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Standard tariffs

Cost-to-serve (CTS) study report

2021/22 Financial year

Executive summary

The standard tariffs cost-of-supply (CoS) study report is based on the Eskom standard tariffs for the 2021/22 financial year. From this point onwards, it is referred to as the cost-to-serve (CTS) study.

This 2021/22 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 following 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 2021/22 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 2021/22 National Energy Regulator of South Africa (NERSA) revenue decision forecasted sales volume (kWh), demand (kVA), and number of customers' points of delivery (PoDs).
  - 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 voltage of 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 (R'million)						
	Voltage	Costing category	No of PoDS	Sales volumes (GWh)	Energy ToU	Energy capacity	Tx network capacity	Tx ancillary services	Dx network capacity	Retail	**Total allocated costs**
	>132kV	C01 : 275 LPU	87	39 192	31 515	6 938	1 106	76	0	12	**39 648**
Urban	≥66kV - ≤132kV	C02 : 132 LPU*	299	20 837	17 884	4 008	502	43	590	78	**23 104**
		C03 : Blank - no customers	0	0	0	0	0	0	0	0	**0**
		C04 : 88 LPU	262	8 342	7 058	1 786	242	17	801	70	**9 973**
		C05 : 66 LPU	77	8 322	7 306	1 600	184	17	1 294	19	**10 420**
	≥500V - <66kV	C06 : 44 LPU	43	1 988	1 803	435	64	4	355	13	**2 674**
		C07 : 33 LPU	87	27 202	23 323	5 539	570	60	2 964	24	**32 479**
		C08 : 6.6 3.3 2.2 LPU	848	22 090	19 328	4 611	589	48	3 162	104	**27 843**
		C09 : 2211 U LPU	854	30 453	27 094	6 261	754	67	5 785	120	**40 081**
		C10 : Blank - no customers	0	0	0	0	0	0	0	0	**0**
	<500V	C11 : 500 U ELEC	6 903 242	8 634	9 643	3 103	799	19	6 653	1 702	**21 920**
		C12 : 500 U RES	120 747	1 450	1 647	355	63	3	1 114	280	**3 463**
		C13 : 500 R RES	0	0	0	0	0	0	0	0	**0**
		C14 : 500 U OTHER SPU*	37 628	1 297	1 309	337	56	3	468	162	**2 335**
		C15 : 500 U OTHER LPU	3 294	1 825	1 673	409	123	4	587	140	**2 936**
Rural	≥500V - <66kV	C16 : 2211 R LPU	1 703	3 957	3 576	919	178	9	2 491	120	**7 293**
		C17 : 500 R ELEC	0	0	0	0	0	0	0	0	**0**
	<500V	C18 : 500 R OTHER LPU	11 498	4 030	3 647	1 047	280	9	3 254	344	**8 580**
		C19 : 500 R OTHER SPU	151 023	4 236	4 306	2 308	744	10	5 665	1 301	**14 333**
		Total	**7 231 691**	**183 856**	**161 112**	**39 654**	**6 255**	**389**	**35 185**	**4 488**	**247 083**

Notes:

1. *Costing categories C17, C10 and C03 are not used in the 2021/22 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 >66kV to below 66kV.*

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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 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 that produces electricity in accordance with its NERSA license.
High-demand season	The time-of-use (ToU) period 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 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 recorded in the customer billing system. This is not the primary voltage of each PoD.

1. Introduction

The objective of the 2021/22 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, that are the volumes, sales kilowatt-hour, demand, and number of PoDs. The costing methodology follows the nature of costs to supply electricity as 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), NERSA Cost to supply framework and the MYPD methodology (October 2016).

There are 3 main steps in the CTS study's costing process that are revenue mapping (or cost functionalisation), cost classification and cost allocation as shown in Figure 1.

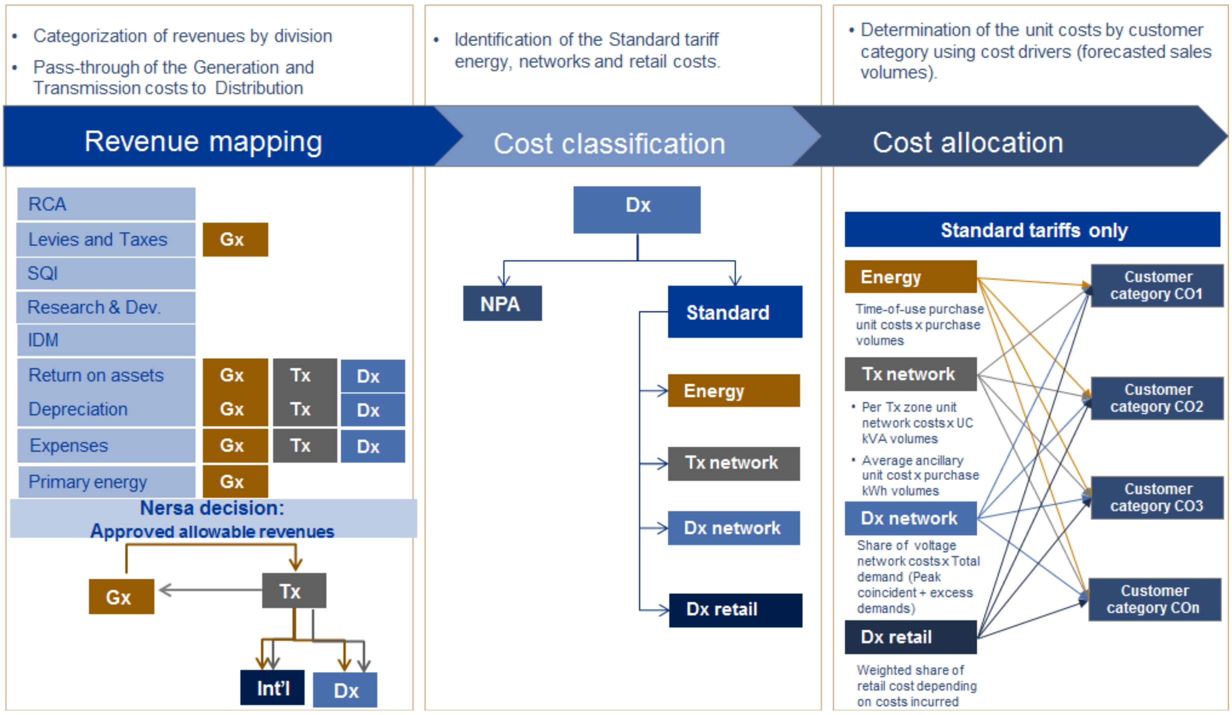


Figure 1: The CTS costing process

Revenue mapping

- The revenue mapping separates the NERSA 2021/22 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 2021/22 implemented as part of the ERTSA tariff increase. The 2021/22 AR 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 to include separation of metering, billing, and impairments. The ERTSA revenue difference is classified as a distribution network cost given it is associated with using detailed demand volumes 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 are 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 2021/22 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 costing category. For energy variable purchases (c/kWh), for generation capacity (kVA), ancillary services (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 (2015) 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 requires electricity distributors to undertake CoS studies at least every five years in accordance with the NERSA standard to reflect changing costs and customer behaviour:
  - This 2021/22 CTS study is submitted a year after the 2019/20 study (August 2020) following the 2018/19 CTS study of May 2019. The 2012/13 CTS study submission was included in the 2013 MYPD3 application (Part B) containing the then proposed tariff structural changes.
  - The cost allocation methods applied in the CTS study align with the principles contained in the NERSA Distribution Tariff Code and the CoS framework.

- 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), 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 2021/22 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 which 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 2021/22 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)*, provides guidance on how to enable tariffing, accordingly, in this CTS study:

- The allocation of costs is based on the NERSA-approved allowable revenue decision for 2021/22; the revenue mapping follows on 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, 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 to the requirements of the MYPD methodology in this CTS study is as follows:

- The CTS study uses the 2021/22 Eskom AR and forecasted sales volumes as determined in the MYPD decision and the 2021/22 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

Compliance with to the requirements of the CoS framework is as follows:

- The required steps are applied to ensure the use of a revenue requirement as determined by NERSA, cost functionalisation (referred to as cost mapping), costs classification and cost allocation.
- 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 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.

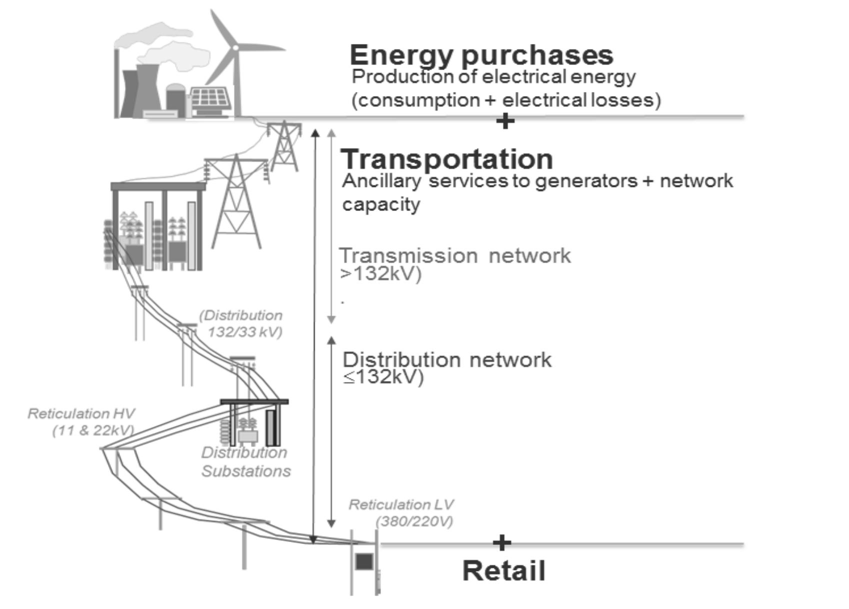


Figure 2: The costs to supply electricity

- 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 (275kV).
- 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 in a day and/or season, 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.

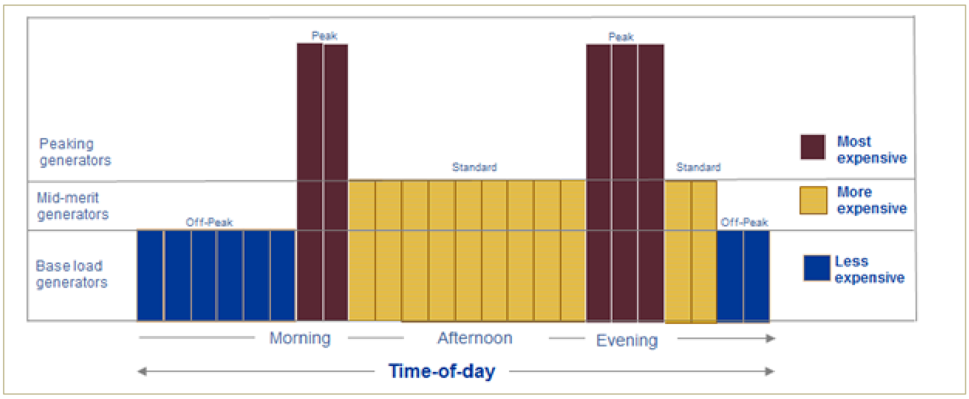


Figure 3: Varying costs of electricity production

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. For example, renewable generating technologies use freely available natural sources of energy while coal power plants need to purchase coal to produce electricity. Consequently, there are different levels of variable electricity production costs by technology type.
- Unpacking variable and fixed generation costs enables a more cost-reflective way to allocate generator costs and creates 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.

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 132kV.
- 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.

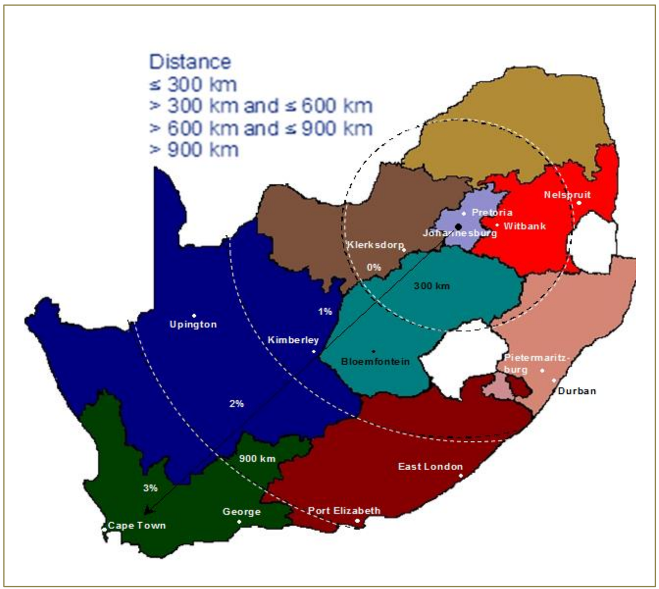


Figure 5: Transmission zones

- Customers taking supply from the transmission network (>132kV / 275kV supply voltage) or who are connected to the transmission network at a nominal voltage lower than or equal to 132kV but do not use distribution network assets, incur transmission network costs and not distribution network costs.

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

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 132kV 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 (≤132kV to ≥33kV), medium-voltage (≤22kV to ≥2.2kV) and reticulation / low-voltage (<500V or 400V).

