APPLICATION TO NERSA

# Eskom Retail Tariff Plan

Proposed changes to Eskom Standard Tariffs
for implementation in 2025/26

18 September 2024

Customer enquiries e-mail: electricitypricing@eskom.co.za

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# Abbreviations

| | |
|---|---|
| CTS | Cost-to-serve |
| ERS | Electrification and rural subsidy |
| GCC | Generation Capacity Charge |
| HV | High voltage |
| IBT | Inclining block tariff |
| IPP | Independent power producer |
| LPU | Large power user |
| LV | Low voltage |
| MV | Medium voltage |
| MYPD | Multi-year price determination |
| NCC | Network capacity charge |
| NDC | Network demand charge |
| NMD | Notified maximum demand |
| POD | Point of delivery |
| PV | Photovoltaic |
| SPU | Small power user |
| SSEG | Small-scale embedded generation |
| TOU | Time-of-use |
| WEPS | Wholesale Electricity Purchase System |

# Definitions

Refer to Eskom's Schedule of Standard Prices for the definition of Eskom charges at www.eskom.co.za/tariffs

# EXECUTIVE SUMMARY

The National Energy Regulator of South Africa (NERSA) is requested to approve the Eskom Distribution License application of proposed changes to the structure of its Schedule of Standard Prices for Eskom Tariffs ("Standard Tariffs"). The proposed changes to be implemented in 2025/26 are contained in this Retail Tariff Plan (RTP) submission and are not an annual price increase request.

The changes are based on the 2024/25 cost-of-supply (or cost-to-serve (CTS)) submitted to NERSA on 02 August 2024 and are compliant with the NERSA Cost of Supply Framework, Tariff Code, Electricity Pricing Policy, and Multi-Year Price Determination (MYPD) methodology. The restructuring aims to address historical mismatches between Eskom's cost structure and revenue recovery, further unbundle tariff charges in a phased approach and simplifying municipal tariffs.

The motivation for restructuring is driven by several factors. Firstly, current tariff rates do not reflect the actual cost proportions of the services provided by Eskom, due to the historical application of average price increases. The evolving nature of the electricity industry necessitates fully unbundled tariffs that distinctly delineate energy and network charges. By ensuring that customers pay for the costs of the services they use, including grid backup, the restructuring will distribute costs fairly and reduce the burden on those without access to alternative generation.

Given that the proposed tariff changes will align tariffs more closely with NERSA allowed costs, Eskom can mitigate revenue risks, enable the integration of renewable energy, and support the transition to a more sustainable electricity market.

## Tariff changes

The RTP builds on previous submissions from 2020 and 2022. The following tariff structural changes[1] to Standard tariffs are requested for approval:

1. An update of all tariff charges with costs from the 2024/25 cost-to-serve (CTS) with the associated adjustment to time-of-use (ToU) periods and rates including further unbundling of energy charges across all tariffs, except for Homelight into fixed generation capacity and legacy charges.
2. Rationalisation of municipal (Local Authority) tariffs by consolidating the previous 15 tariffs into three i.e., Municflex (large power user/LPU), Municrate (small power user/SPU), and Public Lighting (non-metered lighting supplies).

[1] The types of charging components put together in a tariff is its tariff structure. The ideal tariff structure would therefore follow the cost structure. A cost-reflective tariff structure has all cost components reflected separately and charged according to the corresponding cost driver on a per unit basis.

3. For Large power user (LPU) tariffs, raising customer service charges on the number of points of delivery (PODs), and not per account. This will ensure fairness and better reflect the resources required to manage multiple PODs.
4. Unbundling the Homepower tariff into separate energy, network, and retail charges.
5. Converting the residential lifeline tariff, Homelight 20A into a single c/kWh energy rate.
6. Making the affordability subsidy charge in the Gen-Wheeling and Gen-Offset tariffs non-creditable i.e., removing the affordability subsidy credit for customers wheeling energy so that all customers contribute fairly to inter-tariff subsidies.
7. Revising transmission loss factors for generators to reflect the current network configuration eliminating negative charges that previously resulted in rebates for certain generators.

## Customer impacts

When tariff changes are made, customers in the tariff base experience the changes differently primarily due to different customer consumption profiles (time-of-use and energy intensity). On the overall, the impacts increase energy rates and reduce networks and retail charges. There is no change or impact for Homelight 20A that serves indigent customers. More specifically:

- **Municipal Customers (Municflex and Municrate)**: Reduced overall fixed charges, lower winter peak rates, and decreased contributions to subsidies.
- **Urban Large Customers:** Benefit from lower subsidy contributions and reduced winter peak rates, helping improve economic efficiency and competitiveness.
- **Small Urban Customers (Businessrate)**: Significant reductions in monthly bills due to lower fixed charges and TOU tariffs.
- **Rural Customers (Ruraflex and Landrate):** Reduced fixed charges and winter peak rates on TOU tariffs. Small rural customers will experience savings on their monthly bills at average consumption.
- **Residential Customers (Homelight and Homepower):** At average consumption, medium- to high-consumption customers will not be negatively impacted, and customers with PV systems will continue to receive compensation for exported energy, further reducing costs. Indigent customers will remain subsidised with no fixed charges.
- **Generators:** Will benefit from reduced network charges and pay for network losses.

This submission strives to balance the tariff changes fairly across the customer base. The overall impact per tariff category is shown in the table below, indicating that the revenue from restructured tariffs aligns with the approved costs, resulting in zero difference between the current and proposed tariff revenue (revenue neutral).

*Table 1: Summary of costs, existing revenue and revised revenue (R'Million)*

| | CTS allocated allowed costs Rm. | Current tariff revenue Rm. | Diff current tariff revenue and cost | Restuctured tariff revenue Rm | Difference new tariff revenue and cost Rm. | Revised subsidy c/kWh | % change in revenue | Difference in revenue Rm. |
|---|---|---|---|---|---|---|---|---|
| Total all tariffs | R 337 811 | R 337 804 | -R 8 | R 337 803 | -R 8 | 0.00c | 0.00% | R 0 |
| Local-authority tariffs | R 150 340 | R 154 788 | R 4 447 | R 154 227 | R 3 887 | 4.64 | -0.4% | -R 560 |
| Municflex | R 149 312 | R 153 659 | R 4 346 | R 153 199 | R 3 887 | 4.65 | -0.3% | -R 460 |
| Municrate | R 729 | R 897 | R 169 | R 729 | R 0 | 0.01 | -18.8% | -R 169 |
| Public Lighting munic | R 299 | R 232 | -R 68 | R 299 | R 0.02 | 0.01 | 29.3% | R 68 |
| Urban tariffs non-local-authority | R 128 428 | R 133 916 | R 5 488 | R 135 108 | R 6 679 | 9.59 | 0.9% | R 1 191 |
| | | | | | | | | |
| Megaflex | R 109 842 | R 114 342 | R 4 500 | R 115 593 | R 5 751 | 9.32 | 1.1% | R 1 251 |
| Nightsave Large | R 1 527 | R 1 619 | R 92 | R 1 681 | R 154 | 21.14 | 3.8% | R 62 |
| Nightsave Small | R 1 622 | R 1 814 | R 191 | R 1 877 | R 255 | 37.59 | 3.5% | R 63 |
| Miniflex Proposed | R 8 391 | R 8 419 | R 29 | R 8 656 | R 266 | 7.07 | 2.8% | R 237 |
| Transflex 1 | R 4 462 | R 4 322 | -R 140 | R 4 657 | R 195 | 10.76 | 7.7% | R 335 |
| Transflex 2 | R 355 | R 422 | R 67 | R 365 | R 10 | 20.92 | -13.5% | -R 57 |
| Businessrate | R 2 230 | R 2 979 | R 749 | R 2 279 | R 49 | 5.80 | -23.5% | -R 699 |
| Rural tariffs non-local-authority | R 29 647 | R 29 609 | -R 39 | R 29 138 | -R 509 | (5.52) | -1.6% | -R 471 |
| Ruraflex | R 13 171 | R 12 023 | -R 1 148 | R 12 802 | -R 369 | (7.60) | 6.5% | R 779 |
| Nightsave rural | R 2 768 | R 3 070 | R 303 | R 2 628 | -R 140 | (14.44) | -14.4% | -R 442 |
| Landrate & Landlight | R 13 709 | R 14 515 | R 807 | R 13 708 | R 0 | (0.01) | -5.6% | -R 807 |
| Residential tariffs non-local-authority | R 29 250 | R 19 348 | -R 9 903 | R 18 887 | -R 10 363 | (123.04) | -2.4% | -R 460 |
| Homepower | R 3 623 | R 4 083 | R 460 | R 3 623 | -R 1 | (0.04) | -11.3% | -R 460 |
| Homelight 20A | R 15 127 | R 8 683 | -R 6 444 | R 8 683 | -R 6 444 | (142.26) | 0.0% | R 0 |
| Homelight 60A | R 10 500 | R 6 582 | -R 3 918 | R 6 582 | -R 3 918 | (145.08) | 0.0% | R 0 |
| Public lighting non-local-authority | R 145 | R 143 | -R 2 | R 145 | R 0 | 0.10 | 1.2% | R 2 |
| Public Lighting All Night | R 65 | R 52 | -R 12 | R 65 | R 0 | (0.00) | 23.7% | R 12.39 |
| Public Lighting 24 Hours | R 80 | R 91 | R 11 | R 80 | R 0 | (0.01) | -12.0% | -R 10.92 |
| Public Lighting Urban Fixed | R 0.22 | R 0.12 | -R 0.11 | R 0.30 | R 0.08 | 146.95 | 156.4% | R 0.18 |
| Generator TUoS and DUoS revenue | | | | R 298 | | | | R 0 |

# 1. Introduction

The NERSA is requested to approve the Eskom Distribution License application of proposed tariff changes to its Schedule of Standard prices for Eskom Tariffs ("Standard Tariffs") to be implemented in 2025/26, that is the FY2025 Retail Tariff Plan (RTP).

The proposed changes are informed by the Electricity Regulation Act (2006), the Electricity Pricing Policy (2008) and the NERSA Tariff code. This submission has complied with the 40-day Municipal and National Treasury consultation as required by the Municipal Finance Management Act (MFMA). The SALGA comments are contained in Annexure H.

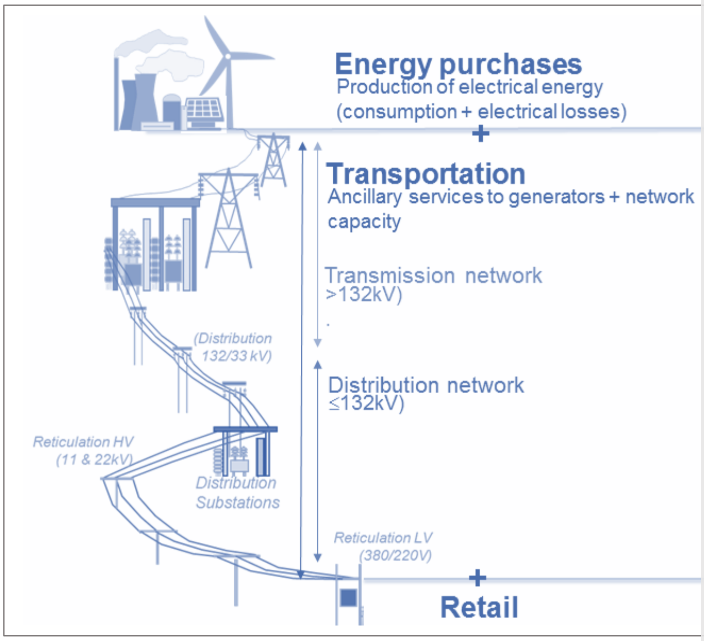
Currently, Eskom Distribution is the only Eskom Holding Licensee approved to sell electricity to end customers. The Standard Tariffs recover the approved Eskom MYPD revenue for local sales excluding Negotiated Pricing Agreements (NPAs) from all Eskom directly supplied customers and Municipal distributors. As per the MYPD methodology, the cost of energy and transmission services is a pass-through from Generation and Transmission to Standard Tariffs. This mechanism will remain in place until legislation and methodologies are established to enable separate revenue determinations per division/subsidiary. Therefore, the RTP is a tariff change proposal for all Standard Tariffs. The proposed tariff changes are based on the NERSA decision for 2024/25 Eskom Multi-year price determination (MYPD) allowable revenues and forecasted sales volumes and are provided in 2024/25 Rand value for comparison to the existing FY2025 tariffs.

The proposed tariff changes are not a price increase application. Upon the NERSA approval of the FY2025 RTP, the proposed tariffs in 2024/25-rand value will be adjusted as per the NERSA 2025/26 tariff increase decision through the NERSA ERTSA process. Prior to implementation, Eskom will submit the NERSA-approved 2025/26 Local authority tariffs for tabling in Parliament on or before 15 March 2025 for a 1 July 2025 implementation in compliance with the Municipal Finance Management Act (MFMA). The non-local-authority (non-municipal) tariffs will come into effect from 1 April 2025 to 31 March 2026 and the local authority (municipal) tariffs from 1 July 2025 to 30 June 2026.

This submission first provides the reasons for the proposed changes followed by a detailed discussion of the basis to update all tariffs with the Cost to supply study/cost-to-serve (CTS). This includes the associated update to the time-of-use (TOU) periods, unbundling of energy charges and the update to the transmission and distribution networks' use of system charges. Thereafter, the tariff-specific proposed changes which are rationalising municipal tariffs, consolidation of the Nightsave tariff, restructuring of residential (household) tariffs, changing the basis for customer service charges and updates to Transmission loss factors for generators, will follow. The impact of the changes on subsidies notably due to updating the tariffs with the CTS and resultant customer impacts follow.

## 2. What is the price of electricity?

The price of electricity is experienced as a tariff that may contain various charges to recover the costs incurred to supply electricity to end customers.




- Electricity produced by generators is first transported at high voltages in the transmission network. Some large industrial, mining and metro customers take supply at these high voltages (275 kV).
- Electricity is then transmitted in the distribution network from high-voltage to medium voltage to low-voltage networks and eventually to reticulation networks.
- Consequently, a customer taking supply in a reticulation network uses the transmission network and the distribution network (upstream networks) to receive electricity supply.
- With new technology notably renewable generation and other distribution energy resources including Battery energy storage systems (BESS) located in the distribution network, electricity generally flows from within the distribution network and no transmission network costs are incurred.

### Different costs by ToU

The variable cost of a unit of electricity (in c/kWh) depends on the time-of-day or time-of-use (ToU) and season. This is because there are varying levels of customer electricity demand during the day and different generators with differing costs are used to supply the electricity.

### Electrical losses

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.

### Retail services

Retail costs are expended to provide customers with services, for example, contact centres, meter readings, billing, and prepayment vending. Customers incur different retail services costs depending on the type of services rendered: for example, prepayment customers do not incur the cost of billing.

### Subsidies

South African energy policies and regulations allow for some customers to receive lower prices than the cost by providing subsidies in the tariffs due to affordability and/or socio-economic reasons.

The price of electricity is equal to the sum of the cost of energy + networks + retail services +/- tariff subsidy receipts or contributions.

## 3. Eskom Standard Tariffs

Eskom retail tariffs are the Standard Tariffs contained in the *Schedule of Standard Prices for Eskom Tariffs* and apply to end-customers directly supplied by Eskom and to municipalities purchasing in bulk from Eskom. Standard Tariffs provide pricing options to meet different customer consumption and service needs whilst adhering to applicable laws, policies, and regulations.

Currently, there are four main Standard Tariff options for Eskom-supplied customers. The options differ based on supply size, geographic location, municipal distributor (Local Authority), directly supplied customers (non-municipal / non-local authority) and generators. Presently, the only difference between the municipal and non-municipal tariffs is the price level to cater for a non-municipal 1 April implementation and a 1 July implementation for municipal tariffs. The four Standard tariff categories are urban, rural, residential and generator tariffs.

- **Urban tariffs:** for municipal, large industrial and mining, and medium to large commercial and institutional concerns in areas classified by Eskom as urban. Urban tariffs consist of the more unbundled tariffs that are Megaflex, Miniflex, Nightsave Urban (Large and Small), Businessrate, Public Lighting, Transflex (rail) and Gen-Wheeling/offset tariffs. Urban tariff customers make up 1% of the Eskom customer connections and 90% of the total electricity supplied; bulk electricity sales to municipal account for 51%.
- **Rural tariffs:** for agricultural customers and municipalities located in rural areas (low density) with a range of large to smaller electricity supply capacity requirements. Rural tariffs are Ruraflex, Nightsave Rural, Landrate and Landlight tariffs. Rural tariff customers make up 3% of the Eskom customer connections and consume 5% of the total electricity supplied; bulk electricity sales to municipalities account for 14% of rural tariff sales.
- **Residential tariffs:** for use of electricity in residential areas/premises and directly supplied by Eskom. Residential customers purchase 4% of the Standard Tariffs' sales. Tariffs include Homelight 20A, Homelight 60A, Homepower and Homeflex (a time-of-use tariff).
- **Generator tariffs:** for power generators that use the Eskom transmission and distribution networks to export their energy and for their operational consumption.

*See the FY2025 Tariff book at:* ESK114-Eskom-Digital-Tariff-Booklet-2024_Final.pdf

# 4. Motivation for the proposed changes

The proposed FY2026 Standard Tariff changes aim is to update existing tariffs towards prices that closely match costs as incurred by different types of customer consumption, and, to promote the efficient use of available resources. That is tariffs that are:

- Based on NERSA **allowed cost structures and levels** with the consequent update to inter-tariff subsidies.
- Further **unbundled into different cost components** for energy charges and residential network charges.
- **Payable by all customers who cause the cost** excluding NERSA-approved tariff subsidies.
- **Enable reduced complication** of Municipal bulk purchases; see detail in section 0.
- Support **optimised centrally dispatched generation** and **rationalise customer peak prices** through updated time-of-use signals that will also further assist the balance of national supply and demand.

## 4.1 Historical average increases

Over the past 11 years, annually, the NERSA MYPD revenues approved separately for electricity generation, transmission, distribution, and retail have not changed at the same rate. However, during this period, Standard Tariffs have increased with average increases. Accordingly, the annual tariff adjustments were at the same rate for distribution, retail transmission and generation. Consequently, there is currently a price and cost mismatch, that is, current tariff rates do not mirror allowed costs separately for energy, use of transmission and distribution networks as well as retail services. Tariffs, therefore, need to be aligned with an updated CTS to accurately reflect the cost of these services to avoid volume and trading risk; to reflect cost drivers more accurately; and to ensure that tariff charges cater for the unbundling of Eskom.

## 4.2 Addressing the price and cost mismatch

To address the price and cost mismatch, the Standard Tariffs are updated using unit costs from the FY2025 cost of supply study/cost-to-serve (CTS) study. The CTS study answers the question: *"How much does it cost to supply electricity to standard tariff customers using the NERSA-approved allowable costs, returns, and forecasted sales?"* The use of the latest unit costs to update existing tariffs also uncovers and resolves embedded inter-tariff subsidies due to average tariff increases.

Additionally, the CTS uses time-of-use (TOU) periods aligned to the System Operator (SO) requirements further creating opportunities for efficiency. This is because the updated TOU improves pricing support to balance supply and demand with the possibility of avoiding more expensive centrally dispatched power. The TOU update is also aligned with large industrial customer requests to review the TOU period in support of production optimisation.

## 4.3 Building on past tariff unbundling

Tariff unbundling is the separation of tariff charges and rates into underlying cost components. It ensures that users of an energy service pay for the costs they incur without passing on cost burdens and associated risks to other customers.

Eskom tariff unbundling in 2009/10 resulted in among others the unbundling of transmission and distribution network charges for large power user tariffs. In 2012/13 Standard Tariffs were further unbundled to provide transparency of the affordability subsidy, phased-in residential fixed charges and separately catered for generator distribution and transmission use-of-system charges. The proposed FY2025 tariff unbundling will incrementally build on the approach that costs are paid for by all who cause the costs.

## 4.4 Tariff unbundling to fairly allocate costs and risks

Further tariff unbundling will make visible the different generation costs (fixed and variable) promoting transparency and comparability of power prices between different generators. Key considerations for tariff unbundling include:

- **Recovery of fixed costs:** when tariff charges recover fixed costs through volumetric charges, a reduction in sales reduces revenue without an equal reduction in all costs.
- **Cost burdening:** customers with their own generation and using the grid may avoid contributing to making generation capacity available i.e., only pay when renewable sources are not available and avoid contributing to renewable generation programme subsidies. Customers without alternative generation are therefore burdened with higher costs for making generation capacity available and for renewable energy programme subsidies.
- **Revenue neutrality:** after updating the tariff rates with the costs from the CTS, the total costs after tariff unbundling need to remain the same.
- **Separate fixed and variable energy charges:** To enable all customers to contribute to all energy service costs incurred. Energy tariff charges that separately recover fixed and variable generation costs are required.
  - Currently, tariffs recover all energy costs through c/kWh energy charges. For example, an average 190c/kWh energy rate consists of 16% fixed costs, 11% renewable energy subsidies and the remainder 140c/kWh (74%) is the variable energy costs. The appropriate energy/power price for comparison is 140c/kWh instead of the total 190c/kWh.
  - Tariffs with tariff charges combining the recovery of energy and network costs when unbundled into network and energy charges do not generate extra revenue but separately reflect energy and

network charges without increasing the price. Additionally, this also assists in the removal of hidden subsidies providing greater cost transparency.

## 4.5 Financial sustainability

Unbundled tariffs also assist with improving Eskom's recovery of NERSA-allowed costs and returns by mirroring prices/tariff rates to the nature and level of costs incurred. Consequently, there is increased tariff and pricing fairness amongst customers whilst reducing Eskom revenue recovery risks and revealing hidden inter-customer subsidies.

When tariffs are not unbundled sufficiently, this imposes revenue risks for the Licensee and unfairly increases tariffs to all customers. Correctly unbundling and structuring tariffs will ensure fair cost recovery, avoid unfair cross-subsidies, and support responsible integration of alternative energy sources. See Figure below for the current Eskom ratio of fixed costs to variable costs, their current recovery in tariffs and the proposed recovery in the updated tariffs.

The below figure shows that only 10% of Eskom’s revenue recovery is through fixed charges, although 73% of its costs are fixed costs. With the proposed tariff changes, fixed revenue recovery will increase to 13%. This approach allows for a phasing-in of fixed tariff charges instead of immediately requiring that 73% of the tariff’s revenue recovery is fixed.

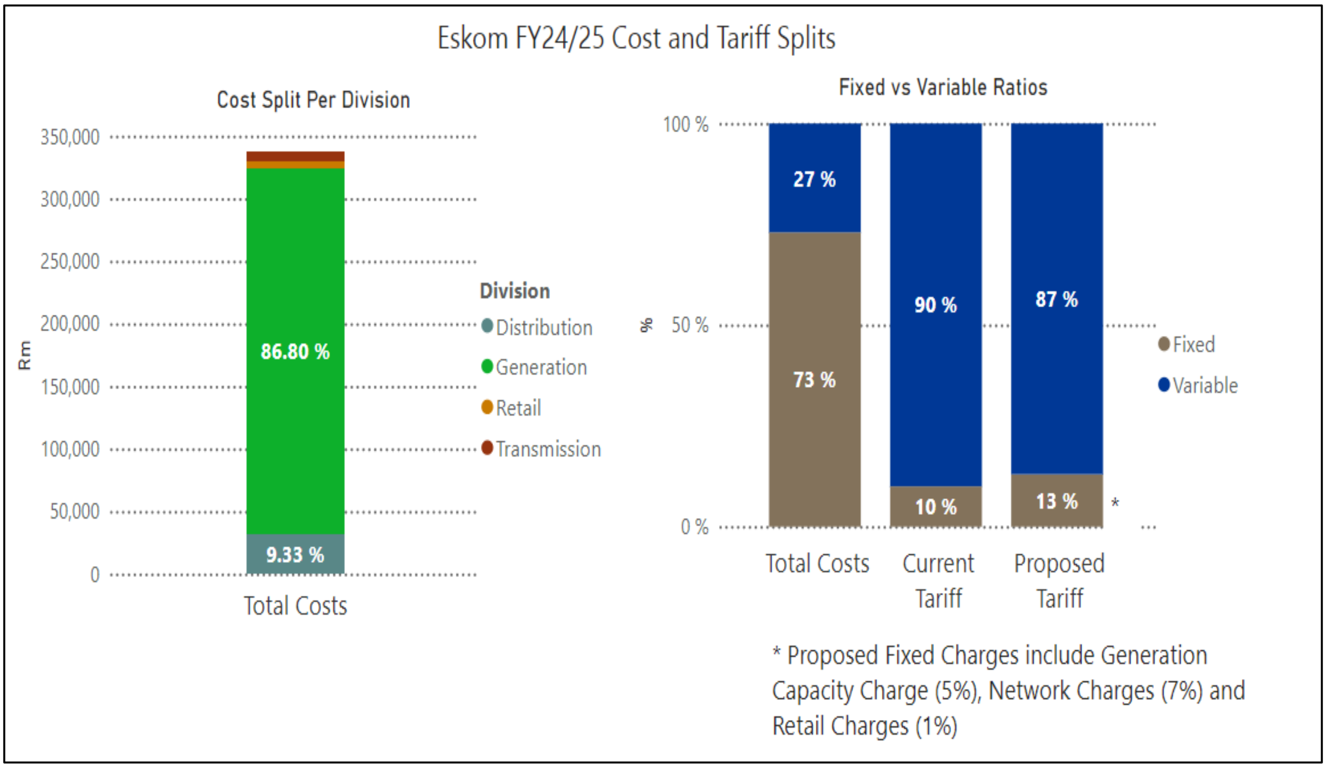



*Figure 1: Eskom volume risk*

## 4.6 To adapt to the changing electricity supply and demand environment

Eskom's tariff restructuring is essential to keep up with changes in the electricity supply and demand environment. The 2023 amendment to the Electricity Regulation Act (ERA) removed the licensing requirement for embedded generators, allowing more small- and medium-scale generators to generate energy for their use or to sell to other customers through wheeling using the Eskom network. To accommodate this shift, tariffs need to be unbundled, separating energy and network charges to ensure transparency and fairness.

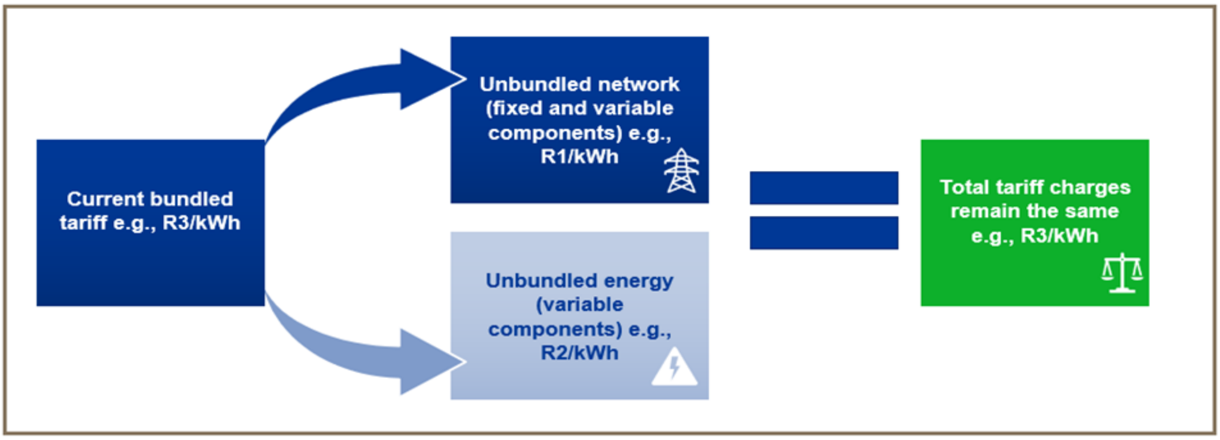



*Figure 2: Illustration of unbundling fixed and variable charges*

Unbundling tariffs into fixed and variable charges results in the total tariff charges remaining the same as shown in the above figure. This unbundling does not generate extra revenue but allows Eskom to accurately recover costs for the different services provided. This approach removes artificial subsidies, provides greater cost transparency, and ensures customers who benefit from grid connectivity for backup or energy exports contribute fairly to network costs. Without restructuring the current tariffs, which recover fixed costs through variable charges, we would continue to impose revenue risks on Eskom and unfairly increase costs for other customers. Correctly structured tariffs will promote fairness, responsible integration of renewable energy, and financial stability for the grid.

# 5. Process followed for tariff changes

## 5.1 Process overview

The main steps undertaken to propose the tariff changes are outlined below and summarised in the Figure below.

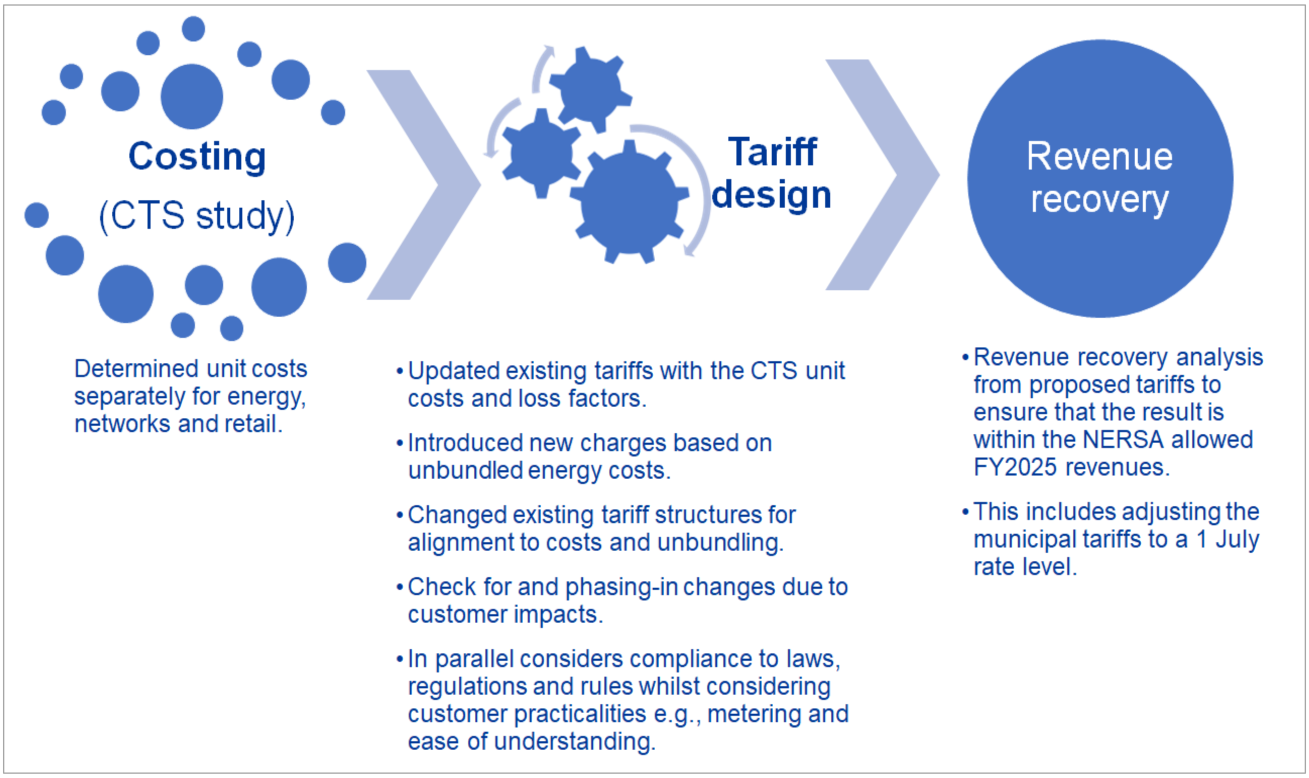



*Figure 3: Proposed tariff changes process overview*

- **Costing:** Conducted a cost of supply/ cost to serve (CTS) study based on the MYPD 5, FY2025 decision allowable revenues (costs + returns) and sales volumes. The outcome from the CTS study was the applicable unit costs separately for energy (generation), use of transmission networks, use of distribution networks and retail services.
- **Tariff design:** Performed tariff design that involved:
  a) Updated existing tariffs with the CTS unit costs and loss factors.
  b) Applied tariff design principles.
  c) Changed existing tariff structures to align to costs and unbundling aims including the introduction of new tariff charges based on unbundled costs.
  d) It is important to note that tariff design, seeks to balance the need for cost-representative charges, ensuring pricing signals to incentivise more optimal consumption, retaining NERSA-approved subsidies and minimising customer impacts. It is influenced by multiple factors including the sophistication of customer needs, metering, affordability, customer impacts and revenue risks (departing from the cost driver and fairness). Tariff design also considers national

policy and direction including the Electricity Pricing Policy (EPP), NERSA codes and rules, stakeholder and customer inputs, and Eskom business requirements.

- **Revenue recovery:** Updated the tariff rates and conducted revenue recovery analysis including adjusting the updated municipal tariffs to be effective on 1 July and ensuring that the NERSA allowed FY2025 revenue recovery to remain the same (revenue neutrality).

## 5.2 Cost to serve (CTS) study

NERSA Cost of Supply (CoS) framework requires that electricity tariffs are developed or updated based on a cost of supply study. Eskom submitted to the NERSA its FY2025 Cost to Serve (CTS) study on 8 August 2024.

The FY2025 CTS basis is the FY2025 NERSA-approved costs separately for generation, transmission, distribution, and retail. The CTS allocates costs informed by how customers cause/contribute to costs. The cost allocation is guided by a cost causation principle, that is, it tracks how each customer category contributes to the costs of supplying electricity based on its consumption and demand or the related cost drivers.

The cost drivers used in the cost allocation are the volumes used in the NERSA MYPD decision for the costing year, that are the sales in kilowatt-hours, the demand (utilised capacity, maximum demand, and chargeable demand), and the number of customer PODs. The CTS process in summary:

- First consider a customer connection’s voltage of supply and density (rural/urban).
- To allocate energy costs and line losses the time-of-use periods supported by the System Operator are applied, this is the first stage to update the energy charges time-of-use periods. Updated loss factors for assets and lines are used to appropriate the respective losses at various points of the Eskom grid.
- Network costs for the transmission grid are allocated based on transmission zone and utilised capacity (higher of the peak and notified maximum demand).
- Distribution grid costs are differentiated by voltage of supply and contribution to distribution network system demand based on customers’ maximum demand.
- Retail costs are allocated based on a point of supply/delivery (POS/POD) and are informed by the supply size and type that provide for the complexity are level of service provided.

The following affected the cost allocation that changes the CTS unit costs used in the tariff updates:

- The MYPD revenue decision separately for energy, transmission networks, distribution networks and retail.
- Changes to the energy TOU periods and unit costs.
- Unbundling of energy costs into active energy, capacity, and legacy (renewable programme subsidy).
- Updated Distribution and Transmission loss factors based on the MYPD decision forecasted volumes.
- Updated customer numbers influencing the unit costs per point of supply (POS) or delivery (POD).
- Changes in the underlying chargeable demands and utilised capacities of the MYPD decision's sales forecast influencing the network costs per kilovolt-ampere (kVA).
- Updated Transmission network costs.

See the next table for a summary of the CTS cost drivers and allocation methods.

*Table 2: CTS cost drivers, allocation methods and unit cost drivers*

| Functionalised costs | Costs driver(s) | Allocation method(s) | Unit costs |
|---|---|---|---|
| Energy Purchases:<br>1. Variable energy purchases<br>2. Legacy charge<br>3. Generation capacity | Wholesale energy purchases (TOU), legacy charge and generation capacity | ToU and seasonally differentiated energy purchase rates and annual maximum demand purchased | c/kWh and R/kVA |
| Transmission purchases | Installed capacity and location (zonal) differentiation | Utilized capacity demand at purchase level per Transmission zone | R/kVA |
| Distribution | Capacity (transformation and lines) | Maximum demands adjusted for diversity in the cost allocation diagram (CAD) | R/kVA |
| Retail costs | Number of PoDs | PoD weighting / ratio to serve various customer types | R/PoD/day |

By applying the unit costs derived from the CTS study, firstly the mismatch between prices and costs is addressed. Secondly, any changes, new tariffs and rates are informed by NERSA-approved costs. Because of this process, the resultant tariff proposals are cost-representative but also fairer.

*Visit: https://www.eskom.co.za/distribution/retail-tariff/ to see the details of the FY2025 Eskom Cost to Serve (CTS) study.*

## 6. Summary of Eskom-proposed changes to the tariff structures and rates

The proposed changes to the tariffs are based on the CTS results and then include specific objectives, pricing signals, subsidies (payment and receipt), and phasing in of changes to minimise impacts.

A summary of the changes per tariff is shown in the following table (excluding the impact of CTS on the level of the charges).

