	0
Urban	≥66kV - ≤132kV	C04 : 88 LPU	405	1 003	1 000	2 408	1 057	2 607	2 665	6 329	1 462	3 610	3 666	8 737
Urban	≥66kV - ≤132kV	C05 : 66 LPU	388	965	870	2 223	1 055	2 635	2 452	6 142	1 443	3 600	3 322	8 365
Urban	≥500V - <66kV	C06 : 44 LPU	84	227	222	533	229	595	591	1 415	313	822	813	1 948
Urban	≥500V - <66kV	C07 : 33 LPU	1 043	3 065	3 603	7 711	3 751	9 744	11 538	25 034	4 794	12 810	15 141	32 745
Urban	≥500V - <66kV	C08 : 6.6 3.3 2.2 LPU	656	1 778	2 122	4 556	1 896	5 111	6 160	13 166	2 551	6 889	8 282	17 722
Urban	≥500V - <66kV	C09 : 2211 U LPU	1 634	4 154	4 422	10 210	4 540	11 577	12 564	28 681	6 174	15 732	16 986	38 892
Urban	≥500V - <66kV	C10 : Blank - no customers	0	0	0	0	0	0	0	0	0	0	0	0
Urban	<500V	C11 : 500 U ELEC	639	1 149	475	2 264	1 695	3 206	1 464	6 364	2 334	4 355	1 939	8 628
Urban	<500V	C12 : 500 U RES	137	226	109	472	344	580	286	1 210	481	806	395	1 682
Urban	<500V	C13 : Blank - no customers	0	0	0	0	0	0	0	0	0	0	0	0
Urban	<500V	C14 : 500 U OTHER SPU*	77	176	90	343	228	522	269	1 019	305	698	360	1 363
Urban	<500V	C15 : 500 U OTHER LPU	68	190	173	431	199	547	506	1 253	267	738	679	1 683
Rural	≥500V - <66kV	C16 : 2211 R LPU	161	434	452	1 048	481	1 251	1 330	3 063	643	1 686	1 782	4 111
Rural	≥500V - <66kV	C17 : Blank - no customers	0	0	0	0	0	0	0	0	0	0	0	0
Rural	<500V	C18 : 500 R OTHER LPU	143	424	406	973	493	1 376	1 371	3 240	636	1 800	1 776	4 213
Rural	<500V	C19 : 500 R OTHER SPU	232	549	274	1 055	726	1 642	789	3 158	958	2 191	1 064	4 213
		Total	**8 278**	**20 834**	**20 426**	**49 539**	**23 782**	**59 173**	**59 438**	**142 393**	**32 060**	**80 007**	**79 864**	**191 931**

Annexure 7: Summary of the Tx losses forecasts

1. Introduction

- Transmission losses reported in the financial year 2018 are 2% of the total supplied energy. The transmission losses are highly influenced by the generation dispatch and location.
- The emergence of Independent Power Producers (IPPs) has significantly decreased transmission losses. This impact is partly because of the location of these IPPs and the amount of energy that is offset from power plants that link directly to the transmission system.
- The study conducted earlier through Eskom research and Enerweb indicated a strong correlation between generation location and transmission losses.
- The generators in the Mpumalanga and Limpopo areas positively contributed to losses whereas those in the Cape had the opposite effect. In the study, it was apparent that the transmission losses are set to reduce as the production of energy increases in the Cape and Karoo areas. This analysis was logical since most of the generators were in Mpumalanga and less around the Cape and Karoo areas.
- From now on, we will use a multiple regression model to analyse data and identify those factors that affect the current levels of losses and develop a forecast.
- Multiple regression analysis is a powerful technique for predicting the unknown value of a variable from the known value of two or more variables - also called predictors.
- More precisely, multiple regression analysis helps us to predict the value of Y for given values of X1, X2, …, Xk.

2. Forecasting model

- The transmission losses reported in the financial year 2018 were 2% of the total supplied energy. Three test cases were evaluated using multiple regression analysis. The difference between the test cases is the formulation of regressors. In the first test case, regressors are made up of the current six generation zones.