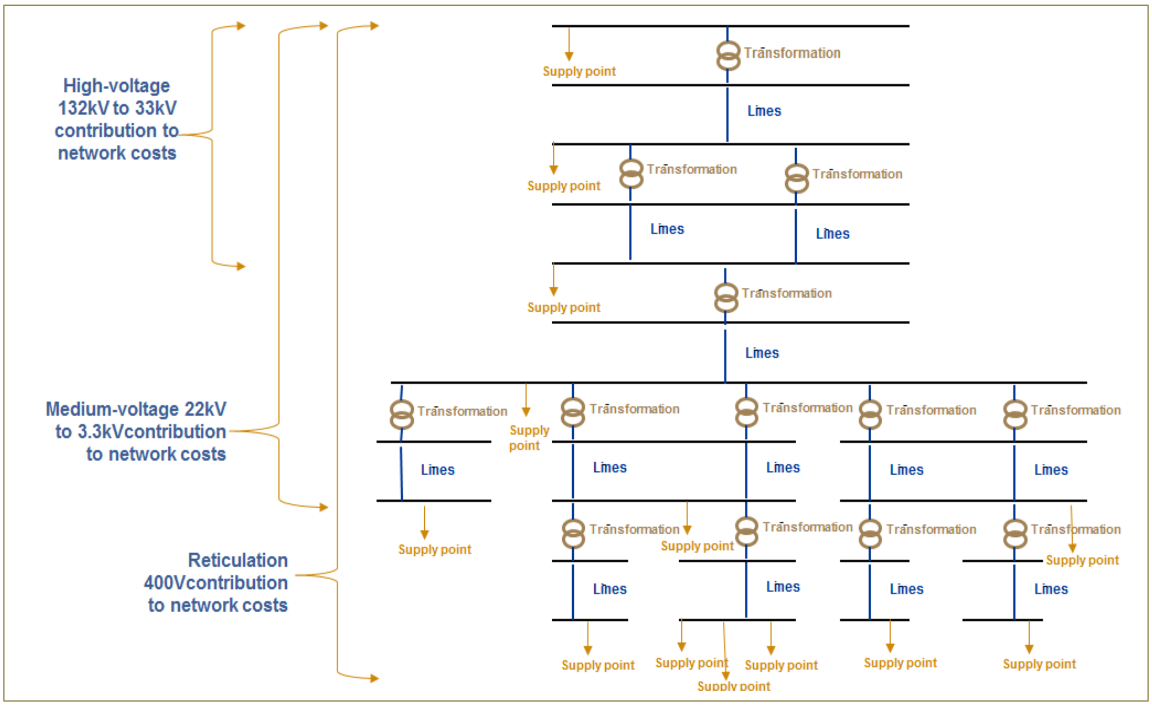


Figure 6: Use of the distribution network at different points of connection

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 7.2 million active customer PoDs. In the past nine years, customer PoDs have increased by 1.02million from additional residential connected through the electrification programme that set to achieve universal access; this excludes 1.7 million inactive PoDs.

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 100kVA. LPU customers have points of supply from 25kVA 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 2021/22 MYPD decision.
- There are 8.75 million active and inactive PoDs at 400V. 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 100kV. In the rural SPU category, 60A and 20A rural supplies are included; because the use of the network considered is similar and the only difference is the lines to supply at 400V.

– The urban residential supplies are separated into two categories: 500U RES for residential supplies and 500U ELEC specific to 60A and 20A 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	87	0	87	0.0010%
Urban	≥ 66kV & ≤ 132kV	C02	132 LPU*	132kV supplies	299	0	299	0.0033%
		C03	*Blank - no customers*	*n/a*	*0*	*0*	*0*	*0%*
		C04	88 LPU	88kV urban supplies	262	0	262	0.0029%
		C05	66 LPU	66kV urban supplies	77	0	77	0.0009%
	≥ 500V & < 66kV	C06	44 LPU	44kV urban supplies	43	0	43	0.0005%
		C07	33 LPU	33kV urban supplies	87	0	87	0.0010%
		C08	6.6 3.3 2.2 LPU	<33kV - 2.2kV urban supplies	848	0	848	0.0095%
		C09	2211 U LPU	<33kV - 11kV urban supplies	854	0	854	0.0095%
		C10	*Blank - no customers*	*n/a*	0	0	0	0%
	<500V	C11	500 U ELEC	≤500V low-usage urban residential	6 903 242	1 721 112	8 624 355	96.12%
		C12	500 U RES	≤500V other urban residential	120 747	6 826	127 573	1.42%
		C13	Blank - no customers	n/a	0	0	0	0.00%
		C14	500 U OTHER SPU*	≤500V urban small power users	37 628	2 127	39 755	0.44%
		C15	500 U OTHER LPU	≤500V urban large power users	3 294	0	3 294	0.04%
Rural	≥ 500V & < 66kV	C16	2211 R LPU	≤22kV - 11kV rural supplies	1 703	0	1 703	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	11 498	0	11 498	0.13%
		C19	500 R OTHER SPU	≤500V rural other small power users	151 023	11 033	162 056	1.81%
				Total	**7 231 691**	**1 741 099**	**8 972 790**	**100.0%**
				% of total	**81%**	**19%**	**100%**	**0.0%**
				Customers at <400V	*7 076 409*	*1 730 066*	*8 806 474*	*98.1%*

**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 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 2021/22 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 2018/19 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 60A and 20A 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 2021/22 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 – 2021/22 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	1 714	4 220	4 059	9 993	4 904	12 226	12 068	29 198	6 618	16 446	16 127	39 192
Urban	≥66kV - ≤132kV	C02 : 132 LPU*	924	2 337	2 211	5 472	2 570	6 490	6 306	15 365	3 493	8 827	8 517	20 837
		C03 : Blank - no customers	0	0	0	0	0	0	0	0	0	0	0	0
		C04 : 88 LPU	372	926	925	2 223	1 011	2 527	2 580	6 119	1 383	3 453	3 506	8 342
		C05 : 66 LPU	386	959	861	2 205	1 059	2 626	2 432	6 117	1 445	3 585	3 292	8 322
	≥500V - <66kV	C06 : 44 LPU	87	234	224	545	237	611	596	1 443	324	844	820	1 988
		C07 : 33 LPU	844	2 430	2 798	6 072	3 202	8 292	9 637	21 131	4 046	10 721	12 434	27 202
		C08 : 6.6 3.3 2.2 LPU	852	2 271	2 602	5 726	2 432	6 462	7 470	16 365	3 284	8 734	10 073	22 090
		C09 : 2211 U LPU	1 247	3 172	3 473	7 892	3 558	9 033	9 971	22 561	4 805	12 205	13 443	30 453
		C10 : Blank - no customers	0	0	0	0	0	0	0	0	0	0	0	0
	<500V	C11 : 500 U ELEC	694	1 092	475	2 261	1 820	3 094	1 458	6 373	2 515	4 186	1 933	8 634
		C12 : 500 U RES	125	188	89	402	314	494	240	1 048	439	682	330	1 450
		C13 : Blank - no customers	0	0	0	0	0	0	0	0	0	0	0	0
		C14 : 500 U OTHER SPU*	72	177	87	335	205	506	251	962	277	683	338	1 297
		C15 : 500 U OTHER LPU	74	208	188	469	213	595	548	1 356	287	803	736	1 825
Rural	≥500V - <66kV	C16 : 2211 R LPU	152	412	437	1 001	455	1 194	1 307	2 956	607	1 606	1 744	3 957
		C17 : Blank - no customers	0	0	0	0	0	0	0	0	0	0	0	0
	<500V	C18 : 500 R OTHER LPU	127	378	366	871	476	1 336	1 347	3 159	603	1 714	1 713	4 030
		C19 : 500 R OTHER SPU	216	548	263	1 027	689	1 713	807	3 209	905	2 261	1 069	4 236
		Total	**7 886**	**19 550**	**19 058**	**46 494**	**23 145**	**57 200**	**57 017**	**137 362**	**31 031**	**76 750**	**76 074**	**183 856**

Table 3: Cost drivers - 2021/22 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	98 723 854	7 751 860
	≥66kV - ≤132kV	C02 : 132 LPU*	66 101 200	5 259 743
		C04 : 88 LPU	32 103 900	2 589 817
		C05 : 66 LPU	24 000 625	1 680 561
	≥500V - <66kV	C06 : 44 LPU	7 808 022	628 911
		C07 : 33 LPU	69 962 504	5 336 853
		C08 : 6.6 3.3 2.2 LPU	72 123 043	4 726 198
		C09 : 2211 U LPU	92 244 217	6 460 487
	<500V	C11 : 500 U ELEC	96 123 741	8 080 981
		C12 : 500 U RES	7 632 131	542 250
		C14 : 500 U OTHER SP	6 759 674	564 000
		C15 : 500 U OTHER LP	14 624 465	499 249
Rural	≥500V - <66kV	C16 : 2211 R LPU	21 097 885	1 150 336
		C18 : 500 R OTHER LP	32 494 375	1 554 534
	<500V	C19 : 500 R OTHER SP	87 705 102	7 314 399
		Total	**729 504 737**	**54 140 178**

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 to values from the MYPD asset valuation study.
- Consists of 22 network positions with position P0 referencing >132kV and the distribution network. The CAD starts from position P1 that has 132kV transformation (T1) and 132kV lines (N1). See Annexure 4 for the distribution network model.
- Groups networks into high-voltage (≤132kV to ≥33kV), medium-voltage (≤22kV to ≥2.2kV) and reticulation / low-voltage (400V) for ease of reference.
- Links to asset loss factors obtained from a distribution network study (see Annexure 5) to enable distribution network losses 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 2021/22 energy wheel, which is a summary of the MYPD forecasted electricity production, supply and demand, Generators (local and imports) supply a total 237 830GWh. This supply volume meets 237 830GWh 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 2021/22 energy wheel.

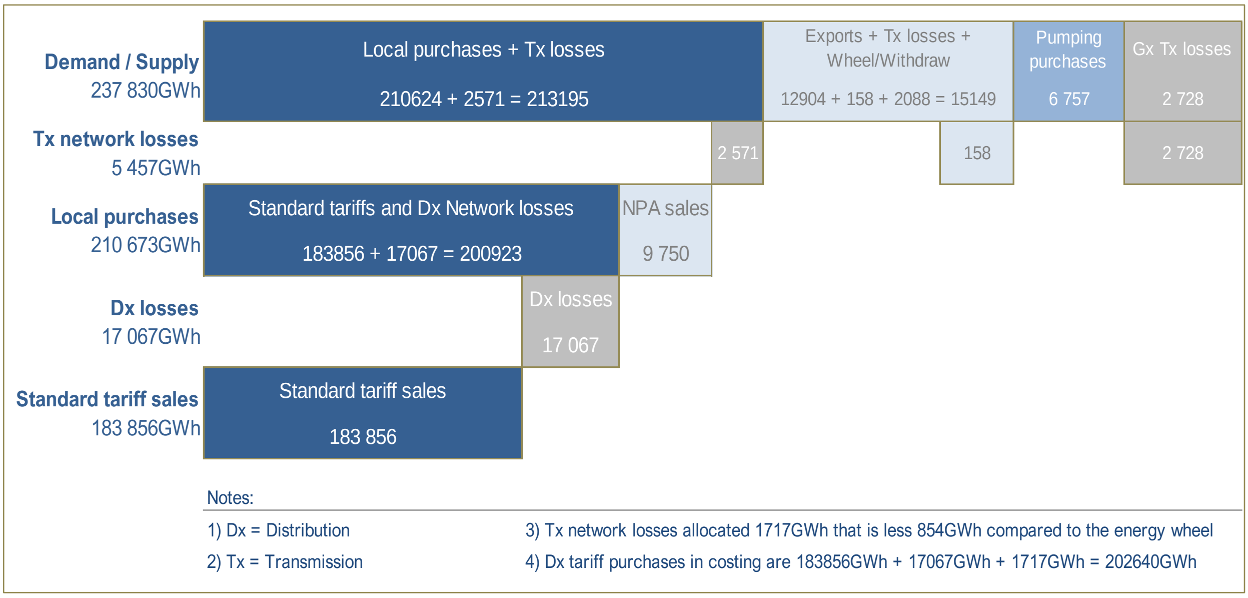
Transmission network electrical losses

- The South African Grid code requires that ±50% of the transmission network losses are for generators and ±50% for loads (local and export purchases).
- Of the total 5 457GWh transmission network losses 2 728GWh is for generators, the remainder 2729GWh is for the loads, that is, 2 571GWh for local sales and 158GWh for international / exports.

Distribution network electrical losses

- In the energy wheel the total distribution network losses are 17 067GWh.
- 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 >132kV 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 losses volumes are then 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 losses 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 of the CTS distribution loss factors to those in the 2021/22 schedule of standard tariffs because they are derived using the 2021/22 forecasted sales volumes that are different to the 2012/13 volumes used to derive the current standard tariff Distribution loss factors.

The 2021/22 distribution network losses (17 087GWh) plus the sales (183 856GWh) are the standard tariffs' energy purchases (200 923GWh). This purchase volume is higher by 5GWh compared to the energy wheel. This is because the energy wheel is calculated at a high level whilst the losses volumes in the CTS study are derived from the detailed sales volumes after the application loss factors.

Table 5: Distribution network losses 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*	55	140	132	328	154	389	378	920	209	529	510	1 248
		C03 : Blank - no customers	0	0	0	0	0	0	0	0	0	0	0	0
		C04 : 88 LPU	22	55	55	133	61	151	155	367	83	207	210	500
		C05 : 66 LPU	23	57	52	132	63	157	146	366	87	215	197	499
	≥500V - <66kV	C06 : 44 LPU	12	31	30	72	31	81	79	191	43	112	109	263
		C07 : 33 LPU	112	322	371	804	424	1 099	1 277	2 800	536	1 421	1 648	3 604
		C08 : 6.6 3.3 2.2 LPU	113	301	345	759	322	856	990	2 168	435	1 157	1 335	2 927
		C09 : 2211 U LPU	165	420	460	1 046	471	1 197	1 321	2 989	637	1 617	1 781	4 035
		C10 : Blank - no customers	0	0	0	0	0	0	0	0	0	0	0	0
	<500V	C11 : 500 U ELEC	105	165	72	342	275	468	220	964	380	633	292	1 305
		C12 : 500 U RES	19	28	13	61	47	75	36	158	66	103	50	219
		C13 : Blank - no customers	0	0	0	0	0	0	0	0	0	0	0	0
		C14 : 500 U OTHER SPU*	11	27	13	51	31	76	38	145	42	103	51	196
		C15 : 500 U OTHER LPU	11	31	28	71	32	90	83	205	43	121	111	276
Rural	≥500V - <66kV	C16 : 2211 R LPU	23	63	67	152	69	182	199	450	92	245	266	603
		C17 : Blank - no customers	0	0	0	0	0	0	0	0	0	0	0	0
	<500V	C18 : 500 R OTHER LPU	21	64	62	147	80	225	227	532	102	289	288	679
		C19 : 500 R OTHER SPU	36	92	44	173	116	288	136	540	152	381	180	713
		Total	**729**	**1 797**	**1 744**	**4 270**	**2 179**	**5 335**	**5 284**	**12 797**	**2 908**	**7 132**	**7 028**	**17 067**

Table 6: 2021/22 CTS study Distribution loss factors

	2021/22 Tariff book		2021/22 CTS Updated Dx loss factors	
	Urban	Rural	Urban	Rural
< 500V	1.1111	1.1527	1.1512	1.1684
≥ 500V & < 66kV	1.0957	1.1412	1.1325	1.1523
≥ 66kV & ≤ 132kV	1.0611		1.0599	
> 132kV	1.0000		1.0000	
< 500V	11.11%	15.27%	15.12%	16.84%
≥ 500V & < 66kV	9.57%	14.12%	13.25%	15.23%
≥ 66kV & ≤ 132kV	6.11%		5.99%	
> 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 the 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 1 717GWh which is a 854GWh difference from the 2 571GWh 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 losses volumes are derived from the sum of the detailed Distribution sales plus distribution network losses.
- When compared to the transmission loss factors the 2021/22 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	2021/22
≤ 300km	1.0026
> 300km and ≤ 600km	1.0126
> 600km and ≤ 900km	1.0226
> 900km	1.0326