*Table 3: Summary of proposed changes to Eskom's retail tariffs*

| Tariff | Change | Comments |
|---|---|---|
| Non-municipal | | |
| Megaflex, Miniflex, WEPS | • Energy charges –<br>○ Introduced a fixed generation capacity charge<br>○ Introduced a c/kWh legacy charge<br>○ Updated with new TOU ratios and periods<br>• Service charge converted from R/account to R/POD | • Refer to Annexure C – and Annexure D – Proposed changes to rate components |
| Transflex | • Energy charges –<br>○ Introduced a fixed generation capacity charge<br>○ Updated with new TOU ratios and periods<br>○ Introduced a c/kWh legacy charge<br>• Service charge converted from R/account to R/POD | • Refer to Annexure C – and Annexure D – Proposed changes to rate components |
| Nightsave Urban Large and Small | • Energy charges –<br>○ Introduced a fixed generation capacity charge<br>○ Introduced a c/kWh legacy charge<br>○ Updated with new TOU ratios and periods<br>• Energy demand charges for these two tariffs have been aligned (made the same)<br>• Service charge converted from R/account to R/POD | • Refer to Annexure C – and Annexure D – Proposed changes to rate components |
| Ruraflex and Nightsave Rural | • Energy charges –<br>○ Introduced a fixed generation capacity charge<br>○ Introduced a c/kWh legacy charge<br>○ Updated with new TOU ratios and periods<br>• Network charges for these two tariffs have been aligned (made the same) | • Refer to Annexure C – and Annexure D – Proposed changes to rate components |

| Tariff | Change | Comments |
|---|---|---|
| | • Service charge converted from R/account to R/POD | |
| Businessrate | • Structural change by introducing the electrification and rural subsidy (ERS) charge<br>• Energy charges – Introduced a fixed generation capacity charge (R/POD/day | • Refer to Annexure D – Proposed changes to rate components |
| Landrate | • Energy charges – Introduced a fixed generation capacity charge (R/POD/day) split 50/50 between fixed (R/POD) and variable charge (c/kWh) to limit customer impact | • Refer to Annexure D – Proposed changes to rate components |
| Landlight 20 and 60A | • No structural changes<br>• Landlight 60A rate has been calculated using 400kWh consumption of Landrate 4. It was previously based on 500 kWh | • Refer to Annexure D – Proposed changes to rate components |
| Homepower | • Structural changes proposed by removing IBT<br>• Introducing a single energy charge (c/kWh), an ancillary service charge (c/kWh), a network demand charge (c/kWh) and a R/day service and administration charge<br>• Introduction of R/POD/day GCC at a 50/50 split between fixed (R/POD/day) and variable (c/kWh) charges to limit customer impact | • Refer to Annexure D – Proposed changes to rate components |
| Homelight 20 and 60A | • Structural changes proposed by removing IBT and converting to a single energy charge (c/kWh) (but the option remains to retain IBT structure) | • Refer to Annexure D – Proposed changes to rate components<br>• Refer to paragraph 0 concerning IBT |
| Public Lighting | • No structural changes - Public Lighting tariff for non-metered lighting supplies (no change just updated with the CTS) | |
| Non-municipa | | |
| Municflex | • Local authority LPU tariffs, Megaflex, Miniflex, Nightsave Urban, Ruraflex, and Nightsave Rural are combined into a new | • Refer to paragraph 0 concerning municipality tariff rationalisation and Annexure |

| Tariff | Change | Comments |
|---|---|---|
| | tariff called Municflex (based on Megaflex structure)<br>• Energy charges –<br>  ○ Introduced a fixed generation capacity charge<br>  ○ Introduced a c/kWh legacy charge<br>  ○ Updated with new TOU ratios and periods<br>• Service charge converted from R/account to R/POD | D – Proposed changes to rate components |
| Municrate | • Local authority small power tariffs are combined into a single tariff called Municrate (based on the existing Businessrate structure)<br>• Energy charges - introduction of Generation Capacity Charge (GCC) at 50/50 split between fixed and variable charges to limit customer impact | • Refer to paragraph 0 concerning municipality tariff rationalisation and Annexure D – Proposed changes to rate components<br>• The introduction of ERS is currently not proposed for this tariff since most of the volumes are in the Landrate and Homepower tariffs, which do not contribute to this subsidy. The majority of the urban municipality customers are in the Municflex tariff and will contribute to the ERS subsidy in the Municflex tariff. |
| | **Generator-related tariffs** | |
| Gen-wheeling | • Energy charges – credit rate updated with new TOU ratios and periods<br>• Remove the crediting of the Affordability Subsidy charge | • Refer to Annexure D – Proposed changes to rate components |
| Gen-offset | • Energy charges – credit rate updated with new TOU ratios and periods<br>• Remove the crediting of the Affordability Subsidy charge | • Refer to Annexure D – Proposed changes to rate components |
| Gen-DUoS | • No structural change<br>• Updated network charges and loss factors based on HV cost-reflective charges for loads | • Refer to Annexure D – Proposed changes to rate components |
| Gen-TUoS | • The negative loss factors for Transmission generators proposed to change | • Not applicable |

## 6.1 How the standard tariff charges were calculated

1) Energy costs have been taken as is from the CTS based on the new TOU changes and repacked volumes. See paragraph 7.
    a) For the TOU tariffs, the costs have been split into c/kWh peak, standard and off-peak periods and seasonally differentiated, based on the new WEPS purchase costs TOU volumes, structure, and periods.
    b) For the Nightsave tariffs, a portion of the energy costs has been converted into an R/kVA energy demand charge.
    c) For non-TOU tariffs, a representative load profile has been used to determine an average annual c/kWh value.
    d) Generation capacity costs have been taken as is from the CTS study results and charged as an R/kVA for LPU tariffs or bundled together with other TOU charges for some SPU tariffs where the GCC was split 50/50 between fixed and variable charges.
    e) Legacy costs have been taken as is from the CTS study results and charged as a c/kWh charge for all tariffs except the Homelight tariff.
2) Transmission network costs have been taken as is from the CTS study results and either charged as a separate R/kVA charge, combined with Distribution network costs, or bundled together with other charges.
3) Distribution network costs have been taken as is from the CTS study results and then designed as explained in Annexure D – Proposed changes to rate components, Paragraph D.5.
4) Retail costs (service and administration) have been used as is from the CTS results, except for tariffs without retail charges (such as Homelight).
5) The sum of all the above, plus revenue from IPP TUoS and DUoS charges, equals the approved revenue requirement.
6) All rates are in 2024/25-rand values. The price increase process will be used to update the rates to the year of application.

The following table summarises how different costs are recovered in tariff charges.

*Table 4: Tariff design basis*

| Tariff | Energy charges c/kWh | Legacy charges c/kWh | Generation Capacity Charges R/kVA | Transmission network charges | Ancillary service charges | Distribution network charges | Retail charges | Subsidies |
|---|---|---|---|---|---|---|---|---|
| Megaflex, Miniflex | TOU cost per period | Legacy cost c/kWh | Generation capacity cost R/kVA | Transmission network cost R/kVA | Transmission ancillary service cost c/kWh | Distribution R/kVA cost, but with intra-tariff network subsidies | Distribution retail cost R/POD/supply size | Pays subsidies |
| Nightsave Urban | TOU cost per period split into R/kVA and c/kWh | Legacy cost c/kWh | Generation capacity cost R/kVA | Transmission network cost R/kVA | Transmission ancillary service cost c/kWh | Distribution R/kVA cost, but with intra-tariff network subsidies | Distribution retail cost R/POD/supply size | Pays subsidies |
| Ruraflex | TOU c/kWh cost per period | Legacy cost c/kWh | Generation capacity cost R/kVA | Transmission network cost R/kVA | Transmission ancillary service cost c/kWh | Distribution R/kVA cost but reduced by inter-tariff subsidies | Distribution retail cost R/POD/supply size | Receives subsidies |
| Nightsave Rural | TOU c/kWh cost per period | Legacy cost c/kWh | Generation capacity cost R/kVA | Transmission network cost R/kVA | Transmission ancillary service cost | Distribution R/kVA cost, but reduced by inter-tariff subsidies | Distribution retail cost R/POD/supply size | Receives subsidies |
| Businessrate | TOU c/kWh cost per period based on average profile cost | Legacy cost c/kWh | Generation capacity cost R/POD/day | Transmission network cost R/POD | Transmission ancillary service cost c/kWh | Distribution cost split in R/POD/day and c/kWh | Distribution retail cost R/POD/supply size | Pays subsidies |
| Landrate | TOU c/kWh cost per period based on average profile cost | Legacy cost c/kWh | Generation capacity cost R/POD/day at a 50/50 split between fixed and variable charge | Transmission network cost R/POD/day | Transmission ancillary service cost c/kWh | Distribution cost, but with inter- and intra-tariff subsidies, aligned to current inter-tariff subsidies level, split in R/POD/day and c/kWh | Distribution retail cost R/POD/ supply size | Receives subsidies |
| Homepower | TOU c/kWh wholesale | Legacy cost c/kWh | Generation capacity cost | Transmission network cost R/POD/day | Transmission ancillary | Distribution cost split in | Distribution retail cost | No subsidies |

| Tariff | Energy charges c/kWh | Legacy charges c/kWh | Generation Capacity Charges R/kVA | Transmission network charges | Ancillary service charges | Distribution network charges | Retail charges | Subsidies |
|---|---|---|---|---|---|---|---|---|
| | cost per period based on average profile cost | | R/POD/day at a 50/50 split between fixed and variable charges | | service cost c/kWh | R/POD/day and c/kWh | R/POD/supply size | |
| Homelight | Designed based on current tariff revenue – with difference to cost determining required subsidy and no separate generation capacity costs (GCC) and legacy charges. | | | | | | | Receives subsidies |
| Public Lighting | TOU c/kWh cost per period based on average profile cost | Legacy cost c/kWh | Generation capacity cost c/kWh | Transmission network costs c/kWh | Transmission ancillary service cost c/kWh | Distribution cost c/kWh | Distribution retail cost c/kWh | No subsidies |

## 7. Time-of-use (TOU) changes

Eskom is proposing changes to the TOU energy charges concerning the rates in each TOU period and the changes to the peak, standard and off-peak hours to align with unbundled energy costs and its structure. Refer to Annexure C for the full motivation for the proposed TOU changes.

Approximately 80% or more of Eskom sales are on TOU tariffs. These tariffs have peak (most expensive), standard (medium) and off-peak (cheapest) hours and charges, as well as having a winter/summer differential. The current TOU charges were last changed in 2005 and no longer reflect costs, the present system, and customer requirements. As a result, the current price signals and TOU hours are not optimal for managing the system.

Therefore, it is proposed to 1) change the TOU hours and 2) change the TOU prices to:

- meet the System Operator's requirements to optimise the operation of the power system;
- provide the right economic signals that promote economic efficiency;
- improve financial sustainability by increasing efficiencies in operating costs; and
- incentivise growth and sales for the benefit of the customers and Eskom.

If approved by NERSA, the changes to the TOU tariffs will apply to all customers on TOU tariffs. The changes proposed are:

- updating the energy rates with the costs from the FY2025 CTS study unit costs.
- increasing the evening peak to three hours (from two hours) and reducing the morning peak to two hours (from three hours); see Figure 4: Proposed changes to the peak, standard and off-peak periods;
- introducing a two-hour standard period on a Sunday evening. See Figure 4: Proposed changes to the peak, standard and off-peak periods; and
- reducing the current 1:8 ratio of the summer (low-demand season) off-peak rate to the winter (high-demand season) peak rate to a 1:6 ratio and adjusting the rest of the rates commensurately. See Table 5: >132kV TOU rates excluding losses; and
- The proposed changes are based on an analysis of the current and future system profile, correlation against system marginal costs and price signals to optimise the profile. These changes will continue to evolve as the industry and market evolve.

## 7.1 Proposed TOU period changes

The following figure demonstrates the changes in the peak (1), standard (2), and off-peak (3) periods between the current TOU hours and the proposed TOU hours.

| | Existing Time-of-Use Periods | | | | | | Proposed Time-of-Use Periods | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | High Season | | | Low Season | | | High Season | | | Low Season | | |
| Time | Weekday | Saturday | Sunday | Weekday | Saturday | Sunday | Weekday | Saturday | Sunday | Weekday | Saturday | Sunday |
| 0:00 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| 1:00 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| 2:00 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| 3:00 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| 4:00 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| 5:00 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| 6:00 | 1 | 3 | 3 | 2 | 3 | 3 | 1 | 3 | 3 | 2 | 3 | 3 |
| 7:00 | 1 | 2 | 3 | 1 | 2 | 3 | 1 | 2 | 3 | 1 | 2 | 3 |
| 8:00 | 1 | 2 | 3 | 1 | 2 | 3 | 2 | 2 | 3 | 1 | 2 | 3 |
| 9:00 | 2 | 2 | 3 | 1 | 2 | 3 | 2 | 2 | 3 | 2 | 2 | 3 |
| 10:00 | 2 | 2 | 3 | 2 | 2 | 3 | 2 | 2 | 3 | 2 | 2 | 3 |
| 11:00 | 2 | 2 | 3 | 2 | 2 | 3 | 2 | 2 | 3 | 2 | 2 | 3 |
| 12:00 | 2 | 3 | 3 | 2 | 3 | 3 | 2 | 3 | 3 | 2 | 3 | 3 |
| 13:00 | 2 | 3 | 3 | 2 | 3 | 3 | 2 | 3 | 3 | 2 | 3 | 3 |
| 14:00 | 2 | 3 | 3 | 2 | 3 | 3 | 2 | 3 | 3 | 2 | 3 | 3 |
| 15:00 | 2 | 3 | 3 | 2 | 3 | 3 | 2 | 3 | 3 | 2 | 3 | 3 |
| 16:00 | 2 | 3 | 3 | 2 | 3 | 3 | 2 | 3 | 3 | 2 | 3 | 3 |
| 17:00 | 1 | 3 | 3 | 2 | 3 | 3 | 1 | 2 | 2 | 2 | 3 | 3 |
| 18:00 | 1 | 2 | 3 | 1 | 2 | 3 | 1 | 2 | 2 | 1 | 2 | 2 |
| 19:00 | 2 | 2 | 3 | 1 | 2 | 3 | 1 | 3 | 3 | 1 | 2 | 2 |
| 20:00 | 2 | 3 | 3 | 2 | 3 | 3 | 2 | 3 | 3 | 1 | 3 | 3 |
| 21:00 | 2 | 3 | 3 | 2 | 3 | 3 | 2 | 3 | 3 | 2 | 3 | 3 |
| 22:00 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| 23:00 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |

*Figure 4: Proposed changes to the peak, standard and off-peak periods of the TOU tariffs*

## 7.2 TOU proposed peak, standard, and off-peak rate changes

Based on requests to reduce winter prices, Eskom reviewed the prices and TOU ratios between the peak, standard, and off-peak periods as well as the high-demand and low-demand seasons. The final changes proposed using the above periods in Figure 4 considered the effect and impact of changing the rates. If the winter price is reduced, it would mean that other prices in all other periods would have to increase to be revenue-neutral.

Too much of a reduction of the winter (high-demand season) rates would increase the summer rates (low-demand season) drastically and reduce the signal for customers to respond to the tariff in winter. The winter TOU period is the time when the avoidance of load shedding is far more critical from a national health, economic, and safety perspective. The changes could not be based only on cost, but on price signals to ensure that demand would be managed in times of constraints and surplus.

The rates are as follows, comparing the WEPS rates before the TOU restructuring and then the rates after the TOU restructuring.

*Table 5: >132kV TOU rates excluding losses*

| | Wholesale energy rates | | | | | |
|---|---|---|---|---|---|---|
| Season | High-demand | | | Low-demand | | |
| Period | Peak | Standard | Off-Peak | Peak | Standard | Off-Peak |
| 1) Existing ratios | 8.00 | 2.31 | 1.18 | 2.50 | 1.67 | 1.00 |
| 2) Existing TOU c/kWh | 543.88 | 164.73 | 89.48 | 177.47 | 122.11 | 77.48 |
| 3) Proposed ratios | 6.00 | 1.50 | 1.00 | 2.49 | 1.40 | 1.00 |
| 4) Proposed TOU c/kWh | 478.66c | 119.66c | 79.78c | 198.64c | 111.69c | 79.78c |

The above proposed TOU c/kWh rates exclude the GCC and legacy charges.

When comparing the unbundled energy unit costs and structure to the existing Standard tariff energy rates at >132kV (excluding losses), the following can be noted:

- The winter peak rate ratio has decreased from a 1:8 ratio to a 1:6 ratio (see points 1 and 3 above).
- This ratio change reduced the winter prices and increased the summer peak prices (see points 2 and 4 above).

# 8. Unbundling energy charges into separate generation capacity and legacy charge

Energy tariffs need to promote efficient use of electricity, support grid management and enable the appropriate recovery of standby/generation capacity. Consequently, energy price structures need to reflect the costs of the electricity generation value chain by separately identifying capacity, active energy costs and any related subsidies. In the CTS study, the generation costs are unbundled into:

- Variable ToU costs with updated time-of-use periods (as discussed in the preceding section.
- Fixed generation capacity costs.
- Legacy costs i.e., the subsidies associated with the Government renewable energy programme.

By separately catering for capacity and legacy costs in the CTS, the cost of energy to all customers, those who rely solely on grid electricity versus those who have their own generators is levelised:

- Customers without generators typically consume enough electricity over time to cover fixed capacity costs through volumetric tariffs.
- In contrast, customers with intermittent generators may not consistently cover these costs. This is like paying an insurance premium only during times of need.
- Over time, the legacy costs can be tracked and reflected in their changing levels.

Consequently, the resultant separate charges would ensure adequate dispatchable capacity and comparable power prices in the electricity industry.

## 8.1 Levels of fixed generation costs

In the FY2025 MYPD decision as mapped in the CTS study, the fixed generation costs contribute more than 35% of the total allowed revenues. If the CTS study were to fully apply the MYPD-allowed fixed level of costs in arriving at unit costs for energy charges, sharp unaffordable prices of electricity would result. The FY2025 CTS therefore adapts a 7% allocation of energy costs to introduce a view of a fixed generation capacity unit cost (R/KVA).

## 8.2 Levelling energy costs in South Africa

By separately catering for capacity costs in the CTS used to unbundle energy charges, the cost of energy to all customers, those who rely solely on grid electricity versus those who have their own generators is levelised:

- Customers without generators typically consume enough electricity over time to cover fixed capacity costs through volumetric tariffs.
- In contrast, customers with intermittent generators may not consistently cover these costs. This is like paying an insurance premium only during times of need.

By unbundling energy costs the resulting standby/capacity demand charge could result in high costs for low load factor customers. Despite this outcome, the approach allows for the unveiling of all costs incurred to provide backup to all customers. It can also function as an incentive for low-load-factor customers to either change their demand patterns or install their own battery or other storage or peak-shifting systems. If the customer battery comes at a lower cost than the system cost of establishing additional peak capacity, this implies an overall net gain to the South African economy.

A generation capacity standby cost is incurred to avail capacity costs associated with providing backup power when the customer's generator is out of service. As such, the standby cost incurred functions as an insurance premium, which enables the customer to avoid incurring the cost of their own back-up capacity.

Presently, standby, or backup generator capacity is also constantly provided to customers who do not have their own generators. For example, Eskom carries sufficient plant and operating reserves to meet the needs of a customer with large switchable block-loads. These customers are currently allowed to switch their loads in or out without notice or incurring standby charges.

## 8.3 How the generation capacity costs were determined at 7%

The method used to determine the allocation of capacity charge used fixed costs associated with the cheapest generators that would provide backup in a system with high renewable penetration – in this case, a combined cycle gas turbine. This follows the assumption future generation capacity will include significant renewable capacity with a gas back-up as informed by the Integrated Resource Plan (IRP).

Combined cycle gas turbines (CCGT) have fixed costs associated with capital costs and fixed operating and maintenance. These costs were calculated to include the overnight installation cost of a CCGT to the annual fixed operating and maintenance costs for a year and that provided for a R/MW that when applied to the peak demand results in a 7% share of the generation allowable revenues.

## 8.4 How the retail generation capacity charge is calculated and charged

The generation capacity costs are allocated in the CTS. Once the total cost has been allocated among the various Eskom customer categories, an R/kVA value is assigned to each customer category such that the total fixed generation cost is recovered throughout the financial year via electricity tariffs. This is achieved by dividing the allocated generation capacity costs by the annual utilised capacity (the higher of the notified maximum demand or maximum demand registered during a rolling 12-month period per customer category).

$$Customer\ Unit\ Costs\ (R/kVA) = \frac{Customer\ Allocated\ Costs\ (R)}{Annual\ Utilized\ Capacity\ (kVA)}$$

This value represents the final generation capacity charge which will be assigned to each customer category.

## 8.5 Legacy charge

Energy procured through the Renewable Energy Independent Power Producer Procurement Programme (REIPPPP) on Power Purchasing Agreements has predetermined prices for a set number of years. These prices are often higher than the current generation costs. These agreements are classified as legacy contracts, meaning their costs are unavoidable, particularly as the industry transitions to an open electricity market where customers can choose renewable energy sources. As more customers opt for renewable energy, the customer base for Eskom-generated energy shrinks, yet these legacy costs remain fixed.

To ensure that all energy consumers contribute fairly to these unavoidable costs, the legacy costs, which were previously embedded in the time-of-use (TOU) energy costs, have now been ring-fenced. The legacy charge, based on allocated legacy costs in the cost-to-serve (CTS) study, is recovered from all customers as a c/kWh charge for all tariffs, except the Homelight tariff. This approach ensures that the financial burden of legacy contracts is equitably distributed among all users of the electricity system.

## 9. Municipal tariff rationalisation

Eskom has since November 2017 looked to review and rationalise its tariffs for municipal bulk purchases including smaller municipal supplies. Municipalities purchase in bulk from Eskom to supply customers connected in their licensed areas of supply and municipal tariff rationalisation aims to reduce complications of Municipal bulk purchases.

This submission builds on previous Eskom submissions to NERSA and the 2019 NERSA decision requiring that municipal tariff rationalisation proposals are based on a cost to supply study (/ CTS study). To this end, the municipal (local authority) tariffs rationalisation proposal uses the latest CTS study to bundle the municipal tariffs into from the existing 15 options into only 3 tariff categories as follows:

- **Municflex:** a new tariff for large power user (LPU) connections based on the Megaflex structure, with rates calculated by combining the costs of Megaflex, Miniflex, Nightsave Urban Large and Small, Ruraflex and Nightsave Rural for local authority supplies. Upon the NERSA approval, the existing Megaflex, Miniflex, Nightsave Urban Large and Small, Ruraflex, and Nightsave Rural will cease to exist and be replaced by Municflex.

- **Municrate:** a new small power user (SPU) connection based on the Businessrate structure, with rates calculated by combining the costs of Landrate, Businessrate and Homepower for local authority supplies. Upon NERSA approval, the existing local authority SPU tariffs Landrate, Businessrate, and Homepower will cease to exist and be replaced by Municrate.

- **Public Lighting** tariffs remain the same and are based on the CTS costs.

Municipal electricity purchase benefits from rationalising the local authority tariffs include:

- The new tariff options will reduce complexity with only one tariff for large power users and one tariff for small power users; Public Lighting tariffs will remain unchanged.
- All Local authority tariffs will be treated as urban tariffs.
- The two-tariff setting will simplify the sales and revenue forecasting process for both municipalities and Eskom as well as simplify the process of determining the electricity purchase cost for municipalities.

The impact of all the proposed changes is provided in Annexure A and in Annexure D – Proposed changes to rate components. The municipal tariff rates in this submission are shown in 12-month values (based on the Eskom financial year April to March), and in nine-month values (based on three months of April to June current tariffs, nine months at the revised CTS-based tariffs.) Refer further to Annexure E – Proposed Standard tariff rates in 2024/25-rand values (excluding **VAT)**, Table 38, Table 39, Table *40*, and

Table 41.

The following figure demonstrates the impact of updating the tariffs with the CTS, per local authority tariff.

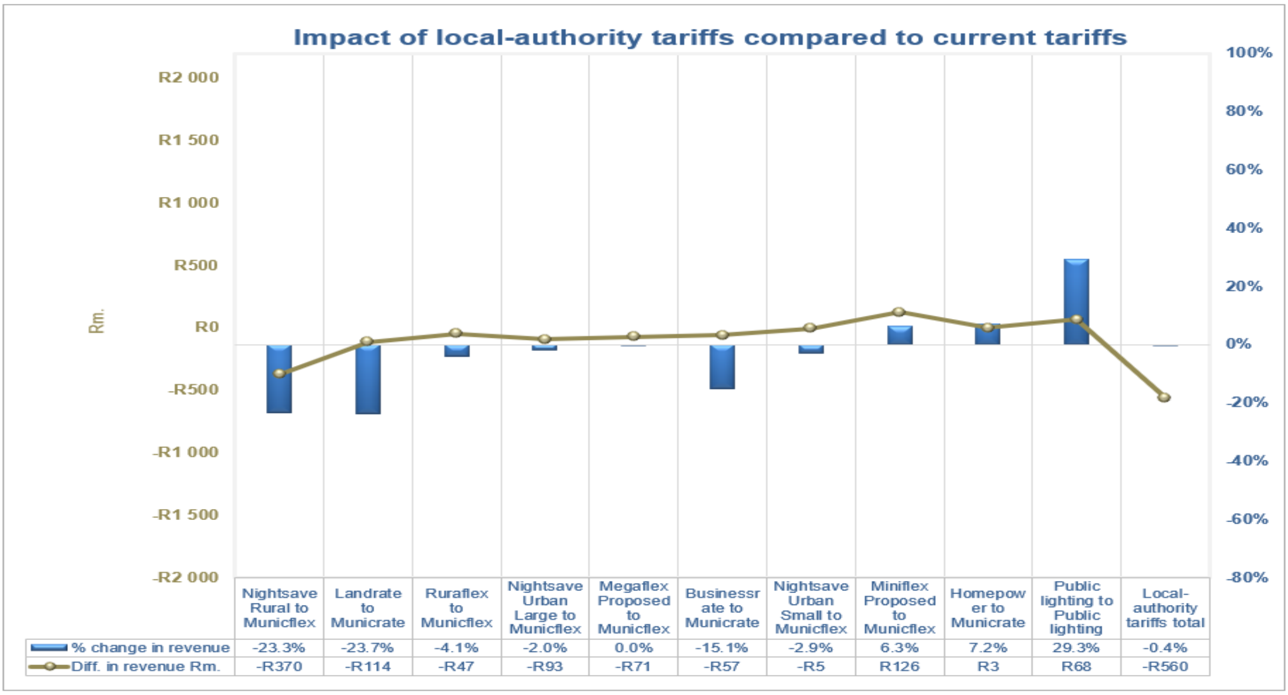



*Figure 5: Impact of the municipal tariff rationalisation per local authority tariff*

Refer to Annexure A – Local authority tariff impacts for more detail on the impact of the tariff changes on the local authority tariffs.

# 10. Distribution network charges

## 10.1 Distribution use-of-system (DUoS) network charges

The Distribution business costs are largely fixed to deliver the capacity needed. If network charges are not cost-reflective and are recovered through variable/volumetric charges such as c/kWh, this places the Distribution business at risk of not recovering costs when the volume is reduced. This could be a result of economic conditions, increased usage of distributed generation, batteries, demand-side management, and the general improvement in smarter and more energy-efficient appliances.

The reliance on the grid is not necessarily reduced, unless the customer goes totally off-grid, but charges for having the grid as a backup (availability at any time) or, in the case of net metering, using the grid as a bank are still required. The introduction of PV, in particular, could result in the customer being a zero net or very low net consumer, and therefore, where network costs are recovered through variable charges, this results in a loss of revenue not commensurate with a reduction in costs. It also results in customers with PV being subsidised by customers without PV. This adds to the potential of a utility death spiral if there is no fair recovery of the grid costs through variable charges. This requires a review of tariff structures, in particular for small power users, to ensure adequate recovery of fixed costs.

If network charges are designed to be fixed charges, this reduces the revenue risk while consequently reducing the signal to manage consumption in peak times. This may result in inefficient use of the network and the Distribution business having to invest uneconomically. For this reason, network charges should recover an appropriate balance between fixed and variable charges and ensure that there is an appropriate signal for peak demand and consumption.

The following figure shows the balance between customer risk and utility risk, depending on the tariff structure choice.

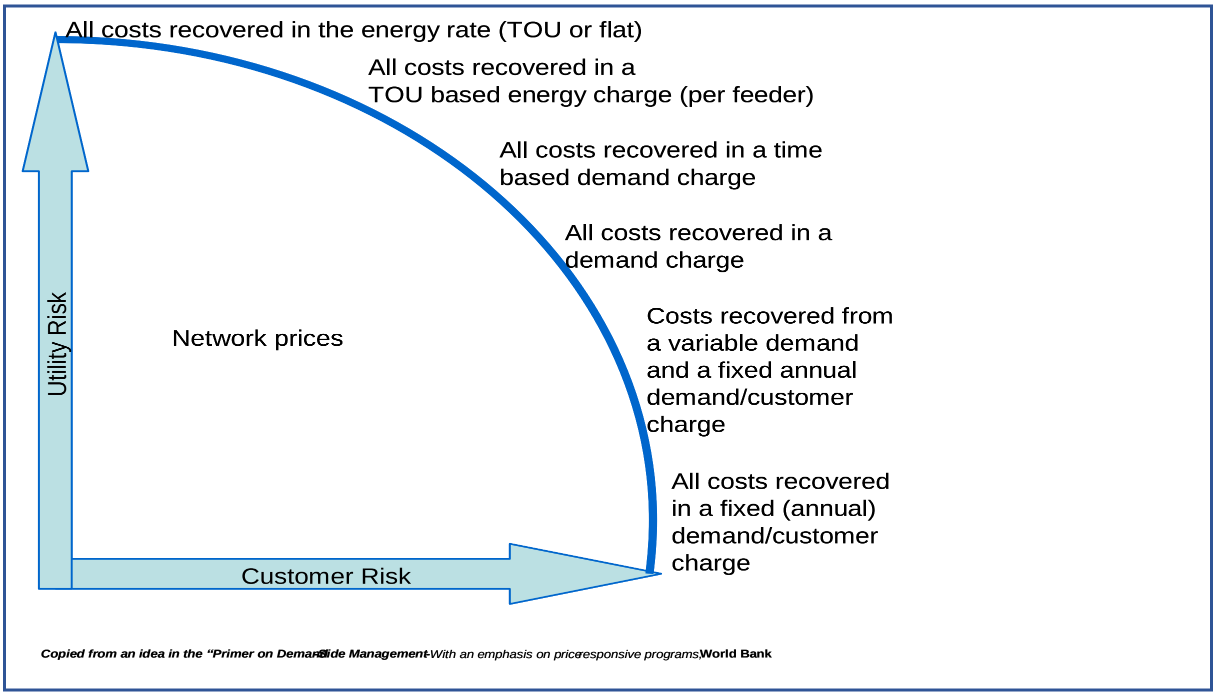



*Figure 6: Network charge design and associated risks*

This figure shows the options available to be considered when designing a network charge. If all fixed costs are recovered through, for instance, an annual lump sum fixed charge, there is little utility risk, and if all costs are recovered through total variable charges, there is very little customer risk. Fixed charges are, however, not popular with low-consumption customers, as these fix the amount payable each month and also reduce customers' benefits when consumption is reduced.

Internationally, there is recognition that network tariffs need to be restructured to move from variable-usage-based charges to tariff structures that better reflect the fixed costs and the demand a customer imposes on the network.

For all tariffs that have network charges, these were updated based on the CTS results and then split into a fixed portion (based on the utilised capacity) and a variable portion (based on maximum demand or consumption). The total network charges were designed to recover the total approved network costs as allocated in the CTS.

Also, refer to Section 17 which shows the total impact per tariff charge type and Annexure D – Proposed changes to rate components, paragraph D.5.

## 10.2 Distribution use-of-system loss factors

For Distribution-connected loads, the loss factors were updated as contained in the CTS. These are loss factors based on voltage and density. The lower the voltage the more assets must be used and the higher the technical losses. The same is true for areas with low densities such as rural areas where electricity must be delivered over longer distances between customers. The inverse is true for customers connected at higher voltage and in more densely populated areas. These loss factors are approved as part of the Schedule of Standard Tariffs approved by NERSA.

For Distribution-connected generators, the same Distribution loss factors as for loads will apply for the network charge rebate for generators. For all SPU tariffs, the loss factors are based on the urban 500 V level and Transmission Zone 0.

The updated loss factors used to determine energy charges for loads and network charge rebates for Distribution-connected generators are provided in the following table.

*Table 6: Updated Distribution loss factors*

| Voltage | Urban | Rural |
|---|---|---|
| < 500V | 1.1862 | 1.1973 |
| ≥ 500V & < 66kV | 1.1556 | 1.1761 |
| ≥ 66kV & ≤ 132kV | 1.0724 | 0.0000 |
| > 132kV/Transmission connected | 1.0000 | 0.0000 |

## 11. Transmission use-of-system (ToUS) charges

Transmission use-of-system charges comprise:

- Transmission network charges for loads
- Transmission network charges for generators
- Transmission loss factors for loads
- Transmission loss factors for generators
- Ancillary service charges for loads and generators.

Transmission network ("transmission") tariff charges are designed based on the NERSA-approved revenue requirement that is a pass-through of cost to Distribution. Transmission use-of-system charges are based on Transmission's cost drivers, and allocation of costs using the methodology prescribed in the South African Grid Code. Figure 12 below illustrates the cost allocation stages followed to determine the Transmission charges and as indicated in Figure 12, the cost drivers are based on the number of customers, the network capacity, the customer demand, the ancillary services provided and transmission losses. Accordingly, Transmission's costs are customer-driven, capacity or demand-driven and energy-driven.

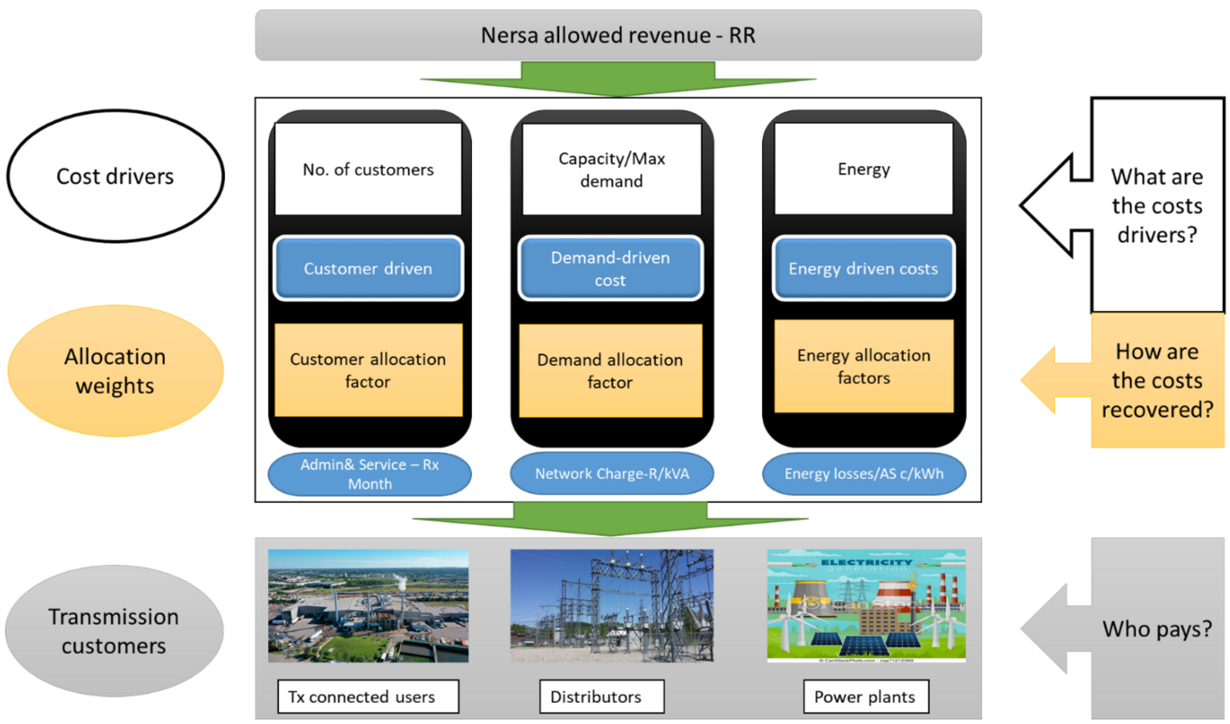



*Figure 7: Transmission cost drivers and customers*

Transmission recovers 50% of its revenue from generators and 50% from demand (load) customers. Both Transmission-connected generators and loads pay a charge based on the geographical pricing zone in which they are located, and these zones differ for generators and loads. There are six pricing zones for generators, namely, the Cape, Karoo, KwaZulu-Natal, Vaal, Mpumalanga, and Waterberg

Zones. The pricing zones for generators are determined through power-flow studies, taking into account the generators' usage of Transmission assets, the impact on technical losses, and their geographical location. The TUoS charges for loads are differentiated into four zones based on the distance of the load, in kilometres, from Johannesburg.

## 11.1 Transmission network charges for generators

The network charges and loss charges for the generators reflect the relative location of each generator and the international import point of connection. The figure below depicts the South African map with the location of each zone as it is currently being applied. The network costs for generators are recovered through the following charges:

- A network charge based on the transmission zone is derived using the distribution factor methodology, which calculates the network charges on a nodal basis. Nodes are subsequently allocated into their respective generation zones, and the charges are aggregated per zone. Eskom is in the process of reviewing the zones and their charges, as these were based on the location of generation in 2011. The current system has changed since then requiring a review.
- Below are the current zones for generators.

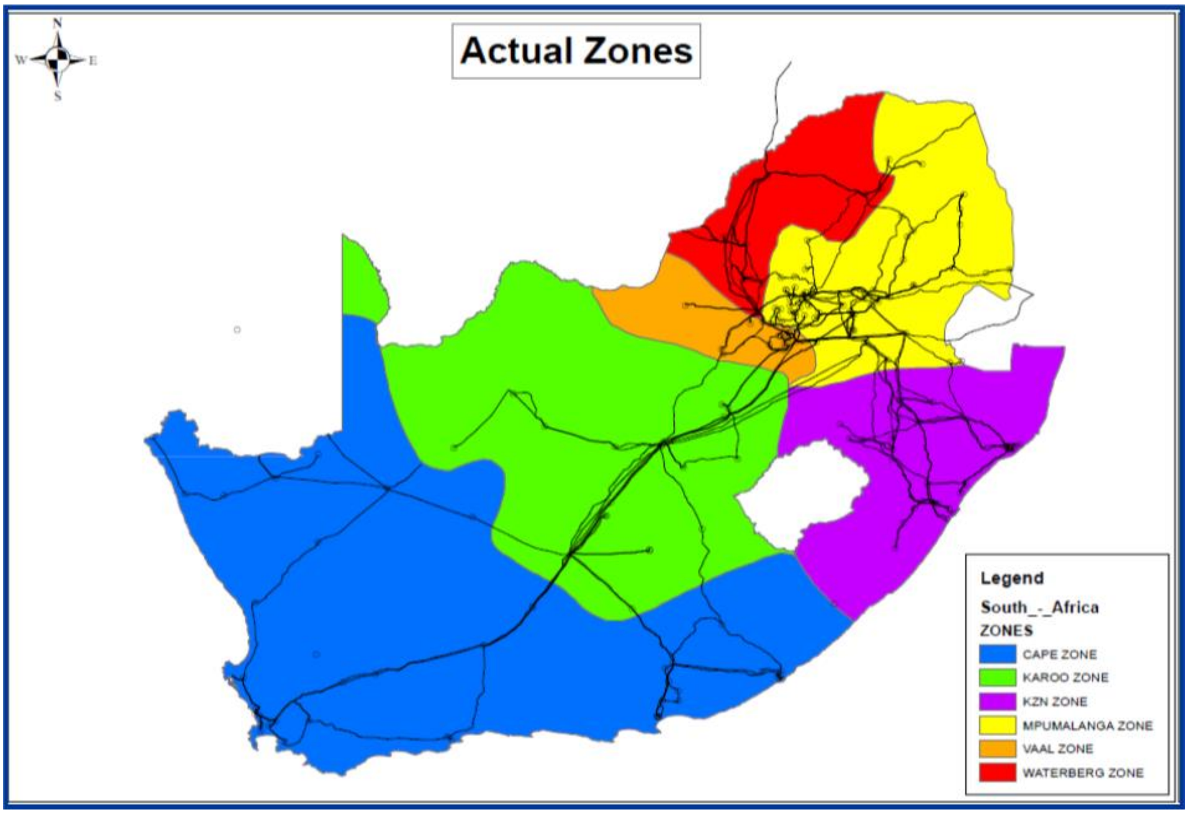



*Figure 8: Transmission zones for generators*

Below are the proposed use-of-system charges applicable to Transmission generators

*Table 7: Proposed Transmission network charges for generators*

| Network charges for Transmission connected generators | Charge |
|---|---|
| **Zone** | **R/kW** |
| Cape | R 0.00 |
| Karoo | R 0.00 |
| Kwazulu-Natal | R 4.14 |
| Vaal | R 13.77 |
| Waterberg | R 17.63 |
| Mpumalanga | R 16.36 |

New studies are underway that would update the current charging structure with more current data and network changes, and they are planned to be submitted at a later stage, separate from this submission.