Table 1: Energy volumes per zone variable and the transmission energy loss percentage

ZONES (all included)	CT	KR	V	KZ	MP	WB	Losses
April 2017 W4.xlsx	936 479	49 155	1 939 281	298 013	10 856 938	4 561 605	0.023681204
August 2017 W4.xlsx	1 449 699	62 748	2 403 506	333 754	10 518 542	5 146 155	0.018266386
December 2017 W2.xlsx	1 471 212	53 640	1 036 017	339 080	10 088 969	5 520 438	0.020236041
February 2018 W1.xlsx	1 240 422	45 423	1 159 319	282 485	9 548 641	5 176 272	0.019696631
January 2018 W2.xlsx	1 177 124	59 940	1 280 701	308 751	10 301 751	5 799 433	0.02095183
July 2017 W4.xlsx	1 446 193	53 103	2 155 283	282 437	10 819 975	5 360 612	0.018875157
June 2017 W5.xlsx	1 370 032	49 974	2 263 379	263 927	10 608 473	5 096 596	0.01807291
March 2018 W0.xlsx	832 528	111 803	1 207 740	336 366	11 385 401	5 580 614	0.021328638
May 2017 W4.xlsx	835 291	50 139	2 425 648	303 367	11 621 500	5 174 496	0.020988345
November 2017 W2.xlsx	1 390 187	55 455	1 128 010	333 705	10 782 761	5 254 229	0.020007135
October 2017 W2.xlsx	1 448 575	65 374	2 353 772	366 256	10 036 436	5 352 149	0.015357778
September 2017 W2.xlsx	1 410 410	59 360	2 143 956	343 984	9 822 582	5 126 317	0.018458765

- Next, the geographical proximity of the power plants was considered, and the generators were grouped accordingly; the last analysis used 6 zones where IPP were considered as a separate variable.
- The results indicated that transmission losses are influenced by the location of the dispatched generators and that they respond to penetration of IPPs. It can be concluded from the results in Table 2 below, that the chosen variables can be used to explain the current levels of losses. The strength of this relationship is indicated by a high R-Square value, which ideally should be closer to 100% for a perfect correlation between the explanatory variables and the dependent variable.

Model	Year 1	Year 2	Year 3	Year 4	Year 5	R Square	Standard Error
Model 1 (6Z-All)	3.05%	3.05%	3.05%	3.05%	3.05%	82.20%	1.40%
Model 2 Geo proxy	2.18%	2.32%	2.66%	2.93%	2.99%	96.70%	4.00%
Model 3 (6Z _IPP)	2.79%	2.79%	2.79%	2.79%	2.79%	78.90%	1.90%
Average per year	2.68%	2.72%	2.83%	2.92%	2.94%	85.93%	2.43%

Table 2: Forecast based on multiple regression model, with the coefficient of determination and the model standard errors.

- The resulting forecast is taken as the weighted average results from the three test cases and the reported year-end energy losses. The forecast losses annual average is 2.51%, with a maximum of 3.05% and a minimum of 2.09%.

	Model1 6Z	Model 2 G	Model 3 6	Model 3 6	YE-Values
Losses	3.05%	2.62%	2.79%	2.09%	2%
Energy	1399625	1399625	1399625	1399625	1399625
Weighted Average	2.51%				

Table 3: The estimated losses forecast calculated as a weighted average, weighting by the energy supply.

3. Conclusions

- The Transmission forecasting model is based on multiple regression analysis. The results indicate that transmission losses are influenced by the location of the dispatched generators and that they respond to penetration of IPPs.
- It can be concluded from the results, that the chosen variables can be used to explain the current levels of losses. The forecast losses annual average is 2.51%, with a maximum of 3.05% and a minimum of 2.09%.