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	98 723 854	7 751 860	7 751 860	0	0	0	7 751 860
	³66kV - £132kV	C02 : 132 LPU*	66 101 200	5 259 743	0	5 259 743	0	0	5 259 743
		C04 : 88 LPU	32 103 900	2 589 817	0	8 008 306	0	0	8 008 306
		C05 : 66 LPU	24 000 625	1 680 561	0	6 950 315	0	0	6 950 315
	³500V - <66kV	C06 : 44 LPU	7 808 022	628 911	0	2 209 198	0	0	2 209 198
		C07 : 33 LPU	69 962 504	5 336 853	0	21 215 188	0	0	21 215 188
		C08 : 6.6 3.3 2.2 LPU	72 123 043	4 726 198	0	11 614 842	10 141 393	0	21 756 236
		C09 : 2211 U LPU	92 244 217	6 460 487	0	16 330 492	13 238 929	0	29 569 421
	<500V	C11 : 500 U ELEC	96 123 741	8 080 981	0	20 928 899	16 966 801	16 322 681	54 218 382
		C12 : 500 U RES	7 632 131	542 250	0	1 404 370	1 138 505	1 095 284	3 638 159
		C14 : 500 U OTHER SPU*	6 759 674	564 000	0	1 460 702	1 184 173	1 139 218	3 784 093
		C15 : 500 U OTHER LPU	14 624 465	499 249	0	1 293 002	1 048 221	1 008 427	3 349 650
Rural	³500V - <66kV	C16 : 2211 R LPU	21 097 885	1 150 336	0	2 983 210	2 388 604	0	5 371 814
		C18 : 500 R OTHER LPU	32 494 375	1 554 534	0	4 108 626	4 844 238	0	8 952 864
	<500V	C19 : 500 R OTHER SPU	87 705 102	7 314 399	0	19 331 929	22 793 134	7 314 399	49 439 462
		Total	**729 504 737**	**54 140 178**	**7 751 860**	**123 098 822**	**73 743 999**	**26 880 009**	**231 474 690**

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. Customer 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 use of the distribution network and maximum demand influence on costs, there is need to calculate customers contribution to the different network positions' maximum demands for cost allocation.

Individual customer's 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' NCPD's contribute to the maximum demands at various network positions is required. This is to enable cost allocation following on 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 that 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 are 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 5 259 743kVA, the pf is 0.96 and the active energy (b) is 20 837GWh.

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) ÷ 8 760 ÷ (c) = (d)

   For C02 at N1, this is 20 837 034 601kWh ÷ 8 760 ÷0.959 = 2 480 299kVA

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:

      (c) - (d) = (e)

      For C02 at N1, this is 5 259 743 kVA - 2 480 299kVA = 2 779 443kVA

   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, that is:

      (e) ÷ Σ(e) = (f)

      For C02 at N1, this is 2 779 443kVA ÷ 32 388 769kVA = 0.0858 or 8.58%

   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 20 837 034 601kWh ÷ 5 259 743 kVA ÷ 0.959 = 0.4716 or 47.16%

   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 5 259 743 kVA x 0.58 = 3 024 676kVA

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, 22 963 310 kVA - 18 946 844kVA = 4 016 466kVA

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 8.58% x 4 016 466kVA = 344 673kVA

8. The total demand (l) used to allocate each network position's total costs to individual costing categories using the network position, is the sum of the allocated excess demand (j) plus the average demand (d), that is:

   (j)+ (d) = (l)

   For C02 at N1, this is 2 480 299kVA + 344 673kVA = 2 824 973kVA

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

   (j)+ (d) = (l)

   For C02 at N1, this is 2 480 299kVA + 344 673kVA = 2 824 973kVA

   (l) ÷ Σ(l) = (m)

   For Co2 at N1, this is 2 824 973kVA ÷ 22 963 310kVA = 12.3%

The determined contribution to total demand for cost allocation by customer category at each 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 (MTS's).

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

		Network position for 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)
			(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*	5 260	20 837	0.959	2 480	2 779	9%	47%	0.5751	3 025	345	2 825	12.30%	243
		Blank - no customers : n/													
		C04 : 88 LPU	2 733	8 805	0.962	1 045	1 689	5%	38%	0.4821	1 318	209	1 254	5.46%	108
		C05 : 66 LPU	1 774	8 784	0.964	1 040	733	2%	59%	0.6878	1 220	91	1 131	4.93%	97
	≥500V - <66kV	C06 : 44 LPU	676	2 137	0.965	253	423	1%	37%	0.4713	319	52	305	1.33%	26
		C07 : 33 LPU	5 922	30 183	0.948	3 635	2 286	7%	61%	0.7054	4 177	284	3 919	17.07%	337
		C08 : 6.6 3.3 2.2 LPU	5 278	24 670	0.947	2 973	2 305	7%	56%	0.6608	3 488	286	3 259	14.19%	281
		C09 : 2211 U LPU	7 148	33 692	0.952	4 040	3 108	10%	57%	0.6699	4 788	385	4 425	19.27%	381
		Blank - no customers : n/													
	<500V	C11 : 500 U ELEC	9 160	9 787	0.985	1 134	8 026	25%	12%	0.1689	1 547	995	2 129	9.27%	183
		C12 : 500 U RES	615	1 644	0.954	197	418	1%	32%	0.4158	256	52	249	1.08%	21
		Blank - no customers : n/	0	0											
		C14 : 500 U OTHER SPU*	639	1 471	0.945	178	462	1%	28%	0.3697	236	57	235	1.02%	20
		C15 : 500 U OTHER LPU	566	2 069	0.950	249	317	1%	44%	0.5449	308	39	288	1.25%	25
Rural	≥500V - <66kV	C16 : 2211 R LPU	1 306	4 492	0.927	553	753	2%	42%	0.5243	685	93	646	2.81%	56
		Blank - no customers : n/													
	<500V	C18 : 500 R OTHER LPU	1 798	4 661	0.914	582	1 216	4%	32%	0.4158	748	151	733	3.19%	63
		C19 : 500 R OTHER SPU	8 461	4 900	0.950	589	7 873	24%	7%	0.1005	850	976	1 565	6.82%	135
		Total	**51 336**	**158 131**	**n/a**	**18 947**	**32 389**	**100%**	**n/a**	**7**	**22 963**	**4 016**	**22 963**	**100%**	**1 977**

Network position coincident peak demand (MVA)	22 963	(o) = total(i)
Network position excess demand (MVA)	4 016	(k) = (o) - (d)
Allocated network position costs : Capital (R'million)	1 977	(p)

6. Revenue mapping

6.1. Revenue mapping

The NERSA 2021/22 allowable revenue decision 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 2021/22 Eskom total R265 852million AR revenue is R214 568million for the Generation Division, R12 995million for Transmission Division and R38 289million for Distribution Division. See Table 10.

Table 10: Revenue mapping - 2021/22 AR decision

Allowable revenues (AR)		Generation	Transmission	Distribution			Eskom total
				Networks	Retail	Total	
PE	PE Total	112 388					112388
E	Expenses	28 771	3 439	20 428	4 375	24 803	57 013
D	Depreciation	49 530	8 414	8 308	26	8 335	66 279
(RAB x WACC)	Return on assets	-7 640	-1 216	-1 017	0	-1 017	-9 874
IDM	IDM	0	0	0	0	0	0
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	7 266	0	0	0	0	7 266
RCA	Regulatory clearing account	24 253	2 358	6 168	0	6 168	32 780
AR	**Allowable revenues**	**214 568**	**12 995**	**33 888**	**4 401**	**38 289**	**265 852**
		81%	*5%*	*13%*	*2%*	*14%*	*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 Distribution Division. In 2021/22, the Generation pass-through costs are separate for ToU energy (c/kWh) and generation capacity costs (R/kW) which are R158 617million and R39 654million respectively.
- The costs passed through from the 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 R10 167million and R9 143million 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 R245 703million for recovery through standard tariffs. Including the 2021/22 ERTSA R1 383million difference, the total revenues for allocation in the 2021/22 CTS study are R247 086million. See Table 11.

Table 11: 2021/22 pass-through to Distribution Division

Allowable revenues (AR)		Generation	Transmission	Distribution	Eskom
PE	PE Total	112 388			112 388
E	Expenses	28 771	3 439	24 803	57 013
D	Depreciation	49 530	8 414	8 335	66 279
(RAB x WACC)	Return on assets	-7 640	-1 216	-1 017	-9 874
IDM	IDM				0
R&D	Research and dev. programme				0
SQI	Service quality incentives				0
L&T	Levis & taxes	7 266			7 266
RCA	Regulatory clearing account	24 253	2 358	6 168	32 780
AR	**Allowable revenues**	**214 568**	**12 995**	**38 289**	**265 852**
				Pass-through to Distribution ↓	
EPPa	**Other transmission costs**				
	Transmission losses		5 451		
	Ancillary services		864		
AR Tx	**Transmission**		**19 309**		
	Purchases from transmission	**10 167**		**9 143**	
	Transmission network	6 739		6 255	
	Transmission losses	2 952		2 499	
	Ancillary services	475		389	
AR Gx	**Generation**	**224 735**			
	Purchases from Generation			**198 272**	
	Energy capacity			39 654	
	ToU Energy			158 617	
AR Gx	**Distribution**			**245 703**	
	Exports & NPA				**20 149**
AR Eskom	**Total Eskom allowable revenues**				**265 852**
	ERTSA Difference			1 383	
	Distribution Standard tariffs			**247 086**	

7. Cost classification

The result of the revenue mapping informs the cost classification of 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), 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 (>132kV).
  - 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 (≤132kV) and retail services.
  - The classification uses the network and retail costs detail underlying the 2021/22 MYPD4 revenue application.
  - The distribution network capital costs are increased by the difference between the MYPD decision's revenues for standard tariffs and the NERSA-approved ERTSA revenues. This is because the difference is due to the use of detailed demand volumes during the ERTSA process.

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	**247 092**
Energy purchases	**200 770**
Energy ToU costs	152 235
Energy Capacity costs	39 654
Transmission technical losses	2 499
Distribution technical losses	0
Environmental levy	6 382
Adjustment to balance the allowed revenues	*0*
Transmission network	**6 644**
Network capacity	6 255
Ancillary services	389
Distribution total	**39 678**
Distribution network	
Network capacity	35 277
Retail services	
Customer service and administration	4 401

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

Distribution	**39 678**
Distribuiton networks total	**35 277**
Capital	14 848
Network capital (incld. ERTSA difference)	14 756
Meter capital	92
Network support : Operating and maintenance	20 428
Repairs and maintenance	8 194
Employee benefits	8 460
Corporate overheads	4 200
Other income	-426
Customer services (retail) total	**4 401**
Retail support	1 648
Marketing	3
Customer service (employee benefits)	1 646
Billing	719
Prepayment	528
Account	191
Meter reading	88
CS Overheads (other costs)	464
Impairment costs	1 457
Non - Top customer	1 207
Top customer	250
Depreciation	26

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 (ToU) unit costs

Active energy is the electricity generated, transported, and consumed. The cost of active energy ToU purchases from the Wholesaler include transmission and distribution network losses. The total Distribution active energy purchase costs from the Wholesaler are R161 112million for 202 640GWh (sales, distribution, and transmission network losses).

The cost allocation reflects the Wholesale ToU energy pricing, and its active energy ToU purchase unit costs are determined as follows (with reference to Table 14):

- The total energy purchase volumes by ToU period and season (i) are allocated the same unit cost by the respective time-of-use periods and season.
- To calculate the energy purchase unit costs by ToU period and season, the ratio of 1:6 proposed by the System Operator (SO) is applied; also see Annexure 9 for a summary of the SO motivation to propose the 1:6 ratio.
- The purchase volumes for each ToU period and season (i) are multiplied by the applicable 1:6 ratio weighting (ii). The resulting sum of the weighted purchase volumes that is the total in (iii) used to determine an overall average c/kWh (v) by dividing this weighted volume with the total energy purchase costs (iv).
- The overall average c/kWh (v) is then multiplied by the ToU ratio for each period and season; to arrive at the c/kWh purchase unit per ToU and season (vi).
- The sum of the energy purchase costs (vii) after applying each ToU rate to the detailed per costing category energy purchase volumes is equal to the total energy purchase cost (iv).

See Table 14 for the calculation of the ToU energy purchase unit costs based on the 1:6 ratio.