## 11.2 Transmission network charges for loads

The TUoS tariffs for loads (or consumers) are based on a historic concentric-pricing approach, based on a cumulative radius from Johannesburg of 300 km. This zoning methodology is arbitrary and based on outcomes of the 1985 De Villiers Commission of Inquiry. Therefore, it does not reflect the actual relative usage of transmission assets by the loads but is intended to recover 50% of Eskom Transmission's revenue. The network charge is increased for each zone.

- For direct Transmission-connected customers, the network charges used in the CTS are based on the charges provided by Transmission and are geographically differentiated by the transmission zones.
- For Distribution-connected customers, the Transmission network charges are geographically differentiated by the transmission zones and voltage.
- The direct Transmission network charges are calculated to take into account the diversified demand of all the embedded customers of Distribution, which will be much higher within the Distribution network than the demand at the main Transmission substation level.

This adjustment is necessary, as the direct TUoS charges are applied to the undiversified demands of all customers, which would result in an over-recovery of the Transmission-related costs. This gives a lower rate for the TUoS charge for customers connected to the Distribution network than the direct TUoS network charge, as the cost is divided by a greater volume.

The >132kV Transmission network charges for loads connected at the Transmission level are shown in the next table.

*Table 8: Proposed Transmission network charges for loads*

| Network charges for Transmission-connected loads | Charge |
|---|---|
| **Zone** | **R/kVA** |
| ≤ 300km | 14.49 |
| > 300km & ≤ 600km | 14.64 |
| > 600km & ≤ 900km | 14.78 |
| > 900km | 14.93 |

The transmission zones for loads are depicted in the figure below.

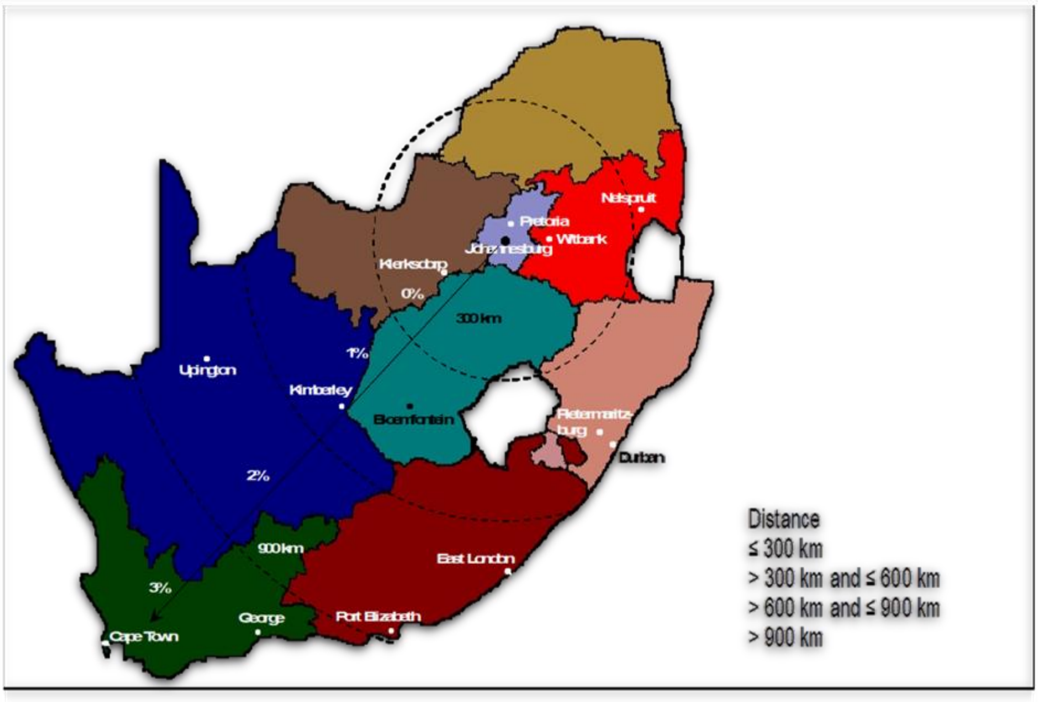



*Figure 9: Transmission zones for loads*

## 11.3 Transmission losses

Electrical losses occur because of transporting electricity from the source (the generator) to the load (the customer). As generators are paid for the energy produced and the customer is charged for the energy received, the difference results in a cost to Distribution and Transmission for the “lost” energy. This is charged as electrical losses. Average loss factors, not actual losses per customer, are used.

- All customers pay for technical losses through their tariff rates, and the cost of losses is added to the energy rates. Eskom also publishes the loss factors as part of its Schedule of Standard Prices.
- The loss factors are updated based on the CTS, and as a result, there has been a change from the current loss factors.

## 11.4 Transmission losses payable by loads

The loss factors for loads are differentiated based on the relative distance of loads from Johannesburg. Loads are charged for transmission losses to recover 50% of the cost of the losses.
For loads connected directly to the transmission system, the loss factors like the TUoS charges are determined by geographical location based on the concentric zones. The further away the customer is from Johannesburg, the greater the technical losses charge.

The cost of electrical losses is recovered as a function of the appropriate loss factors for the relevant zone, the voltage level, and the time-of-use cost of energy. As these are energy-related costs to cover the difference between the amount produced and sold, they need to be recovered from all customers. The updated Transmission loss factors used to determine energy charges for loads and network charge rebates for Distribution-connected generators are provided in the table below.

*Table 9: Proposed Transmission loss factors applicable to loads*

| Loss factors for Transmission connected loads | |
|---|---|
| **Zone** | **Loss factor** |
| **≤ 300km** | **1.0060** |
| **> 300km & ≤ 600km** | **1.0160** |
| **> 600km & ≤ 900km** | **1.0261** |
| **> 900km** | **1.0361** |

## 11.5 Transmission losses payable by Transmission-connected generators

Eskom is proposing to amend the current loss factors applicable to Transmission-connected generators. Currently, in certain Transmission zones, the loss factors are negative, effectively meaning that Eskom could pay a generator for being located in this specific zone. This principle at the time assumed a generator whose injections increase transmission losses faces a positive loss factor, which results in a charge, while a generator whose injections reduce transmission losses faces a negative loss factor, which results in a rebate. The loss factors are added or rebated to the Transmission network charge applicable to generators. Below are the current loss factors per zone.

*Table 10: Current Transmission loss factors applicable to generators*

| Loss factors for Transmission connected generators | Loss factor |
|---|---|
| Cape | 0.971 |
| Karoo | 0.995 |
| Kwazulu-Natal | 1.004 |
| Vaal | 1.020 |
| Waterberg | 1.023 |
| Mpumalanga | 1.021 |

It is to be noted that in the Cape and Karoo, the loss factor is less than 1 as per Table 10, and the network charges are zero (refer to Table 7 ). This means that the formula for the raising of the charges (set out below) results in a negative charge.

*Losses charges = energy produced in **peak, standard** and **off-peak** periods x WEPS rates excluding losses in each TOU period x (**Transmission loss factor** (for generators) -1)/**Transmission loss factor** (for generators).*

It is not possible to pass through negative charges, and for this reason, Eskom is proposing that the loss factors for the Cape and Karoo zones be set to 1 as follows:

*Table 11: Proposed Transmission loss factors applicable to generators*

| Loss factors for Transmission connected generators | |
|---|---|
| **Zone** | **Loss factor** |
| **Cape** | **1.00000** |
| **Karoo** | **1.00000** |
| **Kwazulu-Natal** | **1.01495** |
| **Vaal** | **1.00026** |
| **Waterberg** | **1.01352** |
| **Mpumalanga** | **1.01487** |

## 11.6 Ancillary service charges

The ancillary service charge covers the cost of providing ancillary services. These costs include the cost of reserves, black-start and islanding, constrained generation, and reactive power. The Transmission System Operator purchases these services from generators and some loads. All customers are charged for ancillary services. The ancillary services charge recovers 50% of the cost from generators and the other part from loads. This charge is raised as a c/kWh charge to all users of the networks, generators, and loads, based on voltage only. All tariffs contribute to these costs. The updated ancillary service charges for generators and loads are provided in the next table.

*Table 12: Proposed ancillary service charges*

| Voltage | c/kWh |
|---|---|
| **< 500V** | **0.36** |

| | |
|---|---|
| ≥ 500V & < 66kV | 0.35 |
| ≥ 66kV & ≤ 132kV | 0.32 |
| > 132kV/Transmission connected | 0.30 |

# 12. Residential tariffs

The proposed tariff changes to the residential tariffs are:

- Unbundling the Homepower tariff into separate energy, network, and retail charges.
- Converting the residential lifeline tariff, Homelight 20A into a single c/kWh energy rate, with no impact to the indigent on this tariff.

A key consideration in the changes to the residential tariffs is the need to evolve the tariffs to better meet customer needs. In 2010 the NERSA introduced the Inclining Block Tariffs (IBT) where the c/kWh charge increases the higher the consumption in a month. The inclining block tariff (IBT) as a tariff structure is no longer appropriate because of customer perceptions and provides uneconomic incentives for customers installing embedded generation.

## 12.1 Homepower tariff changes

Eskom proposes the amendment of the Homepower structure to align with that of the other SPU tariffs. This will also remove the IBT energy charge structure. The current Homepower tariff (inclining block rates) structure does not give the right economic signals, for example:

- IBT was designed to subsidise the indigent at extremely low consumption, i.e., consumption at the first block of the IBT.
- The second block rate of the IBT includes fixed network-related charges which are much higher.
- This uneconomic signal greatly incentivises higher-consumption customers to use alternative energy sources and energy efficiency.
- The reduction in consumption by these customers because of the switch to alternative energy sources results in subsidies being unfairly distributed; these customers (mostly affluent, who then reduce consumption) are subsidised by those without alternative energy sources.
- There are limited signals for the actual demand customers impose on the network.

The current Homepower IBT tariff structure provides a cross-subsidy at low consumption levels. Refer to Figure 27, where this is demonstrated. The current residential tariffs recover both network and energy costs through volumetric energy (c/kWh) charges, and they no longer reflect the changing energy environment. For example, a tariff with only a c/kWh energy charge does not reflect the proper avoided costs when customers decide to use alternative energy sources. This switch to alternative energy sources may look very attractive, however the economic test should be against the energy-only costs and not a bundled tariff.

The proposed Homepower structure is based on the updated energy costs which include legacy charge, generation capacity, network, ancillary service, and service/administration costs. The proposed changes will result in increased fixed charges, but the revenue from Homepower will, on average, decrease slightly due to a reduction in costs. Some rebalancing was done between the Homepower supply size categories to recover costs. This change does not aim to recover additional revenue but to properly unbundle costs into tariff charges.

Unbundling and restructuring ensure that customers connected to the grid are charged for the fair use of the network, remove and correct unfair subsidies, provide greater transparency of costs, and ensure the correct economic signal is provided.

It is important to note that even if residential customers use alternative energy sources, they will still need to pay for being connected to the grid. Customers with alternative energy sources still rely on the grid at night or during periods when their alternative energy systems are not generating electricity. Therefore, they need to contribute fairly to using the grid as a backup during these times. However, customers who have completely disconnected from Eskom's supply, with no Eskom connection or meter, will not be required to make any payments to Eskom, as they are not using the grid as a backup.

With the unbundling of the residential tariffs, customers will continue to receive their normal bills based on their monthly energy consumption. The bill will transparently show the charges for energy consumption and the costs related to using the Eskom grid, called network charges.

The proposed unbundling of the residential tariffs will now clearly show the costs associated with grid usage (network charges) and energy consumption separately.

The following table demonstrates the rebalancing done at an overall Homepower tariff category revenue level to recover the costs reflected in the CTS.

*Table 13: Homepower impact (R million)*

| Homepower Summary | Current Tariff Revenue | Calculated Cost | % Difference between Cost and Current Revenue | Adjusted Revenue to be Cost Reflective | % Difference between Cost and Adjusted Revenue |
|---|---|---|---|---|---|
| Homepower 1 | R1 448 339 697 | R1 221 492 658 | -16 % | R1 218 993 808 | 0 % |
| Homepower 2 | R497 331 480 | R421 842 193 | -14 % | R425 921 461 | -1 % |
| Homepower 3 | R209 729 710 | R167 931 946 | -20 % | R168 487 889 | -0 % |
| Homepower 4 | R1 863 653 530 | R1 762 419 718 | -5 % | R1 763 323 987 | -0 % |
| Homepower Bulk | R64 261 178 | R49 739 236 | -27 % | R46 698 606 | 7 % |
| Total Homepower | R4 083 315 594 | R3 623 425 750 | -11 % | R3 623 425 750 | -0 % |

The average customer on all Homepower tariffs will pay less on the proposed tariffs than they are currently paying. The following table shows the current average monthly bill versus the proposed monthly bill for an average Homepower customer.

*Table 14: Homepower current average monthly bill versus the proposed monthly bill*

| Homepower | Average Monthly Consumption (kWh) | Current Average Monthly Bill | Proposed Average Monthly Bill | Difference (R) | Difference (%) |
|---|---|---|---|---|---|
| Homepower 1 | 1100 | R3 832 | R3 225 | -R607 | -16 % |
| Homepower 2 | 1522 | R5 459 | R4 675 | -R784 | -14 % |
| Homepower 3 | 4236 | R14 949 | R12 009 | -R2 940 | -20 % |
| Homepower 4 | 656 | R2 184 | R2 066 | -R118 | -5 % |
| Homepower Bulk | 10442 | R36 429 | R26 473 | -R9 956 | -27 % |
| Total Average | 0 | R3 051 | R2 708 | -R344 | -11 % |

## 12.2 Unbundling the Homeflex tariff

NERSA approved the introduction of a residential time-of-use tariff, called Homeflex, for urban residential customers in 2023/24. The Homeflex tariff is a dynamic tariff and a market tool that can support a more optimal operation of the power system while providing a benefit to customers. This tariff also provides compensation to customers for energy exported. This tariff is more cost-reflective in structure and adaptable to evolving customer needs, changes in technology, and the changing energy environment.

The Homeflex tariff is based on the proposed new TOU structure energy charges, and it is proposed that the fixed charges for Homeflex be unbundled to align with the proposed unbundling of the fixed charges in the Homepower tariffs. This means that the Homeflex tariff will have the same GCC, network, retail, and ancillary service charges as Homepower, however the energy charges are TOU rates.
Customers on the Homeflex tariff may export excess energy onto the grid using their alternative energy systems and will receive compensation from Eskom in the form of energy credits, which will reduce their electricity bills.

This tariff is mandatory for customers with SSEG with the approved post-paid smart metering device and is voluntary for all other residential customers who do not have SSEG.

## 12.3 Homelight tariff changes

For the Homelight tariff, it is proposed to move away from the current IBT structure into a single energy rate structure based on the average of the current Homelight (i.e., current tariff revenue/total current sales). The current IBT is an unpopular structure, is difficult for customers to understand, and causes perverse behaviour when purchasing at high block rates. For large low-income/multiple-family dwellings, the assumption that low consumption equals poor may not necessarily be true. Multiple dwellings may also be supplied from a single electricity supply point. An IBT structure has a significant impact on these customers. In addition, there are more affluent customers, for example, with holiday homes that unfairly benefit from the inclining block rate.

Eskom conducted a survey on the inclining block tariff in January 2022 to assess the customer understanding and opinions of the current inclining block rate tariff, and to substantiate the perceptions listed above. Feedback from the online survey indicated that 59% of the participants have a 75% - 100% understanding of how the tariff works, while 11% of the participants found it difficult to understand.

Of the participants, 54% indicated that they have a negative opinion about the tariff, because of the tariff being perceived as punitive, and unfair, stating challenges around affordability and the high cost of living. Only 17% indicated that they support the tariff and that it promotes an energy-efficient culture. A total of 67% of the participants also shared that they do not believe that you need to pay more per unit if you use more electricity.

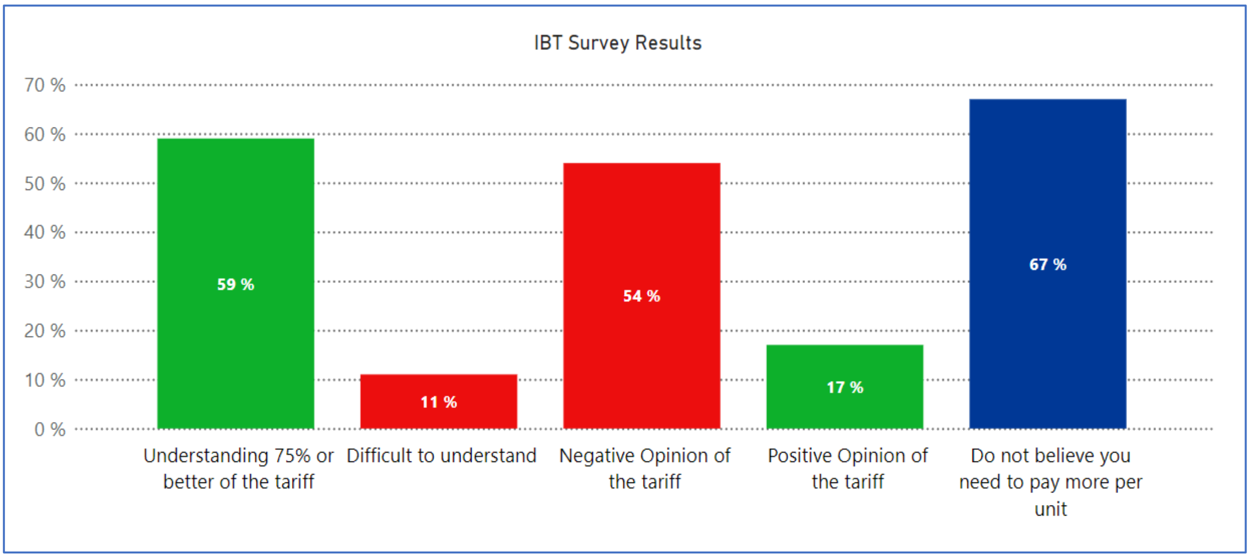



*Figure 10: IBT survey results*

The details of the survey results are provided in Annexure F.

By removing the IBT structure, the subsidies for the Homelight tariff will be retained, and customers will not pay more than their current electricity bill on the average monthly consumption, as demonstrated in the following figures.

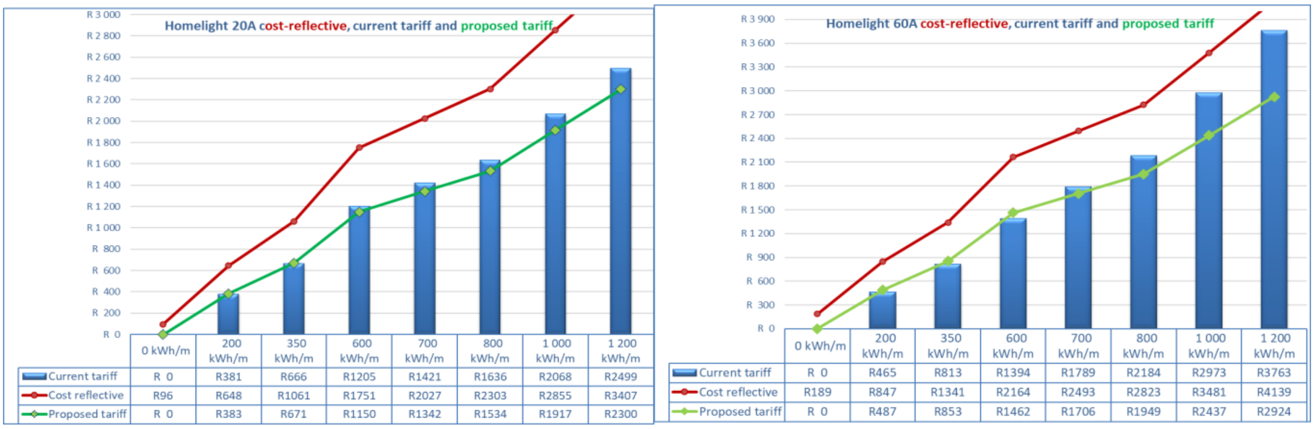



*Figure 11: Homelight 20A and Homelight 60A - cost, current tariff, and revised tariff*

The following tables compare the current tariff with costs. It can be noted that the Homelight 20A tariff does not recover energy, network, retail, or ancillary service costs as these costs are subsidised.

## *Table 15: Homelight current tariffs rates and revenue*

| Homelight | Tariff book energy charge c/kWh Block 1 | Tariff book energy charge c/kWh Block 2 | Tariff book ancillary service charge c/kWh | Tariff book NDC c/kWh | Tariff book NCC R/POD/day | Tariff book service and admin R/POD/day | Current tariff revenues |
|---|---|---|---|---|---|---|---|
| Homelight 20A | 190.28 | 215.62 | 0.00 | 0.00 | R0.00 | R0.00 | R8,682,896,167 |
| Homelight 60A | 232.31 | 394.86 | 0.00 | 0.00 | R0.00 | R0.00 | R6,581,522,856 |

## *Table 16: Homelight cost-reflective rates*

| Homelight | Cost reflective energy charge c/kWh | Cost reflective generation capacity charge R/POD/day | Cost Reflective Legacy Charge c/kWh | Cost reflective ancillary charge c/kWh | Cost reflective network demand charge c/kWh | Cost reflective network capacity charges R/POD/day | Cost reflective service & admin charge R/POD/day | Service and admin charge c/kWh |
|---|---|---|---|---|---|---|---|---|
| Homelight 20A | 179.65 | R0.41 | 20.21 | 0.36 | 75.73 | R1.78 | R0.95 | 40.58 |
| Homelight 60A | 177.40 | R0.98 | 20.21 | 0.36 | 131.26 | R4.27 | R0.95 | 29.34 |

| Homelight | Cost reflective R/y | Difference between cost and current revenue | % subsidy received | Total costs c/kWh |
|---|---|---|---|---|
| Homelight 20A | R15,126,955,967 | R6,444,059,800 | 0.74 | 333.96 |
| Homelight 60A | R10,499,955,853 | R3,918,432,997 | 0.60 | 388.76 |

## *Table 17: Homelight proposed tariff rates*

| Homelight | Block 1 energy charge | Block 2 energy charge | Single energy charge |
|---|---|---|---|
| Homelight 20A | NA | NA | 191.69 |
| Homelight 60A | NA | NA | 243.68 |

This structural change is revenue-neutral to the existing Homelight tariff, that is, recovers the same revenue as the current tariffs, and no change has been made to the overall subsidy received. This structural change is not linked to any of the other tariff changes in this document, as it is not based on cost.

## 13. Service charges converted to R/POD and not R/account

Currently, the administration charge is per point of delivery, and the service charge is per account. Eskom proposes changing the methodology so that both the administration charges and the service charges will be raised per point of delivery and differentiated by size. No change is proposed to the current size categories.

The rationale is that a customer could have many PODs under one account and pay the same service charge as a customer with one account and one POD. This is not equitable or fair, as more retail resources are used where there are multiple PODs to one account. This service charge will not be raised for each transaction separately where the reconciliation of energy is done for wheeling, offset, and banking and where Eskom is the purchaser of energy for generators embedded in a municipality.

This change will mean that the service charges will decrease in value, but customers who have consolidated many points of delivery into one account may see an overall increase in rates. Customers with few PODs per account will see a reduction. This change, however, cannot be viewed in isolation from the other tariff changes, as the total impact of all changes will have to be considered.

## 14. Nightsave changes

Nightsave Urban is currently split into a Nightsave Urban Small category (1 MVA and below) and a Nightsave Urban Large category (> 1 MVA). It has been decided to combine these tariffs into one category, based on the total cost of the Nightsave Urban tariff.

This decision was made as a step toward reducing the number of tariffs and the administrative challenges where customers around the 1 MVA supply size can have an actual bigger or smaller maximum demand. This would require actual tariff conversions between the two Nightsave Urban tariffs. On average, the existing Nightsave Urban Large and Small tariffs have increased due to updating tariffs with costs.

# 15. Subsidies

The following applies to subsidies in electricity tariffs (where the tariff is not cost-reflective):

- Subsidies may be within a tariff and based on the tariff structure, this is called intra-tariff subsidies. For example, where fixed costs are recovered through variable charges, this means that the subsidies are hidden and that higher-consumption customers pay the subsidies. IBT is a perfect example, but this is true for all current tariffs.
- It is also possible for some charges within a tariff category to be higher than the cost and for others within the same category to be lower (as is done with the lower-voltage network charges of the urban LPU tariffs).
- The correct level of subsidies can only be determined through updating tariffs with the CTS study to establish the applicable subsidy charges.
- Subsidies may be applied for affordability and/or socio-economic reasons covering either or all, for usage, network, and connection costs. Where the tariff category as a whole may receive a subsidy, and other tariffs pay this subsidy, this is called an inter-tariff subsidy.
  - These subsidies being paid are typically more transparent, but for the receiving tariffs, they tend to be hidden.
  - The tariffs receiving subsidies are the rural tariffs (Landrate, Ruraflex, and Nightsave Rural) and the Homelight tariffs.
  - The overall level of subsidies for the subsidised rural and Homelight tariffs remains the same in this plan, but some changes have been made structurally within tariff categories.
- The subsidy charges (the electrification and rural subsidy (ERS) and affordability subsidy) in this plan have decreased because of the updating of the rates by the CTS study.
- There is no national directive, rule, or guideline on electricity subsidies, except for the policy positions in the EPP (EPP policy positions on subsidies) and the NERSA 2005 subsidy framework (the status of the latter is not known).
- Most subsidies are from legacy historical decisions, such as the then government's decision in the 1980s to cross-subsidise rural electrification.

Section 16 of the ERA states that NERSA may permit certain levels of cross-subsidies. NERSA has, at its discretion, determined subsidies over the years such as the lower tariff increases to the Homelight tariffs, which placed an additional burden on Eskom's urban non-local authority LPU tariffs. Eskom has no mandate to make changes to socio-economic subsidies and has, therefore, kept these subsidy levels the same.

## 15.1 Inter-tariff subsidies

The inter-tariff subsidies are those paid by other tariffs to the Homelight 20A, Homelight 60A, Landrate, Ruraflex, and Nightsave Rural tariffs. Currently, the tariff revenue from the Landrate and Nightsave Rural tariffs is more than the allocated cost, meaning that these tariffs are currently paying a subsidy instead of being subsidised. This has been corrected in this plan to ensure that the tariffs do not contribute to any subsidies. The inter-tariff subsidies are currently recovered through the ERS charge from all the urban LPU tariffs and the affordability subsidy from only the non-local authority urban LPU tariffs. These are socio-economic subsidies.

The following table provides an overview of current subsidies versus revised subsidies. Some rebalancing has been done between Nightsave Rural and Ruraflex, as Nightsave Rural has been paying subsidies. The subsidy received by Ruraflex has been reduced due to the alignment of the Ruraflex and Nightsave tariffs.

*Table 18: Inter-tariff subsidies*

| Subsidies received | Cost Rm | Current Tariff Rm | Current subsidy received Rm | Revised subsidy received Rm |
|---|---|---|---|---|
| Landrate | R13,709 | R14,515 | R807 | -R0 |
| Ruraflex | R13,171 | R12,023 | -R1,148 | -R369 |
| Nightsave Rural | R2,768 | R3,070 | R303 | -R140 |
| Homelight 20A | R15,127 | R8,683 | -R6,444 | -R6,444 |
| Homelight 60A | R10,500 | R6,582 | -R3,918 | -R3,918 |
| Total | R55,274 | R44,873 | -R10,401 | -R10,872 |

The following figure represents the current and revised subsidies after updating the tariffs according to the principles contained in this plan.

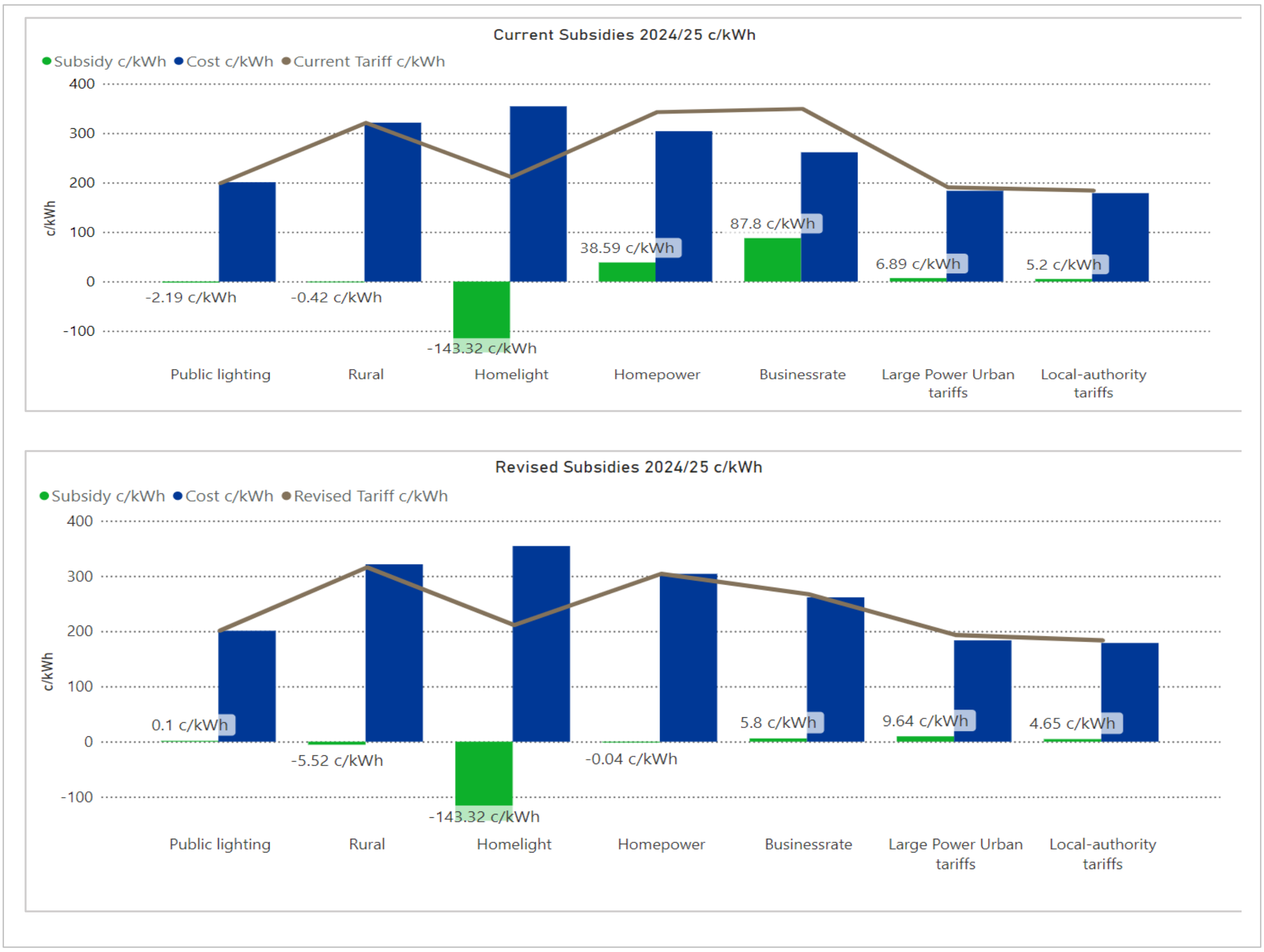



*Figure 12: Current and revised inter-tariff subsidies*

## 15.2 Homelight inter-tariff subsidies

Homelight was introduced as a single energy rate tariff in the late 1980s and was designed by Eskom to provide subsidies for low-consumption customers below 350 kWh, initially for 60A only. At that stage, Eskom also funded the capital cost. The capital cost was subsequently funded by the government through the national electrification programme. The tariff was later split into 20A and 60A versions, with the 20A version being the most subsidised.

In 2010, NERSA redesigned the tariff to be an inclining block rate tariff. NERSA also determined a lower price increase for Homelight 20A than the average. This resulted in a new subsidy (the affordability subsidy charge) payable by non-local authority urban LPU tariffs.

At this stage, the Homelight tariff, on average, only contributes towards energy costs. The tariff does not recover service and administration, maintenance, operating and refurbishment costs. Even though the initial capital is funded by the government, the ongoing costs are, therefore, not fully recovered by the tariff. Current subsidies are R10.3 billion recovered through the ERS charge and the affordability subsidy charge.

This socio-economic subsidy is provided to vulnerable customers within all municipal boundaries where Eskom is the supplier.

## 15.3 Rural inter-tariff subsidies

After representations by the South African Agricultural Union to both the government and Eskom in the early 1980s, Tariff D (now called Landrate) was introduced by Eskom in January 1982 for application in rural areas to assist in the costs of connection. This led to the government determining 2 km of network plus the transformer costs to be “free” for the cost of connection (referred to as the capital allowance). Part of this capital allowance cost was included in the tariff and part through subsidies. After an investigation into the profitability of Tariff D done during 1988, it was seen that the then Tariff D did not cover the cost-of-supply and that the subsidies were increasing. The 2km was then reduced to 200 m. Where applicable the excess of this line allowance, was raised as a connection charge.

In 1994, Eskom introduced a rural LPU version, then Landrate 4 in 1997, and Landlight in 2009.

In 2002, Eskom requested approval from the then NER to reduce all outstanding monthly connection charges of customers by R900,00 per month and include this amount in the Standard Tariffs. The network charges were commensurately increased. The network charge is payable to recover the total network costs of the network not funded through connection charges. The network charge contributes to the capital allowance and the costs of maintaining, operating, and refurbishing the network, and this is payable while there is still a connection. However, because the rural tariffs receive a subsidy, the tariff charges currently recover only some portion of the total costs of the rural networks. This under-recovery is subsidised by the LPU urban tariffs. This is a historical subsidy recovered through the ERS charge.

Even if the connection charge were to fully recover all the connection costs, **which it does not**, the current network charges would not be sufficient to cover maintenance and refurbishment costs. To date, Eskom has continued to provide a capital allowance towards the cost of connection. This also means that new customers are subsidised by existing customers to facilitate connection. This is standard practice for all Eskom tariffs.

It is not correct to assume that customers who have already paid for their network costs through connection charges should not be paying network charges. Connection charges only recover a small portion of the initial capital and as stated above, do not include maintenance, operating, and refurbishment of these assets. Rural customers have higher costs than those in urban areas because of the lower density (mostly one transformer per customer), longer distances between customers, and relatively low consumption of the assets invested. This makes the cost per customer, per kWh, per kVA much higher than that in urban areas, where assets are shared to a much greater extent.

Nightsave Rural currently pays subsidies, while Ruraflex receives the largest allocation of subsidies in the rural tariffs. For this reason, some rebalancing has been done to reduce the subsidies to Ruraflex and give Nightsave a subsidy allocation. This rebalancing has been done equitably, ensuring that the Ruraflex and Nightsave tariffs pay the same network charges.

## 15.4 Intra-tariff subsidies

Intra-tariff subsidies are when one charge is subsidised by another charge within a tariff category; for example, Megaflex higher-voltage network charges subsidise the lower-voltage network charges.

Intra-tariff subsidies are also a result of pooling done in the CTS study exercise, as it is not possible to calculate a tariff for every customer. Therefore, costs are pooled, for example:

- network costs are allocated based on a generic network model, not per individual customer; and
- residential energy tariffs are based on statistically measured representative load profiles, not on actual TOU usage (as this is not measured).

The proposals in this retail plan have reduced some of the intra-tariff subsidies to rebalance some of the subsidies within a tariff category, for example, increasing some Landrate tariffs and reducing others within the Landrate tariff category.

## 15.5 Calculation of the ERS charges and the affordability subsidy charge

The calculations of the ERS charge and the affordability charge are shown next.

The ERS calculation is as follows:

∑ Total cost[1] - ∑ Total revised revenue[1] = Total subsidy

The greater of Total subsidy or ∑ Total network cost [1] = ERS allocation

ERS allocation / ∑ Total GWh[2] x 100 = ERS c/kWh

ERS is then scaled to ensure no additional revenue recovery (revenue neutral to MYPD decision).

[1]= Total for Landrate, Ruraflex, Nightsave Rural, Homelight 20A and Homelight 60A

[2]= Total for local authority and non-local authority tariffs, Megaflex, Miniflex, Nightsave Urban, Transflex 1 and 2, Businessrate and Municflex

The affordability subsidy charge is the difference between the network cost and the total subsidy for the current Homelight 20A tariff, calculated as follows:

∑ Total subsidy [3] - ∑ Total network cost [3] = Affordability subsidy allocation

Affordability subsidy allocation / ∑ Total GWh[4] x 100 = ERS c/kWh

[3]= Total for Homelight 20A

[4]= Total for non-local authority tariffs, Megaflex, Miniflex, Nightsave Urban, Transflex 1 and 2 and Businessrate

To ensure parity with comparable tariffs with the same supply sizes (Miniflex and Nightsave Urban) as Businessrate currently contributes to the above subsidies, Businessrate now also has an ERS charge applied to the tariff. As the proposed Businessrate is significantly reduced because of the tariff being updated with the CTS study values, this change does not increase the current tariff.

The table below shows the value of the subsidy charges. To ensure revenue neutrality so that the overall revenue is equal to the approved MYPD costs, the ERS is adjusted.

*Table 19: ERS charge and affordability charge calculation*

| Tariff | Costs Rm. | New tariff Rm. | Subsidy Rm. | ERS (network cost) Rm. | AFS allocation Rm. | ERS charge c/kWh | ERS charge scaled c/kWh | AFS charge c/kWh |
|---|---|---|---|---|---|---|---|---|
| Landrate | R13,709 | R13,708 | -R0 | -R0 | R0 | 0.00 | 0.00 | 0.00 |
| Ruraflex and Nightsave Rural | R15,939 | R15,430 | -R509 | -R509 | R0 | 0.33 | 0.30 | 0.00 |
| Homelight 20A | R15,127 | R8,683 | -R6,444 | -R3,430 | -R3,014 | 2.24 | 2.02 | 4.33 |
| Homelight 60A | R10,500 | R6,582 | -R3,918 | -R3,918 | R0 | 2.56 | 2.31 | 0.00 |
| Total | R55,274 | R44,402 | -R10,872 | -R7,858 | -R3,014 | 5.13 | 4.63 | 4.33 |

## 16. Amending the Gen-Wheeling and Gen-offset tariffs

The affordability subsidy charge is a socio-economic subsidy provided to the Homelight residential tariff. This subsidy minimises the impact of high electricity price increases for indigent customers, ensuring that they can afford essential electricity services.