Annexure 8: Detail of the allocated energy purchase costs

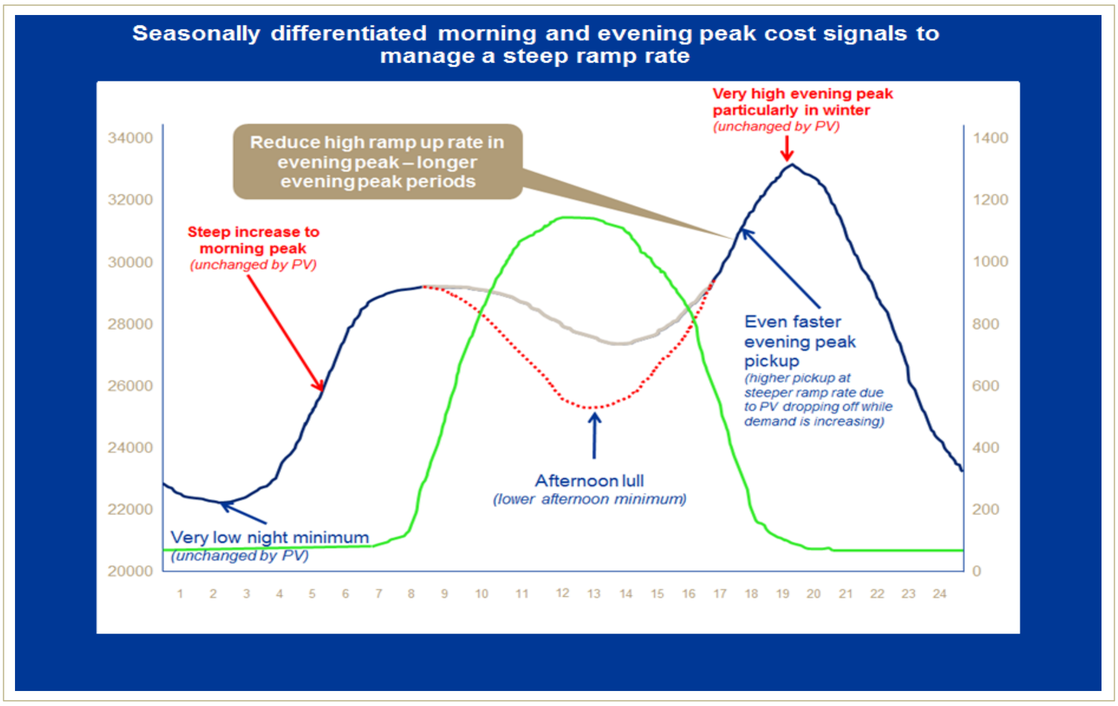
			Annual forecasted sales costs (R'million) [12 months: Apr - Mar]				Dx network losses costs (R'million) [12 months: Apr - Mar]				Tx network losses costs (R'million) [12 months: Apr - Mar]				Legacy charge (R'million) [12 months: Apr - Mar]				Energy purchase costs (R'million) (sales + Dx losses + Tx losses + legacy) [12 months: Apr - Mar]			
			Peak	Standard	Off-peak	Total	Peak	Standard	Off-peak	Total	Peak	Standard	Off-peak	Total	Peak	Standard	Off-peak	Total	Peak	Standard	Off-peak	Total
	>132kV	C01 : 275 LPU	16 576	17 148	11 944	45 668	0	0	0	0	200	208	145	553	1 030	2 567	2 551	6 149	17 807	19 923	14 640	52 370
Urban	³66kV - £132kV	C02 : 132 LPU*	8 972	9 402	6 215	24 588	650	681	450	1 780	178	188	122	487	598	1 509	1 423	3 531	10 397	11 780	8 210	30 387
Urban	³66kV - £132kV	C03 : Blank - no customers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Urban	³66kV - £132kV	C04 : 88 LPU	3 741	3 809	2 709	10 259	271	276	196	743	26	27	19	72	247	611	620	1 479	4 286	4 723	3 545	12 554
Urban	³66kV - £132kV	C05 : 66 LPU	3 583	3 713	2 402	9 698	259	269	174	702	112	116	74	302	239	596	550	1 385	4 193	4 694	3 200	12 087
Urban	³500V - <66kV	C06 : 44 LPU	733	801	554	2 088	114	125	86	325	10	11	8	29	53	139	137	328	909	1 075	785	2 769
Urban	³500V - <66kV	C07 : 33 LPU	10 687	12 499	10 377	33 564	1 663	1 945	1 615	5 222	94	108	88	289	811	2 167	2 561	5 539	13 255	16 718	14 641	44 614
Urban	³500V - <66kV	C08 : 6.6 3.3 2.2 LPU	5 936	6 738	5 682	18 356	924	1 048	884	2 856	44	49	41	135	432	1 167	1 402	3 001	7 335	9 003	8 010	24 348
Urban	³500V - <66kV	C09 : 2211 U LPU	14 407	15 316	11 596	41 318	2 242	2 383	1 804	6 429	191	203	151	546	1 040	2 650	2 862	6 552	17 880	20 552	16 413	54 845
Urban	³500V - <66kV	C10 : Blank - no customers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Urban	<500V	C11 : 500 U ELEC	5 386	4 153	1 296	10 835	1 003	773	241	2 017	38	29	9	77	395	738	328	1 461	6 822	5 693	1 876	14 390
Urban	<500V	C12 : 500 U RES	1 121	769	264	2 155	209	143	49	401	8	6	2	16	81	137	67	285	1 420	1 055	382	2 857
Urban	<500V	C13 : Blank - no customers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Urban	<500V	C14 : 500 U OTHER SPU*	689	665	240	1 594	128	124	45	297	5	5	2	11	52	118	61	231	873	912	348	2 133
Urban	<500V	C15 : 500 U OTHER LPU	596	695	449	1 740	111	129	84	324	12	15	9	36	45	124	114	282	764	962	655	2 382
Rural	³500V - <66kV	C16 : 2211 R LPU	1 444	1 602	1 188	4 234	254	282	209	746	30	34	25	88	108	282	298	688	1 837	2 200	1 720	5 757
Rural	³500V - <66kV	C17 : Blank - no customers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Rural	<500V	C18 : 500 R OTHER LPU	1 362	1 673	1 160	4 194	269	330	229	828	34	42	29	105	106	300	297	703	1 771	2 345	1 714	5 830
Rural	<500V	C19 : 500 R OTHER SPU	2 121	2 068	705	4 893	418	408	139	965	15	15	5	35	162	371	180	714	2 716	2 862	1 029	6 607
		Total	**77 353**	**81 051**	**56 781**	**215 184**	**8 514**	**8 916**	**6 205**	**23 636**	**998**	**1 054**	**730**	**2 782**	**5 400**	**13 475**	**13 453**	**32 329**	**92 265**	**104 496**	**77 168**	**273 930**