The active energy unit costs are then applied to costing category purchase volumes expressed at >132kV, that is, including the distribution and transmission network losses. See Table 15 for the resulting energy purchases 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 14: Active energy purchase unit cost 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)	8 687	21 532	20 981	25 536	63 071	62 833	202 640
(ii)	1:6 Time-of-use ratio	***6.00***	***1.50***	***1.00***	***2.49***	***1.40***	***1.00***	
(iii)	Weighted energy purchase volumes (GWh)	52 121	32 297	20 981	63 585	88 300	62 833	320 118
(iv)	**Energy purchase costs (R'million)**	***161 116***						
(v)	**Weighted average unit cost (c/kWh)**	**50.3303**						
(vi)	**1:6 ratio energy purchase unit costs (c/kWh)**	**301.98c**	**75.49c**	**50.33c**	**125.32c**	**70.46c**	**50.33c**	
(vii)	Costs after multiplying with unit costs	26 232	16 254	10 560	32 002	44 440	31 624	**161 112**
	Difference to energy purchase costs (R'million)	*-3.85*						
	%Difference to energy purchase costs (%)	*-0.002%*						

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

			Winter total purchase costs (R'million) [3 months : Jun - Aug]				Summer total purchase costs (R'million) [9 months : Apr - May & Sep-Mar]				Energy purchase costs (R'million) (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	5 220	3 214	2 062	10 496	6 200	8 692	6 127	21 019	11 420	11 906	8 189	31 515
Urban	³66kV - £132kV	C02 : 132 LPU*	3 000	1 897	1 196	6 092	3 463	4 917	3 411	11 791	6 462	6 814	4 608	17 884
		C03 : Blank - no customers	0	0	0	0	0	0	0	0	0	0	0	0
		C04 : 88 LPU	1 194	744	495	2 433	1 348	1 895	1 382	4 625	2 542	2 638	1 877	7 058
		C05 : 66 LPU	1 266	786	470	2 523	1 443	2 011	1 330	4 783	2 709	2 797	1 800	7 306
	³500V - <66kV	C06 : 44 LPU	300	201	129	630	339	491	343	1 172	639	692	471	1 803
		C07 : 33 LPU	2 902	2 088	1 602	6 592	4 566	6 647	5 518	16 731	7 468	8 735	7 120	23 323
		C08 : 6.6 3.3 2.2 LPU	2 932	1 954	1 492	6 379	3 475	5 190	4 284	12 949	6 407	7 144	5 776	19 328
		C09 : 2211 U LPU	4 295	2 731	1 994	9 020	5 087	7 261	5 725	18 073	9 382	9 993	7 719	27 094
		C10 : Blank - no customers	0	0	0	0	0	0	0	0	0	0	0	0
	<500V	C11 : 500 U ELEC	2 420	951	276	3 647	2 633	2 516	847	5 997	5 053	3 468	1 123	9 643
		C12 : 500 U RES	437	164	52	652	454	402	140	995	890	565	192	1 647
		C13 : Blank - no customers	0	0	0	0	0	0	0	0	0	0	0	0
		C14 : 500 U OTHER SPU*	251	154	50	455	296	411	146	854	547	565	196	1 309
		C15 : 500 U OTHER LPU	259	183	110	552	311	489	321	1 121	571	672	431	1 673
Rural	³500V - <66kV	C16 : 2211 R LPU	535	364	257	1 156	667	984	769	2 420	1 202	1 348	1 026	3 576
		C17 : Blank - no customers	0	0	0	0	0	0	0	0	0	0	0	0
	<500V	C18 : 500 R OTHER LPU	455	339	219	1 013	709	1 120	806	2 634	1 165	1 458	1 024	3 647
		C19 : 500 R OTHER SPU	765	485	155	1 405	1 011	1 414	476	2 901	1 777	1 899	630	4 306
		Total	**26 232**	**16 254**	**10 560**	**53 046**	**32 002**	**44 440**	**31 624**	**108 066**	**58 234**	**60 694**	**42 184**	**161 112**

Table 16: Allocated active energy purchase costs at >132kV 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	301.98c	75.49c	50.33c	104.10c	125.32c	70.46c	50.33c	71.35c	171.06c	71.75c	50.33c	79.70c
Urban	≥66kV - ≤132kV	C02 : 132 LPU*	301.98c	75.49c	50.33c	103.57c	125.32c	70.46c	50.33c	71.38c	172.04c	71.79c	50.33c	79.83c
Urban	≥66kV - ≤132kV	C03 : Blank - no customers												
Urban	≥66kV - ≤132kV	C04 : 88 LPU	301.98c	75.49c	50.33c	102.90c	125.32c	70.46c	50.33c	71.03c	172.81c	71.81c	50.33c	79.53c
Urban	≥66kV - ≤132kV	C05 : 66 LPU	301.98c	75.49c	50.33c	105.32c	125.32c	70.46c	50.33c	71.96c	172.49c	71.80c	50.33c	80.80c
Urban	≥500V - <66kV	C06 : 44 LPU	301.98c	75.49c	50.33c	101.37c	125.32c	70.46c	50.33c	71.14c	172.83c	71.85c	50.33c	79.42c
Urban	≥500V - <66kV	C07 : 33 LPU	301.98c	75.49c	50.33c	95.39c	125.32c	70.46c	50.33c	69.59c	162.19c	71.60c	50.33c	75.35c
Urban	≥500V - <66kV	C08 : 6.6 3.3 2.2 LPU	301.98c	75.49c	50.33c	97.76c	125.32c	70.46c	50.33c	69.43c	171.14c	71.77c	50.33c	76.77c
Urban	≥500V - <66kV	C09 : 2211 U LPU	301.98c	75.49c	50.33c	100.21c	125.32c	70.46c	50.33c	70.22c	171.16c	71.77c	50.33c	77.99c
Urban	≥500V - <66kV	C10 : Blank - no customers												
Urban	<500V	C11 : 500 U ELEC	301.98c	75.49c	50.33c	139.75c	125.32c	70.46c	50.33c	81.53c	174.09c	71.77c	50.33c	96.77c
Urban	<500V	C12 : 500 U RES	301.98c	75.49c	50.33c	140.47c	125.32c	70.46c	50.33c	82.25c	175.76c	71.85c	50.33c	98.40c
Urban	<500V	C13 : Blank - no customers												
Urban	<500V	C14 : 500 U OTHER SPU*	301.98c	75.49c	50.33c	117.62c	125.32c	70.46c	50.33c	76.89c	171.24c	71.76c	50.33c	87.42c
Urban	<500V	C15 : 500 U OTHER LPU	301.98c	75.49c	50.33c	100.95c	125.32c	70.46c	50.33c	70.96c	170.67c	71.76c	50.33c	78.67c
Rural	≥500V - <66kV	C16 : 2211 R LPU	301.98c	75.49c	50.33c	98.81c	125.32c	70.46c	50.33c	70.00c	169.47c	71.75c	50.33c	77.29c
Rural	≥500V - <66kV	C17 : Blank - no customers												
Rural	<500V	C18 : 500 R OTHER LPU	301.98c	75.49c	50.33c	97.93c	125.32c	70.46c	50.33c	70.15c	162.48c	71.57c	50.33c	76.15c
Rural	<500V	C19 : 500 R OTHER SPU	301.98c	75.49c	50.33c	116.77c	125.32c	70.46c	50.33c	77.18c	167.53c	71.68c	50.33c	86.78c
		Total	**301.98c**	**75.49c**	**50.33c**	**103.61c**	**125.32c**	**70.46c**	**50.33c**	**71.36c**	**170.16c**	**71.74c**	**50.33c**	**79.51c**

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	304.57c	76.17c	50.79c	105.03c	126.43c	71.09c	50.77c	71.99c	172.56c	72.39c	50.78c	80.41c
Urban	≥66kV - ≤132kV	C02 : 132 LPU*	324.67c	81.17c	54.09c	111.34c	134.75c	75.77c	54.10c	76.74c	184.98c	77.20c	54.10c	85.83c
Urban	≥66kV - ≤132kV	C03 : Blank - no customers												
Urban	≥66kV - ≤132kV	C04 : 88 LPU	321.24c	80.30c	53.55c	109.47c	133.33c	74.96c	53.55c	75.58c	183.85c	76.39c	53.55c	84.61c
Urban	≥66kV - ≤132kV	C05 : 66 LPU	328.09c	82.01c	54.66c	114.41c	136.19c	76.56c	54.68c	78.19c	187.44c	78.02c	54.67c	87.79c
Urban	≥500V - <66kV	C06 : 44 LPU	344.57c	86.13c	57.50c	115.71c	143.03c	80.42c	57.51c	81.24c	197.25c	82.00c	57.51c	90.68c
Urban	≥500V - <66kV	C07 : 33 LPU	343.67c	85.92c	57.28c	108.57c	142.58c	80.17c	57.26c	79.18c	184.54c	81.47c	57.26c	85.74c
Urban	≥500V - <66kV	C08 : 6.6 3.3 2.2 LPU	344.25c	86.04c	57.35c	111.41c	142.87c	80.31c	57.35c	79.13c	195.10c	81.80c	57.35c	87.50c
Urban	≥500V - <66kV	C09 : 2211 U LPU	344.48c	86.11c	57.41c	114.30c	142.98c	80.39c	57.42c	80.11c	195.28c	81.88c	57.41c	88.97c
Urban	≥500V - <66kV	C10 : Blank - no customers												
Urban	<500V	C11 : 500 U ELEC	348.53c	87.13c	58.09c	161.29c	144.64c	81.32c	58.09c	94.09c	200.93c	82.84c	58.09c	111.69c
Urban	<500V	C12 : 500 U RES	348.59c	87.15c	58.12c	162.18c	144.66c	81.35c	58.12c	94.96c	202.89c	82.95c	58.12c	113.61c
Urban	<500V	C13 : Blank - no customers												
Urban	<500V	C14 : 500 U OTHER SPU*	348.53c	87.13c	58.09c	135.75c	144.64c	81.32c	58.09c	88.74c	197.64c	82.83c	58.09c	100.89c
Urban	<500V	C15 : 500 U OTHER LPU	351.88c	88.00c	58.64c	117.64c	146.07c	82.13c	58.64c	82.70c	198.91c	83.65c	58.64c	91.68c
Rural	≥500V - <66kV	C16 : 2211 R LPU	352.97c	88.23c	58.82c	115.48c	146.55c	82.39c	58.85c	81.86c	198.15c	83.89c	58.84c	90.36c
Rural	≥500V - <66kV	C17 : Blank - no customers												
Rural	<500V	C18 : 500 R OTHER LPU	358.67c	89.64c	59.76c	116.29c	149.03c	83.79c	59.83c	83.40c	193.17c	85.08c	59.81c	90.51c
Rural	<500V	C19 : 500 R OTHER SPU	353.74c	88.43c	58.96c	136.78c	146.80c	82.54c	58.96c	90.41c	196.25c	83.96c	58.96c	101.65c
		Total	**332.65c**	**83.14c**	**55.41c**	**114.09c**	**138.27c**	**77.69c**	**55.46c**	**78.67c**	**187.66c**	**79.08c**	**55.45c**	**87.63c**

8.2. 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 >132kV and therefore their maximum demand as recorded at their connection to the distribution network (≤132kV) requires an adjustment to include asset losses. This reflects the maximum demand measured at the point of connection to the transmission network (>132kV).
- 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 >132kV 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 18.

Table 18: 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	0.960	60.1%	0.70	5 400	414	5 074	98 724	6 938	113.95	70.28
Urban		C02 : 132 LPU*	0.959	47.2%	0.58	3 108	382	2 931	66 101	4 008	113.95	60.64
Urban	≥66kV - ≤132kV	C03 : Blank - no customers										
Urban	≥66kV - ≤132kV	C04 : 88 LPU	0.962	38.2%	0.48	1 354	232	1 306	32 104	1 786	113.95	55.63
Urban	≥66kV - ≤132kV	C05 : 66 LPU	0.964	58.7%	0.69	1 254	101	1 170	24 001	1 600	113.95	67
Urban	≥500V - <66kV	C06 : 44 LPU	0.965	37.4%	0.47	327	58	318	7 808	435	113.95	55.69
Urban	≥500V - <66kV	C07 : 33 LPU	0.948	61.4%	0.71	4 293	314	4 050	69 963	5 539	113.95	79.16
Urban	≥500V - <66kV	C08 : 6.6 3.3 2.2 LPU	0.947	56.3%	0.66	3 584	317	3 372	72 123	4 611	113.95	63.93
Urban	≥500V - <66kV	C09 : 2211 U LPU	0.952	56.5%	0.67	4 921	427	4 579	92 244	6 261	113.95	67.88
Urban	≥500V - <66kV	C10 : Blank - no customers										
Urban	<500V	C11 : 500 U ELEC	0.985	12.4%	0.17	1 590	1 104	2 269	96 124	3 103	113.95	32.28
Urban	<500V	C12 : 500 U RES	0.954	32.0%	0.42	263	57	260	7 632	355	113.95	46.52
Urban	<500V	C13 : 500 R RES										
Urban	<500V	C14 : 500 U OTHER SPU*	0.945	27.8%	0.37	243	63	246	6 760	337	113.95	49.79
Urban	<500V	C15 : 500 U OTHER LPU	0.950	43.9%	0.54	317	44	299	14 624	409	113.95	27.97
Rural	≥500V - <66kV	C16 : 2211 R LPU	0.927	42.4%	0.52	704	104	672	21 098	919	113.95	43.55
Rural	≥500V - <66kV	C17 : 500 R ELEC										
Rural	<500V	C18 : 500 R OTHER LPU	0.914	32.4%	0.42	768	167	765	32 494	1 047	113.95	32.21
Rural	<500V	C19 : 500 R OTHER SPU	0.950	7.0%	0.10	874	1 083	1 688	87 705	2 308	113.95	26.31
			Total			29 000	4 868	29 000	729 505	39 654	113.95	54.36

8.3. 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 R389million is the total purchase cost. At the purchase volumes which including transmission network losses the unit cost is 0.1450c/kWh.
- The R389million 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 19.
- 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 19.

Table 19: 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	39 540	76	39 192	0.1935	39 192	0.1935
Urban	≥66kV - ≤132kV	C02 : 132 LPU*	22 403	43	22 085	0.1935	20 837	0.2051
Urban	≥66kV - ≤132kV	C03 : Blank - no customers	0	0	0		0	
Urban	≥66kV - ≤132kV	C04 : 88 LPU	8 875	17	8 842	0.1935	8 342	0.2051
Urban	≥66kV - ≤132kV	C05 : 66 LPU	9 042	17	8 821	0.1935	8 322	0.2051
Urban	≥500V - <66kV	C06 : 44 LPU	2 270	4	2 251	0.1935	1 988	0.2191
Urban	≥500V - <66kV	C07 : 33 LPU	30 951	60	30 807	0.1935	27 202	0.2191
Urban	≥500V - <66kV	C08 : 6.6 3.3 2.2 LPU	25 176	48	25 017	0.1935	22 090	0.2191
Urban	≥500V - <66kV	C09 : 2211 U LPU	34 741	67	34 488	0.1935	30 453	0.2191
Urban	≥500V - <66kV	C10 : Blank - no customers	0	0	0		0	
Urban	<500V	C11 : 500 U ELEC	9 965	19	9 940	0.1935	8 634	0.2227
Urban	<500V	C12 : 500 U RES	1 674	3	1 669	0.1935	1 450	0.2227
Urban	<500V	C13 : Blank - no customers	0	0	0		0	
Urban	<500V	C14 : 500 U OTHER SPU*	1 497	3	1 494	0.1935	1 297	0.2227
Urban	<500V	C15 : 500 U OTHER LPU	2 127	4	2 101	0.1935	1 825	0.2227
Rural	≥500V - <66kV	C16 : 2211 R LPU	4 627	9	4 560	0.1935	3 957	0.2229
Rural	≥500V - <66kV	C17 : Blank - no customers	0	0	0		0	
Rural	<500V	C18 : 500 R OTHER LPU	4 790	9	4 708	0.1935	4 030	0.2261
Rural	<500V	C19 : 500 R OTHER SPU	4 962	10	4 949	0.1935	4 236	0.2261
		Total	**202 640**	**389**	**200 923**	**0.1935**	**183 856**	**0.2114**

8.4. 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 of distribution network demands (diversified demand).

- For the cost allocation, as outlined consequentially in Table 20, the annualised transmission network maximum demand is grouped into four transmission zones that are the concentric zones differentiated by the distance from the South African region with 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 >132kV. The zonal R/kVA purchases unit costs (ii) apply to the costing category at >132kV.
- To determine the costs for supplies connected to the distribution network, the allocated >132kV 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 >132kV), the average unit cost for supplies connected to the distribution network appears lower than for >132kV 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 (≤132kV).
- The cost for Transmission network capacity is therefore dependent on the transmission zone and voltage of supply. See Table 20 (ii) for >132kV unit costs and (viii) for ≤132kV connected supplies. See Table 21 for the total allocated costs mapped to costing categories.