The Eskom wheeling policy clearly specifies that the Offtaker (/ customer) receiving wheeled energy from a private generator must contribute to subsidies on the energy delivered through the Eskom network. This means that the contribution to subsidies cannot be avoided when a customer is wheeling energy from a private generator. However, the Gen-wheeling and Gen-Offset tariffs in the Eskom schedule of standard prices includes a credit for the affordability subsidy charge, allowing customers who are wheeling to receive a credit for this subsidy. This approach can also result in an effective offset of network-related charges payable under a wheeling transaction.

The proposal is to correct this in the Gen-Wheeling and Gen-offset tariffs to align with the policy and ensure that customers receiving wheeled energy pay the required subsidies. This correction will ensure fairness for all customer groups contributing to socio-economic inter-tariff subsidies.

## 17. Impact of the proposed structural changes per tariff

The impact of the proposed structural changes on each tariff category and tariff charges is indicated in the table below.

*Table 20: Impact of the proposed structural changes*

| Change | Impact |
|---|---|
| **Updating rates with costs from a CTS study** | • Energy costs (including GCC and legacy) increase by an average of 15% relative to other charges. This is due to the correction of the misalignment caused by applying average increases to all tariffs instead of increases per Eskom division. It also highlights that the current energy charges are lower than they ought to be.<br>• Distribution network costs are reduced by an average of 38% and Transmission network costs are reduced by an average of 37%.<br>• Retail costs are reduced by an average of 48%. |
| **Unbundling of energy charges into Generation capacity charge and legacy charge** | Unbundling of the energy charges into a generation capacity charge and a legacy charge results in a reduction in the variable TOU c/kWh energy charge, which has decreased by 3%. |
| **Changes to TOU periods and rates** | The impact on customers will depend on their load profile and response to the TOU changes. Reduced winter rates will result in lower costs for high consumers during winter. High summer peak users will incur higher costs. The exact impact of the TOU response is indeterminable at the tariff design stage. |
| **Basing service charge per POD** | Although the service and administration charges have significantly reduced with an update of the CTS study, charging the service fee per POD rather than per account may negatively impact customers with multiple PODs linked to one account. |
| **LV Subsidy charge due to municipality tariff rationalisation** | Splitting the LV subsidy charge between non-local authority and local authority LPU tariffs has resulted in different charges for each, with higher charges for non-local authority LPU tariffs as illustrated in the revised subsidy for Megaflex due to higher volumes of low and medium voltage customers. The LV subsidy charge has been reduced significantly, by an average of 90%, for both categories. Local authority LPU tariffs now contribute only to low- and medium-voltage subsidies within their tariff pool. |
| **ERS and affordability subsidy charges** | The ERS and affordability subsidies see a significant reduction due to rate updates based on the CTS study. Currently, these subsidy charges are overstated. |

| | |
|---|---|
| **Change** | **Impact** |
| **Local authority Tariffs due to municipality tariff rationalisation** | Based on the CTS study and combined for both rural and urban categories, these tariffs generally see an average decrease except for Public Lighting tariffs, which face a significant increase due to previous under-recovery against costs. |
| **Public Lighting Tariffs** | Significant increase resulting from updating tariffs with the CTS study. This tariff has been under-recovering significantly against costs and barely recovers energy costs. |
| **Nightsave Urban Tariffs** | Both Nightsave Urban Large and Small have been aligned to make the energy demand charges the same. Both tariffs see an average increase of 3.6% due to updating with the CTS study. |
| **Businessrate Tariffs** | A significant reduction due to CTS study updates. This tariff category now also contributes to the ERS subsidy charge to align with the other commercial LPU tariffs paying this contribution. |
| **Ruraflex and Nightsave Rural Tariffs** | Network charges for these tariffs have been aligned (made the same), leading to a reduction of 14% for Nightsave Rural and an increase of 6% for Ruraflex, with overall subsidies remaining the same. The slight increase in Ruraflex is also due to the cost-reflective increase in energy charges. |
| **Landrate and Landlight Tariffs** | Overall reduction of 6.5% for Landrate and Landlight tariffs due to updating with the CTS study. The tariff is currently recovering more than the cost. Rebalancing was done for the tariff to recover cost. All the Landrate and Landlight tariffs will see a reduction. |
| **Homepower Tariffs** | The impact varies per supply size category due to CTS study updates. On average, Homepower tariffs see a reduction of 11% due to cost-based pricing without subsidies. Removing IBT and introducing a more cost-reflective fixed R/day charge results in lower-consumption customers paying more and customers consuming at average consumption paying less on their monthly electricity bills. |
| **Homelight Tariffs** | The existing subsidies are retained, meaning that customers on a Homelight tariff will not pay more than the current tariff because the tariffs will remain subsidised. There is no tariff increase to the Homelight tariff as a result of tariff restructuring. |

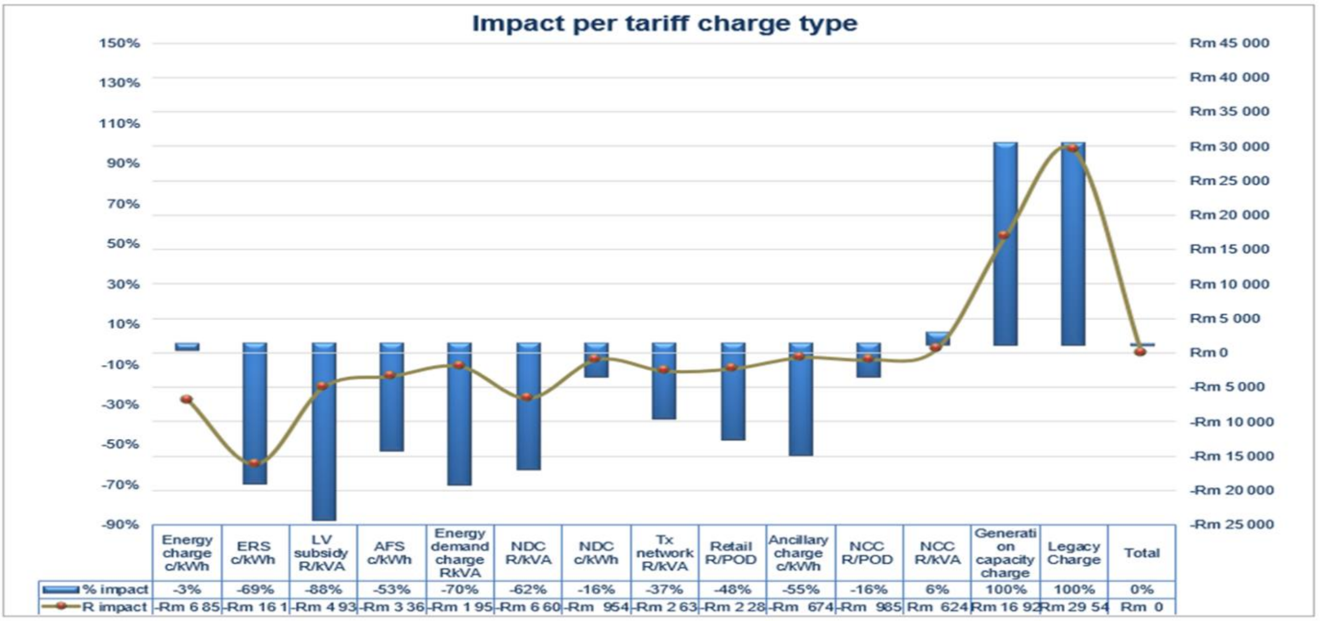



*Figure 13: Impact per charge type*

To be noted in the figure above is that the current energy charge revenue, when aligned with the total updated energy-related costs (including the generation capacity and legacy charges), has increased significantly, and the majority of the remainder of the charges have decreased. The following table shows these impacts in rand.

The following figure shows these impacts per tariff charge type in percentage for the urban large power tariffs and Municflex.

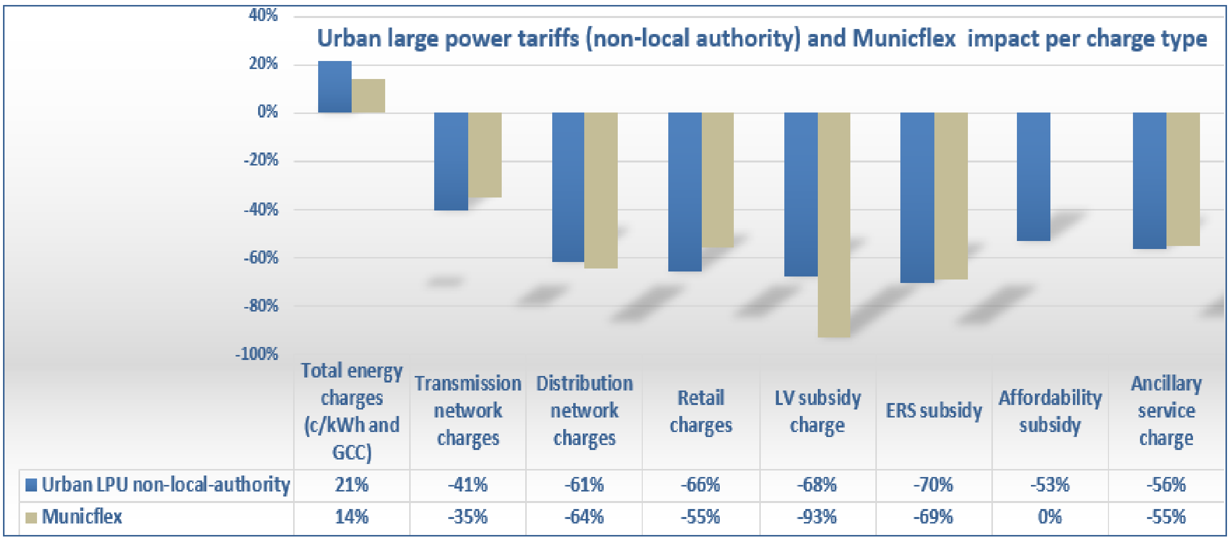



*Figure 14: Percentage impact per tariff charge type for urban large power tariffs and Municflex*

*Table 21: Summary of total impact, per tariff category*

| Rm. impact of changes to rates per category | Urban LPU non-local-authority | Rural LPU non-local-authority | Urban SPU non-local-authority | Rural SPU non-local-authority | Public lighting non-local authority | Homelight | Local-authority LPU | Local-authority SPU | Local-authority Public lighting | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| Network charge current | R 17 752 | R 4 485 | R 1 187 | R 5 214 | R 0 | R 0 | R 13 411 | R 307.7 | R 0 | **R 42 357** |
| Network charges proposed | R 11 374 | R 4 459 | R 1 056 | R 5 273 | R 0 | R 0 | R 8 731 | R 237 | R 0 | **R 31 130** |
| % difference | -36% | -1% | -11% | 1% | 0% | 0% | -35% | -23% | 0% | **-27%** |
| | | | | | | | | | | |
| Energy charges current | R 93 969 | R 9 648 | R 5 547 | R 7 281 | R 143 | R 15 264 | R 122 888 | R 441 | R 231 | **R 255 414** |
| Energy charges proposed | R 114 449 | R 9 584 | R 4 215 | R 7 452 | R 145 | R 15 264 | R 140 117 | R 431 | R 299 | **R 291 956** |
| % difference | 22% | -1% | -24% | 2% | 1% | 0% | 14% | -2% | 29% | **14%** |
| | | | | | | | | | | |
| Retail charges current | R 971 | R 961 | R 328 | R 2 020 | R 0.12 | R 0.00 | R 386.42 | R 149.00 | R 0.04 | **R 4 815** |
| Retail charges proposed | R 455 | R 383 | R 472 | R 983 | R 0.30 | R 0.00 | R 172 | R 61 | R 0.406 | **R 2 527** |
| % difference | -53% | -60% | 44% | -51% | 156% | 0% | -55% | -59% | 802% | **-48%** |
| | | | | | | | | | | |
| ERS and AF charges current | R 17 037 | R 0 | R 0 | R 0 | R 0 | R 0 | R 12 549 | R 0 | R 0 | **R 29 586** |
| ERS and AF charges proposed | R 6 161 | R 0 | R 40 | R 0 | R 0 | R 0 | R 3 867 | R 0 | R 0 | **R 10 067** |
| % difference | -64% | 0% | 0% | 0% | 0% | 0% | -69% | 0% | 0% | **-66%** |
| | | | | | | | | | | |
| LV subsidy current | R 1 209 | R 0 | R 0 | R 0 | R 0 | R 0 | R 4 423 | R 0 | R 0 | **R 5 632** |
| LV subsidy proposed | R 389 | R 0 | R 0 | R 0 | R 0 | R 0 | R 312 | R 0 | R 0 | **R 701** |
| % difference | -68% | 0% | 0% | 0% | 0% | 0% | -93% | 0% | 0% | **-88%** |
| | | | | | | | | | | |
| Total current | R 130 937 | R 15 093 | R 7 062 | R 14 515 | R 143 | R 15 264 | R 153 659 | R 898 | R 232 | **R 337 804** |
| Total proposed | R 132 828 | R 14 426 | R 5 781 | R 13 708 | R 145 | R 15 264 | R 153 199 | R 729 | R 300 | **R 336 679** |
| R Difference | R 1 891 | -R 667 | -R 1 281 | -R 807 | R 2 | R 0 | -R 460 | -R 169 | R 68 | **-R 1 124** |

## 18. Conclusion

The tariff changes contained in this retail tariff plan submission are based on an updated Cost to Serve (CTS) study, aligning all tariff rates with the current cost of supply as mandated by NERSA. Different tariff rates no longer reflect the different services being provided (not aligned with unbundled divisional energy, network, and retail costs) due to the application of average price increases.

It is vital that tariff charges accurately reflect current divisional costs to avoid volume and trading risks and to reflect cost drivers accurately. This is made possible through the cost-to-serve study where costs are allocated based on the different services provided, the cost drivers, customer segmentation, assets used, demand, voltage, losses, and the different load profiles for each customer.

The changing energy landscape, characterised by declining sales and the growing adoption of alternative energy sources, necessitates a significant overhaul of outdated tariff structures to reflect present realities. It is no longer feasible to recover fixed costs solely through kWh charges, and difficult but essential decisions are required to ensure that the use of system costs are fairly recovered from all grid users to avoid unintended subsidies. Additionally, the future competitive electricity market necessitates fully unbundled tariffs that distinctly delineate energy and network charges. Consequently, energy charges have been unbundled into a fixed generation capacity charge and a legacy charge to recover the fixed costs of generation and the subsidy for the renewable energy programme.

For municipal tariffs, reducing the number of tariffs will simplify the determination of municipal purchase costs, allowing for a better allocation of subsidies which reduces municipal contributions to subsidies. Residential tariffs also require substantial revision, with the existing Inclining Block Tariff (IBT) structure being inappropriate, unpopular, and overly complex. Eskom proposes to eliminate the IBT and transparently show cost-reflective network and retail charges for Homepower and Homeflex tariffs.

The primary objectives of this submission are to correct tariff structures to align with cost drivers and divisional costs, minimise customer impact, and incentivise customer behaviour to optimise system use. While the structural changes are designed to be revenue-neutral overall, individual customer impacts will vary based on specific consumption profiles and the nature of the structural adjustments. This submission acknowledges that achieving zero impact for all customers is impossible but strives to balance the changes fairly across the customer base.

All tariff rates in this document will be updated during the FY2026 ERTSA tariff increase process.

## 19. Future Tariff Developments

It is essential that the existing misalignments in tariff levels and structures are addressed to ensure a more accurate reflection of costs and efficient price signals. The three key areas of misalignments in tariff levels and structures are:

- Overall average tariff levels do not reflect prudent and efficient costs.
- Tariff structures, in terms of fixed/capacity and volumetric/energy charges, do not reflect the actual ratio of fixed to variable costs across the supply chain.
- Time-of-use tariff structures do not reflect the actual cost differentials for supplying at different times.

To provide appropriate price signals, as emphasised by the Electricity Pricing Policy, it is essential to correct these misalignments. Achieving this requires periodically adjusting tariffs based on updated assumptions and inputs, allowing for continuous improvements and adjustments in response to evolving market conditions and new information. This also ensures that tariffs remain relevant and reflective of the true costs and requirements of the electricity supply chain.

This document is a step towards this goal and to move towards a more cost-reflective and efficient tariff structure that meets the evolving needs of the electricity market and its participants.

The next phase in the journey of tariff design may include:

- Further alignment of the retail charges with costs from updated CTS studies;
- Annual updating of different rates due to Eskom unbundled and separate divisional increases – no longer a single average increase applied to all rates;
- Further rationalisation of tariffs;
- Further development regarding generator use-of-system charges and net-billing rates;
- Further revision to the TOU tariffs;
- Moving to make TOU mandatory for all new three-phase SPU connections, and
- Introduction of flexible short-term tariff options to address customer needs and Eskom operational requirements;
- Review of transmission tariff zone structures for generators and loads; and
- Review of transmission use of system charges cost allocation methodologies.

## Annexure A – Local authority tariff impacts

The proposed changes to the local authority tariffs are as follows:

- A new tariff LPU based on the Megaflex structure, but rates are calculated by combining the costs of Megaflex, Miniflex, Nightsave Urban Large and Small, Ruraflex, and Nightsave Rural for local authority supplies.
- A new SPU tariff based on the Businessrate structure, but rates are calculated by combining the costs of Landrate, Businessrate, and Homepower for local authority tariffs.
- Public Lighting tariffs are based on the cost-reflective CTS study results.
- The impact of all the proposed changes in this document is provided in this Annexure A.
- The municipal tariff rates in this submission are shown in 12-month values (based on the Eskom financial year of April to March for comparison against the non-local authority 12-month rates) and in nine-month values (based on three-month April to June current tariffs, nine months at the revised CTS-based tariffs adjusted for the later price increase). Refer, furthermore, to Annexure E – Proposed Standard tariff rates in 2024/25-rand values (excluding **VAT)**,Table 38,
- Table 39,
- Table *40* and
- Table 41.
- If approved by NERSA, the existing local authority LPU tariffs Megaflex, Miniflex, Nightsave Urban Large and Small, Ruraflex, and Nightsave Rural will cease to exist and be replaced by Municflex.
- If approved by NERSA, the existing local authority SPU tariffs Landrate, Businessrate, and Homepower will cease to exist and be replaced by Municrate.

The following table provides the costs, current revenue, and revised revenue per current local authority tariff.

*Table 22: Rand impact per local authority tariff*

| Municipal tariffs | CTS allocated allowed costs Rm. | Current tariff revenue Rm. | Diff current tariff revenue and cost | Restuctured tariff revenue Rm | Difference new tariff revenue and cost Rm. | Revised subsidy c/kWh | % change in revenue due to restructuring | Difference in revenue due to restructuring Rm. |
|---|---|---|---|---|---|---|---|---|
| Local-authority tariffs total | R 150 340 | R 154 788 | R 4 447 | R 154 227 | R 3 887 | **4.64** | 0% | -R 560 |
| Megaflex Proposed to Municflex | R 140 086 | R 144 162 | R 4 077 | R 144 092 | R 4 006 | 5.06 | -0.05% | -R 71 |
| Miniflex Proposed to Municflex | R 2 088 | R 2 011 | -R 77 | R 2 137 | R 49 | 4.85 | 6.27% | R 126 |
| Nightsave Urban Large to Municflex | R 4 412 | R 4 585 | R 173 | R 4 492 | R 80 | 3.61 | -2.03% | -R 93 |
| Nightsave Urban Small to Municflex | R 171 | R 183 | R 12 | R 177 | R 7 | 10.13 | -2.91% | -R 5 |
| Ruraflex to Municflex | R 1 209 | R 1 132 | -R 77 | R 1 085 | -R 124 | (25.42) | -4.15% | -R 47 |
| Nightsave Rural to Municflex | R 1 347 | R 1 585 | R 238 | R 1 216 | -R 132 | (23.21) | -23.32% | -R 370 |
| Businessrate to Municrate | R 261 | R 379 | R 119 | R 322 | R 61 | 75.04 | -15.12% | -R 57 |
| Landrate to Municrate | R 437 | R 481 | R 44 | R 367 | -R 70 | (71.02) | -23.69% | -R 114 |
| Homepower to Municrate | R 31 | R 37 | R 6 | R 40 | R 9 | 75.86 | 7.24% | R 3 |
| Public lighting to Public lighting | R 299 | R 232 | -R 68 | R 299 | R 0.02 | 0.01 | 29.27% | R 68 |

The following is to be noted regarding the above impacts:

- Overall, Municipal tariffs will see a reduction of R560 million on their tariffs.

- There is a total revenue decrease based on Municflex due to local authority LPU tariffs no longer contributing to non-local authority low-voltage subsidies and updating of rates with the CTS study.
- The current rural tariffs, Ruraflex, Nightsave Rural, and Landrate, have the highest reduction when based on Municflex, and this is mainly due to these tariffs being pooled with the urban tariffs. This overall saving will assist the smaller municipalities that are on rural tariffs.
- Three tariffs see increases:
  - Public Lighting tariffs have the highest percentage increase due to updating tariffs with the CTS study.
  - Miniflex is increased by 6.27% mainly due to converting the current c/kWh NDC into the Municflex R/kVA NDC. However, the impact on individual customers will depend on their TOU profile.
  - Homepower has increased by 7%, mainly due to the removal of the non-cost reflective IBT structure.

The following table provides the breakdown per tariff charge type of the impact of the restructuring on the local authority tariffs.

*Table 23: Local authority tariffs rand and percentage impact per tariff category*

| Rm. impact of changes to rates | Municflex | Municrate | Local-authority Public lighting | Total local authority tariffs |
|---|---|---|---|---|
| **Network charge current** | R 13 411 | R 308 | R 0 | R 13 719.0 |
| **Network charges proposed** | R 8 731 | R 237 | R 0 | R 8 967.8 |
| **% difference** | -35% | -23% | 0% | -35% |
| | | | | |
| **Energy charges current** | R 122 888 | R 441 | R 231 | R 123 560.8 |
| **Energy charges proposed** | R 140 117 | R 431 | R 299 | R 140 847.0 |
| **% difference** | 14% | -2% | 29% | 14% |
| | | | | |
| **Retail charges current** | R 386 | R 149 | R 0.0449 | R 535.5 |
| **Retail charges proposed** | R 172 | R 61 | R 0.4055 | R 234.0 |
| **% difference** | -55% | -59% | 802% | -56% |
| | | | | |
| **ERS and AS charges current** | R 12 549 | R 0 | R 0 | R 12 549.5 |
| **ERS and AF charges proposed** | R 3 867 | R 0 | R 0 | R 3 866.7 |
| **% difference** | -69% | 0% | 0% | -69% |
| | | | | |
| **LV subsidy current** | R 4 423 | R 0 | R 0 | R 4 423.1 |
| **LV subsidy proposed** | R 312 | R 0 | R 0 | R 312.0 |
| **% difference** | -93% | 0% | 0% | -93% |
| | | | | |
| **Total current** | R 153 659 | R 898 | R 232 | R 154 787.8 |
| **Total proposed** | R 153 199 | R 729 | R 300 | R 154 227.5 |
| **R Difference** | -R 460 | -R 169 | R 68 | -R 560.4 |
| **% Difference** | 0% | -19% | 29% | 0% |

It can be noted in the above table, that in most cases the energy charges have increased, and all other charges have been reduced.

The following figures provide the potential impacts per tariff category at different consumption levels.

## A.1 Businessrate compared to Municrate

The customers on the current Businessrate local authority tariff will see a reduction on their monthly bill with the migration to the proposed Municrate tariff.

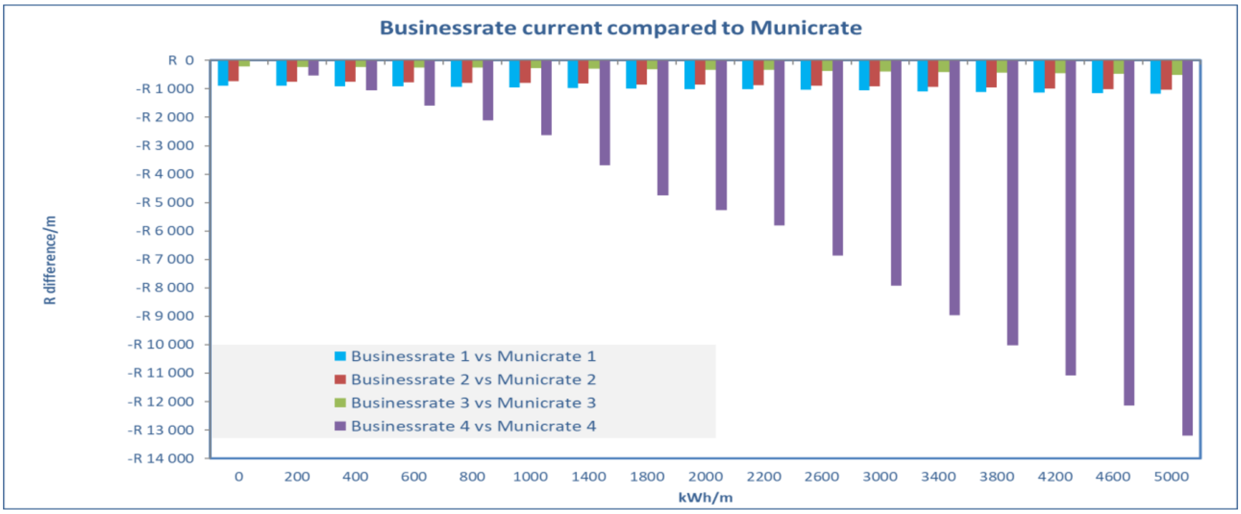



*Figure 15: Businessrate compared to Municrate at different consumption levels*

## A.2 Landrate compared to Municrate

The customers on the current Landrate local authority tariff will see a reduction on their monthly bill with the migration to the proposed Municrate tariff.

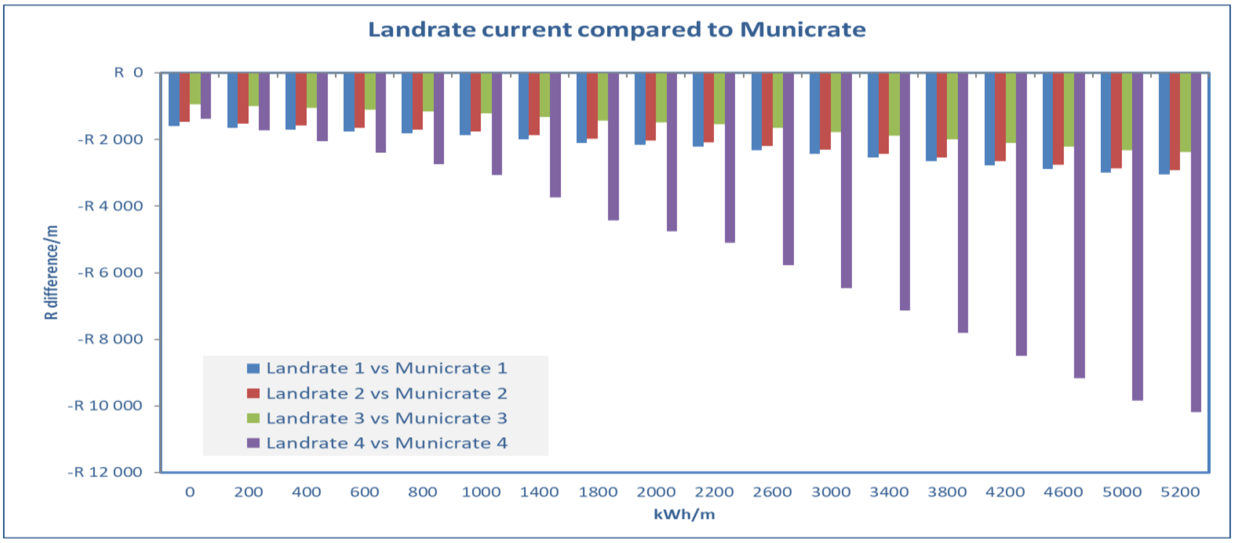



*Figure 16: Landrate compared to Municrate at different consumption levels*

## A.3 Homepower compared to Municrate

The customers on the current Homepower 2 and 3 local authority tariffs will see a reduction on their monthly bill at average consumption with the migration to the proposed Municrate tariff. A negative impact is observed on Homepower 1 and 4 sub-tariffs, based on the average consumption of these tariffs. This is due to the unbundling of the tariff from the IBT structure into a cost-reflective structure, resulting in lower consumption customers paying slightly higher than the current tariff. A similar impact is observed on the Homepower non-local authority tariffs.

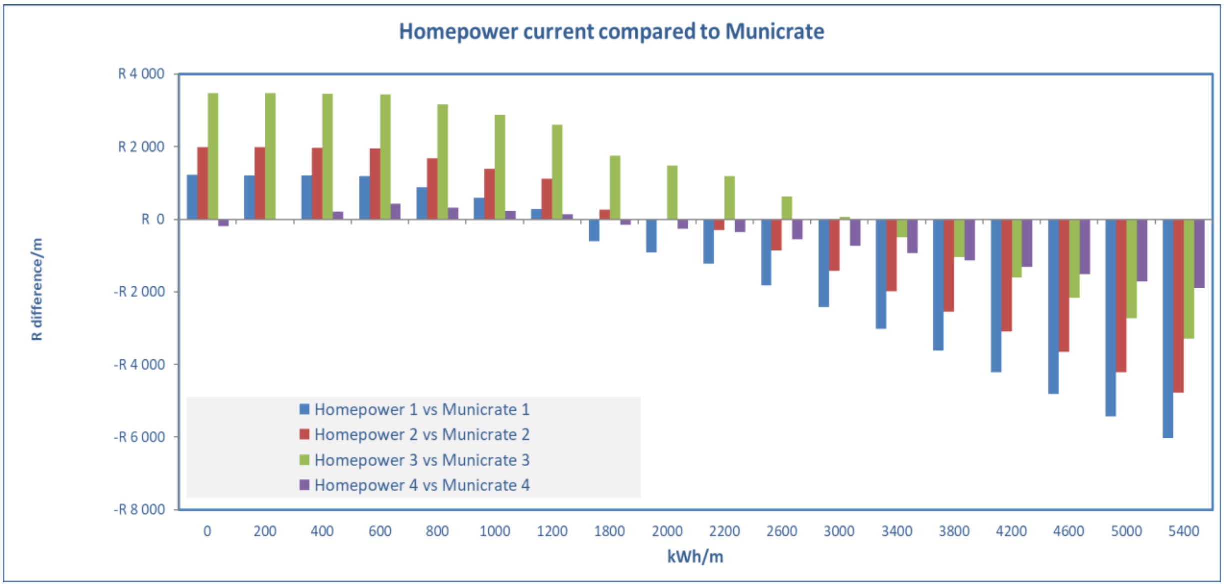



*Figure 17: Homepower compared to Municrate at different consumption levels*

## A.4 Comparison tools

Comparison tools will be provided to assess the impact of the proposed changes.

## Annexure B - non-local authority tariff impacts

The next set of figures provides a comparison between the current and proposed non-local authority SPU tariffs at different consumption levels and also compares these against cost.

### B.1 Businessrate non-local authority

The customers on the Businessrate non-local authority tariff will see a reduction on their monthly bill with the proposed tariff changes.

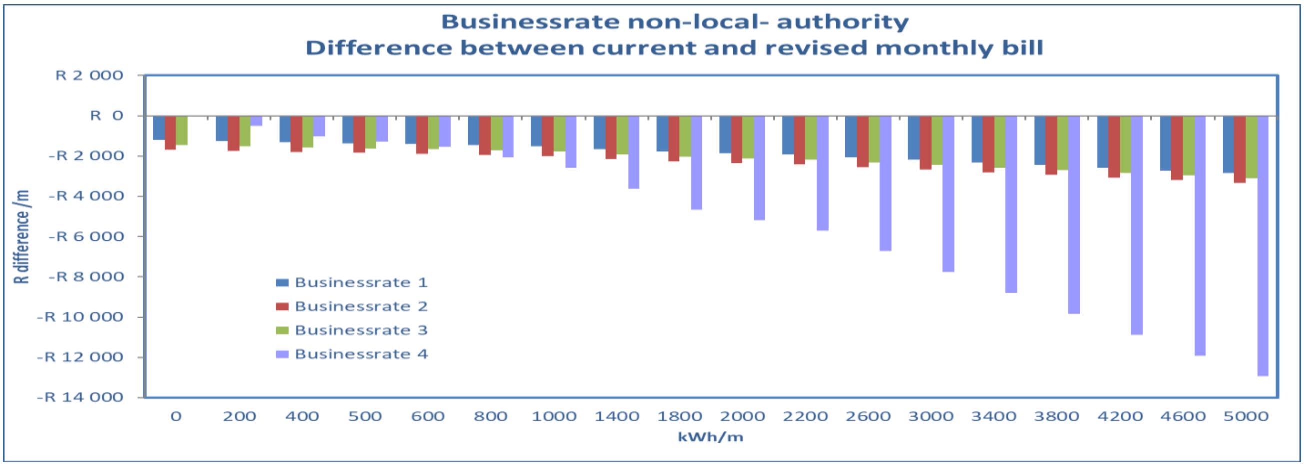



*Figure 18: Businessrate non-local authority tariffs impact at different consumption levels*

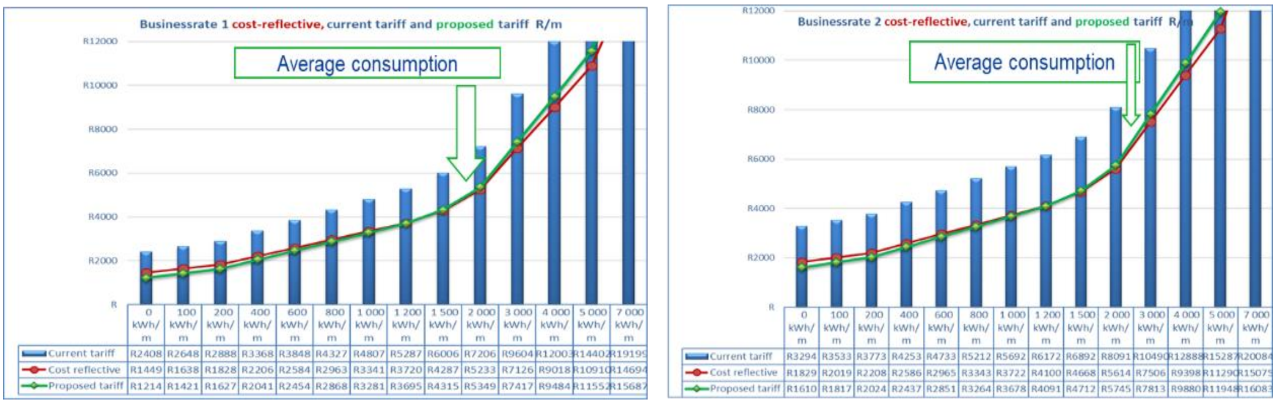



*Figure 19: Businessrate 1 and 2 non-local authority tariffs comparison of cost-reflective, current, and proposed tariffs*

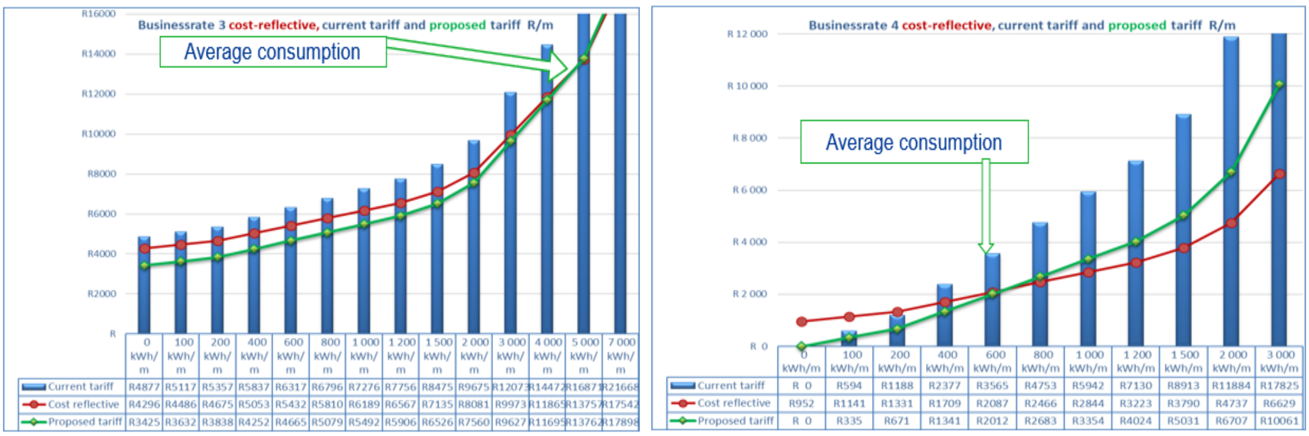


*Figure 20: Businessrate 3 and 4 non-local authority tariffs comparison of cost-reflective, current, and proposed tariffs*

## B.2 Landrate and Landlight non-local authority

The customers on the Landrate and Landlight non-local authority tariff will see a reduction on their monthly bill with the proposed tariff changes.