Annexure 9: ToU periods and 1:6 ratio

The hourly cost of energy purchases is dependent on the mix of generators and their production costs. Subsequently, the energy purchase unit costs are dependent on the production time of day.

A 1:8 ToU unit cost ratio has been used since 2005. In 2009, the SO identified the need for ToU changes. However, system constraints at the time discouraged any immediate changes. More recently, the SO has identified the need to change the ToU periods' hours and the energy purchase unit costs ratio:

- The change is motivated by a need to manage high system demand in the morning and peak evening periods and the difference during the high (winter) and low (summer) demand seasons.
- The daily peaks are characterised by a steep increase in demand and the consequent use of expensive generators during a few hours in a day.
- The SO requirements are summarised in the figure below.



The existing and proposed ToU periods are shown in the table below.

	Jun to Aug (3 mths) Winter: high demand						April to May and Sep to Mar (9 mths) Summer: low demand					
	Week day		Sat		Sun		Week day		Sat		Sun	
	Exist 1:8	New 1:6	Exist 1:8	New 1:6	Exist 1:8	New 1:6	Exist 1:8	New 1:6	Exist 1:8	New 1:6	Exist 1:8	New 1:6
00h00		6 hours										
01h00												
02h00												
03h00	6 hours		7 hours	7 hours			6 hours	6 hours	7 hours	7 hours		
04h00												
05h00												
06h00		2 hours					1 hour	1 hours				
07h00	3 hours							2 hours				
08h00		9 hours				17 hours	3 hours					17 hours
09h00			5 hours	5 hours					5 hours	5 hours		
10h00												
11h00					24 hours						24 hours	
12h00	8 hours											
13h00							8 hours	9 hours				
14h00			6 hours	5 hours					6 hours	6 hours		
15h00												
16h00												
17h00	2 hours			2 hours		2 hours						2 hours
18h00		3 hours	2 hours				2 hours		2 hours	2 hours		
19h00								3 hours				
20h00	3 hours	2 hours					2 hours					
21h00			4 hours	5 hours		5 hours		2 hours	4 hours	4 hours		5 hours
22h00	2 hours	2 hours					2 hours					
23h00								1 hour				
Peak	5	5	0	0	0	0	5	5	0	0	0	0
Standard	11	11	7	7	0	2	11	12	7	7	0	2
Off-peak	8	8	17	17	24	22	8	7	17	17	24	22
Total	24	24	24	24	24	24	24	24	24	24	24	24
	*Earlier and 1hour shorter morning peak *1 hour longer evening peak		*Shift evening standard 1 hour earlier		* Reduction of Off-peak by 2 hours		*Earlier and 1hour shorter morning peak *1 hour longer evening peak		* No change		* Reduction of Off-peak by 2 hours	

Annexure 10: The Barry Curve