Table 20: 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	57 456 000	11.14	640
> 300km and ≤ 600km	33 257 696	11.26	374
> 600km and ≤ 900km	882 158	11.37	10
> 900km	7 128 000	11.48	82
Total	**98 723 854**		**1 106**

(iv) Total transmission network capacity costs (R'million)	**6 255**
(v) Total transmission network capacity costs less allocated >132kV costs (R'million)	**5 149**
(vi) Average Tx network unit cost for Dx connected supplies (R/kVA)	**7.17**

Transmission zone	(vii) >132kV / Tx connected Annulised UC volumes (kVA)	(viii) Per Transmission zone differentiated R/kVA unit cost	(ix) Dx network >32kV Allocated purchase costs R'million
≤ 300km	529 267 305	7.14	**3 777**
> 300km and ≤ 600km	99 541 150	7.21	**718**
> 600km and ≤ 900km	24 203 879	7.28	**176**
> 900km	64 975 241	7.35	**478**
Total	**717 987 575**		**5 149**

Table 21: 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	98 724	1 106	11.21
Urban	≥66kV - ≤132kV	C02 : 132 LPU*	66 101	502	7.60
		C03 : Blank - no customers	0	0	
		C04 : 88 LPU	32 104	242	7.53
		C05 : 66 LPU	24 001	184	7.69
	≥500V - <66kV	C06 : 44 LPU	7 808	64	8.19
		C07 : 33 LPU	69 963	570	8.15
		C08 : 6.6 3.3 2.2 LPU	72 123	589	8.17
		C09 : 2211 U LPU	92 244	754	8.17
		C10 : Blank - no customers	0	0	
	<500V	C11 : 500 U ELEC	96 124	799	8.31
		C12 : 500 U RES	7 632	63	8.32
		C13 : 500 R RES	0.00	0.00	
		C14 : 500 U OTHER SPU*	6 760	56	8.31
		C15 : 500 U OTHER LPU	14 624	123	8.38
Rural	≥500V - <66kV	C16 : 2211 R LPU	21 098	178	8.42
		C17 : 500 R ELEC	0.00	0.00	
	<500V	C18 : 500 R OTHER LPU	32 494	280	8.60
		C19 : 500 R OTHER SPU	87 705	744	8.48
		Total	**729 505**	**6 255**	**8.57**

8.5. Distribution network capacity unit costs

Distribution network capacity costs include network capital (capital) and the 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 was 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 at 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 the varying age 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: ≥33kV), medium and low-voltage (MV& LV: ≤22kV). 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 the demand calculated using A&E method as discussed 5.7 Distribution network demand for cost allocation.
  - See Table 22 for the allocated distribution network capacity costs by network position. See Table 23 and Table 24 for the summary of the allocated distribution network costs by customer category.

Table 22: 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%	1 977	35.7%	2 817	4 795	Dx HV
		88 kV	N2	11.9%	1 176	21.2%	1 676	2 852	Dx HV
		66 kV	N3	7.2%	705	12.7%	1 004	1 709	Dx HV
		44 kV	N4	1.9%	189	3.4%	270	459	Dx HV
		33 kV	N5	0.4%	39	0.7%	55	94	Dx HV
Transformation Dx - Dx		88 kV Secondary	T2	4.1%	200	3.6%	285	485	Dx HV
		66 kV Secondary	T3 / T4 / T5	7.6%	374	6.7%	532	906	Dx HV
		44 kV Secondary	T6 / T7 / T8	4.1%	203	3.7%	289	491	Dx HV
		33 kV Secondary	T9 / T10 / T11 / T12	13.9%	683	12.3%	974	1 657	Dx HV
					5 546	**100%**	**7 902**	**13 448**	Dx HV
Transformation Dx - Rx	High Density (urban)	22 kV Secondary 11 kV Secondary	T13 / T14 / T15 / T16 / T17	37.6%	1 844	20.0%	2 507	4 351	Dx MV & LV
		6.6 kV Secondary 3.3 kV Secondary	T18 / T19 / T20 / T21 / T22 / T23	9.9%	487	5.3%	662	1 148	Dx MV & LV
	Low Density (rural)	22 kV Secondary 11 kV Secondary		0.0%	0	0.0%	0	0	Dx MV & LV
		6.6 kV Secondary 3.3 kV Secondary		0.0%	0	0.0%	0	0	Dx MV & LV
Lines Rx	High Density (urban)	22 kV 11 kV	N6	10.1%	994	10.8%	1 351	2 345	Dx MV & LV
		6.6 kV	N7	0.3%	30	0.3%	40	70	Dx MV & LV
	Low Density (rural)	22 kV 11 kV	N11	30.6%	3 015	32.7%	4 100	7 115	Dx MV & LV
		6.6 kV		0.0%	0	0.0%	0	0	Dx MV & LV
Transformation Rx - LV	High Density (urban)	Residential Low-usage residential Other	T24	11.8%	577	6.3%	784	1 361	Dx MV & LV
	Low Density (rural)	Low-usage residential Other	T25	11.0%	542	5.9%	737	1 279	Dx MV & LV
Lines LV	High Density (urban)	Residential	N9	2.9%	282	3.1%	383	665	Dx MV & LV
		Low-usage residential	N8	13.2%	1 296	14.1%	1 762	3 058	Dx MV & LV
		Other	N10	0.5%	44	0.5%	60	105	Dx MV & LV
	Low Density (rural)	Residential	N13	0.0%	0	0.0%	0	0	Dx MV & LV
		Low-usage residential	N12	1.0%	101	1.1%	138	239	Dx MV & LV
					9 211	**100%**	**12 526**	**21 736**	Dx MV & LV
			Transformation	33.3%	**4 908**	**39%**	**7 902**	**13 448**	
			Lines	66.7%	**9 848**	**61%**	**12 526**	**21 736**	
			Total	**100.0%**	**14 756**	**100%**	**20 428**	**35 185**	

Table 23: 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	0.960	60.1%	0.70	4 660	414	5 074	0	0	0
Urban	≥66kV - ≤132kV	C02 : 132 LPU*	0.959	47.2%	0.58	2 480	345	2 825	243	347	590
		C03 : Blank - no customers				0	0	0	0	0	0
		C04 : 88 LPU	0.962	38.2%	0.48	3 061	600	3 661	330	471	801
		C05 : 66 LPU	0.964	58.7%	0.69	4 076	337	4 413	534	760	1 294
	≥500V - <66kV	C06 : 44 LPU	0.965	37.4%	0.47	826	194	1 020	147	209	355
		C07 : 33 LPU	0.948	61.4%	0.71	13 024	1 264	14 288	1 222	1 742	2 964
		C08 : 6.6 3.3 2.2 LPU	0.947	56.3%	0.66	12 254	1 607	13 861	1 319	1 843	3 162
		C09 : 2211 U LPU	0.952	56.5%	0.67	16 713	1 443	18 156	2 424	3 361	5 785
		C10 : Blank - no customers				0	0	0	0	0	0
	<500V	C11 : 500 U ELEC	0.985	12.4%	0.17	6 711	4 554	11 265	2 806	3 847	6 653
		C12 : 500 U RES	0.954	32.0%	0.42	1 165	270	1 435	471	644	1 114
		C13 : 500 R RES				0	0	0	0	0	0
		C14 : 500 U OTHER SPU*	0.945	27.8%	0.37	1 052	303	1 355	197	271	468
		C15 : 500 U OTHER LPU	0.950	43.9%	0.54	1 472	208	1 680	247	340	587
Rural	≥500V - <66kV	C16 : 2211 R LPU	0.927	42.4%	0.52	2 275	313	2 588	1 052	1 440	2 491
		C17 : 500 R ELEC				0	0	0	0	0	0
	<500V	C18 : 500 R OTHER LPU	0.914	32.4%	0.42	2 898	555	3 452	1 374	1 880	3 254
		C19 : 500 R OTHER SPU	0.950	7.0%	0.10	3 440	3 910	7 350	2 391	3 274	5 665
			Total			76 106	16 316	92 422	14 756	20 428	35 185

Table 24: Distribution network capacity unit costs (R/kVA)

	Voltage	Costing category	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
	>132kV	C01 : 275 LPU	5 074	98 724	0.00	0.00
Urban	≥66kV - ≤132kV	C02 : 132 LPU*	2 825	66 101	17.40	0.74
		C03 : Blank - no customers	0	0	0	0
		C04 : 88 LPU	3 661	32 104	18.23	2.08
		C05 : 66 LPU	4 413	24 001	24.43	4.49
	≥500V - <66kV	C06 : 44 LPU	1 020	7 808	29.05	3.79
		C07 : 33 LPU	14 288	69 963	17.29	3.53
		C08 : 6.6 3.3 2.2 LPU	13 861	72 123	19.01	3.65
		C09 : 2211 U LPU	18 156	92 244	26.55	5.23
		C10 : Blank - no customers	0	0	0.00	0.00
	<500V	C11 : 500 U ELEC	11 265	96 124	49.22	5.77
		C12 : 500 U RES	1 435	7 632	64.73	12.17
		C13 : 500 R RES	0	0	0.00	0.00
		C14 : 500 U OTHER SPU*	1 355	6 760	28.81	5.77
		C15 : 500 U OTHER LPU	1 680	14 624	29.12	3.34
Rural	≥500V - <66kV	C16 : 2211 R LPU	2 588	21 098	80.22	9.84
		C17 : 500 R ELEC	0	0	0.00	0.00
	<500V	C18 : 500 R OTHER LPU	3 452	32 494	78.54	8.34
		C19 : 500 R OTHER SPU	7 350	87 705	64.23	5.38
			92 422	729 505	31.72	4.02

8.6. Retail unit costs

The allocated retail costs are metering costs (meter capital and meter reading costs), customer service (employee benefits, returns, impairments 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 25.

Table 25: 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

8.6.1. Meter capital unit costs

The allocated meter capital costs are R92million, and the cost allocation following on Table 26 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 26: Meter capital cost allocation

Meter Description		No. of Pods	Replacement Cost/meter - 2011/12	Annualised Replacement Cost	Meter capital allocation (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	6 907 189	1 762	1 980 271 658	61%	55.70	8.06
Prepayment - ED	1A	0	1 932	0	0%	0.00	0.00
Split meter (Wired interface)	1B	0	1 932	0	0%	0.00	0.00
Split meter (Wireless interface)	1C	0	2 732	0	0%	0.00	0.00
Single Phase - Conventional	2	86 797	6 551	92 537 662	3%	2.60	29.99
3 Phase < 50 kVA - Conventional	3	172 498	11 662	327 380 756	10%	9.21	53.38
3 Phase 75 & 100 kVA - Conventional	4	38 636	22 390	140 787 053	4%	3.96	102.49
Ruraflex < 50 kVA - Conventional	5	0	21 665	0	0%	0.00	0.00
100 kVA - Urban	100	46	21 665	162 188	0%	0.00	99.17
100 kVA - Rural	101	24	21 665	84 620	0%	0.00	99.17
150 kVA - Urban	150	16	21 956	57 171	0%	0.00	100.50
150 kVA - Rural	151	15	21 956	53 598	0%	0.002	100.50
200 kVA - Urban	200	45	22 188	162 493	0%	0.00	101.57
200 kVA - Rural	201	26	22 188	93 885	0%	0.00	101.57
300 kVA - Urban	300	34	23 014	127 343	0%	0.00	105.35
300 kVA - Rural	301	29	23 014	108 616	0%	0.00	105.35
500 kVA - Urban	500	158	23 955	614 017	0%	0.02	109.66
500 kVA - Rural	501	80	23 955	311 881	0%	0.01	109.66
1000 kVA - Urban	1000	217	23 955	846 628	0%	0.02	109.66
1000 kVA - Rural	1001	268	23 955	1 044 803	0%	0.03	109.66
1 Feeder Point 10 - 50 MVA - Urban	10000	4 243	241 508	166 784 585	5%	4.7	1 105.53
1 Feeder Point 10 - 50 MVA - Rural	10001	7 554	241 508	296 885 142	9%	8.4	1 105.53
1 Feeder Point 10 - 50 MVA - Urban	20000	0	241 508	0	0%	0.0	0.00
1 Feeder Point 10 - 50 MVA - Rural	20001	0	241 508	0	0%	0.0	0.00
1 Feeder Point > 50 MVA - Urban	30000	1 450	241 508	56 991 256	2%	1.6	1 105.53
1 Feeder Point > 50 MVA - Rural	30001	5 204	241 508	204 539 654	6%	5.8	1 105.53
1 Feeder Point > 50 MVA - Urban	40000	0	241 508	0	0%	0.00	0.00
1 Feeder Point > 50 MVA - Rural	40001	0	241 508	0	0%	0.00	0.00
No Meter	0	5 855	0	0	0%	0.00	0.00
Total		7 230 383	2 276 152	3 269 845 009	100%	92	12.72

Table 27: 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	0	0	0	0	0	6 633	24 322	**30 955**
Urban	≥66kV - ≤132kV	C02 : 132 LPU*	0	99	0	0	1 393	1 206	18 904	279 799	**301 400**
		C03 : Blank - no customer	0	0	0	0	0	0	0	0	**0**
		C04 : 88 LPU	0	99	0	0	0	110	35 377	233 087	**268 673**
		C05 : 66 LPU	0	0	0	0	215	110	12 262	67 437	**80 024**
	≥500V - <66kV	C06 : 44 LPU	0	0	0	0	0	0	0	45 536	**45 536**
		C07 : 33 LPU	0	99	0	0	0	0	8 844	86 231	**95 175**
		C08 : 6.6 3.3 2.2 LPU	0	401	0	0	39 279	102 906	562 014	161 057	**865 658**
		C09 : 2211 U LPU	0	1 796	0	0	17 967	99 818	513 295	246 392	**879 268**
		C10 : Blank - no customer	0	0	0	0	0	0	0	0	**0**
	<500V	C11 : 500 U ELEC	55 668 214	0	0	0	0	0	0	0	**55 668 214**
		C12 : 500 U RES	0	1 316	4 813 950	0	382 599	20 009	1 409	0	**5 219 283**
		C13 : 500 R RES	0	0	0	0	0	0	0	0	**0**
		C14 : 500 U OTHER SPU*	0	1 917 943	0	0	0	0	0	0	**1 917 943**
		C15 : 500 U OTHER LPU	0	305 934	0	0	2 222 217	110 654	738 631	198	**3 377 634**
Rural	≥500V - <66kV	C16 : 2211 R LPU	0	0	0	86 223	481 480	559 929	572 665	10 753	**1 711 049**
		C17 : 500 R ELEC	0	0	0	0	0	0	0	0	**0**
	<500V	C18 : 500 R OTHER LPU	0	0	0	1 622 446	10 566 168	207 274	44 221	399	**12 440 508**
		C19 : 500 R OTHER SPU	0	0	0	9 071 166	0	0	0	0	**9 071 166**
		Total	**55 668 214**	**2 227 687**	**4 813 950**	**10 779 834**	**13 711 318**	**1 102 015**	**2 514 257**	**1 155 211**	**91 972 486**

8.6.2. Meter reading unit costs

The allocated meter reading costs are R87.5million and the cost allocation following on Table 28 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 contribution to the total meter reading costs.
- The meter reading costs are therefore contribution multiplied by the total R87.5million. 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 is applied PoD detail per meter type and then summarised by costing category; see Table 29.