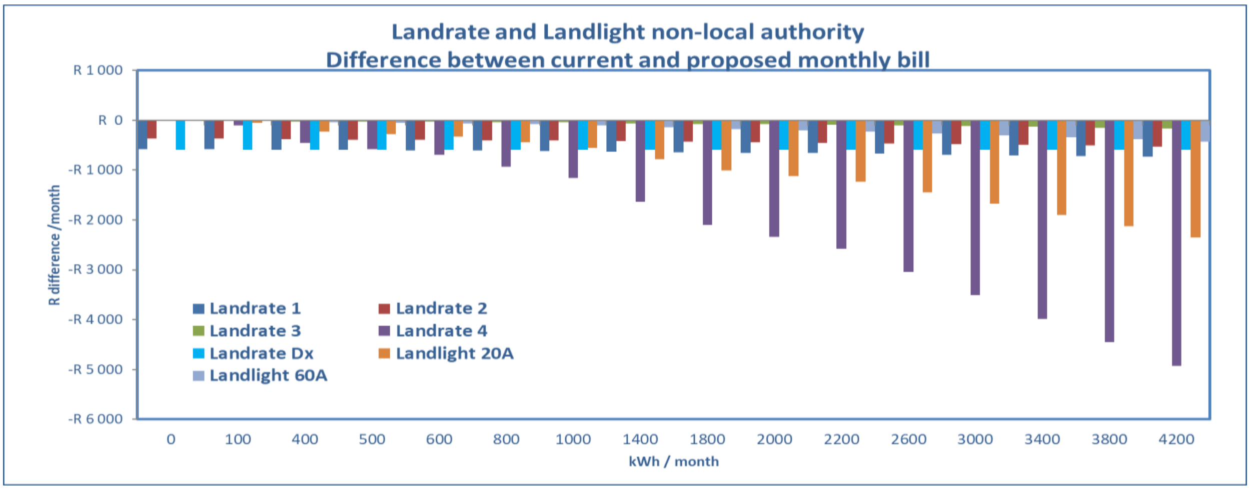



*Figure 21: Landrate and Landlight non-local authority tariffs impact at different consumption levels*

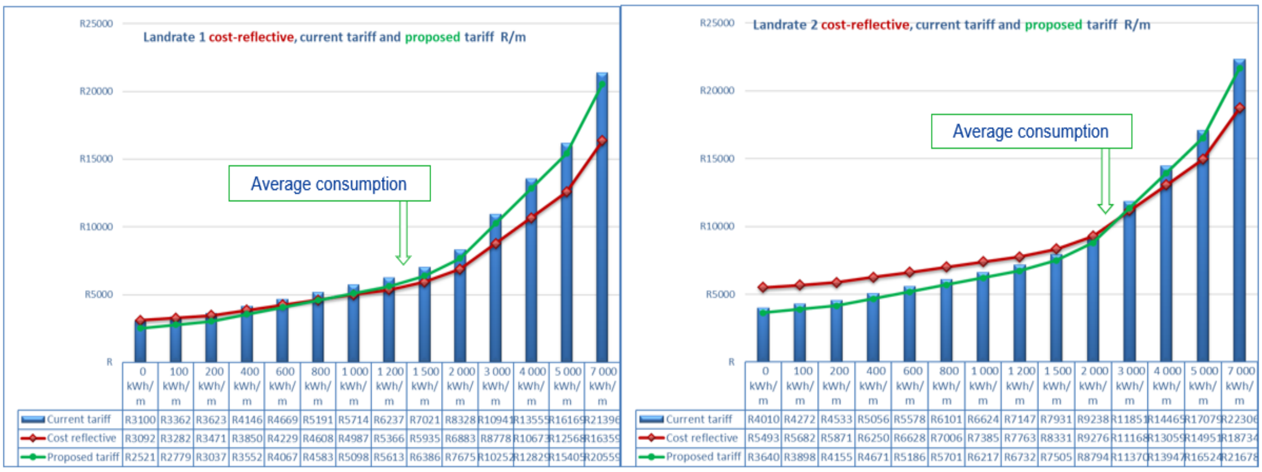



*Figure 22: Landrate 1 and 2 non-local authority tariffs comparison of cost-reflective, current, and proposed tariffs*

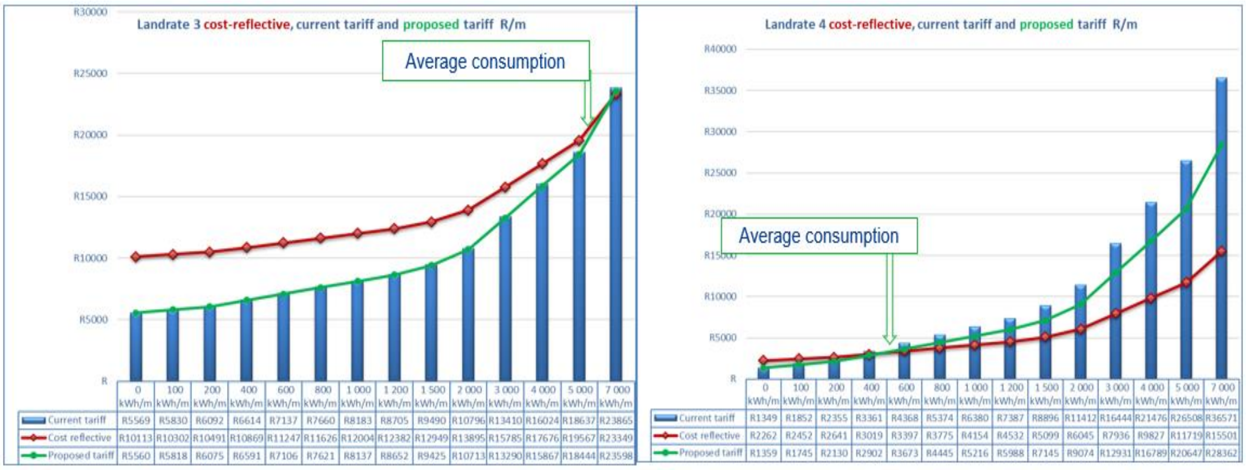



*Figure 23: Landrate 3 and 4 non-local authority tariffs comparison of cost-reflective, current, and proposed tariffs*

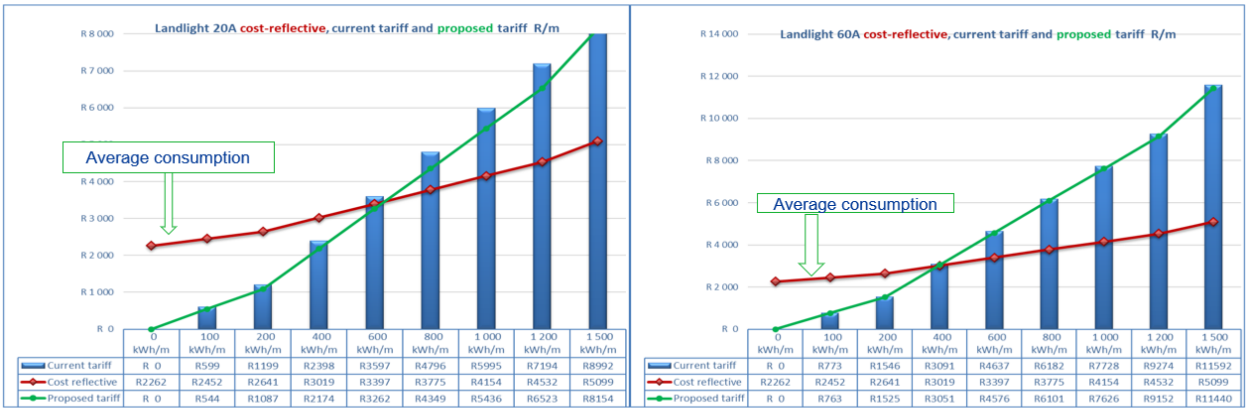



*Figure 24: Landlight 20A and 60A non-local authority tariffs comparison of cost-reflective, current, and proposed tariffs*

## B.3 Homepower non-local authority

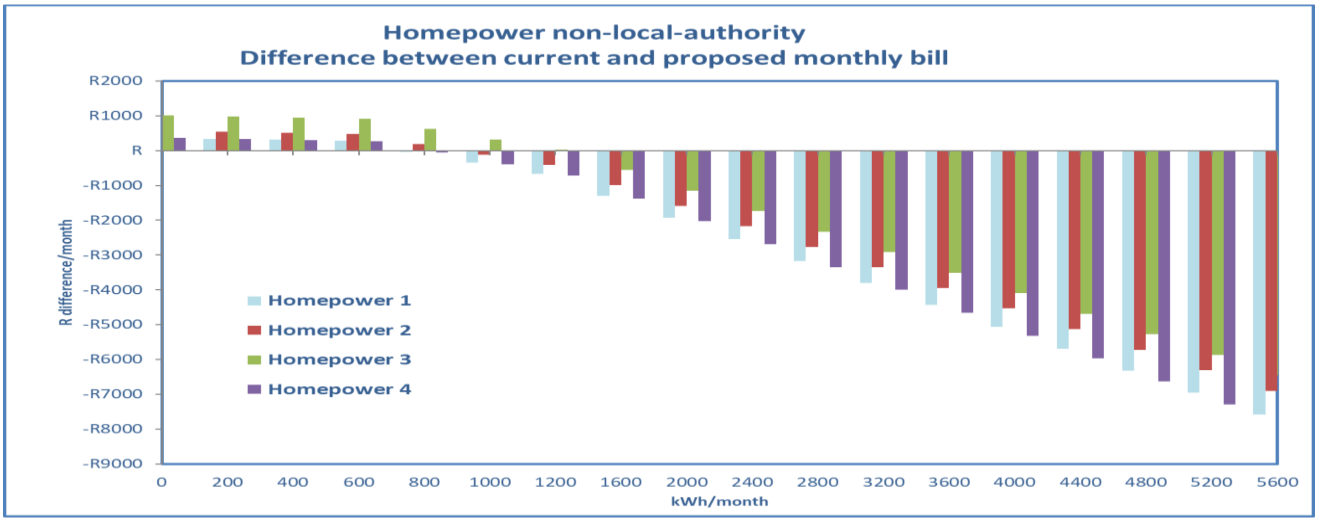
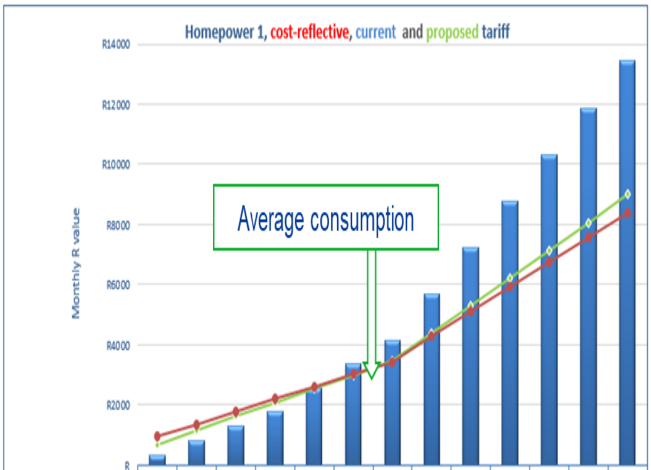
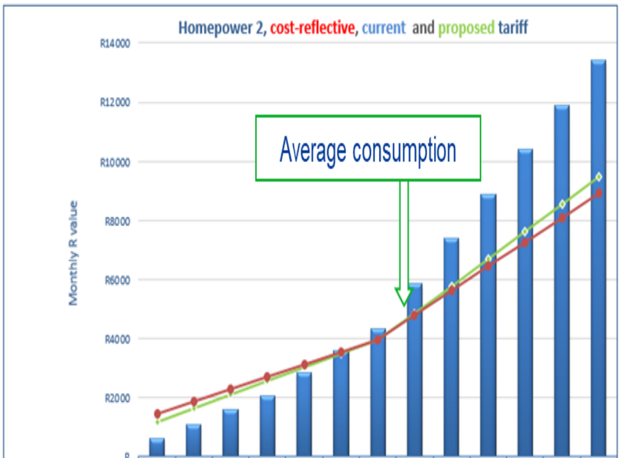



*Figure 25: Homepower non-local authority tariffs impact at different consumption levels*

The average customer on all Homepower tariffs will pay less on the proposed tariffs than they are currently paying.

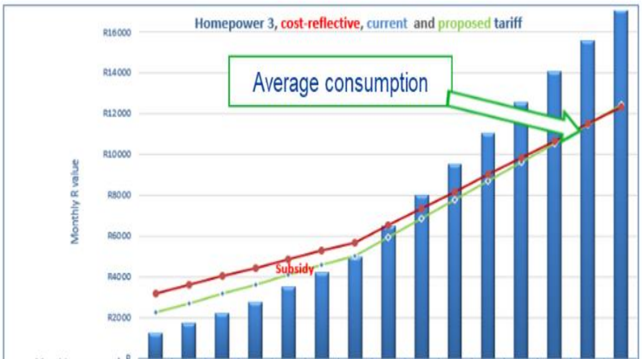



| Monthly consumption | 0 kWh | 200 kWh | 400 kWh | 600 kWh | 800 kWh | 1 000 kWh | 1 200 kWh | 1 600 kWh | 2 000 kWh | 2 400 kWh | 2 800 kWh | 3 200 kWh | 3 600 kWh |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Homepower 1 current | R320 | R811 | R1302 | R1793 | R2569 | R3344 | R4120 | R5670 | R7221 | R8772 | R10323 | R11874 | R13425 |
| Homepower 1 proposed | R690 | R1151 | R1612 | R2073 | R2534 | R2995 | R3456 | R4378 | R5300 | R6223 | R7145 | R8067 | R8989 |
| Homepower 1 cost-reflective | R947 | R1361 | R1776 | R2190 | R2604 | R3019 | R3433 | R4261 | R5090 | R5919 | R6747 | R7576 | R8404 |

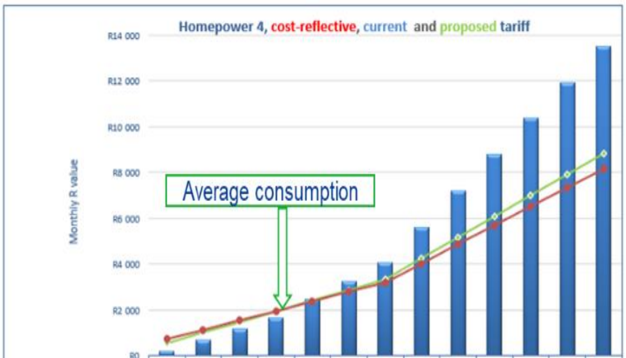



| Monthly consumption | 0 kWh | 200 kWh | 400 kWh | 600 kWh | 800 kWh | 1 000 kWh | 1 200 kWh | 1 600 kWh | 2 000 kWh | 2 400 kWh | 2 800 kWh | 3 200 kWh | 3 600 kWh |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Homepower 2 current | R600 | R1091 | R1582 | R2073 | R2829 | R3585 | R4341 | R5853 | R7365 | R8878 | R10390 | R11902 | R13414 |
| Homepower 2 proposed | R1167 | R1628 | R2090 | R2551 | R3012 | R3473 | R3934 | R4856 | R5778 | R6700 | R7622 | R8544 | R9467 |
| Homepower 2 cost-reflective | R1470 | R1884 | R2299 | R2713 | R3127 | R3542 | R3956 | R4784 | R5613 | R6442 | R7270 | R8099 | R8927 |

*Figure 26: Homepower 1 and 2 non-local authority tariffs comparison of cost-reflective, current, and proposed tariff*




| Monthly consumption | 0 kWh | 200 kWh | 400 kWh | 600 kWh | 800 kWh | 1 000 kWh | 1 200 kWh | 1 600 kWh | 2 000 kWh | 2 400 kWh | 2 800 kWh | 3 200 kWh | 3 600 kWh | 4 000 kWh | 4 400 kWh |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Homepower 3 current | R1238 | R1729 | R2220 | R2711 | R3467 | R4223 | R4979 | R6491 | R8004 | R9516 | R11028 | R12540 | R14052 | R15565 | R17077 |
| Homepower 3 proposed | R2243 | R2704 | R3165 | R3626 | R4087 | R4549 | R5010 | R5932 | R6854 | R7776 | R8698 | R9620 | R10542 | R11464 | R12387 |
| Homepower 3 cost-reflective | R3194 | R3608 | R4023 | R4437 | R4851 | R5266 | R5680 | R6508 | R7337 | R8166 | R8994 | R9823 | R10651 | R11480 | R12308 |




| Monthly consumption | 0 kWh | 200 kWh | 400 kWh | 600 kWh | 800 kWh | 1 000 kWh | 1 200 kWh | 1 600 kWh | 2 000 kWh | 2 400 kWh | 2 800 kWh | 3 200 kWh | 3 600 kWh |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Homepower 4 current | R196 | R687 | R1178 | R1669 | R2459 | R3248 | R4038 | R5617 | R7197 | R8776 | R10356 | R11935 | R13515 |
| Homepower 4 proposed | R554 | R1015 | R1476 | R1937 | R2398 | R2860 | R3321 | R4243 | R5165 | R6087 | R7009 | R7931 | R8853 |
| Homepower 4 cost-reflective | R711 | R1125 | R1539 | R1954 | R2368 | R2782 | R3197 | R4025 | R4854 | R5682 | R6511 | R7339 | R8168 |

*Figure 27: Homepower 3 and 4 non-local authority tariffs comparison of cost-reflective, current, and proposed tariffs*

## B.4 Public Lighting non-local authority


*Figure 28: Public Lighting All-Night and 24-Hour non-local authority tariffs comparison of cost-reflective, current, and proposed tariffs*

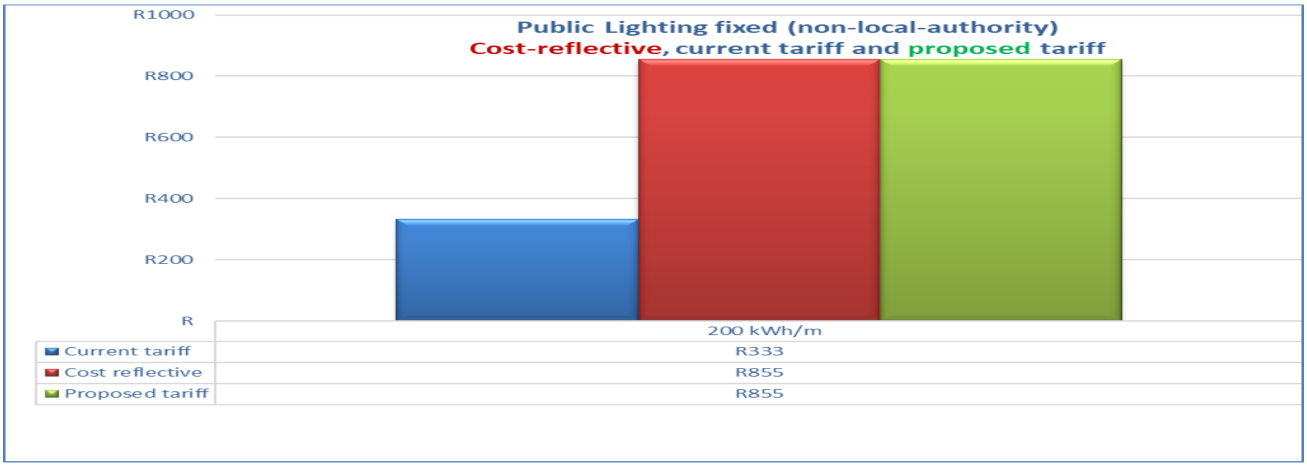



*Figure 29: Public Lighting Fixed non-local authority tariff comparison of cost-reflective, current, and proposed tariffs*

## B.5 Total impacts for large power non-local authority tariffs per voltage

The following table provides the impact per voltage for the large power non-local authority tariffs

*Table 24: Total impact per voltage for the non-local authority large power tariffs*

| LPU tariffs impact per voltage (%) | Megaflex | Miniflex | Nightsave Large | Nightsave Small | Transflex 1 | Transflex 2 | Ruraflex | Nightsave Rural |
|---|---|---|---|---|---|---|---|---|
| <500V | -6% | -1% | -8% | 2% | | | 5% | -16% |
| ≥500V & <66kV | 2% | 5% | 5% | 8% | 4% | -10% | 9% | -13% |
| ≥66kV & <132kV | -4% | -2% | -3% | -5% | 9% | -16% | | |
| >132kV | -2% | | | | 5% | | | |
| **Total** | **1%** | **3%** | **4%** | **3%** | **8%** | **-13%** | **6%** | **-14%** |

| LPU tariffs impact per voltage (Rm.) | Megaflex | Miniflex | Nightsave Large | Nightsave Small | Transflex 1 | Transflex 2 | Ruraflex | Nightsave Rural |
|---|---|---|---|---|---|---|---|---|
| <500V | -R 1 | -R 17 | -R 2 | R 22 | | | R 357 | -R 271 |
| ≥500V & <66kV | R 1 777 | R 253 | R 71 | R 41 | R 39 | -R 21 | R 422 | -R 171 |
| ≥66kV & <132kV | -R 263 | -R 2 | -R 8 | R 0 | R 292 | -R 36 | R 0 | R 0 |
| >132kV | -R 263 | R 3 | R 0 | R 0 | R 4 | R 0 | R 0 | R 0 |
| **Total** | **R 1 251** | **R 237** | **R 62** | **R 63** | **R 335** | **-R 57** | **R 779** | **-R 442** |

## B.6 Comparison tools

Comparison tools will be provided to assess the impact of the proposed changes.

# Annexure C – Motivation for the changes to TOU energy charges and rates structure

## C.1 Background

Energy costs and structure are the basis for all Standard tariffs TOU. The current Standard tariffs TOU structure (periods and rates) do not reflect the cost structure, and the TOU price signal is not aligned to the Eskom's present system operator (SO) requirements. Eskom proposes changes to the TOU rates and periods to align with the changes to the TOU energy costs and align with the SO TOU signals for the following reasons:

1. To meet the SO requirements to optimise the operation of the power system.
2. To provide the correct signal for consumption and right economic signals that promote economic efficiency.
3. To incentivise growth and sales for the benefit of both the customers and Eskom.
4. To improve financial sustainability by increasing efficiencies in operating costs.

The changes to the energy cost structure was used in the CTS study to update the Standard tariffs, and proposed TOU periods and associated cost changes. Customers have formally requested both Eskom and NERSA to review the TOU tariffs, expressing concerns that the high winter TOU energy rates prohibit the optimisation of their production and impede their economic efficiency, which has a negative impact on their financial sustainability, their competitiveness in the global economy, and their ability to grow. Both the Eskom shareholder and NERSA have, furthermore, requested that Eskom revise the TOU tariffs.

## C.2 Drivers, motivation, and strategic objectives for the proposed changes to the TOU tariff structure

The current Standard tariffs TOU energy charges structure no longer reflects the present system requirements and costs incurred during the time-of-use hours. Changes are required to this structure to assist the System Operator to optimise how Eskom's system is managed, scheduled, and dispatched. The changes to the Standard tariffs TOU energy charges to mirror SO TOU signals and costs, will optimise the management of the power system, enable an increase in sales and incentivise growth. The changes will also reduce Eskom's revenue risks (moving some of the winter revenue risk to summer) and reduce trading risk caused by a misalignment between wholesale and Standard tariffs.

After the implementation of the proposed changes, it is expected that with an updated CTS, the energy charges will be updated in the future to accommodate changes in the energy mix, future changes in the Generation capacity availability, future System Operator requirements, and customer needs.

## C.3 System Operator's requirements

The System Operator's requirements to manage the power system optimally are as follows:

a) The ideal system load profile is flat, as expensive generators must be used to supply electricity during peak times. The current power system has two peaks, that is, the morning peak and the evening peak. The evening peak occurs when the electricity demand is the highest in the day, and expensive peaking generators may have to be uneconomically used for very few hours in a day to provide electricity to the country. The winter evening peak hours are when the system demand is highest in the year.

The System Operator has also recognised the impact of PV on the system and how dispatchable plants (mainly coal plants) will have to be used to manage the impact that renewables will have on system operations. For example, customers using SSEG systems such as PV will reduce the energy in the system during the day but will not change the current morning and evening peak period system demand.

TOU pricing signals, therefore, will continue to be needed to manage the high system demand in the morning and evening peak periods as well as to manage the variation of system demand levels between the high- and low-demand months (summer and winter months).

b) The System Operator must plan for sufficient generation to be available to meet the highest demand in the day. When compared to the minimum load on the power system a significantly additional higher amount of MW is required to meet the evening peak demand. This significant difference in the minimum and maximum system demand is not an efficient technical and economical use of generation capacity.

TOU pricing signals are, therefore, needed to optimise the system load profile, that is, to reduce demand when the system is constrained during peak hours and incentivise electricity usage when there is an operational surplus during certain hours of the day.

c) The System Operator requires the evening ramp-up rate currently being experienced in the system to be managed, as the current generators can only ramp up to meet the steep increase in the evening peak at a technically limited rate. If the ramp-up rate to the evening peak is not addressed, the system will not be able to meet the demand at these times, and this will affect the security of supply.

This system requirement means that the evening peak hours need to be increased to reduce the ramp-up rate in the evenings. The proposed TOU hour changes include an increase in the evening peak for both summer and winter; currently, there are two evening peak hours, and it is proposed that there be three evening peak hours.

Customers using PV systems during the day result in a drop in the demand for electricity during the day – with the highest drop in system demand in the middle of the day. This midday demand drop (called the “duck curve”) affects the power system negatively, as it means that the generators must ramp up at an even faster rate than before to meet the evening peak demand. This is a higher pickup at a steeper ramp rate because of PV energy production dropping off, while demand increases.

d) The System Operator has requested that the Sunday evening peak demand currently being experienced at a national system level be managed so that uneconomical use of expensive peaking generators for very few hours can be avoided. Avoiding the use of expensive peaking generators will reduce Eskom costs.

e) In the proposed TOU hour changes, two standard hours are being introduced during the times that the system has a Sunday evening peak. In the current Standard TOU tariffs, all hours on a Sunday are off-peak hours, with the low off-peak price, and there is currently no price signal to manage the Sunday evening peak demand.

The below example of the System Operator requirements demonstrates the changes required to the TOU tariffs to optimally manage the power system. The PV generation is for IPP PVs only in the example below. The installed capacity for rooftop PVs is more than double that of the IPPs, however there is no metering for this. The impact of rooftop PVs is already inherently included in the residual demand; however, it will likely become even greater in future.

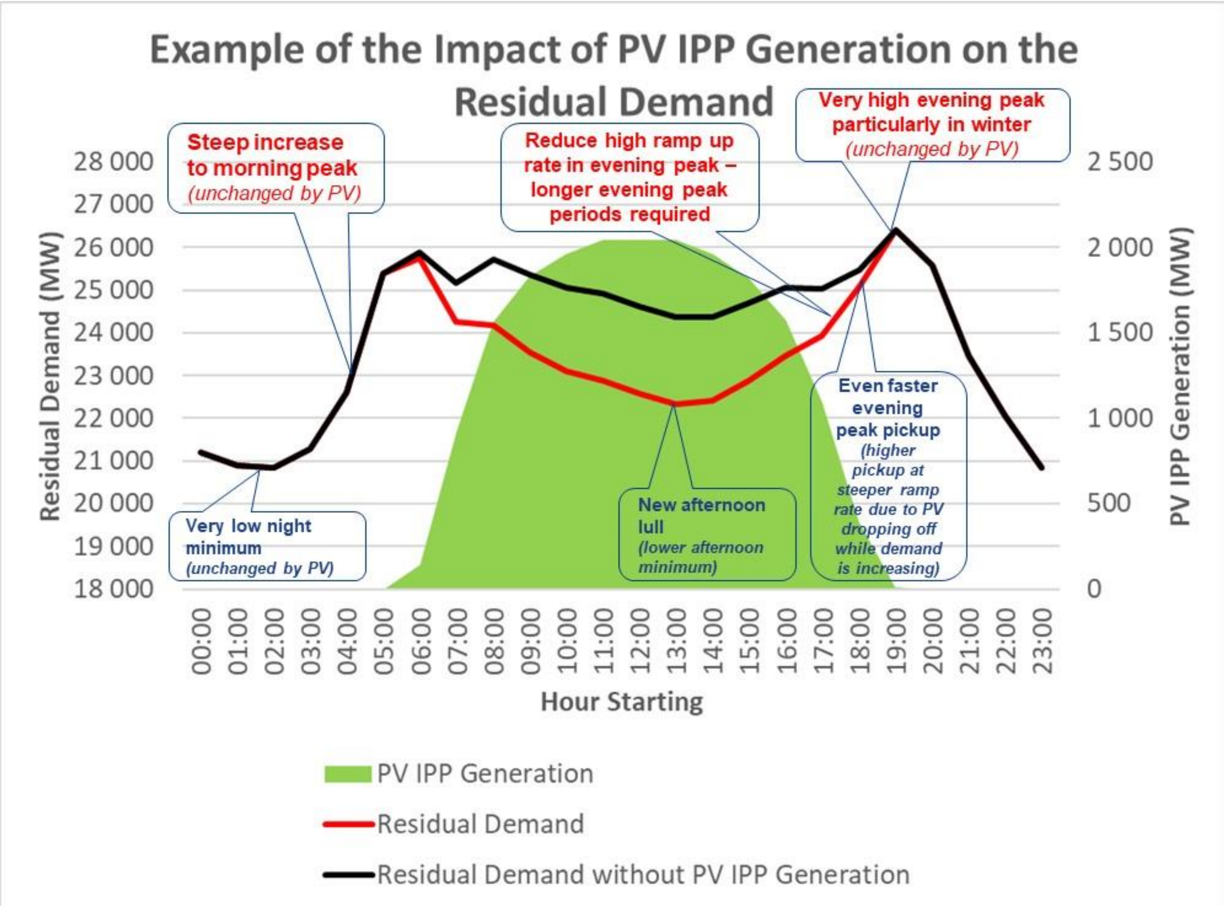


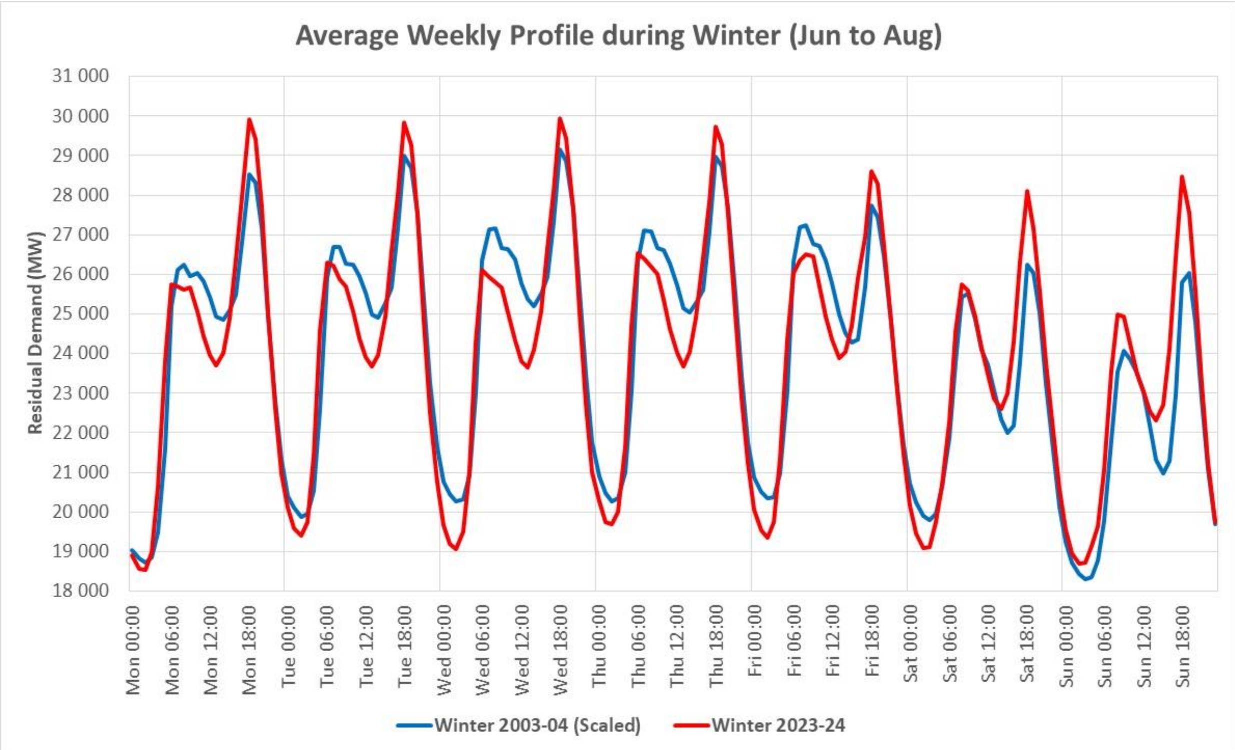

*Figure 30: Eskom's System Operator illustrative overview and requirements to optimally manage the power system*

## C.4 Changes to the system profile over the last 20 years

Customers who have responded to the current TOU pricing signals have assisted Eskom in managing the peak periods. This response has contributed to the flattening of Eskom's load profile and the management of demand, particularly in the winter TOU periods (June to August). The changes in the Eskom system load profile over 20 years (normalised) from 2003/4 to 2023/24 are shown in the next figure.

Analysis of the scaled winter and summer average week of the national system profile from 2003/4 to 2023/24 shows the following changes in the system profile:

1. A reduction in the morning peak over the years
2. A significant increase in the evening peak over the years
3. An increase in the Sunday evening demand



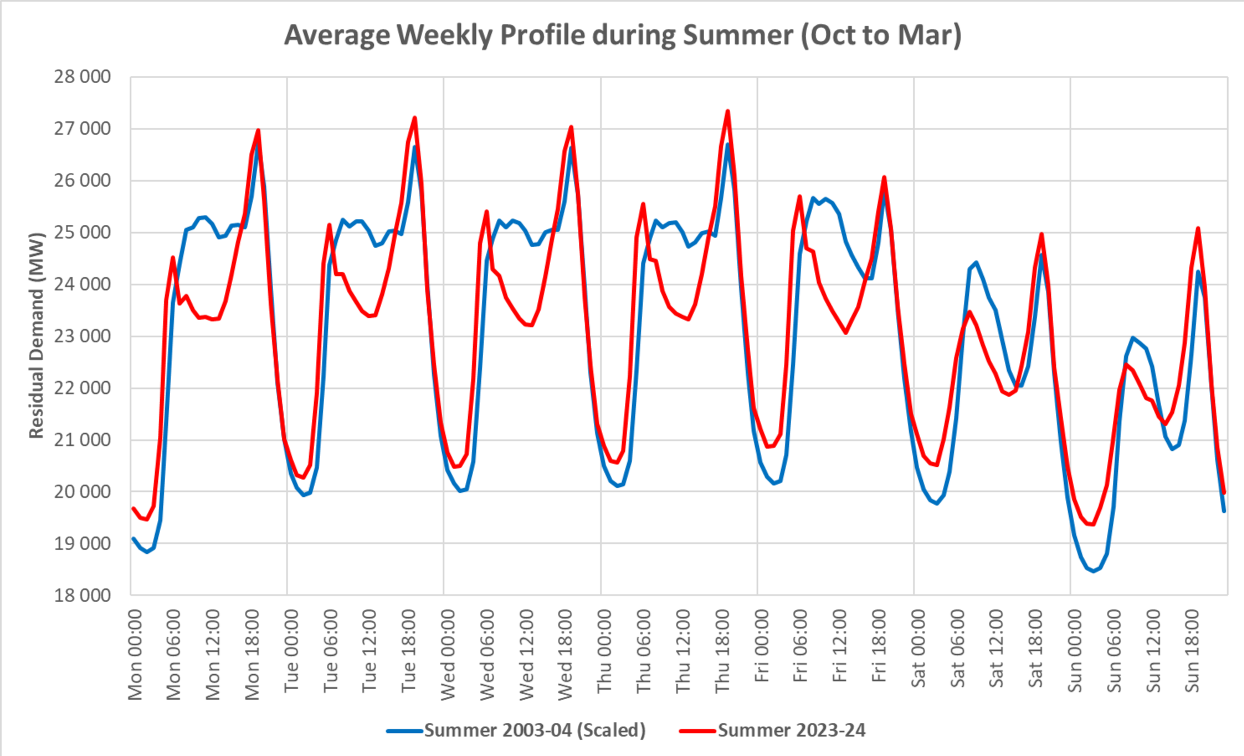



*Figure 31: Scaled winter and summer average week of the national system profile from 2003/4 to 2023/24*

From the changes to the system profile over the last 20 years, it is evident that customers have responded to the time-of-use price signals, especially in the morning periods.

Studies show that the changes to the system profile due to customers responding to the current TOU tariffs have been the same for the last 30 years, before the impact of lifestyle changes from the COVID-19 virus.

## C.5 The future system load profile

The system requirements in the future also need to be accommodated in the changes to be made to the TOU tariffs. The impact of renewables, wheeling, and decreasing sales must be taken into consideration to improve the future system load factor and manage the operational constraint/surplus during certain hours of the day. The changes to the TOU tariffs are, therefore, needed to drive cost efficiencies to support Eskom's long-term price path.

Analysis has been done on the average summer and winter weekday system profile for 2025 and 2030 based on the IRP draft 2016 base case plus some additional renewables (as approved by Eskom's Integrated Strategic Energy Planning).

The average summer and winter weekday system profile in 2025 and 2030 is shown in the figure below.

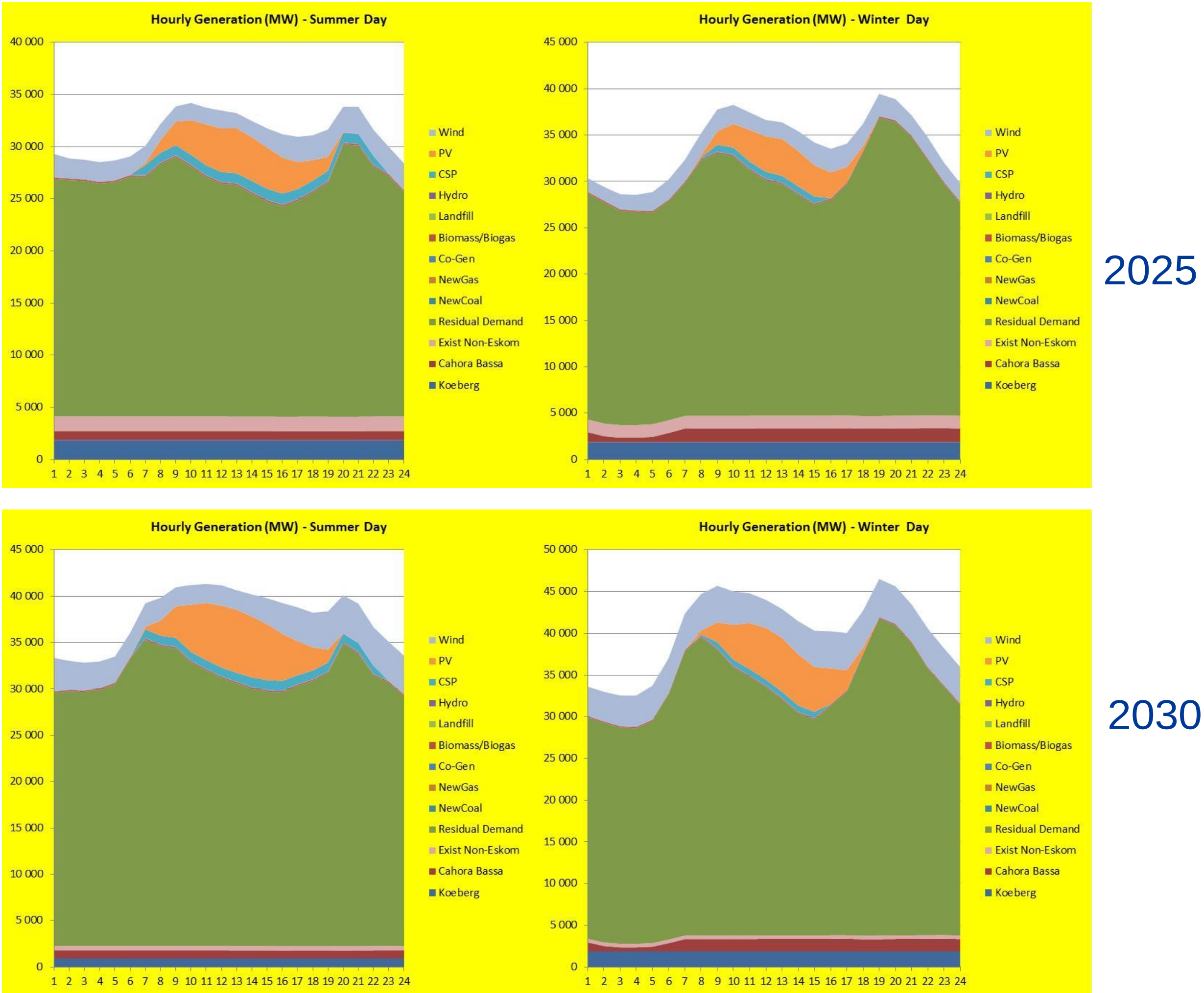



*Figure 32: Average summer and winter weekday system profile in 2025 and 2030*

It is evident from the future system outlook that TOU tariffs are still required in the future to optimise residual demand.