Table 28: 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	6 907 189	0.0	0	0.00%	0.00	
Prepayment - ED	1A	0	0.0	0	0.00%	0.00	
Split meter (Wired interface)	1B	0	0.0	0	0.00%	0.00	
Split meter (Wireless interface)	1C	0	0.0	0	0.00%	0.00	
Single Phase - Conventional	2	86 797	1.0	86 797	9.02%	7.89	90.93
3 Phase < 50 kVA - Conventional	3	172 498	1.0	172 498	17.92%	15.69	90.93
3 Phase 75 & 100 kVA - Conventional	4	38 636	3.0	115 908	12.04%	10.54	272.80
Ruraflex < 50 kVA - Conventional	5	0	11.1	0	0.00%	0.00	
100 kVA - Urban	100	46	2.7	124	0.01%	0.01	244.29
100 kVA - Rural	101	24	11.1	266	0.03%	0.02	1 006.48
150 kVA - Urban	150	16	2.7	43	0.00%	0.00	244.29
150 kVA - Rural	151	15	11.1	166	0.02%	0.02	1 006.48
200 kVA - Urban	200	45	2.7	121	0.01%	0.01	244.29
200 kVA - Rural	201	26	11.1	288	0.03%	0.03	1 006.48
300 kVA - Urban	300	34	2.7	91	0.01%	0.01	244.29
300 kVA - Rural	301	29	11.1	321	0.03%	0.03	1 006.48
500 kVA - Urban	500	158	2.7	423	0.04%	0.04	244.29
500 kVA - Rural	501	80	11.1	885	0.09%	0.08	1 006.48
1000 kVA - Urban	1000	217	2.7	583	0.06%	0.05	244.29
1000 kVA - Rural	1001	268	11.1	2 966	0.31%	0.27	1 006.48
1 Feeder Point 10 - 50 MVA - Urban	10000	4 243	31.5	133 668	13.88%	12.15	2 864.37
1 Feeder Point 10 - 50 MVA - Rural	10001	7 554	31.5	237 935	24.72%	21.64	2 864.37
1 Feeder Point 10 - 50 MVA - Urban	20000	0	31.5	0	0.00%	0.00	
1 Feeder Point 10 - 50 MVA - Rural	20001	0	31.5	0	0.00%	0.00	
1 Feeder Point > 50 MVA - Urban	30000	1 450	31.5	45 675	4.74%	4.15	2 864.37
1 Feeder Point > 50 MVA - Rural	30001	5 204	31.5	163 926	17.03%	14.91	2 864.37
1 Feeder Point > 50 MVA - Urban	40000	0	31.5	0	0.00%	0.00	
1 Feeder Point > 50 MVA - Rural	40001	0	31.5	0	0.00%	0.00	
No Meter	0	5 855	0.0	0	0.00%	0.00	
Total		**7 230 383**		**962 684**	**100.00%**	**87.54**	**275.85**

Table 29: 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	0	0	0	0	0	17 186	63 016	**80 202**
Urban		C02 : 132 LPU*	0	244	0	0	3 176	2 687	48 939	724 930	**779 976**
Urban	≥66kV - ≤132kV	C03 : Blank - no custom	0	0	0	0	0	0	0	0	**0**
Urban	≥66kV - ≤132kV	C04 : 88 LPU	0	244	0	0	0	244	91 660	603 295	**695 443**
Urban	≥66kV - ≤132kV	C05 : 66 LPU	0	0	0	0	489	244	31 752	174 727	**207 212**
Urban	≥500V - <66kV	C06 : 44 LPU	0	0	0	0	0	0	0	117 928	**117 928**
Urban	≥500V - <66kV	C07 : 33 LPU	0	244	0	0	0	0	22 915	223 421	**246 580**
Urban	≥500V - <66kV	C08 : 6.6 3.3 2.2 LPU	0	977	0	0	100 876	265 788	1 455 655	417 044	**2 240 339**
Urban	≥500V - <66kV	C09 : 2211 U LPU	0	4 153	0	0	45 720	258 105	1 329 800	638 089	**2 275 866**
Urban	≥500V - <66kV	C10 : Blank - no custom	0	0	0	0	0	0	0	0	**0**
Urban	<500V	C11 : 500 U ELEC	0	0	0	0	0	0	0	0	**0**
Urban	<500V	C12 : 500 U RES	0	3 176	11 196 706	0	989 874	51 803	3 597	0	**12 245 156**
Urban	<500V	C13 : 500 R RES	0	0	0	0	0	0	0	0	**0**
Urban	<500V	C14 : 500 U OTHER SPU	0	3 710 631	0	0	0	0	0	0	**3 710 631**
Urban	<500V	C15 : 500 U OTHER LPU	0	788 325	0	0	5 753 485	286 260	1 913 466	489	**8 742 023**
Rural	≥500V - <66kV	C16 : 2211 R LPU	0	0	0	249 629	1 314 250	1 468 804	1 483 743	41 032	**4 557 458**
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	4 238 884	27 524 245	547 870	114 575	4 026	**32 429 599**
Rural	<500V	C19 : 500 R OTHER SPU	0	0	0	19 210 711	0	0	0	0	**19 210 711**
		Total	**0**	**4 507 995**	**11 196 706**	**23 699 224**	**35 732 114**	**2 881 805**	**6 513 289**	**3 007 994**	**87 539 126**

8.6.3. Marketing unit costs

The allocated marketing costs are R2.74million and the cost allocation following on Table 30 is as follows:

- An average R/PoD (c) is the marketing unit cost, and it is calculated by dividing the R2.74million (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 31.

Table 30: 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		6 903 242	34 241	127 123	163 358	12 631	892	1 705	97	7 243 290
(b) Total marketing costs (Rands)		2 741 983								
(c) R/PoD marketing unit cost		0.38								
(d) Marketing cost by customer group (Rands)		2 613 256	12 962	48 123	61 840	4 781	338	645	37	2 741 983

Table 31: Marketing costs by costing category

	Voltage	Costing category	No of PoDS (active)	Allocated marketing costs (Rands)	R/PoD unit cost
	>132kV	C01 : 275 LPU	87	33	0.38
Urban	≥66kV - ≤132kV	C02 : 132 LPU*	299	113	0.38
		C03 : Blank - no customers	0	0	
		C04 : 88 LPU	262	99	0.38
		C05 : 66 LPU	77	29	0.38
	≥500V - <66kV	C06 : 44 LPU	43	16	0.38
		C07 : 33 LPU	87	33	0.38
		C08 : 6.6 3.3 2.2 LPU	848	322	0.38
		C09 : 2211 U LPU	854	324	0.38
		C10 : Blank - no customers	0	0	
	<500V	C11 : 500 U ELEC	6 903 242	2 617 447	0.38
		C12 : 500 U RES	120 747	45 783	0.38
		C13 : 500 R RES	0.00	0.00	
		C14 : 500 U OTHER SPU*	37 628	14 267	0.38
		C15 : 500 U OTHER LPU	3 294	1 249	0.38
Rural	≥500V - <66kV	C16 : 2211 R LPU	1 703	646	0.38
		C17 : 500 R ELEC	0.00	0.00	
	<500V	C18 : 500 R OTHER LPU	11 498	4 359	0.38
		C19 : 500 R OTHER SPU	151 023	57 262	0.38
		Total	7 231 691	2 741 983	0.38

8.6.4. Customer service weightings

Customer service weightings are used to allocate billing and customer service (employee benefits, returns, impairments 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 cost 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 2021/22 revenue application is used.
- The determined customer service weightings by customer group are in Table 32.

Table 32: 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

8.6.5. Billing unit costs

The allocated billing costs are R719million made up of R528million for prepayment and R191 for accounts (post-payment). The prepayment costs are mainly vendor commission costs.

The billing cost allocation following on Table 33 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 33 and by costing category in Table 34.

Table 33: 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)	8 624 355	40 182	127 153	163 677	12 868	1 086	2 305	1 101	8 972 727
(b) Prepayment costs (R'million)	528								
(c) Customer service weighting	1	12	6	24	83	270	270	270	
(d) Weighted number of PoDs (d) = (c) x (a)	8 624 355	482 186	762 919	3 928 252	1 068 037	293 220	622 350	297 270	16 078 588
(e) Account costs (R'million)	191								
(f) Average weighted R/PoD (f) = (e)÷total(d)	12								
(g) Allocation weighted R/PoD (g) = (f) x (c)	11.86	142.3	71.1	284.5	984.1	3 201.2	3 201.2	3 201.2	
(h) Allocated account costs (R'million) (h) = (g) x (a)	102	6	9	47	13	3	7	4	191
(i) Total allocated billing costs (R'million) (b) + (h)	630	6	9	47	13	3	7	4	719
(j) Active number of PoDs	6 903 242	38 055	120 327	152 644	12 868	1 086	2 305	1 101	7 231 628
(k) Allocated billing costs (R/PoD/annum) (k) = (i)÷(j)	91	150	75	305	984	3 201	3 201	3 201	
(l) Allocated billing costs (R/PoD/month) (l) = (k)÷12.0033	7.60	12.52	6.26	25.42	81.98	266.69	266.69	266.69	
(m) Allocated billing costs (R/PoD/day) (m) = (l)÷(365÷12)	0.25	0.41	0.21	0.84	2.70	8.77	8.77	8.77	

Table 34: 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	87	278 425	266.62
Urban	≥66kV - ≤132kV	C02 : 132 LPU*	299	925 022	257.74
Urban	≥66kV - ≤132kV	C03 : Blank - no customers	0	0	
Urban	≥66kV - ≤132kV	C04 : 88 LPU	262	835 426	265.65
Urban	≥66kV - ≤132kV	C05 : 66 LPU	77	241 989	261.82
Urban	≥500V - <66kV	C06 : 44 LPU	43	137 613	266.62
Urban	≥500V - <66kV	C07 : 33 LPU	87	275 375	263.70
Urban	≥500V - <66kV	C08 : 6.6 3.3 2.2 LPU	848	2 570 873	252.57
Urban	≥500V - <66kV	C09 : 2211 U LPU	854	2 599 186	253.56
Urban	≥500V - <66kV	C10 : Blank - no customers	0	0	
Urban	<500V	C11 : 500 U ELEC	6 903 242	629 958 904	7.60
Urban	<500V	C12 : 500 U RES	120 747	9 496 084	6.55
Urban	<500V	C13 : 500 R RES	0.00	0.00	
Urban	<500V	C14 : 500 U OTHER SPU*	37 628	5 651 098	12.51
Urban	<500V	C15 : 500 U OTHER LPU	3 294	4 668 493	118.07
Rural	≥500V - <66kV	C16 : 2211 R LPU	1 703	3 980 271	194.71
Rural	≥500V - <66kV	C17 : 500 R ELEC	0	0	
Rural	<500V	C18 : 500 R OTHER LPU	11 498	10 828 102	78.46
Rural	<500V	C19 : 500 R OTHER SPU	151 023	46 066 550	25.41
		Total	**7 231 691**	**718 513 412**	**8.28**

8.6.6. Customer service unit costs

The allocated customer services costs are a total of R2 914million made up of R1 443million employee benefits (EB), R12million returns, R1 098million impairments and R361million other expenses.

- 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 8.6.5.
- The allocated customer service costs are shown in Table 35 by customer group and in Table 36 by costing category.

Table 35: Customer service allocation (EB, returns, impairments, 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	6 903 242	40 182	127 153	163 677	12 868	1 086	2 305	1 101	7 251 615
(b) Total allocated costs (R'million)	**1 015**	**152**	**241**	**1 240**	**337**	**93**	**197**	**317**	**3 593**
Employee benefits (R'million)	777	54	86	442	120	33	70	63	1 646
Other expenses and returns (R'million)	239	17	26	136	37	10	22	4	490
Impairments (R'million)	0	81	129	662	180	49	105	250	1 457
(c) Allocation weighted R/PoD/annum (c) = (b) ÷(a)	147.1	3 789.0	1 894.5	7 578.0	26 207.4	85 252.9	85 252.9	288 194.8	495.4
(d) Allocation weighted R/PoD/month (d) = (c)÷11.99	12.3	315.8	157.9	631.5	2 184.0	7 104.5	7 104.5	24 016.5	41.3
(e) Allocation weighted R/PoD/day (e) = (d)÷(365÷12)	0.4	10.4	5.2	20.8	71.8	233.6	233.6	789.6	1.4

Table 36: 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	87	12	373.61
Urban	≥66kV - ≤132kV	C02 : 132 LPU*	299	76	697.08
		C03 : Blank - no customers	0	0	
		C04 : 88 LPU	262	68	715.51
		C05 : 66 LPU	77	19	668.85
	≥500V - <66kV	C06 : 44 LPU	43	12	788.40
		C07 : 33 LPU	87	23	728.41
		C08 : 6.6 3.3 2.2 LPU	848	99	320.45
		C09 : 2211 U LPU	854	116	371.96
		C10 : Blank - no customers	0	0	
	<500V	C11 : 500 U ELEC	6 903 242	1 014	0.40
		C12 : 500 U RES	120 747	253	5.73
		C13 : 500 R RES	0.00	0.00	
		C14 : 500 U OTHER SPU*	37 628	150	10.95
		C15 : 500 U OTHER LPU	3 294	125	103.56
Rural	≥500V - <66kV	C16 : 2211 R LPU	1 703	111	178.73
		C17 : 500 R ELEC	0.00	0.00	
	<500V	C18 : 500 R OTHER LPU	11 498	288	68.63
		C19 : 500 R OTHER SPU	151 023	1 226	22.25
		Total	**7 231 691**	**3 593**	**1.36**

8.6.7. Summary of the retail cost allocation

The retail costs (including metering costs) allocated by costing categories are shown in Table 37.

Table 37: 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	87	0.1	0.00003	0.28	11.86	**12**	140 846	11 737	386
Urban	≥66kV - ≤132kV	C02 : 132 LPU*	299	1.1	0.00011	0.93	76.08	**78**	261 142	21 762	715
Urban	≥66kV - ≤132kV	C03 : Blank - no customers	0	0.0	0.00000	0.00	0.00	**0**			
Urban	≥66kV - ≤132kV	C04 : 88 LPU	262	1.0	0.00010	0.84	68.42	**70**	268 026	22 336	734
Urban	≥66kV - ≤132kV	C05 : 66 LPU	77	0.3	0.00003	0.24	18.80	**19**	251 000	20 917	688
Urban	≥500V - <66kV	C06 : 44 LPU	43	0.2	0.00002	0.14	12.37	**13**	294 767	24 564	808
Urban	≥500V - <66kV	C07 : 33 LPU	87	0.3	0.00003	0.28	23.13	**24**	272 961	22 747	748
Urban	≥500V - <66kV	C08 : 6.6 3.3 2.2 LPU	848	3.1	0.00032	2.57	99.18	**105**	123 657	10 305	339
Urban	≥500V - <66kV	C09 : 2211 U LPU	854	3.2	0.00032	2.60	115.94	**122**	142 503	11 875	390
Urban	≥500V - <66kV	C10 : Blank - no customers	0	0.0	0.00000	0.00	0.00	**0**			
Urban	<500V	C11 : 500 U ELEC	6 903 242	56	3	630	1 014	**1 702**	247	21	0.68
Urban	<500V	C12 : 500 U RES	120 747	17	0.05	9	253	**280**	2 316	193	6
Urban	<500V	C13 : 500 R RES	0	0	0	0	0	**0**			
Urban	<500V	C14 : 500 U OTHER SPU*	37 628	5.6	0.01427	5.65	150.41	**162**	4 297	358	12
Urban	<500V	C15 : 500 U OTHER LPU	3 294	12.1	0.00125	4.67	124.51	**141**	42 894	3 575	118
Rural	≥500V - <66kV	C16 : 2211 R LPU	1 703	6.3	0.00065	3.98	111.10	**121**	71 255	5 938	195
Rural	≥500V - <66kV	C17 : 500 R ELEC	0	0	0	0	0	**0**			
Rural	<500V	C18 : 500 R OTHER LPU	11 498	44.9	0.00436	10.83	288.02	**344**	29 895	2 491	82
Rural	<500V	C19 : 500 R OTHER SPU	151 023	28.3	0.05726	46.07	1 226.23	**1 301**	8 612	718	24
		Total	**7 231 691**	**180**	**2.7**	**719**	**3 593**	**4 493**	621	52	1.70

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 38 and Table 39.

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 distribution embedded generators separately is 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 2021/22 CTS study.

Table 38: Summary of the CTS study allocated costs

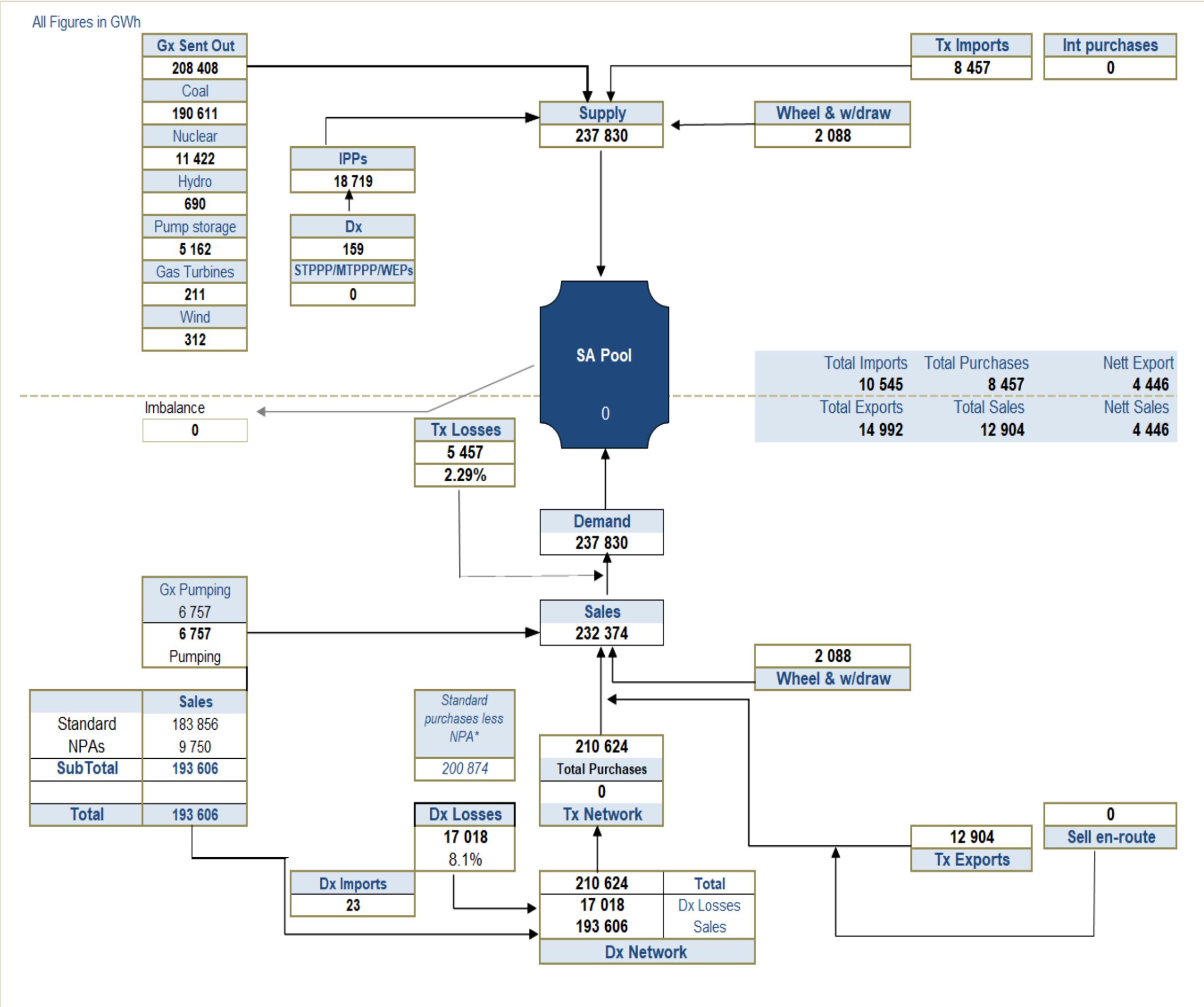
					Allocated costs (R'million)							
	Voltage	Costing category	No of PoDS	Sales volumes (GWh)	Energy ToU	Energy capacity	Tx network capacity	Tx ancillary services	Dx network capacity	Retail	**Total allocated costs**
	>132kV	C01 : 275 LPU	87	39 192	31 515	6 938	1 106	76	0	12	**39 648**
Urban	≥66kV - ≤132kV	C02 : 132 LPU*	299	20 837	17 884	4 008	502	43	590	78	**23 105**
Urban	≥66kV - ≤132kV	C03 : Blank - no customers	0	0	0	0	0	0	0	0	**0**
Urban	≥66kV - ≤132kV	C04 : 88 LPU	262	8 342	7 058	1 786	242	17	801	70	**9 974**
Urban	≥66kV - ≤132kV	C05 : 66 LPU	77	8 322	7 306	1 600	184	17	1 294	19	**10 420**
Urban	≥500V - <66kV	C06 : 44 LPU	43	1 988	1 803	435	64	4	355	13	**2 674**
Urban	≥500V - <66kV	C07 : 33 LPU	87	27 202	23 323	5 539	570	60	2 964	24	**32 479**
Urban	≥500V - <66kV	C08 : 6.6 3.3 2.2 LPU	848	22 090	19 328	4 611	589	48	3 162	105	**27 844**
Urban	≥500V - <66kV	C09 : 2211 U LPU	854	30 453	27 094	6 261	754	67	5 785	122	**40 082**
Urban	≥500V - <66kV	C10 : Blank - no customers	0	0	0	0	0	0	0	0	**0**
Urban	<500V	C11 : 500 U ELEC	6 903 242	8 634	9 643	3 103	799	19	6 653	1 702	**21 920**
Urban	<500V	C12 : 500 U RES	120 747	1 450	1 647	355	63	3	1 114	280	**3 463**
Urban	<500V	C13 : 500 R RES	0	0	0	0	0	0	0	0	**0**
Urban	<500V	C14 : 500 U OTHER SPU*	37 628	1 297	1 309	337	56	3	468	162	**2 335**
Urban	<500V	C15 : 500 U OTHER LPU	3 294	1 825	1 673	409	123	4	587	141	**2 937**
Rural	≥500V - <66kV	C16 : 2211 R LPU	1 703	3 957	3 576	919	178	9	2 491	121	**7 294**
Rural	≥500V - <66kV	C17 : 500 R ELEC	0	0	0	0	0	0	0	0	**0**
Rural	<500V	C18 : 500 R OTHER LPU	11 498	4 030	3 647	1 047	280	9	3 254	344	**8 580**
Rural	<500V	C19 : 500 R OTHER SPU	151 023	4 236	4 306	2 308	744	10	5 665	1 301	**14 333**
		Total	**7 231 691**	**183 856**	**161 112**	**39 654**	**6 255**	**389**	**35 185**	**4 493**	**247 088**

Table 39: Summary of the CTS study's unit costs

			Average unit costs (allocated costs divided by sales volumes)						
	Voltage	Costing category	Energy ToU unit costs (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)	**Total Avg. unit cost (c/kWh)**
	>132kV	C01 : 275 LPU	80.41c	R 70.28	R 11.21	0.1935c	R 0.00	R 385.879	101.16c
Urban	≥66kV - ≤132kV	C02 : 132 LPU*	85.83c	R 60.64	R 7.60	0.2051c	R 17.40	R 715.459	110.88c
Urban	≥66kV - ≤132kV	C03 : Blank - no customers							
Urban	≥66kV - ≤132kV	C04 : 88 LPU	84.61c	R 55.63	R 7.53	0.2051c	R 18.23	R 734.319	119.56c
Urban	≥66kV - ≤132kV	C05 : 66 LPU	87.79c	R 66.66	R 7.69	0.2051c	R 24.43	R 687.671	125.21c
Urban	≥500V - <66kV	C06 : 44 LPU	90.68c	R 55.69	R 8.19	0.2191c	R 29.05	R 807.580	134.51c
Urban	≥500V - <66kV	C07 : 33 LPU	85.74c	R 79.16	R 8.15	0.2191c	R 17.29	R 747.838	119.40c
Urban	≥500V - <66kV	C08 : 6.6 3.3 2.2 LPU	87.50c	R 63.93	R 8.17	0.2191c	R 19.01	R 338.786	126.05c
Urban	≥500V - <66kV	C09 : 2211 U LPU	88.97c	R 67.88	R 8.17	0.2191c	R 26.55	R 390.418	131.62c
Urban	≥500V - <66kV	C10 : Blank - no customers							
Urban	<500V	C11 : 500 U ELEC	111.69c	R 32.28	R 8.31	0.2227c	R 49.22	R 0.676	253.88c
Urban	<500V	**C12 : 500 U RES**	**113.61c**	**R 46.52**	**R 8.32**	**0.2227c**	**R 64.73**	**R 6.344**	**238.82c**
Urban	<500V	C13 : 500 R RES							
Urban	<500V	C14 : 500 U OTHER SPU*	100.89c	R 49.79	R 8.31	0.2227c	R 28.81	R 11.774	179.95c
Urban	<500V	C15 : 500 U OTHER LPU	91.68c	R 27.97	R 8.38	0.2227c	R 29.12	R 117.518	160.93c
Rural	≥500V - <66kV	C16 : 2211 R LPU	90.36c	R 43.55	R 8.42	0.2229c	R 80.22	R 195.219	184.32c
Rural	≥500V - <66kV	C17 : 500 R ELEC							
Rural	<500V	C18 : 500 R OTHER LPU	90.51c	R 32.21	R 8.60	0.2261c	R 78.54	R 81.905	212.93c
Rural	<500V	C19 : 500 R OTHER SPU	101.65c	R 26.31	R 8.48	0.2261c	R 64.23	R 23.595	338.37c
		Total	**87.63c**	**R 54.36**	**R 8.57**	**0.2114c**	**R 31.72**	**R 1.702**	**134.39c**

Annexure 1: 2021/22 NERSA decision energy wheel

This energy is populated with the energy volumes in GWh as provided for in the 2021/22 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 20A
  - Township residential – Homelight 60A
  - Commercial – Businessrate
  - Agricultural – Landrate