1. Although there is renewable energy in the national load profile shown in 2025 and 2030, this is not “dispatchable”. Eskom must provide the “balance of energy” or “residual demand” – shown in the green area and below in the load profile.
2. There are still morning and evening peaks in the system. Morning and evening peaks become “peakier” over time and still need to be managed by price signals.
3. A difference remains in the demand level in winter and summer, which still requires different price signals for winter and summer.
4. The drop in midday demand is evident and is more pronounced over time.

The proposed changes to the Standard TOU tariffs are required not only to manage the current system constraints but also to mitigate future system challenges.

## C.6 The features of the proposed changes to the Standard TOU tariffs

The proposed changes to the Standard TOU tariffs include:

a) changes to the time-of-use hours and periods of the day; and

b) changes to the tariff peak, standard, and off-peak ratios and rates.

The proposed TOU hours and periods have been done in consultation with, and have been signed off by, the System Operator to ensure that the System Operator's requirements to optimise the management of the system are met. The existing and proposed periods of the Standard tariffs are shown in the table below.

*Table 25: Existing and proposed TOU periods*

| | Existing TOU time periods | | | | | | Proposed new TOU time periods | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | High | | | Low | | | High | | | Low | | |
| | Weekday | Saturday | Sunday | Weekday | Saturday | Sunday | Weekday | Saturday | Sunday | Weekday | Saturday | Sunday |
| 0 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| 1 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| 2 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| 4 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| 5 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| 6 | 1 | 3 | 3 | 2 | 3 | 3 | 1 | 3 | 3 | 2 | 3 | 3 |
| 7 | 1 | 2 | 3 | 1 | 2 | 3 | 1 | 2 | 3 | 1 | 2 | 3 |
| 8 | 1 | 2 | 3 | 1 | 2 | 3 | 2 | 2 | 3 | 1 | 2 | 3 |
| 9 | 2 | 2 | 3 | 1 | 2 | 3 | 2 | 2 | 3 | 2 | 2 | 3 |
| 10 | 2 | 2 | 3 | 2 | 2 | 3 | 2 | 2 | 3 | 2 | 2 | 3 |
| 11 | 2 | 2 | 3 | 2 | 2 | 3 | 2 | 2 | 3 | 2 | 2 | 3 |
| 12 | 2 | 3 | 3 | 2 | 3 | 3 | 2 | 3 | 3 | 2 | 3 | 3 |
| 13 | 2 | 3 | 3 | 2 | 3 | 3 | 2 | 3 | 3 | 2 | 3 | 3 |
| 14 | 2 | 3 | 3 | 2 | 3 | 3 | 2 | 3 | 3 | 2 | 3 | 3 |
| 15 | 2 | 3 | 3 | 2 | 3 | 3 | 2 | 3 | 3 | 2 | 3 | 3 |
| 16 | 2 | 3 | 3 | 2 | 3 | 3 | 2 | 3 | 3 | 2 | 3 | 3 |
| 17 | 1 | 3 | 3 | 2 | 3 | 3 | 1 | 2 | 2 | 2 | 3 | 3 |
| 18 | 1 | 2 | 3 | 1 | 2 | 3 | 1 | 2 | 2 | 1 | 2 | 2 |
| 19 | 2 | 2 | 3 | 1 | 2 | 3 | 1 | 3 | 3 | 1 | 2 | 2 |
| 20 | 2 | 3 | 3 | 2 | 3 | 3 | 2 | 3 | 3 | 1 | 3 | 3 |
| 21 | 2 | 3 | 3 | 2 | 3 | 3 | 2 | 3 | 3 | 2 | 3 | 3 |
| 22 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| 23 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |

**Peak = 1**
**Standard = 2**
**Off-peak = 3**

The proposed changes to Standard tariff TOU periods are as follows:

1. Morning peaks are reduced by one hour for both summer and winter (that is, a two-hour morning peak period instead of the previous three-hour morning peak period). The morning peaks are not the highest system demand and can be managed.
2. Evening peaks are increased by one hour for both summer and winter (that is, a three-hour evening peak period instead of the previous two-hour evening peak period to reduce the evening ramp-up rate).
3. Sundays have two standard hours to assist the system with high demand on Sunday evenings.
4. Standard hours for Saturday and Sunday have been moved forward to start at 17:00 for winter only. Standard hours for Saturday and Sunday start at 18:00 for summer.

Several scenarios and their impacts have been analysed, and there have been extensive consultation workshops internally in Eskom and externally with customers on the proposed changes and the impact of the proposed changes. The System Operator, Eskom divisions, the Energy Intensive Users Group (EIUG), and the Association of Municipal Electricity Utilities (AMEU) are some of the key stakeholders consulted.

The proposed changes to the energy TOU structure and rates peak, standard, and off-peak ratios and rates, including the changes to the hours, are shown in the table below.

*Table 26: Current and proposed energy rate structure at >132kV (excluding losses)*

| | Wholesale energy rates | | | | | |
|---|---|---|---|---|---|---|
| Season | High-demand | | | Low-demand | | |
| Period | Peak | Standard | Off-Peak | Peak | Standard | Off-Peak |
| 1) Existing ratios | 8.00 | 2.31 | 1.18 | 2.50 | 1.67 | 1.00 |
| 2) Existing TOU c/kWh | 543.88 | 164.73 | 89.48 | 177.47 | 122.11 | 77.48 |
| 3) Proposed ratios | 6.00 | 1.50 | 1.00 | 2.49 | 1.40 | 1.00 |
| 4) Proposed TOU c/kWh | 478.66c | 119.66c | 79.78c | 198.64c | 111.69c | 79.78c |

When comparing the proposed Standard tariff rates (excluding losses) at >132kV, the following can be noted:

- The winter peak rate ratio has been decreased from a 1:8 ratio to a 1:6 ratio (see points 1 and 4 above).
- These ratio changes have reduced the winter peak prices and increased the summer peak prices (see points 2 and 4 above).

# Annexure D – Proposed changes to rate components

The information below sets out the proposed changes to each rate component per tariff.

## D.1 Service and administration charges

a) Retail tariff charges recover the cost of administration (meter reading and billing) and customer service (queries, applications, quotations, call centres, etc.). It is proposed that this charge be cost-reflective for all tariffs, except Homelight.

b) The charges per tariff will be based on the updated CTS study using the following units:

*Table 27: Structure of the service and administration charges*

| Tariff | Charge unit | Features |
|---|---|---|
| Businessrate 1, 2, 3 | • R/POD/day | • No change from current tariffs with a combined service and administration charge, not differentiated on size |
| Businessrate 4 | • c/kWh | • No change from current tariffs, with a combined service and administration charge, bundled together with other c/kWh charges |
| Landrate 1, 2, 3 | • R/POD/day | • No change from current tariffs, with a combined service and administration charge, not differentiated on size |
| Landrate Dx | • R/POD/day | • No change from current tariffs, with a combined service and administration charge, bundled together with other R/POD charges |
| Landrate 4, Landlight 20A, Landlight 60A | • c/kWh | • No change from current tariffs, with a combined service and administration charge, not differentiated on size and, bundled together with other c/kWh charges |
| Homepower 1, 2, 3, 4 | • R/POD/day | • This is a proposed change from the current tariff, where a combined service and an administration charge is reintroduced |
| Homeflex 1, 2, 3, 4 | • R/POD/day | • The Homeflex combined service and an administration charge are introduced to align with the proposed Homepower tariff combined service and an administration charge. |
| WEPS, Megaflex, Miniflex, Nightsave Urban and Rural, Ruraflex, Megaflex Gen, Ruraflex Gen, Transflex 1 and Transflex 2, Gen DUoS and Gen TUoS, | • R/POD /day | • Structural change with a service charge changing from R/account/day to R/POD/day |

| Tariff | Charge unit | Features |
|---|---|---|
| Gen Offset, Gen Wheeling, Gen Purchase | • R/POD/day | • No change from current tariffs – an administration charge for each transaction |
| Public Lighting | • c/kWh | • No change from current tariffs, with a combined service and administration charge bundled together with other c/kWh charges |
| **New tariffs** | | |
| Municflex | • R/POD/day | • Same structure as Megaflex, but based on local authority cost for current Megaflex, Miniflex, Nightsave Urban, Ruraflex and Nightsave Rural<br>• The above tariffs have been combined into one new tariff called Municflex<br>• Separate service and administration charge per POD. |
| Municrate | • R/POD/day | • Combined service and administration charge, not differentiated on size<br>• Same structure as Businessrate, but based on the combined costs for Businessrate, Landrate, and Homepower<br>• Landrate Dx has been converted to the Public Lighting Fixed tariff |

## D.2 Active energy charges

a) The active energy charges for all tariffs will be based on the updated energy TOU costs, ratios, periods and updated loss factors.

b) The energy charges may be averaged annually, seasonally, or by TOU, depending on the tariff structure.

c) All tariffs should at least recover energy costs. Subsidies should only be applied to network and retail costs.

d) The active energy charges per tariff will be based on the updated CTS study using the unit costs as provided in the below table.

*Table 28: Structure for the active energy charges*

| Tariff | Charge unit | Features |
|---|---|---|
| **Non-local authority tariffs** | | |
| Businessrate 1, 2, 3 | • Single active energy c/kWh charge | • Reflecting variable energy costs only<br>• Single average rate based on representative TOU profile |
| Businessrate 4 | • Single active energy c/kWh | • Single average rate based on representative TOU profile, bundled together with all other costs and converted into a single c/kWh charge |
| Landrate 1, 2, 3, 4 | • Single active energy c/kWh charge | • Reflecting variable TOU energy costs only |

| Tariff | Charge unit | Features |
|---|---|---|
| **Non-local authority tariffs** | | |
| | | • Single average rate based on representative TOU profile<br>• For Landrate 4, combined with the c/kWh service and administration charge<br>• Is subsidised |
| Landrate Dx | • R/POD/day | • Single average rate calculated based on representative TOU profile, bundled together with other costs and converted into a R/POD/day charge based on 200 kWh/m |
| Landlight 20A and 60A, | • Single active energy c/kWh charge | • Single average energy charge based on representative TOU profile, bundled together with all other costs and converted into a single c/kWh charge<br>• Is subsidised |
| Homepower 1, 2, 3, 4 | • Single active energy c/kWh charge | • This is a proposed change from the current IBT structure where the fixed costs are removed from the active energy charges, and recovered transparently through retail and network charges<br>• Single average active variable energy charge based on representative TOU profile and costs<br>• Also refer to paragraph 12.1 which motivates the proposed changes |
| Homelight 20A and 60A | • Single active energy c/kWh charge recovering all cost-less subsidies | • This is a proposed change from the current IBT structure<br>• Single average energy charge based on representative TOU profile, bundled together with other costs and converted into a single c/kWh charge<br>• The option remains to retain IBT structure<br>• Subsidised |
| WEPS, Megaflex, Miniflex, Ruraflex, Megaflex Gen, Ruraflex Gen, Homeflex 1, 2, 3, 4, Transflex 1 and Transflex 2, | • Active energy c/kWh charges<br>• TOU, seasonally, voltage (reflecting losses) and transmission zone differentiated. | • Changes to the TOU ratios and periods<br>• Reflecting TOU structure and costs plus losses |
| Nightsave Urban and Rural | • Active energy c/kWh charges and R/kVA energy demand charges | • Nightsave Urban Large and Small combined |

| Tariff | Charge unit | Features |
|---|---|---|
| **Non-local authority tariffs** | | |
| | • Time, seasonally, voltage (reflecting losses), and transmission zone differentiated. | • Reflecting TOU variable energy costs plus losses, separated into seasonal c/kWh energy charges, and R/kVA seasonal demand charges applicable in peak and standard periods |
| Gen DUoS and Gen TUoS | • The TOU active energy charges are used to calculate the loss charge applied to the DUoS and TUoS network charges | • Loss charges based on revised energy TOU costs<br>• Gen TUoS loss factors revised |
| Gen-offset | • Negative TOU-based c/kWh charges<br>• Time, seasonally, voltage (reflecting losses), and transmission zone differentiated | • Credit for energy exported<br>• These rates are equal to the applicable tariff TOU active energy charges |
| **Applicable to both non-local authority and local authority tariffs** | | |
| Public Lighting All-Night, Public Lighting 24-Hour | • Single energy c/kWh | • Structurally no change from current tariffs<br>• Single average rate calculated based on representative TOU profile, bundled together with other costs and converted into a single c/kWh charge<br>• Public Lighting tariff for non-metered lighting supplies (no change just updated with the CTS study). [Previously approved in Eskom but not approved by NERSA – required it to be based on a cost-to-serve study. Only have NERSA approval for subsidies for Homelight and rural tariffs]<br>• |
| Public Lighting Fixed charge tariff | • R/POD/day | • Single average rate calculated based on representative TOU profile, bundled together with other costs and converted into a R/POD/day charge based on 200 kWh/m.<br>• GCC is converted to the energy charge<br>• Public Lighting tariff for non-metered lighting supplies (no change just updated with the CTS study). [Previously approved in Eskom but not approved by NERSA – required it to be based on a cost-to-serve study. Only have NERSA approval for subsidies for Homelight and rural tariffs] |
| Gen-wheeling | • Negative TOU-based c/kWh active energy charges, excluding losses | • Credit for energy exported based on updated energy costs and structure excluding losses. |

| Tariff | Charge unit | Features |
|---|---|---|
| **Non-local authority tariffs** | | |
| | | • These rates are equal to the WEPS active energy charges less losses |
| Gen-purchase | • Positive TOU-based c/kWh active energy charges, excluding losses | • Add-back of Eskom purchased energy but consumed by the customer<br>• The rates are equal to the TOU active energy rates less losses |
| **New tariffs** | | |
| **Local authority tariffs** | | |
| Municflex | • Active energy c/kWh charges that are TOU, seasonally, voltage (reflecting losses), and transmission zone differentiated | • Changes to the TOU ratios and periods<br>• Reflecting TOU structure and variable energy costs plus losses<br>• Same structure as Megaflex, but based on the combined local authority energy cost for the current Megaflex, Miniflex, Nightsave Urban, Ruraflex and Nightsave Rural tariffs |
| Municrate | • Single energy c/kWh | • Same structure as Businessrate, but based on the combined costs for Businessrate, Landrate, and Homepower<br>• Single active average rate calculated based on a combined representative TOU profile energy cost<br>• Landrate Dx converted to Public Lighting Fixed charge tariff |

## D.3 Generation capacity charges

a) The generation capacity charge will be introduced for most tariffs

b) The active energy charges per tariff will be based on the updated CTS study using the following units:

*Table 29: Structure for the generation capacity charges*

| Tariff | Charge unit | Features |
|---|---|---|
| **Non-local authority tariffs** | | |
| Businessrate1, 2, 3 | • R/POD/day charge | • New charge, reflecting fixed energy costs<br>• Charge based on NMD |
| Businessrate4 | • Single active energy c/kWh | • Single average rate |
| Landrate 1, 2, 3, 4 | • A combination of R/POD/day charge and a single active energy c/kWh charge | • New charge, reflecting fixed energy costs<br>• Charge based on NMD for the fixed portion and consumption in kWh for the variable portion |
| Landrate Dx | • R/POD/day | • Included in the R/POD/day charge |

| Tariff | Charge unit | Features |
|---|---|---|
| **Non-local authority tariffs** | | |
| Landlight 20A and 60A, | • Single active energy c/kWh charge | • Included in the single average energy charge |
| Homepower and Homeflex 1, 2, 3, 4 | • R/POD/day charge | • New charge, reflecting fixed energy costs<br>• Charge based on NMD based on representative TOU profile and costs. |
| Homelight 20A and 60A | • Single active energy c/kWh charge recovering all cost-less subsidies | • Included in the single average energy charge<br>• Subsidised |
| WEPS, Megaflex, Miniflex, Ruraflex, Megaflex Gen, Ruraflex Gen, Transflex 1 and Transflex 2, | • R/kVA | • New charge, reflecting fixed energy costs<br>• Charge based on utilised capacity |
| Nightsave Urban and Rural, | • R/kVA | • New charge, reflecting fixed energy costs<br>• Charge based on utilised capacity |
| Gen DUoS and Gen TUoS, | • N/A | • N/A |
| Gen-offset | • N/A | • N/A |
| **Applicable to both non-local authority and local authority tariffs** | | |
| Public Lighting All-Night, Public Lighting 24-Hour | • Single energy c/kWh | • Included in the single average energy charge |
| Public Lighting Fixed charge tariff | • R/POD/day | • Included in the fixed charge |
| Gen-wheeling | • N/A | • N/A |
| Gen-purchase | • N/A | • N/A |
| **New tariffs** | | |
| **Local authority tariffs** | | |
| Municflex | • R/kVA | • New charge, reflecting fixed energy costs<br>• Charge based on utilised capacity |
| Municrate | • A combination of R/POD/day charge and a single active energy c/kWh charge | • Charge based on NMD for the fixed portion and consumption in kWh for the variable portion |

## D.4 Legacy charges

| Tariff | Charge unit | Features |
|---|---|---|
| **Non-local authority tariffs** | | |
| All SPU tariffs (Businessrate, Landrate, Homepower, and Landlight) | • Included in the c/kWh energy charges | • Charge based on consumption in kWh |
| Homelight 20A and 60A | • N/A | • N/A |
| Megaflex, Miniflex, Ruraflex, Megaflex Gen, Ruraflex Gen, Homeflex, Transflex 1 and Transflex 2, | • c/kWh | • New charge, reflecting legacy costs.<br>• Charge based on consumption in kWh |
| Nightsave Urban and Rural, | • c/kWh | • New charge, reflecting Legacy costs.<br>• Charge based on consumption in kWh |
| Gen DUoS and Gen TUoS, | • N/A | • N/A |
| Gen-offset | • N/A | • N/A |
| **Applicable to both non-local authority and local authority tariffs** | | |
| Public Lighting All-Night, Public Lighting 24-Hour | • Single energy c/kWh | • Included in the single average energy charge |
| Public Lighting Fixed charge tariff | • R/POD/day | • Included in the fixed charge |
| Gen-wheeling | • N/A | • N/A |
| Gen-purchase | • N/A | • N/A |
| **New tariffs** | | |
| **Local authority tariffs** | | |
| Municflex | • c/kWh | • New charge, reflecting legacy costs.<br>• Charge based on consumption in kWh |
| Municrate | • Included in the c/kWh energy charges | • Included in the single average energy charge |

## D.5 Network charges

a) The network charges are differentiated according to Distribution's current voltage and geographic categories. The geographic aspect (locational signal) is provided in the network charges through a rural and an urban differentiation.

b) The calculations of the network charges have been split into the following categories:

*Table 30: Network charge calculation categories*

| Category | Tariffs applicable |
|---|---|
| Non-local authority urban LPU tariffs | Combining current tariffs; Megaflex, Miniflex, Nightsave Urban, and Megaflex Gen Network costs and revenues |
| Local authority tariff Municflex | Combining current local authority tariffs; Megaflex, Miniflex, Nightsave Urban, Ruraflex, and Nightsave Rural Network costs and revenues |
| Non-local authority rural LPU tariffs | Combining current tariffs; Ruraflex, Ruraflex Gen, and Nightsave Rural Network costs and revenues |
| Municrate | Combining current local authority tariffs; Businessrate, Landrate, and Homepower network costs and revenues |
| Businessrate | Businessrate cost and revenues |
| Landrate | Landrate cost and revenues |
| Homepower | Homepower cost and revenues |
| Homeflex | Homepower cost and revenues |
| Homelight | No network charge |
| Public Lighting | No network charge |

c) For the urban LPU tariffs, the Distribution network costs have been split into fixed R/kVA unit rates (based on utilised capacity and not dependent on consumption) and variable R/kVA unit rates (dependent on demand in a month).

- Network charges are differentiated according to Distribution's current voltage and geographic categories. The geographic aspect (locational signal) is provided in the network charges through a rural and an urban differentiation.
- For the urban non-local authority LPU tariffs (Megaflex, Miniflex, Nightsave Urban, Megaflex Gen), the HV and Transmission-connected network charges are based on cost, plus a transparent subsidy raised to recover shortfall because of the LV and MV connected rates that are lower than cost.

  i. A total of 70% of costs has been allocated as fixed and divided by the total utilised capacity to determine the R/kVA NCC.

  ii. A total of 30% of costs has been allocated as variable and divided by the total maximum demand to determine the R/kVA NDC according to the existing voltage categories.

  iii. For Miniflex, the NDC was then converted to a c/kWh value by dividing the cost by the peak and standard energy sales, and the NCC was added to the Transmission network charge.

  iv. As the two lower-voltage categories are currently subsidised, a subsidy of an average of 8% has been applied to the NCC of the two lower-voltage categories. This has adjusted the cost-reflective NCC for these two lower-voltage categories.

v. The shortfall against cost for the two lower-voltage categories has then been converted into the LV subsidy charge.

vi. It is to be noted that total network charges as well the LV subsidy charges have reduced due to updating the network tariffs with costs.

d) For the LPU local authority tariff Municflex:

i. No change was made to the four voltage categories.

ii. The network charges are based on local authority cost for current local authority Megaflex, Miniflex, Nightsave Urban, Ruraflex, and Nightsave Rural tariffs.

iii. A total of 70% of costs has been allocated as fixed and divided by the total utilised capacity to determine the network capacity charge according to the existing voltage categories.

iv. A total of 30% of costs has been allocated as variable and divided by the total maximum demand to determine the network demand charge according to the existing voltage categories.

v. As the two lower-voltage categories are currently subsidised, a subsidy of an average of 19% has been applied to the NCC and NDC charges of the two lower-voltage categories.

vi. The shortfall against the cost for the two lower-voltage categories has then been converted into the LV subsidy charge for local authority tariffs.

e) For the rural LPU non-local authority tariffs (Ruraflex, Nightsave Rural), the network charge has been calculated as an average for both Ruraflex and Nightsave Rural (the network charge is a combined charge) Distribution and transmission costs and volumes and then reduced by applying subsidies so that the current level of subsidies is maintained.

i. The network costs for Transmission and a percentage of the Distribution costs have been combined to calculate the NCC.

ii. The network charges for the two tariffs have been aligned, that is, made the same. Nightsave Rural currently has a different network capacity charge from Ruraflex. This has resulted in a slight increase in Nightsave Rural and a reduction in Ruraflex's overall contribution to network charges mainly due to volume changes.

iii. Between the two tariffs, the total current level of subsidies related to **all charges** has been maintained, as any changes to the overall subsidy must be guided by NERSA and government policy. For Gen DUoS Urban, the network charge will only be applicable for the > 66 kV category and is calculated as the total Distribution network costs (urban NCC and NDC)/utilised capacity for the Dx > 66 kV category.

vii. The shortfall against the cost for the two lower voltage categories has been converted into the LV subsidy charge for the local authority LPU tariffs.

f) For Landrate, the network costs for Transmission and Distribution have been combined to calculate the network charge. The overall network charges were kept the same as current tariffs to recover the network costs. The Landrate tariff will see an overall reduction due to these updates.

g) For Businessrate, the Distribution network costs have been split into a fixed (not dependent on consumption) and variable (dependent on consumption) allocation.

- The network costs for Transmission and Distribution have been combined to calculate the network charge.
- The overall network charges are lower than the current tariff fixed charges rate due to updating with the CTS study.

h) For Homepower, cost-reflective network charges have been introduced due to unbundling of the IBT tariff structure, where network costs have been split into a fixed (not dependent on consumption) and variable (dependent on consumption) allocation.

i) For Homeflex, cost-reflective network charges have been introduced due to the unbundling of the Homepower tariff structure, to align with the Homepower network costs, where network costs have been split into a fixed (not dependent on consumption) and variable (dependent on consumption) allocation.

j) For Homelight, network costs have not been taken into consideration in the proposed tariff, as the current tariff was used as the basis to retain the current subsidies.

k) For Municrate:

- The network costs for Transmission and Distribution have been combined to calculate the network charge.
- The network charges have been based on the cost-reflective combined network costs for the local authority tariffs, Business rate, Landrate, and Homepower.

The network charge units per tariff are described in the following table.

*Table 31: Structure of the network charges*

| Tariff | Charge unit | Features |
|---|---|---|
| **Non-local authority tariffs** | | |
| Businessrate 1, 2, 3 | • R/POD network capacity charge<br>• c/kWh network demand charge | • Structurally no change from current tariffs<br>• Reflecting Distribution and Transmission network costs combined, split into a fixed R/kVA/POD and a variable (c/kWh) charge<br>• Increasing the fixed-portion charge (the NCC) and commensurate reduction of the variable-portion charge (the NDC) |
| Businessrate 4 | • Network energy charge c/kWh | • Structurally no change from current tariffs<br>• Reflecting Distribution and Transmission network costs combined<br>• The variable-cost component is recovered through the c/kWh network demand charge, and the fixed-cost component is bundled into the c/kWh energy charge. |
| Landrate 1, 2, 3, 4 | • R/POD network capacity charge<br>• c/kWh network demand charge | • Structurally no change from current tariffs<br>• Reflecting Distribution and Transmission network costs combined, less subsidies, and split into a fixed R/kVA/POD and a variable (c/kWh) component<br>• Increasing the fixed charge (the NCC) and commensurate reduction of the variable charge (the NDC)<br>• Is subsidised |
| Landrate Dx | • R/POD/day | • Structurally no change from current tariffs<br>• Bundled together with other costs and converted into a R/POD/day charge based on 200 kWh/m<br>• Is subsidised |
| Landlight 20A and 60A | • c/kWh charge | • Structurally no change from current tariffs |

| Tariff | Charge unit | Features |
|---|---|---|
| | | • Single c/kWh charge reflecting Distribution and Transmission network costs combined, less subsidies, bundled together with other costs, and converted into a single c/kWh charge<br>• Is subsidised |
| Homepower 1, 2, 3, 4 | • R/POD network capacity charge<br>• c/kWh network demand charge | • This is a proposed change from the current IBT structure where the current fixed costs are removed from the active energy charges and recovered transparently through retail and network charges.<br>• Reflecting Distribution and Transmission network costs combined, split into a R/POD fixed-charge and a c/kWh variable-charge<br>• Increasing the fixed-portion charge component (NCC)) |
| Homeflex 1, 2, 3, 4 | • R/POD network capacity charge<br>• c/kWh network demand charge | • Network charges unbundled to align with Homepower tariff |
| WEPS, Megaflex, Miniflex, Nightsave Urban | • R/kVA network capacity charge<br>• R/kVA network demand charge (Miniflex c/kWh)<br>• R/kVA LV subsidy charge<br>• Voltage differentiated | • Structurally no change from current tariffs<br>• Based only on non-local authority urban<br>• Separate Transmission and Distribution network charges<br>• Increasing the fixed-charge (NCC) and commensurate reduction of variable-charge (NDC)<br>• LV subsidy charge reflecting only LV subsidy on non-local authority urban tariffs |
| Transflex 1 and 2 | • R/POD/day | • Structurally no change from current tariffs<br>• Reflecting Distribution and Transmission network costs combined |
| Ruraflex, Nightsave Rural | • R/kVA network capacity charge<br>• c/kWh network demand charge<br>• Voltage differentiated | • Structurally no change from current tariffs<br>• Combined Transmission and Distribution network charges, less subsidies |

| Tariff | Charge unit | Features |
|---|---|---|
| | | • Calculated network charges on combined Nightsave Rural and Ruraflex costs |
| Gen-DUoS, | • R/kW network charges<br>• Losses charge<br>• Voltage differentiated | • Structurally no change from current tariffs, but tariff charges updated to be equal to the cost reflective HV load charge |
| Gen-TUoS | • R/kW network charges<br>• Losses charge<br>• Voltage differentiated | • No changes in this retail tariff plan to the rates or structure. |
| Gen Offset | • No network charges | |
| **Applicable to both non-local authority and local authority tariffs** | | |
| Public Lighting All-Night tariff and Public Lighting 24-Hour tariff | • Single energy c/kWh | • Structurally no change from current tariffs<br>• Network costs bundled into energy charges |
| Public Lighting Fixed charge tariff | • R/POD/day | • Structurally no change from current tariffs<br>• Network costs bundled in fixed charge |
| Gen-wheeling | • Standard network charges payable (also refer to applicable tariff)<br>• Voltage differentiated | • Structurally no change from current tariffs<br>• R/kW |
| Gen-purchase | • No network charges | • N/A |
| **New tariffs** | | |
| **Local authority tariffs** | | |
| Municflex | • R/kVA network capacity charge, and<br>• R/kVA network demand charge and<br>• R/kVA LV subsidy charge<br>• Voltage differentiated | • Separate Transmission and Distribution network charges<br>• Same structure as Megaflex, but based on local authority cost for current Megaflex, Miniflex, Nightsave Urban, Ruraflex, and Nightsave Rural tariffs<br>• Increasing the fixed-portion charge component (NCC) and a commensurate reduction of the variable-portion charge component (NDC) |

| Tariff | Charge unit | Features |
|---|---|---|
| | | • LV subsidy charge reflecting only LV subsidy on local authority urban tariffs |
| Municrate | • R/POD network capacity charge<br>• c/kWh network demand charge | • Reflecting Distribution and Transmission network costs combined, split into a fixed R/kVA/POD and a variable (c/kWh) component<br>• Same structure as Businessrate, but based on the combined costs for Businessrate, Landrate, and Homepower<br>• Landrate Dx will be converted to the Public Lighting Fixed charge tariff. |

## D.6 Ancillary service charge

a) The ancillary service charge is based on the CTS study and applies to the following tariffs:

*Table 32: Structure of the ancillary service charges*

| Tariff | Charge unit | Features |
|---|---|---|
| **Non-local authority tariffs** | | |
| Businessrate 1, 2, 3 | • c/kWh ancillary service charge | • Structurally no change from current tariffs<br>• Reflecting ancillary service costs |
| Businessrate 4 | • c/kWh ancillary service charge | • Structurally no change from current tariffs<br>• Reflecting ancillary service costs bundled into the active energy charge |
| Landrate 1, 2, 3, 4 | • c/kWh ancillary service charge | • Structurally no change from current tariffs<br>• Reflecting ancillary service costs |
| Landrate Dx | • R/POD/day | • Structurally no change from current tariffs<br>• Bundled together with other costs and converted into a R/POD/day charge based on 200 kWh/m |
| Landlight 20A and 60A | • c/kWh | • Structurally no change from current tariffs<br>• Bundled together with other costs and converted into a single c/kWh charge |
| Homepower 1, 2, 3, 4 | • c/kWh ancillary service charge | • This is a proposed change from the current IBT structure<br>• Reflecting ancillary service costs |

| Tariff | Charge unit | Features |
| --- | --- | --- |
| Homeflex 1, 2, 3, 4 | • c/kWh ancillary service charge | • Reflecting ancillary service costs to align with the Homepower tariff |
| WEPS, Megaflex, Miniflex, Nightsave Urban, Transflex 1 and 2 | • c/kWh ancillary service charge<br>• Voltage differentiated | • Structurally no change from current tariffs<br>• Reflecting ancillary service costs |
| Ruraflex and Nightsave Rural | • c/kWh ancillary service charge<br>• Voltage differentiated | • Structurally no change from current tariffs<br>• Reflecting ancillary service costs |
| Gen-DUoS and Gen-TUoS | • c/kWh ancillary service charge<br>• Voltage differentiated | • Structurally no change from current tariffs<br>• Reflecting ancillary service costs |
| Gen Offset | • c/kWh ancillary service charge<br>• Voltage differentiated | • Structurally no change from current tariffs<br>• Reflecting ancillary service costs |
| **Applicable to both non-local authority and local authority tariffs** | | |
| Public Lighting All-Night tariff, Public Lighting 24-Hour tariff | • c/kWh | • Structurally no change from current tariffs<br>• Reflecting ancillary service costs bundled into active energy charges |
| Public Lighting Fixed charge tariff | • R/POD/day | • Structurally no change from current tariffs<br>• Reflecting ancillary service costs bundled into the fixed charge |
| Gen-wheeling | • c/kWh ancillary service charge<br>• Voltage differentiated | • Structurally no change from current tariffs<br>• Reflecting ancillary service costs |
| Gen-purchase | • c/kWh ancillary service charge<br>• Voltage differentiated | • Structurally no change from current tariffs<br>• Reflecting ancillary service costs |
| **New tariffs** | | |
| **Local authority tariffs** | | |
| Municflex | • c/kWh ancillary service charge<br>• Voltage differentiated | • Structurally no change from current tariffs<br>• Reflecting ancillary service costs combined for all non-local authority LPU tariffs |
| Municrate | • c/kWh ancillary service charge | • Reflecting ancillary service costs combined for all non-local authority LPU tariffs |

## D.7 ERS and affordability charge

a) The ERS charge is applicable to the following tariffs:

*Table 33: Structure of the ERS charge and the affordability subsidy charge*

| Tariff | Charge unit | Features |
|---|---|---|
| **Non-local authority tariffs** | | |
| Businessrate 1, 2, 3 | • c/kWh ERS charge | • Reflecting contribution to subsidies |
| Businessrate 4 | • c/kWh ERS charge | • Reflecting contribution to subsidies |
| Landrate 1, 2, 3, 4 | • N/A | • Receives subsidies |
| Landrate Dx | • N/A | • Receives subsidies |
| Landlight 20A and 60A | • N/A | • Receives subsidies |
| Homepower and Homeflex 1, 2, 3, 4 | • N/A | • Does not receive or pay subsidies |
| WEPS, Megaflex, Miniflex, Nightsave Urban, Transflex | • c/kWh ERS charge<br>• c/kWh affordability charge | • Reflecting contribution to subsidies |
| Ruraflex, Nightsave Rural | • N/A | • Receives subsidies |
| Gen-DUoS, Gen-TUoS | • N/A | • Generators do not contribute to subsidies |
| Gen-offset | • N/A | • Subsidies as applicable, paid on consumption |
| **Applicable to both non-local authority and local authority tariffs** | | |
| Public Lighting All Night tariff and Public Lighting 24-Hour tariff | • N/A | • Does not receive or pay subsidies |
| Public Lighting Fixed Charge tariff | • N/A | • Does not receive or pay subsidies |
| Gen-Wheeling | • c/kWh ERS charge | • Reflecting contribution to network subsidies |
| Gen -Purchase | • c/kWh affordability charge | • Reflecting contribution to affordability-related subsidies |
| **New tariffs** | | |
| **Local authority tariffs** | | |
| Municflex | • c/kWh ERS charge | • Reflecting contribution to network subsidies |
| Municrate | • N/A | • N/A |

## D.8 Reactive energy charge

a) The reactive energy charges value remains unchanged from the current and is applicable to the following tariffs:

*Table 34: Structure for the reactive energy charge*

| Tariff | Charge unit | Features |
|---|---|---|
| **Non-local authority tariffs** | | |
| Businessrate 1, 2, 3 | • N/A | • Does not have a reactive energy charge |
| Businessrate 4 | • N/A | • Does not have a reactive energy charge |
| Landrate 1, 2, 3, 4 | • N/A | • Does not have a reactive energy charge |
| Landrate Dx | • N/A | • Does not have a reactive energy charge |
| Landlight 20A and 60A | • N/A | • Does not have a reactive energy charge |
| Homepower and Homeflex 1, 2, 3, 4 | • N/A | • Does not have a reactive energy charge |
| WEPS, Megaflex, Miniflex, Ruraflex. | • c/kVArh | • Payable as current tariffs on reactive energy in the high-demand season |
| Transflex 1 and 2 | • c/kVArh | • Payable as current tariffs on reactive energy in the high and low-demand season |
| Nightsave Urban, Nightsave Rural | • N/A | • Does not have a reactive energy charge |
| Gen-DUoS, Gen-TUoS | • N/A | • Does not have a reactive energy charge |
| Gen Offset | • N/A | • Does not have a reactive energy charge |
| **Applicable to both non-local authority and local authority tariffs** | | |
| Public Lighting All-Night tariff, Public Lighting 24-Hour tariff | • N/A | • Does not have a reactive energy charge |
| Public Lighting Fixed charge tariff | • N/A | • Does not have a reactive energy charge |
| Gen-wheeling | • N/A | • Does not have a reactive energy charge |
| Gen-purchase | • N/A | • Does not have a reactive energy charge |
| **New tariffs** | | |
| **Local authority tariffs** | | |
| Municflex | • c/kVArh | • Payable as current Megaflex on reactive energy in the high-demand season |
| Municrate | • N/A | • Does not have a reactive energy charge |

# Annexure E – Proposed Standard tariff rates in 2024/25-rand values (excluding VAT)

*Table 35: Urban LPU tariffs: WEPS, Megaflex, Miniflex, and Nightsave Urban (non-local authority)*

| Large power user non-local-authority tariffs | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Urban non-local authority tariffs | | | | | | | | | | | | | | | |
| Transmission zone | Voltage | High-demand season TOU active energy charges (WEPS, Megaflex and Miniflex) | | | Low-demand season TOU active energy charges (WEPS, Megaflex and Miniflex) | | | Legacy Charge c/kWh | Generation capacity charge R/kVA | High-demand season energy demand charge | Low-demand season energy demand charge | High-demand season active energy charge | Low-demand season active energy charge | Network capacity charge R/kVA | Transmission network charge R/kVA |
| | | Peak | Standard | Off-Peak | Peak | Standard | Off-Peak | | | Nightsave | Nightsave | Nightsave | Nightsave | Miniflex | WEPS, Megaflex and Nightsave |
| <300km | <500V | 571.17c | 142.79c | 95.20c | 237.03c | 133.28c | 95.20c | 20.21c | R 15.52 | R 262.15 | R 61.32 | 141.73c | 136.20c | R 44.22 | R 9.43 |
| | ≥500V & <66kV | 556.43c | 139.10c | 92.74c | 230.92c | 129.84c | 92.74c | 19.69c | R 35.90 | R 255.38 | R 59.74 | 138.07c | 132.69c | R 41.00 | R 9.09 |
| | ≥66kV & <132kV | 516.37c | 129.09c | 86.07c | 214.29c | 120.49c | 86.07c | 18.27c | R 27.15 | R 237.00 | R 55.44 | 128.13c | 123.13c | R 19.84 | R 8.29 |
| | >132kV* | 481.51c | 120.37c | 80.26c | 199.82c | 112.36c | 80.26c | 17.04c | R 31.15 | R 219.68 | R 51.39 | 119.48c | 114.82c | R 14.49 | R 14.49 |
| >300km to <= 600km | <500V | 576.88c | 144.21c | 96.15c | 239.40c | 134.61c | 96.15c | 20.21c | R 15.52 | R 264.75 | R 61.93 | 143.14c | 137.55c | R 44.32 | R 9.53 |
| | ≥500V & <66kV | 562.00c | 140.49c | 93.67c | 233.22c | 131.14c | 93.67c | 19.69c | R 35.90 | R 257.92 | R 60.33 | 139.44c | 134.00c | R 41.09 | R 9.18 |
| | ≥66kV & <132kV | 521.54c | 130.38c | 86.93c | 216.43c | 121.69c | 86.93c | 18.27c | R 27.15 | R 239.35 | R 55.99 | 129.40c | 124.36c | R 19.93 | R 8.38 |
| | >132kV* | 486.33c | 121.58c | 81.06c | 201.82c | 113.48c | 81.06c | 17.04c | R 31.15 | R 223.19 | R 52.21 | 120.67c | 115.96c | R 14.64 | R 14.64 |
| >600km to <= 900km | <500V | 582.59c | 145.64c | 97.10c | 241.77c | 135.94c | 97.10c | 20.21c | R 15.52 | R 267.38 | R 62.55 | 144.56c | 138.92c | R 44.41 | R 9.62 |
| | ≥500V & <66kV | 567.56c | 141.88c | 94.60c | 235.53c | 132.43c | 94.60c | 19.69c | R 35.90 | R 260.49 | R 60.93 | 140.83c | 135.34c | R 41.18 | R 9.27 |
| | ≥66kV & <132kV | 526.70c | 131.67c | 87.79c | 218.58c | 122.90c | 87.79c | 18.27c | R 27.15 | R 241.73 | R 56.55 | 130.69c | 125.59c | R 20.01 | R 8.46 |
| | >132kV* | 491.14c | 122.78c | 81.86c | 203.82c | 114.60c | 81.86c | 17.04c | R 31.15 | R 225.41 | R 52.73 | 121.87c | 117.11c | R 14.78 | R 14.78 |
| >900km | <500V | 588.30c | 147.07c | 98.05c | 244.14c | 137.27c | 98.05c | 20.21c | R 15.52 | R 269.99 | R 63.16 | 145.97c | 140.27c | R 44.51 | R 9.72 |
| | ≥500V & <66kV | 573.13c | 143.28c | 95.53c | 237.84c | 133.73c | 95.53c | 19.69c | R 35.90 | R 263.02 | R 61.53 | 142.20c | 136.66c | R 41.27 | R 9.36 |
| | ≥66kV & <132kV | 531.86c | 132.96c | 88.65c | 220.72c | 124.10c | 88.65c | 18.27c | R 27.15 | R 244.09 | R 57.10 | 131.96c | 126.82c | R 20.09 | R 8.54 |
| | >132kV* | 495.96c | 123.98c | 82.66c | 205.82c | 115.73c | 82.66c | 17.04c | R 31.15 | R 227.61 | R 53.24 | 123.05c | 118.26c | R 14.93 | R 14.93 |
| WISP energy rate excluding losses | | 478.66c | 119.66c | 79.78c | 198.64c | 111.69c | 79.78c | | | | | | | | |

*Transmission connected

| Distribution network charges Urban | | | | | | | |
|---|---|---|---|---|---|---|---|
| Voltage | NCC R/kVA (Megaflex, Nightsave and WEPS) | NDC R/kVA (Megaflex, Nightsave and WEPS) | NDC c/kWh (Miniflex) | LV subsidy charge R/kVA (All LPU) | Ancillary service charge c/kWh (All LPU) | ERS charge c/kWh (All LPU) | Affordability subsidy charge c/kWh (All LPU) |
| <500V | R 34.79 | R 42.94 | 26.34c | 0.00 | 0.36c | 4.63c | 4.33c |
| ≥500V & <66kV | R 31.91 | R 21.44 | 8.52c | 0.00 | 0.35c | 4.63c | 4.33c |
| ≥66kV & <132kV | R 11.55 | R 8.45 | 8.33c | R 9.05 | 0.32c | 4.63c | 4.33c |
| >132kV* | R 0 | R 0 | R 0 | R 9.05 | 0.30c | 4.63c | 4.33c |

*132kV/Transmission connected

| Urban retail charges based on MUC (All LPU) | Service charge R/POD/day | Admin charge R/POD/day | Service charge R/Acc/day |
|---|---|---|---|
| ≤ 100 kVA | R 12.19 | R 0.65 | |
| > 100 kVA & ≤ 500 kVA | R 57.02 | R 11.00 | |
| > 500 kVA & ≤ 1 MVA | R 176.09 | R 17.18 | |
| > 1 MVA | R 176.09 | R 17.18 | |
| Key customers | R 992.07 | R 17.18 | |

| Reactive energy c/kVArh (high demand season only) | |
|---|---|
| Megaflex | Miniflex |
| 28.13 | 12.25 |

## Table 36: Rural LPU tariffs: Ruraflex and Nightsave Rural (non-local authority)

| Rural non-local-authority tariffs | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Transmission zone | Voltage | High-demand season TOU active energy charges (Ruraflex) | | | Low-demand season TOU active energy charges (Ruraflex) | | | Legacy Charge c/kWh | Generation capacity charge R/kVA | High-demand season energy | Low-demand season energy | High-demand season active energy charge | Low-demand season active | Network capacity charge (R/kVA) | Transmssion network charge R/kVA fui |
| | | Peak | Standard | Off-Peak | Peak | Standard | Off-Peak | | | Nightsave | Nightsave | Nightsave | Nightsave | Bundled (Transmission and Distributio | Unbundled |
| <300km | <500V | 576.51c | 144.12c | 96.09c | 239.25c | 134.52c | 96.09c | 20.40c | R 14.79 | R 340.82 | R 79.74 | 129.29c | 124.34c | R 46.16 | R 9.56 |
| | ≥500V & <66kV | 566.31c | 141.57c | 94.39c | 235.01c | 132.14c | 94.39c | 20.04c | R 22.31 | R 334.79 | R 78.33 | 127.00c | 122.13c | R 42.86 | R 9.32 |
| | ≥66kV & <132kV | | | | | | | | | | | | | | |
| | >132kV | | | | | | | | | | | | | | |
| >300km to <= 600km | <500V | 582.28c | 145.56c | 97.05c | 241.64c | 135.87c | 97.05c | 20.40c | R 14.79 | R 344.21 | R 80.53 | 130.58c | 125.57c | R 46.25 | R 9.66 |
| | ≥500V & <66kV | 571.97c | 142.99c | 95.33c | 237.36c | 133.46c | 95.33c | 20.04c | R 22.31 | R 338.11 | R 79.11 | 128.27c | 123.35c | R 42.95 | R 9.41 |
| | ≥66kV & <132kV | | | | | | | | | | | | | | |
| | >132kV | | | | | | | | | | | | | | |
| >600km to <= 900km | <500V | 588.04c | 147.00c | 98.01c | 244.03c | 137.21c | 98.01c | 20.40c | R 14.79 | R 347.63 | R 81.33 | 131.88c | 126.82c | R 46.35 | R 9.75 |
| | ≥500V & <66kV | 577.63c | 144.40c | 96.28c | 239.71c | 134.78c | 96.28c | 20.04c | R 22.31 | R 341.48 | R 79.89 | 129.54c | 124.58c | R 43.05 | R 9.51 |
| | ≥66kV & <132kV | | | | | | | | | | | | | | |
| | >132kV | | | | | | | | | | | | | | |
| >900km | <500V | 593.81c | 148.45c | 98.97c | 246.43c | 138.56c | 98.97c | 20.40c | R 14.79 | R 351.02 | R 82.13 | 133.16c | 128.06c | R 46.44 | R 9.85 |
| | ≥500V & <66kV | 583.29c | 145.82c | 97.22c | 242.06c | 136.11c | 97.22c | 20.04c | R 22.31 | R 344.80 | R 80.67 | 130.80c | 125.79c | R 43.14 | R 9.60 |
| | ≥66kV & <132kV | | | | | | | | | | | | | | |
| | >132kV | | | | | | | | | | | | | | |

| Distribution network charges Rural | | | | | | | |
|---|---|---|---|---|---|---|---|
| Voltage | NCC R/kVA | NDC R/kVA | NDC c/kWh | LV subsidy R/kVA charge | Ancillary Service Charge c/kWh | ERS charge c/kWh | Affordability subsidy charge c/kWh |
| <500V | | | 42.86 | | 0.36 | | |
| ≥500V & <66kV | | | 37.16 | | 0.36 | | |
| ≥66kV & <132kV | | | | | | | |
| >132kV* | | | | | | | |

| Rural retail charges based on MUC | Service charge R/POD/day | Admin charge R/POD/day | Service charge R/Acc/day |
|---|---|---|---|
| ≤ 100 kVA | R 20.53 | R 1.20 | |
| > 100 kVA & ≤ 500 kVA | R 57.02 | R 11.00 | |
| > 500 kVA & ≤ 1 MVA | R 176.09 | R 17.18 | |
| > 1 MVA | R 176.09 | R 17.18 | |
| Key customers | R 992.07 | R 17.18 | |

| Reactive energy c/kVArh (high demand season |
|---|
| Ruraflex |
| 17.59 |

## *Table 37: SPU tariffs: Businessrate, Landrate, Homelight, Homepower and Public Lighting (non-local authority)*

Non-local-authority small power user tariffs

| Businessrate | Energy charge c/kWh | Generation capacity charge R/POD/day | Ancillary service charge c/kWh | NDC c/kWh | NCC R/POD/day | Service and admin charge R/POD/day | ERS charge |
|---|---|---|---|---|---|---|---|
| 1 | 188.86c | R 8.82 | 0.36c | 12.90c | R 18.04 | R 13.04 | 4.63c |
| 2 | 188.86c | R 13.10 | 0.36c | 12.90c | R 26.80 | R 13.04 | 4.63c |
| 3 | 188.86c | R 32.69 | 0.36c | 12.90c | R 66.86 | R 13.04 | 4.63c |
| 4 | 317.48c | 0.00c | 0.36c | 12.90c | | | 4.63c |

| Landrate | Energy charge c/kWh* | Generation capacity charge R/POD/day | Ancillary service charge c/kWh | NDC c/kWh | NCC R/POD/day | Service and admin charge R/POD/day |
|---|---|---|---|---|---|---|
| 1 | 202.57c | R 5.99 | 0.36c | 54.75c | R 55.17 | R 21.73 |
| 2 | 202.57c | R 11.90 | 0.36c | 54.75c | R 86.03 | R 21.73 |
| 3 | 202.57c | R 23.28 | 0.36c | 54.75c | R 137.77 | R 21.73 |
| 4 | 330.64c | R 3.94 | 0.36c | 54.75c | R 40.73 | |
| Landrate Dx | | | | | | R 79.74 |
| Landlight 20A | 543.60c | | | | | |
| Landlight 60A | 762.65c | | | | | |

| Homepower | Energy charge c/kWh Block 1 | Energy charge c/kWhBlock 2 | Generation capacity charge R/POD/day | Ancillary service charge c/kWh | NDC c/kWh | NCC R/POD/day | Service and admin charge R/POD/day |
|---|---|---|---|---|---|---|---|
| 1 | 206.78c | 206.78c | R 3.20 | 0.36c | 23.39c | R 10.76 | R 8.72 |
| 2 | 206.78c | 206.78c | R 5.65 | 0.36c | 23.39c | R 24.01 | R 8.72 |
| 3 | 206.78c | 206.78c | R 13.74 | 0.36c | 23.39c | R 51.29 | R 8.72 |
| 4 | 206.78c | 206.78c | R 2.09 | 0.36c | 23.39c | R 7.41 | R 8.72 |
| Homepower Bulk | 206.78c | 206.78c | R 21.19/KVA | 0.36c | 23.39c | R 49.07/KVA | R 12.84 |

| Homeflex | High | | | Low | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Peak c/kWh* | Standard c/kWh* | Off-peak c/kWh* | Peak c/kWh* | Standard c/kWh* | Off-peak c/kWh* | Legacy Charge c/kWh | Generation capacity charge R/POD/day | Ancillary service charge c/kWh | NDC c/kWh | NCC R/POD/day | Service and admin charge R/POD/day |
| 1 | 571.17c | 163.00c | 115.41c | 257.24c | 153.49c | 115.41c | 20.21c | R 3.20 | 0.36c | 23.39c | R 10.76 | R 8.72 |
| 2 | 571.17c | 163.00c | 115.41c | 257.24c | 153.49c | 115.41c | 20.21c | R 5.65 | 0.36c | 23.39c | R 24.01 | R 8.72 |
| 3 | 571.17c | 163.00c | 115.41c | 257.24c | 153.49c | 115.41c | 20.21c | R 13.74 | 0.36c | 23.39c | R 51.29 | R 8.72 |
| 4 | 571.17c | 163.00c | 115.41c | 257.24c | 153.49c | 115.41c | 20.21c | R 2.09 | 0.36c | 23.39c | R 7.41 | R 8.72 |
| *Included in the above energy charges is the GCC c/kWh variable component of | | | 0.00c | | | | | | | | | |
| Net-billing offset rate | 571.17 | 163.00 | 115.41 | 257.24 | 153.49 | 115.41 | | | | | | |

| Homelight | Energy charge c/kWh Block 1 | Energy charge c/kWh Block 2 | Single rate |
|---|---|---|---|
| 20A | | | 191.69c |
| 60A | | | 243.68c |

| Public Lighting Non Munic | All night | R/100W/month |
|---|---|---|
| All night c/kWh | 206.28c | R 68.76 |
| 24 hours c/kWh | 196.47c | R 143.42 |
| Fixed charge R/day | R 28.10 | |
| Maintenance charge | Per luminaire | Per High mast luminaire |
| | R 88.41 | R 2 058.10 |

## Table 38: LPU tariff: Municflex – 12-month view before adjustment for July increase

Large power user local-authority tariffs (12 month view, unadjusted for 3 month and 9 months financial year)

Municflex (12 month view)

| Transmission zone | Voltage | High-demand season TOU active energy charges | | | Low-demand season TOU active energy charges | | | Legacy Charge c/kWh | Generation capacity charge R/kVA | Transmission network charge R/kVA |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Peak | Standard | Off-Peak | Peak | Standard | Off-Peak | | | |
| <300km | <500V | 572.97c | 143.21c | 95.52c | 237.81c | 133.70c | 95.55c | 20.28c | R 14.53 | R 9.48 |
| | ≥500V & <66kV | 556.48c | 139.11c | 92.75c | 230.93c | 129.85c | 92.75c | 19.69c | R 33.68 | R 9.09 |
| | ≥66kV & <132kV | 516.37c | 129.09c | 86.07c | 214.29c | 120.49c | 86.07c | 18.27c | R 28.21 | R 8.29 |
| | >132kV* | 481.51c | 120.37c | 80.26c | 199.82c | 112.36c | 80.26c | 17.04c | R 31.15 | R 14.49 |
| >300km to <= 600km | <500V | 580.76c | 145.19c | 96.81c | 241.02c | 135.53c | 96.82c | 20.35c | R 14.53 | R 9.62 |
| | ≥500V & <66kV | 562.86c | 140.72c | 93.84c | 233.58c | 131.34c | 93.83c | 19.72c | R 33.68 | R 9.20 |
| | ≥66kV & <132kV | 521.54c | 130.38c | 86.93c | 216.43c | 121.69c | 86.93c | 18.27c | R 28.21 | R 8.38 |
| | >132kV* | 486.33c | 121.58c | 81.06c | 201.82c | 113.48c | 81.06c | 17.04c | R 31.15 | R 14.64 |
| >600km to <= 900km | <500V | 586.23c | 146.55c | 97.73c | 243.31c | 136.80c | 97.74c | 20.34c | R 14.53 | R 9.72 |
| | ≥500V & <66kV | 568.63c | 142.16c | 94.80c | 235.99c | 132.69c | 94.80c | 19.73c | R 33.68 | R 9.31 |
| | ≥66kV & <132kV | 526.70c | 131.67c | 87.79c | 218.58c | 122.90c | 87.79c | 18.27c | R 28.21 | R 8.46 |
| | >132kV* | 491.14c | 122.78c | 81.86c | 203.82c | 114.60c | 81.86c | 17.04c | R 31.15 | R 14.78 |
| >900km | <500V | 592.77c | 148.19c | 98.80c | 245.98c | 138.32c | 98.80c | 20.37c | R 14.53 | R 9.81 |
| | ≥500V & <66kV | 574.02c | 143.50c | 95.69c | 238.21c | 133.94c | 95.69c | 19.72c | R 33.68 | R 9.39 |
| | ≥66kV & <132kV | 531.86c | 132.96c | 88.65c | 220.72c | 124.10c | 88.65c | 18.27c | R 28.21 | R 8.54 |
| | >132kV* | 495.96c | 123.98c | 82.66c | 205.82c | 115.73c | 82.66c | 17.04c | R 31.15 | R 14.93 |
| WISP energy rate excluding losses | | 478.66c | 119.66c | 79.78c | 198.64c | 111.69c | 79.78c | | | |

*Transmission connected

Distribution network charges

| Voltage | NCC R/kVA | NDC R/kVA | | LV subsidy charge R/kVA | Ancillary service charge c/kWh | ERS charge c/kWh | Affordability subsidy charge c/kWh |
|---|---|---|---|---|---|---|---|
| < 500V | R 35.24 | R 42.92 | | 0.00 | 0.36c | 4.63c | NA |
| ≥ 500V & < 66kV | R 32.29 | R 21.54 | | 0.00 | 0.35c | 4.63c | NA |
| ≥ 66kV & ≤ 132kV | R 14.18 | R 8.38 | | R 1.94 | 0.32c | 4.63c | NA |
| > 132kV* | | | | R 1.94 | 0.30c | 4.63c | NA |

*132kV/Transmission connected

| Size based on MUC | Service charge R/POD/day | Admin charge R/POD/day | Service charge R/Acc/day |
|---|---|---|---|
| ≤ 100 kVA | R 12.19 | R 0.65 | |
| > 100 kVA & ≤ 500 kVA | R 57.02 | R 11.00 | |
| > 500 kVA & ≤ 1 MVA | R 176.09 | R 17.18 | |
| > 1 MVA | R 176.09 | R 17.18 | |
| Key customers | R 992.07 | R 17.18 | |

| Reactive energy c/kVArh (high demand season only | |
|---|---|
| Municflex | |
| 28.13 | |

## Table 39: SPU tariff: Municrate – 12-month view before adjustment for July increase

Local-authority small power user tariffs (12 month view average unadjusted for 3 months and 9 months financial year)

| Municrate | Energy charge c/kWh | Generation capacity charge R/POD/day | Ancillary service charge c/kWh | NDC c/kWh | NCC R/POD/day | Service and admin charge R/POD/day | ERS charge |
|---|---|---|---|---|---|---|---|
| 1 | 203.73c | R 4.76 | 0.36c | 38.08c | R 29.75 | R 16.43 | 0.00c |
| 2 | 203.73c | R 8.75 | 0.36c | 38.08c | R 60.27 | R 16.43 | 0.00c |
| 3 | 203.73c | R 18.47 | 0.36c | 38.08c | R 120.71 | R 16.43 | 0.00c |
| 4 | 312.89c | | 0.36c | 38.08c | 0.00c | 0.00c | 0.00c |

| Public Lighting munic | All night | R/100W/month |
|---|---|---|
| All night c/kWh | 221.98c | R 73.99 |
| 24 hours c/kWh | 191.49c | R 139.79 |
| Fixed charge R/day | R 26.92 | |
| Maintenance charge | Per luminaire | Per High mast luminaire |
| | R 92.46 | R 2 159.41 |

## *Table 40: LPU tariff: Municflex – adjusted for a nine-month view (July increase)*

| Local-authority Municflex large power user tariff (9 month view) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Transmission zone | Voltage | High-demand season TOU active energy charges | | | Low-demand season TOU active energy charges | | | Legacy Charge c/kWh | Generation capacity charge R/kVA | Transmission network charge R/kVA |
| | | Peak | Standard | Off-Peak | Peak | Standard | Off-Peak | | | |
| <300km | <500V | 587.60c | 146.87c | 97.96c | 243.88c | 137.11c | 97.99c | 20.80c | R 14.90 | R 9.72 |
| | ≥500V & <66kV | 570.69c | 142.66c | 95.12c | 236.83c | 133.17c | 95.12c | 20.20c | R 34.54 | R 9.32 |
| | ≥66kV & <132kV | 529.56c | 132.39c | 88.27c | 219.76c | 123.57c | 88.27c | 18.74c | R 28.93 | R 8.51 |
| | >132kV* | 493.81c | 123.44c | 82.31c | 204.92c | 115.23c | 82.31c | 17.48c | R 31.95 | R 14.86 |
| >300km to <= 600km | <500V | 595.59c | 148.90c | 99.28c | 247.18c | 138.99c | 99.29c | 20.87c | R 14.90 | R 9.86 |
| | ≥500V & <66kV | 577.23c | 144.31c | 96.24c | 239.55c | 134.69c | 96.23c | 20.23c | R 34.54 | R 9.44 |
| | ≥66kV & <132kV | 534.86c | 133.71c | 89.15c | 221.96c | 124.80c | 89.15c | 18.74c | R 28.93 | R 8.59 |
| | >132kV* | 498.75c | 124.69c | 83.13c | 206.97c | 116.38c | 83.13c | 17.48c | R 31.95 | R 15.01 |
| >600km to <= 900km | <500V | 601.20c | 150.29c | 100.23c | 249.52c | 140.29c | 100.24c | 20.86c | R 14.90 | R 9.97 |
| | ≥500V & <66kV | 583.15c | 145.79c | 97.22c | 242.02c | 136.08c | 97.22c | 20.23c | R 34.54 | R 9.54 |
| | ≥66kV & <132kV | 540.15c | 135.03c | 90.03c | 224.16c | 126.04c | 90.03c | 18.74c | R 28.93 | R 8.68 |
| | >132kV* | 503.68c | 125.92c | 83.95c | 209.03c | 117.53c | 83.95c | 17.48c | R 31.95 | R 15.16 |
| >900km | <500V | 607.91c | 151.97c | 101.32c | 252.26c | 141.85c | 101.32c | 20.89c | R 14.90 | R 10.06 |
| | ≥500V & <66kV | 588.68c | 147.16c | 98.13c | 244.29c | 137.36c | 98.13c | 20.23c | R 34.54 | R 9.63 |
| | ≥66kV & <132kV | 545.44c | 136.36c | 90.91c | 226.36c | 127.27c | 90.91c | 18.74c | R 28.93 | R 8.76 |
| | >132kV* | 508.63c | 127.15c | 84.77c | 211.08c | 118.69c | 84.77c | 17.48c | R 31.95 | R 15.31 |
| WEPS rate excluding losses | | 490.86c | 122.70c | 81.82c | 203.70c | 114.54c | 81.82c | | | |

*Transmission connected

| Distribution network charges | | | | | | | |
|---|---|---|---|---|---|---|---|
| Voltage | NCC R/kVA | NDC R/kVA | | LV subsidy charge R/kVA | Ancillary service charge c/kWh | ERS charge c/kWh | Affordability subsidy charge c/kWh |
| <500V | R 36.14 | R 44.02 | | 0.00 | 0.37c | 4.75c | NA |
| ≥500V & <66kV | R 33.11 | R 22.09 | | 0.00 | 0.36c | 4.75c | NA |
| ≥66kV & <132kV | R 14.54 | R 8.59 | | R 1.99 | 0.33c | 4.75c | NA |
| >132kV* | | | | R 1.99 | 0.31c | 4.75c | NA |

*132kV/Transmission connected

| Size based on MUC | Service charge R/POD/day | Admin charge R/POD/day |
|---|---|---|
| ≤ 100 kVA | R 12.50 | R 0.67 |
| > 100 kVA & ≤ 500 kVA | R 58.48 | R 11.28 |
| > 500 kVA & ≤ 1 MVA | R 180.59 | R 17.62 |
| > 1 MVA | R 180.59 | R 17.62 |
| Key customers | R 1 017.41 | R 17.62 |

| Reactive energy c/kVArh (high demand season only | |
|---|---|
| Municflex | |
| 28.85 | |

## *Table 41: SPU tariffs: Municrate and Public Lighting – adjusted for a nine-month view (July increase)*

| Local-authority small power user tariffs (9 month view) | | | | | | |
|---|---|---|---|---|---|---|
| Municrate | Energy charge c/kWh | Generation capacity charge R/POD/day | Ancillary service charge c/kWh | NDC c/kWh | NCC R/POD/day | Service and admin charge R/POD/day |
| 1 | 208.93c | R 4.88 | 0.37c | 39.05c | R 30.51 | R 16.85 |
| 2 | 208.93c | R 8.97 | 0.37c | 39.05c | R 61.81 | R 16.85 |
| 3 | 208.93c | R 18.94 | 0.37c | 39.05c | R 123.79 | R 16.85 |
| 4 | 320.88c | | 0.37c | 39.05c | R 0.00 | R 0.00 |

| Public Lighting munic | All night | R/100W/month |
|---|---|---|
| All night c/kWh | 227.65c | R 75.88 |
| 24 hours c/kWh | 196.38c | R 143.36 |
| Fixed charge R/day | R 27.61 | |
| Maintenance charge | Per luminaire | Per High mast luminaire |
| | R 94.82 | R 2 214.56 |

*Table 42: Gen-DUoS tariff*

**Gen-DUoS**

| DUoS network charges for generators | |
|---|---|
| Voltage | Network capacity charge [R/kW] |
| < 500V | |
| ≥ 500V & < 66kV | |
| ≥ 66kV & ≤ 132kV | R 16.50 |

| Distribution loss factors for Distribution connected generators | | |
|---|---|---|
| Voltage | Urban loss factor | Rural loss factor |
| < 500V | 1.1862 | 1.1973 |
| ≥ 500V & < 66kV | 1.1556 | 1.1761 |
| ≥ 66kV & ≤ 132kV | 1.0724 | 0.0000 |
| > 132kV/Transmission connected | 1.0000 | 0.0000 |

| Transmission loss factors for Distribution connected generators | |
|---|---|
| Voltage | Zone |
| ≤ 300km | 1.0060 |
| > 300km & ≤ 600km | 1.0160 |
| > 600km & ≤ 900km | 1.0261 |
| > 900km | 1.0361 |

| Voltage | Ancillary service charge c/kWh (Urban) | Ancillary service charge c/kWh (Rural) |
|---|---|---|
| <500V | 0.36 | 0.36 |
| ≥500V & <66kV | 0.35 | 0.36 |
| ≥66kV & <132kV | 0.32 | 0.00 |
| >132kV* | 0.30 | 0.00 |

| Urban retail charges based on MEC | Service charge R/POD/day | Admin charge R/POD/day |
|---|---|---|
| ≤ 100 kVA/kW | R 12.19 | R 0.65 |
| > 100 kVA/kW & ≤ 500 kVA/kW | R 57.02 | R 11.00 |
| > 500 kVA/kW & ≤ 1 MVA/MW | R 176.09 | R 17.18 |
| > 1 MVA/MW | R 176.09 | R 17.18 |
| Transmission connected | R 992.07 | R 17.18 |

| Rural retail charges based on MEC | Service charge R/POD/day | Admin charge R/POD/day |
|---|---|---|
| ≤ 100 kVA/kW | R 20.53 | R 1.20 |
| > 100 kVA/kW & ≤ 500 kVA/kW | R 57.02 | R 11.00 |
| > 500 kVA/kW & ≤ 1 MVA/MW | R 176.09 | R 17.18 |
| > 1 MVA/MW | R 176.09 | R 17.18 |

## *Table 43: Gen-TUoS tariffs*

**Gen-TUoS**

| Loss factors and network charges for Transmission connected generators | | |
|---|---|---|
| Zone | Loss factor | Network charge [R/kW] |
| Cape | 1.00000 | R 0.00 |
| Karoo | 1.00000 | R 0.00 |
| Kwazulu-Natal | 1.01495 | R 4.14 |
| Vaal | 1.00026 | R 13.77 |
| Waterberg | 1.01352 | R 17.63 |
| Mpumalanga | 1.01487 | R 16.36 |

| Ancillary service charge for Transmission connected generators | Ancillary service charge [c/kWh] |
|---|---|
| Generators | 0.3000 |

| Retail charges based on MEC | Service charge R/POD/day | Admin charge R/POD/day |
|---|---|---|
| Transmission connected | R 992.07 | R 17.18 |

| ERS charge c/kWh (Urban LPU) c/kWh |
|---|
| 4.63 |

## *Table 44: Gen-wheeling tariffs*

**Gen-wheeling**

| Tariff name | Type of charge | Rate |
|---|---|---|
| Gen-wheeling non Munic urban | Energy charge (credit) | WEPS non-local-authority tariff energy rates excluding losses |
| | Administration charge | WEPS non-local-authority tariff administration charge |
| | All other tariff charges | NA |
| Gen-wheeling non Munic rural | Energy charge (credit) | WEPS non-local-authority tariff energy rates excluding losses |
| | Administration charge | Ruraflex non-local-authority tariff administration charge |
| | All other tariff charges | NA |
| Gen-wheeling Munic urban | Energy charge (credit) | Municflex local-authority tariff WEPS energy rates excluding losses |
| | Administration charge | WEPS local-authority tariff administration charge |
| | All other tariff charges | NA |
| Gen-wheeling Munic rural | Energy charge (credit) | NA |
| | Administration charge | NA |
| | All other tariff charges | NA |

## Table 45: Gen-offset tariffs

| Gen-offset | | |
|---|---|---|
| Tariff name | Type of charge | Rate |
| Gen-offset urban | Energy charge (credit) | WEPS non-local authority tariff energy rates per Transmission Zone and voltage |
| | Ancillary service charge (credit) | WEPS non-local authority tariff ancillary service charge |
| | Administration charge | WEPS non-local authority tariff administration charge |
| | All other tariff charges | NA |
| Gen-offset rural | Energy charge (credit) | Ruraflex non-local authority tariff energy rates per Transmission Zone and voltage |
| | Ancillary service charge (credit) | Ruraflex non-local authority tariff ancillary service charge |
| | Administration charge | Ruraflex non-local authority tariff administration charge |
| | All other tariff charges | NA |

## Table 46: Gen-purchase tariffs

| Gen-puchase | | |
|---|---|---|
| Tariff name | Type of charge | Rate |
| Gen-purchase- urban | Energy charge | WEPS non-local-authority tariff energy rates excluding losses |
| | Affordability subsidy charge | WEPS non-local-authority affordability subsidy charge |
| | Administration charge | WEPS non-local-authority tariff administration charge |
| | All other tariff charges | NA |
| Gen-purchase-rural | Energy charge | WEPS non-local-authority tariff energy rates excluding losses |
| | Administration charge | Ruraflex non-local authority tariff administration charge |
| | All other tariff charges | NA |
| Gen-purchase Munic | Energy charge | Municflex local-authority tariff WEPS energy rates excluding losses |
| | Administration charge | Municflex local-authority affordability subsidy charge |
| | All other tariff charges | NA |

# Annexure F – Survey on customer perceptions of the IBT

One of the structural changes proposed in the Retail Tariff Restructuring Plan initially submitted to NERSA in August 2020 and 2022, was for Eskom to amend the structure of the existing inclining block tariff (IBT) for residential customers. Following the submission, NERSA requested further explanation and asked if the motivation for the proposed changes could be substantiated with evidence from a customer survey.

In response, Eskom conducted a customer feedback survey on the inclining block tariff in January 2022. The purpose of the survey was to assess customer understanding of the current inclining block rate tariff and gather opinions about the tariff.

**Methodology**

The customer feedback research project was divided into two distinct sections:

**Section 1: Comprehensive online survey**

- An MS Teams customer survey tool was developed.
- The survey content included a section on biographic information and tariff-specific questions to determine the customers' understanding of and opinions about the inclining block tariff (IBT).
- The data was collected through the internal survey of all the Eskom employees.
- The short ten-question survey included multiple choice-, rating - and open-ended questions.
- The online survey was shared via e-mail with all Eskom employees on 18 January 2022 and the closing date was on 31 January 2022.

**Section 2: Customer SMS survey**

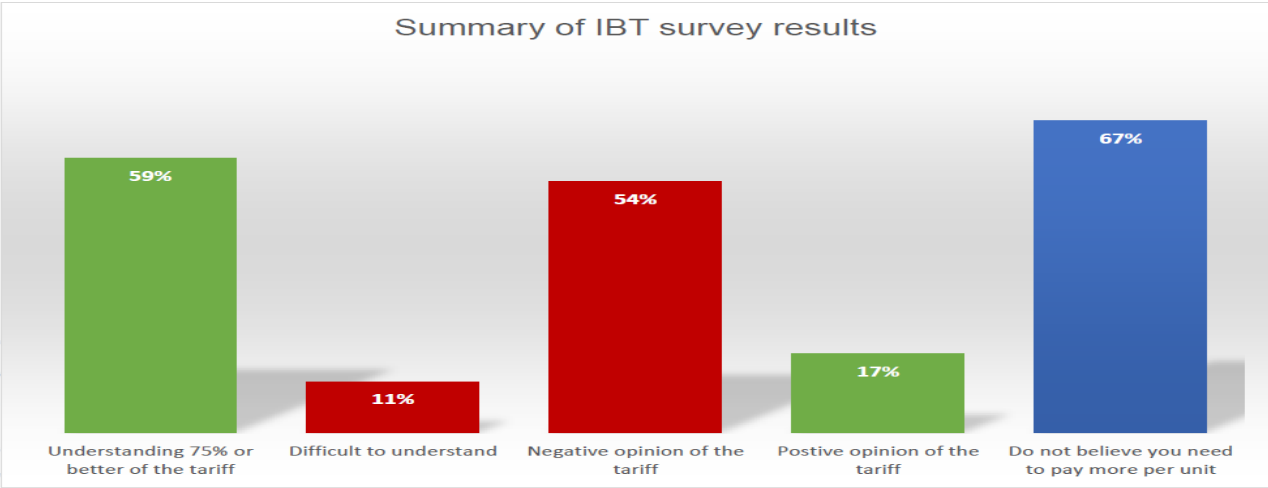
- A single question was compiled to share with Eskom Distribution customers via SMS
- The question was translated into 11 official languages in South Africa was posed as follows: "*Dear Eskom Customer Please reply with YES if you are satisfied with a stepped tariff or NO: it is confusing and it costs more if I buy more. Thank you*"
- The number of SMSs is 100 000 per Operating Unit, totalling 900 000 customers in the 9 Operating Units

**Summary of the survey results – online survey**

Feedback received from the online survey indicated:

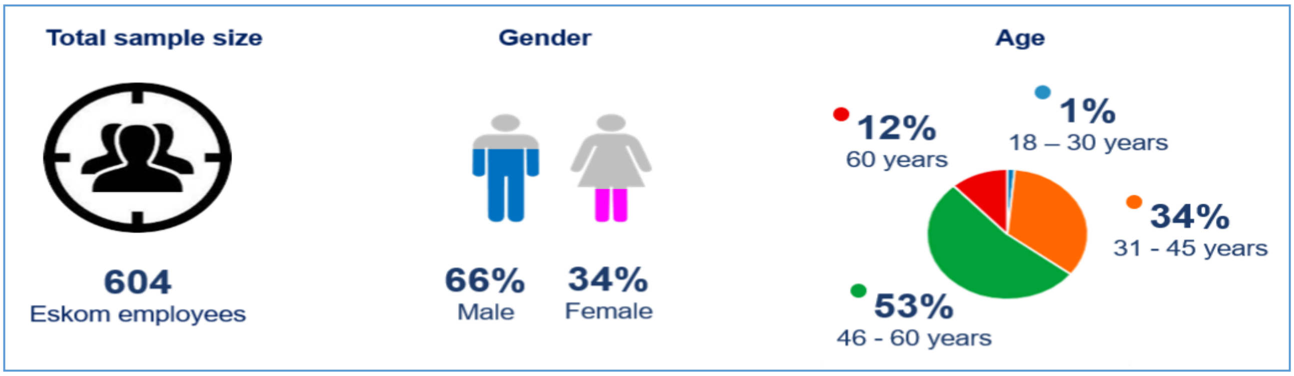
- 59% of the participants have a 75% - 100% understanding of how the tariff works,
- 11% of the participants found it difficult to understand and hard to explain the tariff to customers.
- 54% of the participants indicated that they have a negative opinion about the tariff, because the tariff is perceived as punitive and unfair, and they state challenges around affordability and the high cost of living.
- 17% indicated that they support the tariff and that it promotes an energy-efficient culture.

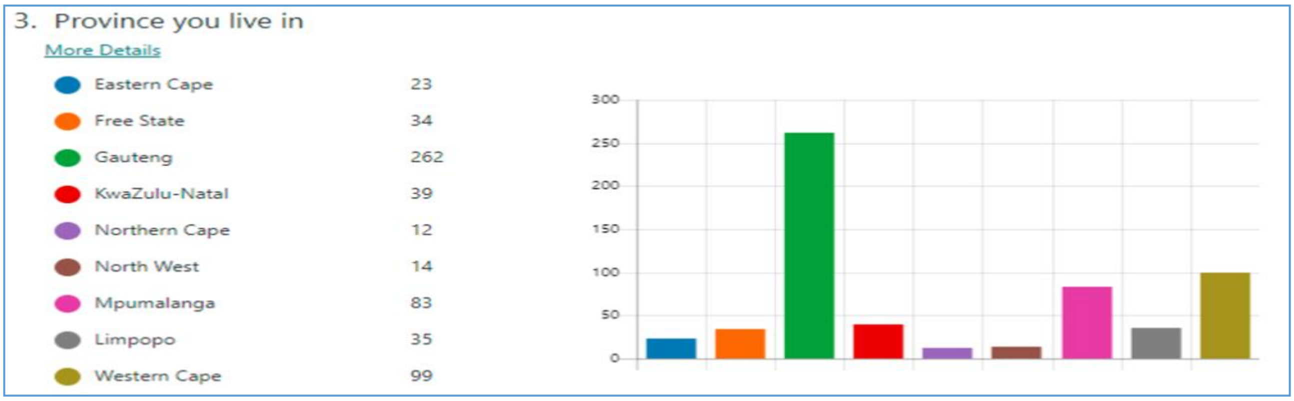
- 67% of the participants also shared that they do not believe you need to pay more per unit if you use more electricity.