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

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

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

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

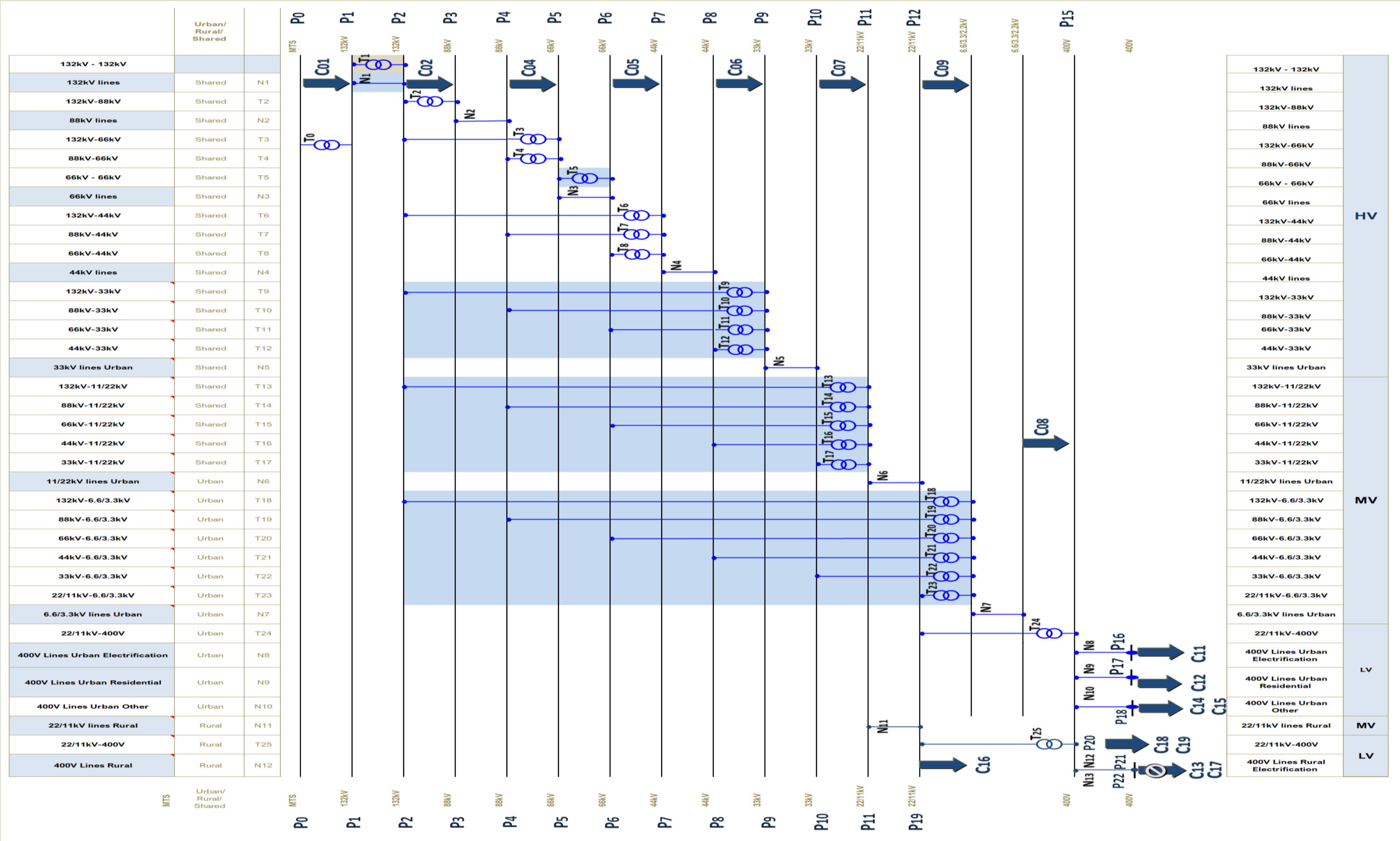
Landrate	Low demand season [3 months : Jun - Aug]	High demand season [9 months : Apr - May & Sep-Mar]
Peak	23%	22%
Standard	52%	52%
Off peak	25%	26%

Annexure 3: Demand assumptions for small power users (SPU's)

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



Annexure 5: Asset loss factors

		Tech. asset (pu) loss factor		Loss factor	
	MTS - 132kV	1.000000000	0%	T0	
HV	132kV - 132kV	1.000000000	0%	T1	1.0000000
HV	132kV lines	1.010786141	1%	N1	1.0167326
HV	132kV-88kV	1.001276621	0%	T2	1.0167326
HV	88kV lines	1.019705209	2%	N2	1.0167326
HV	132kV-66kV	1.009000030	1%	T3	1.0167326
HV	88kV-66kV	1.009000030	1%	T4	1.0167326
HV	66kV - 66kV	1.000000000	0%	T5	1.0000000
HV	66kV lines	1.011249292	1%	N3	1.0167326
MV	132kV-44kV	1.010347219	1%	T6	1.0125994
MV	88kV-44kV	1.010347219	1%	T7	1.0125994
MV	66kV-44kV	1.009806710	1%	T8	1.0125994
MV	44kV lines	1.027095405	3%	N4	1.0125994
MV	132kV-33kV	1.017613412	2%	T9	1.0125994
MV	88kV-33kV	1.006806600	1%	T10	1.0125994
MV	66kV-33kV	1.037228879	4%	T11	1.0125994
MV	44kV-33kV	1.008012023	1%	T12	1.0125994
MV	33kV lines Urban	1.046418373	5%	N5	1.0125994
MV	132kV-11/22kV	1.007125788	1%	T13	1.0125994
MV	88kV-11/22kV	1.007507602	1%	T14	1.0125994
MV	66kV-11/22kV	1.009806710	1%	T15	1.0125994
MV	44kV-11/22kV	1.008012023	1%	T16	1.0125994
MV	33kV-11/22kV	1.003677877	0%	T17	1.0125994
MV	11/22kV lines Urban	1.036160433	4%	N6	1.0125994
MV	132kV-6.6/3.3kV	1.017613412	2%	T18	1.0125994
MV	88kV-6.6/3.3kV	1.017613412	2%	T19	1.0125994
MV	66kV-6.6/3.3kV	1.009806710	1%	T20	1.0125994
MV	44kV-6.6/3.3kV	1.008012023	1%	T21	1.0125994
MV	33kV-6.6/3.3kV	1.003677877	0%	T22	1.0125994
MV	22/11kV-6.6/3.3kV	1.008012023	1%	T23	1.0125994
MV	6.6/3.3kV lines Urban	1.033328993	3%	N7	1.0125994
LV	22/11kV-400V	1.012577056	1%	T24	0.9921274
LV	400V Lines Urban Electrification	1.027981463	3%	N8	0.9921274
LV	400V Lines Urban Residential	1.027981463	3%	N9	0.9921274
LV	400V Lines Urban Other	1.027981463	3%	N10	0.9921274
MV	22/11kV lines Rural	1.050833688	5%	N11	1.0243674
LV	22/11kV-400V	1.012577056	1%	T25	1.0064898
LV	400V Lines Rural	1.027981463	3%	N12	1.0064898
LV	400V Lines Rural Residential	1.027981463	3%	N13	1.0064898

Annexure 6: Standard tariff energy purchase volumes

			Annual forecasted sales (GWh) [12 months: Apr - Mar]				Dx network losses [12 months: Apr - Mar]				Tx network losses [12 months: Apr - 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	Peak	Standard	Off-peak	Total
	>132kV	C01 : 275 LPU	6 618	16 446	16 127	39 192	0	0	0	0	58	147	143	349	6 676	16 594	16 271	39 540
Urban	≥66kV - ≤132kV	C02 : 132 LPU*	3 493	8 827	8 517	20 837	209	529	510	1 248	54	136	128	317	3 756	9 491	9 155	22 403
Urban	≥66kV - ≤132kV	C03 : Blank - no customers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Urban	≥66kV - ≤132kV	C04 : 88 LPU	1 383	3 453	3 506	8 342	83	207	210	500	5	14	14	34	1 471	3 674	3 730	8 875
Urban	≥66kV - ≤132kV	C05 : 66 LPU	1 445	3 585	3 292	8 322	87	215	197	499	39	96	87	221	1 570	3 895	3 576	9 042
Urban	≥500V - <66kV	C06 : 44 LPU	324	844	820	1 988	43	112	109	263	3	7	8	18	370	964	936	2 270
Urban	≥500V - <66kV	C07 : 33 LPU	4 046	10 721	12 434	27 202	536	1 421	1 648	3 604	22	57	66	144	4 604	12 199	14 147	30 951
Urban	≥500V - <66kV	C08 : 6.6 3.3 2.2 LPU	3 284	8 734	10 073	22 090	435	1 157	1 335	2 927	25	64	70	159	3 744	9 955	11 477	25 176
Urban	≥500V - <66kV	C09 : 2211 U LPU	4 805	12 205	13 443	30 453	637	1 617	1 781	4 035	40	102	111	253	5 482	13 924	15 336	34 741
Urban	≥500V - <66kV	C10 : Blank - no customers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Urban	<500V	C11 : 500 U ELEC	2 515	4 186	1 933	8 634	380	633	292	1 305	7	12	6	25	2 902	4 831	2 231	9 965
Urban	<500V	C12 : 500 U RES	439	682	330	1 450	66	103	50	219	1	2	1	5	507	787	381	1 674
Urban	<500V	C13 : Blank - no customers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Urban	<500V	C14 : 500 U OTHER SPU*	277	683	338	1 297	42	103	51	196	1	2	1	4	320	788	390	1 497
Urban	<500V	C15 : 500 U OTHER LPU	287	803	736	1 825	43	121	111	276	4	12	10	26	334	936	857	2 127
Rural	≥500V - <66kV	C16 : 2211 R LPU	607	1 606	1 744	3 957	92	245	266	603	10	27	29	67	709	1 878	2 039	4 627
Rural	≥500V - <66kV	C17 : Blank - no customers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Rural	<500V	C18 : 500 R OTHER LPU	603	1 714	1 713	4 030	102	289	288	679	12	35	34	81	717	2 037	2 035	4 790
Rural	<500V	C19 : 500 R OTHER SPU	905	2 261	1 069	4 236	152	381	180	713	3	7	3	13	1 061	2 649	1 252	4 962
		Total	**31 031**	**76 750**	**76 074**	**183 856**	**2 908**	**7 132**	**7 028**	**17 067**	**284**	**720**	**712**	**1 717**	**34 223**	**84 602**	**83 815**	**202 640**

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 Producer (IPPs) has significantly decreased transmission losses. This impact is partly because of the location of these IPPs and the amount of energy that is off set 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 area positively contributed to losses whereas those in the Cape 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 generators were located 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 the 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 losses 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 the 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 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 the maximum of 3.05% and the minimum of 2.09%.

Annexure 8: Detail of the allocated energy purchase costs

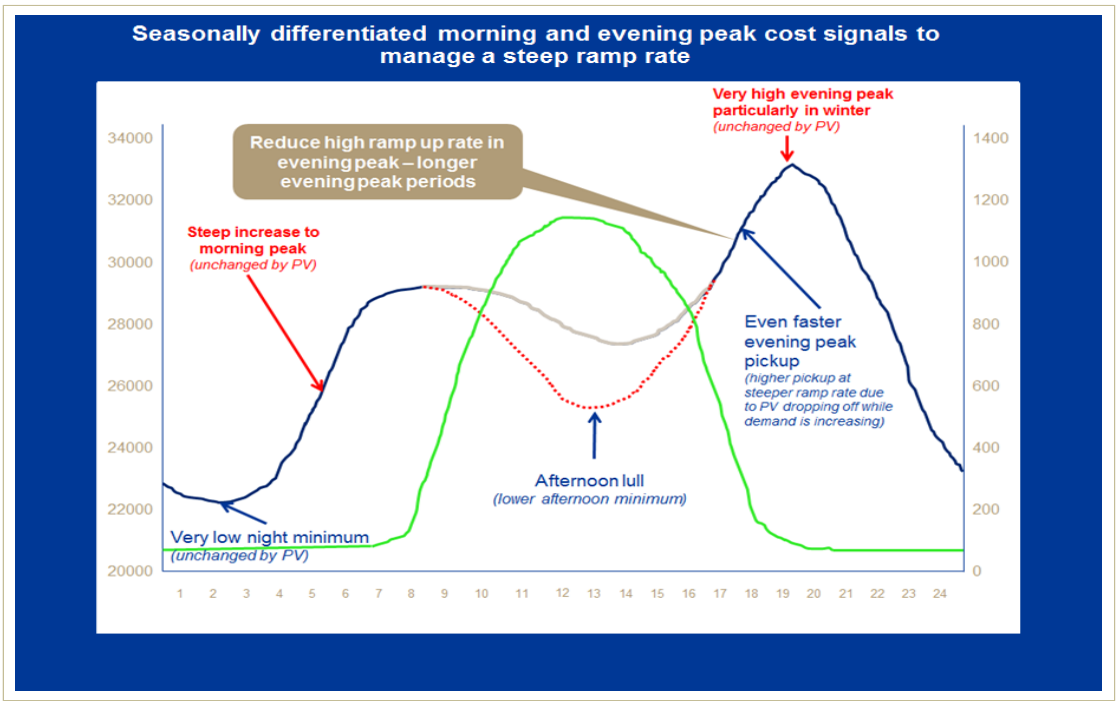
			Annual forecasted sales costs (R'million) [12 months: Apr - Mar]				Dx network losses costs (R'million) [12 months: Apr - Mar]				Tx network losses costs (R'million) [12 months: Apr - Mar]				Energy purchase costs (R'million) (sales + Dx losses + Tx losses) [12 months: Apr - Mar]			
			Peak	Standard	Off-peak	Total	Peak	Standard	Off-peak	Total	Peak	Standard	Off-peak	Total	Peak	Standard	Off-peak	Total
	>132kV	C01 : 275 LPU	10 174	11 556	7 172	28 902	0	0	0	0	145	165	101	412	10 319	11 721	7 274	29 314
Urban	^{3}66kV - £132kV	C02 : 132 LPU*	4 837	5 467	3 198	13 501	248	280	164	691	104	118	69	290	5 188	5 865	3 430	14 483
		C03 : Blank - no customers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		C04 : 88 LPU	1 978	2 211	1 400	5 589	101	113	72	286	19	22	14	56	2 098	2 347	1 485	5 930
		C05 : 66 LPU	2 129	2 437	1 365	5 931	109	125	70	304	70	80	44	194	2 307	2 641	1 479	6 428
	^{3}500V - <66kV	C06 : 44 LPU	496	551	329	1 376	61	68	40	169	8	9	6	22	564	627	376	1 567
		C07 : 33 LPU	5 540	7 106	5 225	17 872	679	871	641	2 191	63	81	58	203	6 282	8 059	5 924	20 265
		C08 : 6.6 3.3 2.2 LPU	3 853	4 783	3 504	12 141	472	586	430	1 488	42	51	37	130	4 367	5 421	3 971	13 759
		C09 : 2211 U LPU	7 868	9 141	6 217	23 226	965	1 121	762	2 848	122	142	95	359	8 955	10 403	7 074	26 433
		C10 : Blank - no customers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	<500V	C11 : 500 U ELEC	3 578	3 073	777	7 429	507	435	110	1 052	32	28	7	67	4 117	3 536	894	8 548
		C12 : 500 U RES	752	555	149	1 456	106	79	21	206	7	5	1	13	865	639	172	1 676
		C13 : Blank - no customers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		C14 : 500 U OTHER SPU*	433	464	133	1 029	61	66	19	146	4	4	1	9	498	534	153	1 184
		C15 : 500 U OTHER LPU	455	554	337	1 346	64	78	48	191	9	10	6	25	528	642	391	1 562
Rural	^{3}500V - <66kV	C16 : 2211 R LPU	871	1 060	676	2 607	124	151	96	372	20	24	15	59	1 015	1 235	788	3 038
		C17 : Blank - no customers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	<500V	C18 : 500 R OTHER LPU	775	1 035	639	2 448	123	164	101	389	20	27	17	64	918	1 226	757	2 901
		C19 : 500 R OTHER SPU	1 425	1 558	433	3 416	226	247	69	542	13	14	4	31	1 664	1 819	505	3 989
		Total	**45 162**	**51 551**	**31 554**	**128 268**	**3 847**	**4 385**	**2 642**	**10 874**	**677**	**782**	**476**	**1 935**	**49 687**	**56 717**	**34 673**	**141 077**

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 was 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	6 hours						6 hours	6 hours				
03h00			7 hours	7 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