The details of the survey questionnaire and results are summarised below:

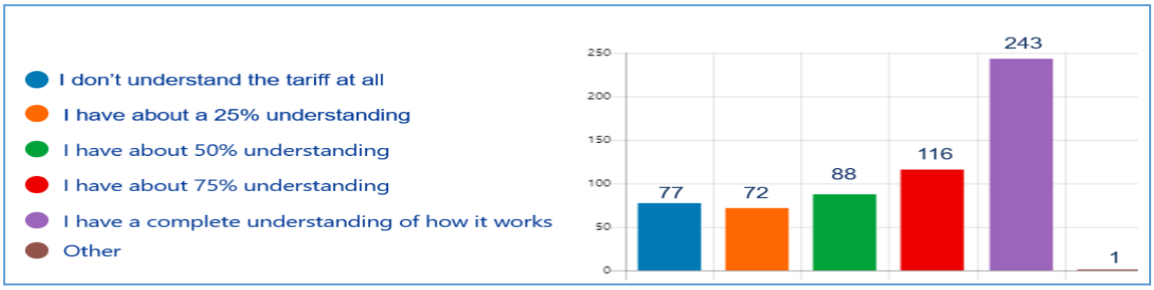
The number of survey respondents was 604 employees across all provinces, with most respondents in Gauteng and Western Cape.

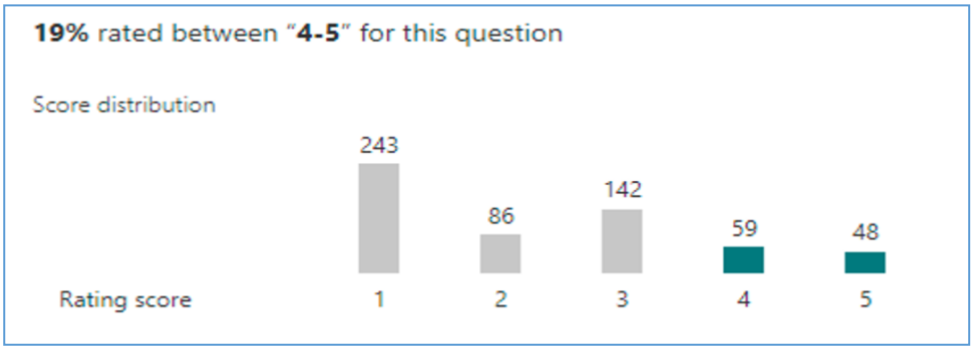


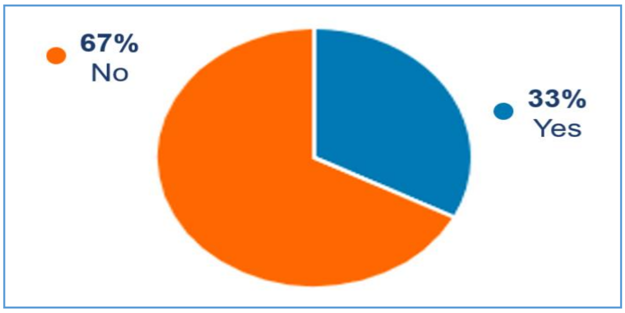




When asked about their electricity usage a month, most of the customers indicated that they pay over R1000 per month which implies that their consumption is in the second energy block of the IBT tariff.


The customers were also asked to rate their understanding of the tariff, and 59% of the respondents indicated that they had a complete understanding of the tariff. However, when asked to rate their opinion of the tariff on a scale of 1-5, with 1 being "I don't like it at all" and 5 being "I like this tariff", while 54% of the customers expressed their dislike and only 19% indicated that they like the tariff. Of the participants, 67% also shared that they do not believe that you need to pay more per unit if you use more electricity.




**Summary of the survey results – Customer SMS survey**

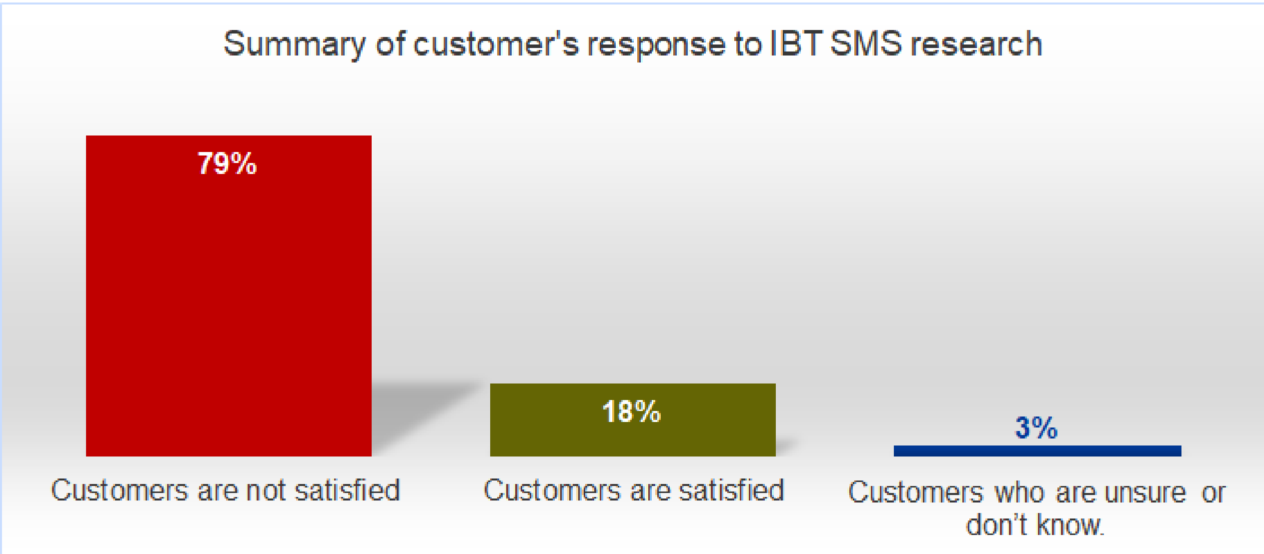
Feedback received from the SMS survey indicated:

- 79% of the participants are not satisfied with the IBT tariff, as it costs more,

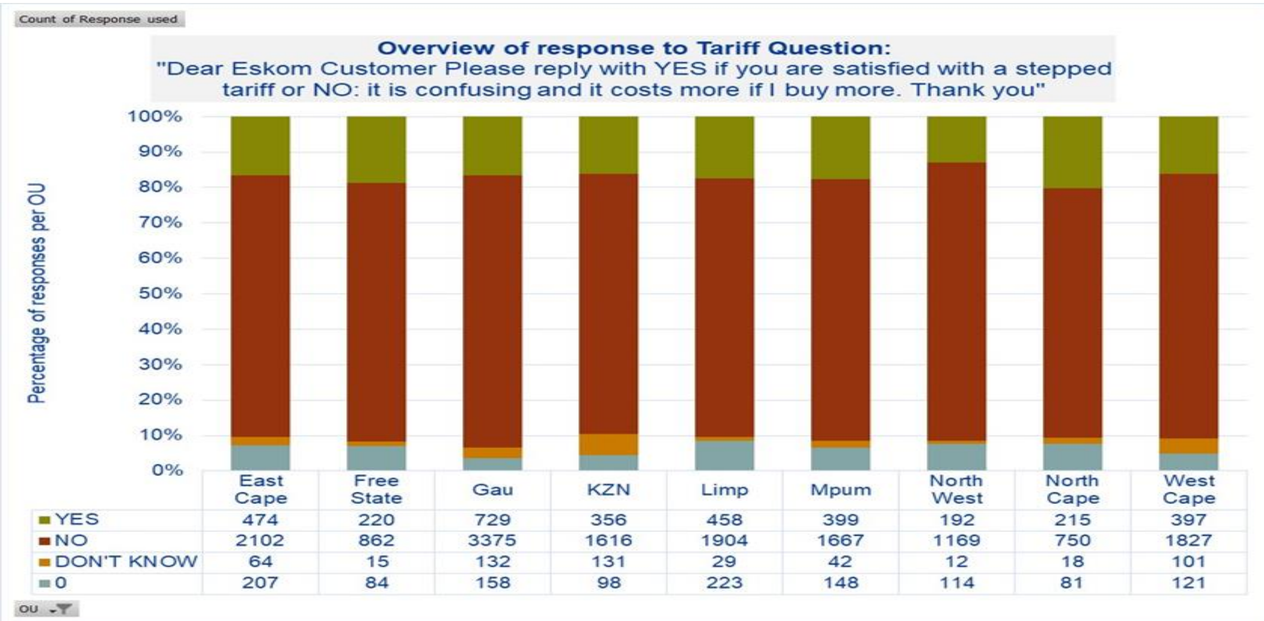
- 18% of the participants are satisfied. Some customers who responded that they are satisfied gave us a further comment which shows that they want to buy more, but cannot afford to, so they are resorting to alternative energy which may be unsafe in our unpredictable climate.
- 5% of the participants are unsure or don't know.

Customers further, explained that they cannot afford electricity, which is a basic human right, as it is becoming expensive. They also want to purchase more, but cannot, as they are penalised for using more.

There were responses from SASSA recipients who would like to see special tariffs created for them or concessions and deductions.




The following are the customers' responses to our survey grouped per province.




"Don't Know" is the same as "Unsure" in this survey.

"0" refers to customers who did not answer our question but commented on an electricity problem that they are experiencing.

The survey questionnaire sent to customers is shown below:

## Customer survey on the inclining block rate tariff

Your response to this survey very important. The results will form part of the customer information that Eskom submits to the National Electricity Regulator of South Africa (NERSA)related to the residential electricity tariffs that are currently implemented by both Eskom and the various municipalities.

The purpose of the survey is to assess **customer understanding** of the current inclining block rate tariff, as well as opinions about the tariff.

The information you provide will be treated with the strictest confidentiality. The survey is completed anonymously, and **you will not be identified**. All data hosting, statistical analyses and interpretation will be conducted by an internal team.

## What is an inclining block rate tariff?

The inclining block rate tariff is a stepped tariff used for residential customers and is applied by both Eskom and municipalities as a requirement by NERSA. This tariff has different charges for blocks of consumption, with higher charges on each step as you consume more, that is, the charge for a unit of electricity increases as consumption moves from one block to the next over a period of a month

Below is an example to illustrate the tariff (as Eskom and municipalities' have different tariffs that they use):

- the first block or step will be for the first 300 kWh in a month at a rate of say R1,20 per kWh, and
- the next block for any consumption above 300 kWh in a month will be charged at R2,30 per kWh.

## Quick survey overview

1. The survey will take approximately 5 - 10 minutes to complete, with only 5 questions. Please complete it in **one** session if possible.
2. Make sure the survey is complete by clicking the 'submit' button at the end of the survey. If you do not complete the entire survey and submit your responses, your responses will be lost.
3. **Kindly respond by 20 January 2021.**
   Feedback on the results of this survey will be conveyed to you once the data has been analysed and shared with Eskom's senior leadership.

## Biographic Information

**This section** is a biographic section where we ask questions about you to add context to the results.

**Please answer the following questions by responding to the appropriate options provided.**

Gender

- ○ Male
- ○ Female

Age group

- ○ 18 – 30
- ○ 31 – 45
- ○ 46 – 60
- ○ > 60

Province you live in:

- ○ Eastern Cape
- ○ Free State
- ○ Gauteng
- ○ KwaZulu-Natal
- ○ Northern Cape
- ○ North West
- ○ Mpumalanga
- ○ Limpopo
- ◉ Western Cape

## Customer's feedback on the Inclining block rate tariff

Please answer the following questions **only if you are on an inclining block** (stepped) residential tariff, whether you are supplied by Eskom or a municipality

1) Please rate your understanding of the tariff on a scale of 1 -5, **1** – I don't understand the tariff at all, **2** - I have about a 25% understanding, **3** -I understand it about 50%, **4** about 75% understanding and **5** - I completely understand how it works.

| | 1 | 2 | 3 | 4 | 5 |
|---|---|---|---|---|---|
| Please rate your understanding of the tariff | | | | | |

2) Explaining the tariff

| | Yes | No |
|---|---|---|
| Do you believe that your electricity supplier could do better with explaining the tariff? | | |

3) Please rate your opinion of the tariff on a scale of 1-5, 1 being "I don't like it at all" and 5 being "I like this tariff".

| | 1 | 2 | 3 | 4 | 5 |
|---|---|---|---|---|---|
| Please rate your opinion of the tariff | | | | | |

4) Please provide a reason for your rating in question 3).

| |
|---|
| |

5) – Price of electricity

| | Yes | No |
|---|---|---|
| Do you believe that you need to pay more per unit if you use more electricity? | | |

6) Please provide a reason for your rating in question 5

| |
|---|
| |

## Annexure G – Eskom Response to NERSA Reasons for Decision on the 2022 RTP

In the 2022 Eskom Retail Tariff Plan, NERSA highlighted key concerns in their reasons for the decision. Eskom's response to these concerns is provided in the table below.

| NERSA REASON FOR DECISION RTP 2022 | | | | ESKOM RESPONSE |
|---|---|---|---|---|
| **Proposal** | **Benefits** | **Risks of approval/non-approval** | **Recommendation** | |
| **The proposed new tariff, Homeflex, will be a residential time-of-use tariff, for urban residential customers that have embedded generation installations.** | The adoption of rooftop solar by consumers can contribute to the reduction of the load. The ability to sell excess power at time-of-use rates may encourage customers to sell excess power to the grid. | • This proposal may be perceived as trying to discourage customers from installing solar.<br>• This needs to be balanced with the fact that customers without solar are subsiding customers with solar therefore approval will ensure that these customers continue to contribute to their fixed costs even when consumption from the grid declines.<br>• This new tariff requires the installation of bi-directional meters. This tariff is also based on an offset rate NERSA does not currently have jurisdiction on. | **Approval is recommended, except for the offset rate.** | • The Homeflex tariff as approved by NERSA has been implemented by Eskom.<br>• The 24/25 RTP proposes that the fixed charges for Homeflex be unbundled to align with the proposed unbundling of the fixed charges in the Homepower tariffs. This unbundling will correct unfair subsidies where customers with solar PV are subsidised by those without solar PV. *Refer to paragraph 6.8 in the document for further details.* |
| **Aligning tariffs to the Cost to Serve (CTS) study unit costs** | This ensures that customers are paying costs aligned to the cost to supply them. | • Eskom's tariffs have not been updated to align them with the cost to serve since 2013 therefore current tariffs are not aligned with costs, however the changes that are being proposed are integrated in such a way that any change in one tariff without a change in the others will lead to either a revenue under or over recovery and time is limited to address this challenge. | **Approval is not recommended at this stage.** | • In Eskom's proposed 24/25 RTP all the tariff rates have been updated with a 2024/25 cost-to-serve (CTS) study based on the 2024/25 NERSA approved requirement and volumes to reflect costs per Eskom Division.<br>• All the tariff structural changes are based on the updated CTS study and the restructured tariff revenue is designed to balance the NERSA-approved revenue in the CTS study.<br>• Eskom will be engaging NERSA in the tariff change process to ensure that reasons for changes and tariff integration |

| NERSA REASON FOR DECISION RTP 2022 | | | | ESKOM RESPONSE |
|---|---|---|---|---|
| **Proposal** | **Benefits** | **Risks of approval/non-approval** | **Recommendation** | |
| | | | | points are discussed beforehand and concerns are addressed before final submission. |
| **The rationalisation of municipal tariffs from 13 to 3 tariffs used by Eskom to sell to municipalities.** | The rationalisation will provide relief for Rural Nightsave-connected municipalities which will realise a decrease in the purchase costs of up to 20%. The proposal will simplify the process of billing municipalities by Eskom. | • The implications of the revision of the Electricity Regulation Act (ERA) to allow for the establishment of a separate TX company and a Wholesaler from which municipalities will be able to purchase power will change the relationship between Eskom DX and municipalities as not been factored into this proposal.<br>• The legal separation of NTCSA is currently underway and is likely to be finalised in May 2023 ahead of the changes in ERA.<br>• The question has been raised on whether the changes this year will be translated into lower consumer tariffs due to the timing of the change.<br>• Municipalities with Rural Nightsave tariffs will continue facing difficulties in making a surplus from the sale of electricity.<br>• The proposal creates a new subsidy between rural and urban customers, this impact has not been thoroughly assessed. | Approval is not recommended at this stage. | • The RTP does not deal with the criteria for wholesale purchases by municipalities. The conditions and criteria will be determined through the new market codes currently being developed by NTCSA.<br>• The tariff rates (energy purchase structure) proposed in the RTP will be the same irrespective of whether the customer is supplied by Distribution or the NTCSA.<br>• There are no additional subsidies created by reclassifying all municipal bulk points as an urban category, rather this creates a fair level playing field for all municipalities because all municipal points will be treated the same. Overall, municipalities see a reduction of R560 million in revenue in the proposed 24/25 RTP<br>• Refer to Appendix A in the document for further details. |
| **The Time-of-Use (TOU) ratio and time changes** | The reduction of the ratio between peak and off-peak will provide relief for customers who are on TOU and will help in reducing evening peak demand, provided that | • Section 15(1) of the ERA prescribes principles governing the setting and approval of tariffs including that it must enable an efficient licensee to recover the full cost of its licensed activities, including a reasonable margin or return. TOU tariffs are not cost-reflective but are intended to | Not recommended for approval. | The proposed changes to the TOU tariffs are based on the cost as indicated in the updated CTS study. Although TOU tariffs are primarily designed to help better manage the system by encouraging customers to shift or reduce consumption, it is critical that they also reflect the actual costs incurred. |

| NERSA REASON FOR DECISION RTP 2022 | | | | ESKOM RESPONSE |
|---|---|---|---|---|
| **Proposal** | **Benefits** | **Risks of approval/non-approval** | **Recommendation** | |
| | customers respond accordingly. Studies show that properly structured TOU tariffs prompt price-sensitive customers to shift their consumption and thus reduce the energy component of their bills (between 5–10%). This should be also seen in the context of long-term measures to relieve customers of the burden brought about by TOU tariffs. | send signals for customers to reduce or shift their consumption. It is more expensive to produce during morning and evening peaks as Eskom has to use more expensive sources of generation such as pumped storage and OCGTs, however, this relationship is not 1:1. On the other hand Policy Position 31 of the EPP encourages the use of TOU tariffs for LPUs. | | Eskom Distribution purchases energy from NTCSA on a TOU basis. However, the current Standard TOU tariff structure, including its periods and rates, does not align with the wholesale purchase structure and rates. This misalignment creates a disconnect between costs and retail tariff levels, which could lead to inefficient cost recovery.<br>To ensure that tariff structures are both cost-reflective and compliant with Section 15(1) of the ERA, it is essential to accurately reflect costs in retail tariffs. Refer to Appendix C for further details. |
| **The increase of fixed charges from 10% to 24%.** | Eskom states that even though around 76% of Eskom's costs are fixed, the majority of its costs are recovered through variable tariffs (90%). This places a risk on its ability to recover its costs should sales volumes decline significantly. | • The increase of fixed charges under the current environment of extended load shedding cannot be justified because of Eskom's inability to meet demand with the existing generation assets.<br>• There is, however, a need for proper classification of costs through an appropriate unbundling process. | Not recommended for approval. | The proposed 24/25 RTP is based on unbundled costs in line with the cost classification done in the CTS study.<br>Eskom acknowledges the concerns raised regarding the impact of fixed charges on customers. This impact has been minimised in the proposed RTP. The proposed changes, including the introduction of the generation capacity charge, increase the fixed charge contribution from 10% to 13%. |
| **The introduction of a Generation Capacity Charge.** | This proposal is also not recommended under the current environment where Eskom is not able to meet the current demand and extended load shedding associated | • The increase of fixed charges under the current environment of extended load shedding would be difficult to justify due to Eskom's inability to meet demand with the existing generation assets. | Not recommended for approval at this stage. | • Generation Capacity Charge is required to recover the cost related to the provision of Generation capacity. This cost is fixed and does not change with loadshedding.<br>• The introduction of the GCC is crucial for reducing the revenue risk associated with volumetric recovery rates, particularly as |

| NERSA REASON FOR DECISION RTP 2022 | | | | ESKOM RESPONSE |
|---|---|---|---|---|
| **Proposal** | **Benefits** | **Risks of approval/non-approval** | **Recommendation** | |
| | with it non-performance of the Eskom fleet (lower EAF). | | | the integration of variable energy resources increases and necessitates backup capacity.<br>• Importantly, the implementation of the GCC will result in a reduction of the variable c/kWh charge, easing the burden on consumers. |
| **The removal of Inclining Block Tariffs (IBTs) from Homepower and Homelight tariffs is not recommended.** | The Regulator put this tariff structure in place for a specific reason, the removal needs to happen when there is clear evidence that they have not served their purpose, and this must be supported by empirical data. | • NERSA is currently undertaking a study to assess the impact of IBTs and delaying this proposal will allow for this exercise to be completed and its findings to inform the decision that the Regulator needs to make. | Not recommended for approval. | • Eskom appreciates NERSA's initiative to undertake a study to assess the impact of Inclining Block Tariffs (IBTs).<br>• Given that Eskom conducted a similar survey in January 2022, we are particularly interested in the findings of NERSA's study and look forward to its outcome.<br>• The Eskom survey revealed that 54% of participants perceive the IBT as punitive and unfair, with concerns around affordability and the rising cost of living.<br>• Additionally, only 17% of respondents believe that the tariff promotes an energy-efficient culture, while 67% expressed that they do not see the need to pay more per unit for increased electricity usage.<br>• Refer to Appendix F for more details. |
| **The conversion of service charges to each Point of Delivery (POD).** | This is to align with the cost of supply requirement that these costs are to be recovered for each point of delivery and not each account. NERSA will assess the | • This proposal is required to align the recovery of service and administration costs with the cost of supply framework provision that these costs should be recovered for each POD and account. The impact of this proposal on customers has not been analysed therefore the delay | Not recommended for approval. | • The impact of this change will vary depending on the number of PODs consolidated under each customer's account. On average, retail charges have decreased by approximately 48%, leading to significant savings on service charges. |

| NERSA REASON FOR DECISION RTP 2022 | | | | ESKOM RESPONSE |
|---|---|---|---|---|
| **Proposal** | **Benefits** | **Risks of approval/non-approval** | **Recommendation** | |
| | impact on these customers and any hidden costs once it has been modelled to the 2023/24 ERTSA. | in implementing this proposal will allow for more analysis and will not have a negative impact on the utility. | | • However, a comprehensive impact assessment of all proposed changes (not only this one change) should be conducted to evaluate the overall effect on the customer's bill.<br>• Customers will be provided with tools to assess impacts, and examples will also be provided to NERSA. |
| **The full bundling of Homepower.** | The unbundling of this tariff and introduction of additional fixed charges will send an incorrect message and confirm the criticism that Eskom is proposing these changes to discourage customers from installing solar panels. | • There is no need to urgently unbundle this tariff as Eskom has a specific tariff for customers with solar installations. This will deal with the risks raised by Eskom. | Not recommended for approval. | • The current Homepower tariff structure does not accurately reflect costs, as it recovers both network and energy costs through variable energy charges (c/kWh).<br>• This approach is outdated and no longer appropriate, as customers who reduce their consumption are incorrectly benefiting from subsidies intended for indigent households.<br>• To address this issue, it is necessary to unbundle the fixed and variable components of the tariff.<br>• A cost-reflective tariff structure for Homepower is proposed to ensure fair and transparent recovery of network costs. This revision is aligned with the Electricity Pricing Policy, policy positions 2 and 27 and is intended to ensure that all customers contribute equitably to the costs of maintaining the network, without discouraging the adoption of solar installations. |

## Annexure H – Eskom responses to SALGA inputs

In response to Eskom's retail tariff plan, SALGA has expressed broad support for several aspects of Eskom's retail tariff restructuring plan. They commend the modest increase in fixed charges and the removal of the Inclining Block Tariff (IBT) for the Homepower and Homelight tariffs. SALGA also supports the proposed changes to Municflex tariffs and encourages NERSA to implement Eskom's recommendations in this area. Additionally, SALGA supports Eskom's proposed Time-of-Use (TOU) tariff changes while urging careful consideration of the peak-to-off-peak ratio adjustment. However, SALGA raised certain concerns regarding tariff structures and compliance with the Electricity Pricing Policy (EPP), and these issues are addressed in the response below.

### 1. Continuation of the Nightsave Tariff

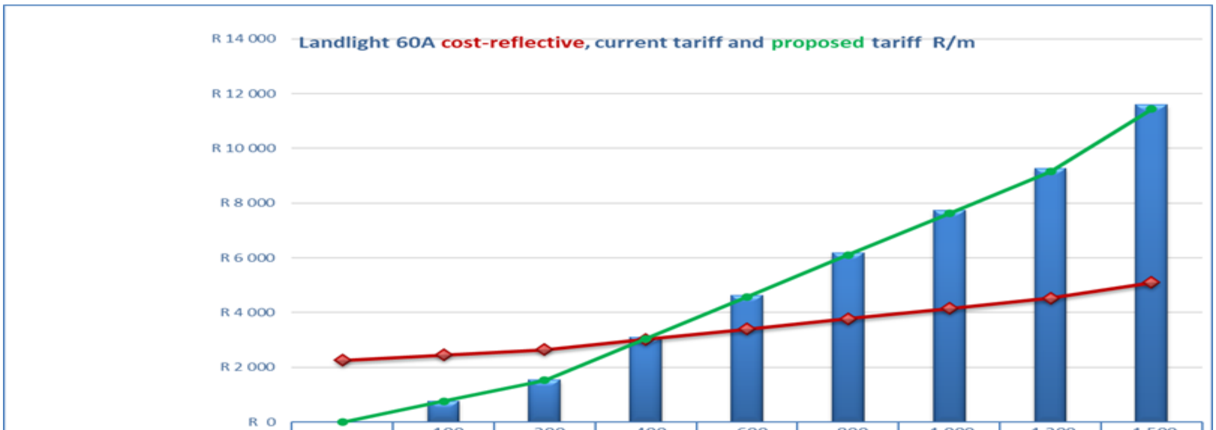
SALGA correctly notes that the Nightsave tariff is not in compliance with the Electricity Pricing Policy (EPP), which mandates large consumers to be on Time-of-Use (TOU) tariffs. Eskom agrees and confirms that we plan to phase out the Nightsave tariff as part of our future tariff restructuring efforts as indicated in section 8. This process has already started with the rationalisation of municipal tariffs, which discontinues the Nightsave tariff for municipalities. This transition ensures that all urban LPU tariffs for municipalities are in line with TOU requirements and the EPP.

### 2. Landlight 60A Tariff Rate Calculations

The adjustment from 500 kWh to 400 kWh better reflects the actual consumption of small rural power users, who typically consume below 100 kWh. Although reflecting the lower consumption accurately would have resulted in a 300% increase in the tariff rate, Eskom has chosen to mitigate this impact by adjusting the consumption threshold to 400 kWh. This ensures that customers are not significantly affected, while the tariff remains cost-reflective.

In addition, after updating the Landrate tariff to align with the Cost-to-Serve (CTS) study, it was discovered that the tariff was recovering more than the actual costs. As a result, adjustments were made to ensure cost recovery without overburdening customers. The reduction in the Landlight 60A tariff is aligned with the lower rates for Landrate 4, ensuring that the average use at 400 kWh results in a tariff close to what customers are already paying. This approach maintains affordability while reflecting actual usage.

The figure below compares Landrate 4 cost-reflective rates to the current and proposed Landlight 60A tariff, demonstrating that at 400kWh consumption, Landrate 4 and Landlight 60A pay roughly the same amount.



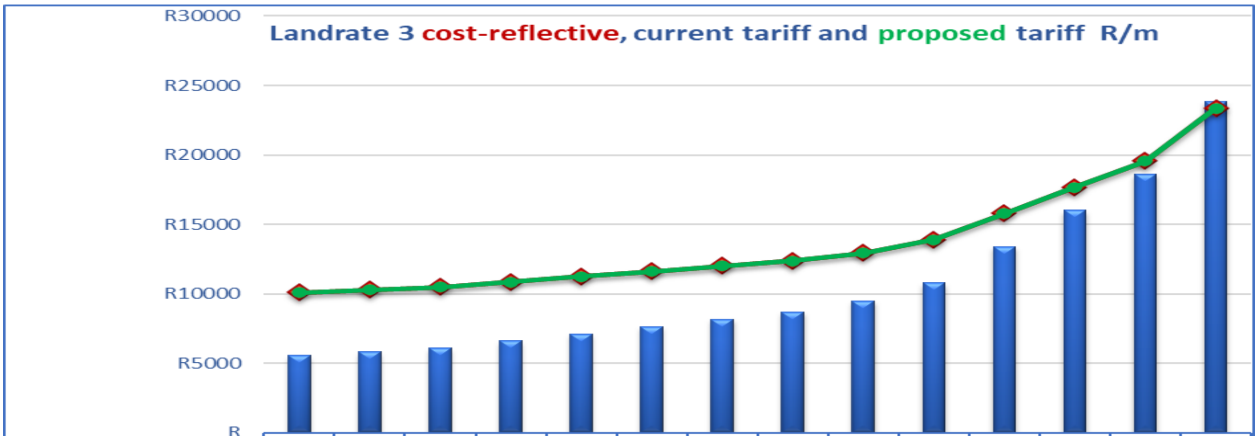

| | 0 kWh/m | 100 kWh/m | 200 kWh/m | 400 kWh/m | 600 kWh/m | 800 kWh/m | 1 000 kWh/m | 1 200 kWh/m | 1 500 kWh/m |
|---|---|---|---|---|---|---|---|---|---|
| Current tariff | R 0 | R773 | R1546 | R3091 | R4637 | R6182 | R7728 | R9274 | R11592 |
| Cost reflective Landrate 4 | R2262 | R2452 | R2641 | R3019 | R3397 | R3775 | R4154 | R4532 | R5099 |
| Proposed tariff | R 0 | R763 | R1525 | R3051 | R4576 | R6101 | R7626 | R9152 | R11440 |

### 3. Demand Charge Classification for Small Power Tariffs (Homepower, Businessrate, Landrate, and Municrate)

We appreciate SALGA's support for removing the Inclining Block Tariff (IBT) from Homepower and Homelight tariffs. Regarding the classification of network demand charges, the Distribution Tariff Code, as approved by NERSA, allows for variable network charges (c/kWh), referred to as network demand charges. Eskom believes that maintaining a portion of these charges as a variable, rather than moving entirely to fixed charges, offers a better balance between ensuring revenue stability and encouraging efficient consumption behaviour. If network charges were entirely fixed, customers would have less incentive to adjust their usage during peak periods, which could result in inefficient network use and force Eskom's Distribution business to invest in infrastructure unnecessarily to handle peak demand. To address this, Eskom's strategy is to recover network costs through a combination of fixed and variable charges, creating a balanced distribution of risk between customers and the utility, as outlined in section 5.6.

SALGA's concerns have been duly noted. Eskom's primary objective is to align current tariffs with actual costs and unbundle tariffs like Homepower. A phased approach is adopted, where after the unbundling of tariffs, further structural adjustments will be proposed to base network charges on R/kVA or R/Amp. Over time, network cost recovery will gradually shift more towards fixed charges, but this will be implemented incrementally to minimise the impact on customers. A complete move to recovering network charges solely through fixed capacity-based charges would result in a significant increase in electricity bills for small power customers. To mitigate this, Eskom proposes a balanced approach, with a mix of fixed and variable charges, ensuring a smoother transition while maintaining efficient and equitable cost recovery.

The graph below illustrates the potential impact of fully recovering network charges through fixed capacity-based charges, which would significantly raise electricity bills for Landrate customers, supporting the need for a split between fixed and variable charges to minimise this impact.




| | 0 kWh/m | 100 kWh/m | 200 kWh/m | 400 kWh/m | 600 kWh/m | 800 kWh/m | 1 000 kWh/m | 1 200 kWh/m | 1 500 kWh/m | 2 000 kWh/m | 3 000 kWh/m | 4 000 kWh/m | 5 000 kWh/m | 7 000 kWh/m |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Current tariff | R5569 | R5830 | R6092 | R6614 | R7137 | R7660 | R8183 | R8705 | R9490 | R10796 | R13410 | R16024 | R18637 | R23865 |
| Cost reflective | R10113 | R10302 | R10491 | R10869 | R11247 | R11626 | R12004 | R12382 | R12949 | R13895 | R15785 | R17676 | R19567 | R23349 |
| Proposed tariff | R10113 | R10302 | R10491 | R10870 | R11248 | R11627 | R12005 | R12384 | R12952 | R13898 | R15790 | R17682 | R19575 | R23360 |

## 4. Municflex and Municrate Tariffs

We are encouraged by SALGA's explicit support for the Municflex tariffs. For Municrate tariffs, Eskom acknowledges SALGA's concerns about splitting the Generation Capacity Charge (GCC) into R/POD and c/kWh components. The phased approach to splitting the GCC is designed to minimise the impact of fixed charges on small rural and residential customers, aligning with NERSA's recommendation from the 2022 Retail Tariff Plan decision. Eskom remains committed to ensuring the fair distribution of costs across all customer categories.

## 5. TOU Tariff Changes

Eskom appreciates SALGA's support for changes to TOU hours and pricing to reflect the operational needs of the power system. However, Eskom notes the concerns regarding reducing the peak-to-off-peak ratio from 8:1 to 6:1. The proposed TOU changes are aligned with updated energy-related costs and are required to better manage the system to increase the security of supply, therefore they provide the correct signal for consumption. The change also addresses customer requests to reduce the high winter peak rates. Municipalities that have the same Eskom TOU rates for their import and export rates of SSEG customers are encouraged to align their rates to the proposed Eskom TOU rates (once approved) to achieve a revenue-neutral impact.

The evening peaks are not reduced by most SSEGs. Studies show that there is a steeper ramp-up to the evening peaks that has resulted from the midday reduction from alternative energy, which needs to be managed. TOU pricing signals, therefore, will continue to be needed to manage the high system demand in the morning and evening peak periods as well as to manage the variation of system demand levels between the high- and low-demand months (summer and winter months) and is revenue neutral to the NERSA allowed revenue. It is to be noted that this submission deals with the unbundling of tariffs and not cost items. The costs and variances are addressed through the MYPD process.

### 6. Splitting of Generation Capacity Charges into Fixed and Variable for Small Tariffs

Eskom acknowledges SALGA's concerns about the split between fixed and variable charges for the GCC. The phased approach to splitting the GCC is designed to minimise the impact of fixed charges on small rural and residential customers, aligning with NERSA's recommendation from the 2022 Retail Tariff Plan decision. Eskom is committed to a gradual unbundling of tariffs that aligns with capacity-based signals (R/kVA or R/Amps). For this to be fully effective, the widespread deployment of smart meters will be required to enable accurate measurement of capacity for these charges.

### 7. Subsidies and Cross-Subsidisation

The key concerns raised by SALGA on subsidies can be divided into three major areas: the Electrification and Rural Subsidy (ERS), Homepower tariffs, and the Homelight 60A tariff.

#### Electrification and Rural Subsidy (ERS)

The ERS is a socio-economic subsidy aimed at supporting electrification and rural customers located in various municipalities. This subsidy is funded by all large power urban tariffs. The ERS subsidy charge has significantly reduced due to the tariff updates with the Cost to Serve (CTS) study. This reduction indicates that the previous average price increases applied to the subsidy charges were higher than required. Further details on these adjustments can be found in Section 5.12.

#### Homepower Tariffs

Regarding the Homepower category, the existing subsidies have primarily resulted from the application of average tariff increases rather than a deliberate design to subsidise indigent customers. The Homepower tariff structure includes a wide range of consumption capacities, from single-phase 16kVA to 100kVA, which serves both high- and low-consumption customers. In response to SALGA's suggestion that Homepower residential customers should contribute to subsidies, Eskom will assess whether such contributions should apply to all Homepower customers or only to high-consuming customers. This assessment will be done in conjunction with the proposal by SALGA to review capacity options within the Homepower tariff to determine optimal capacity sizes for future tariff restructuring phases, ensuring that the tariff categories better reflect actual consumption patterns and customer needs.

**Homelight 60A Tariffs**

The Homelight 60A tariff currently receives a subsidy that originated from NERSA's MYPD2 decision, which pre-determined the non-local-authority Inclining Block Tariff (IBT) rates from 2010/11 to 2012/13. During this period, the IBT rates applied received average increases much lower than the standard tariff increases, and the difference in price increases was carried by the non-local-authority urban tariff category. This subsidy was initially introduced to assist low-income households, and Eskom's approach in this plan is to maintain these subsidies to ensure that low-consumption customers do not pay more than their current electricity bill on the average monthly consumption. This is crucial in mitigating energy poverty and preventing financial strain on vulnerable households.

Eskom acknowledges the discrepancies between municipal and Eskom tariff structures and remains committed to working closely with NERSA and stakeholders to ensure that these subsidies are appropriately recovered and that vulnerable consumers are adequately protected. While Eskom remains open to exploring proposals regarding socio-economic subsidies, it is clear that a national subsidy framework is necessary. Such a framework would provide certainty and clear guidance on which customer categories should contribute to subsidies and which should receive them, ensuring alignment with national policies and the EPP.

## 8. Voltage Differentials

Eskom acknowledges the long-standing issue of voltage differentials raised by SALGA. Expanding the existing tariff categories to be differentiated at the substation and network levels would require extending the current energy-related transmission and voltage zone-differentiated tariffs. This expansion would result in increasing the number of energy tariffs from 16 to 32, with similar increases for network charges. Such differentiation would create additional tariff categories for large power users (LPUs) and Time-of-Use (TOU) customers, which would add significant administrative complexity for both Eskom and municipalities. This would directly counter the objective of rationalising and simplifying tariffs to reduce complexity and streamline tariff structures.

It is important to note that Eskom's current approach to tariffs is based on the principle of pooling costs, which is allowed for in the Tariff Codes. Pooling ensures that costs are averaged across categories, preventing the need for extensive differentiation at every level of connection. Introducing further granularity, such as separate charges for customers connected at the busbar versus those connected to the line, would result in lengthier and more complex tariff tables for LPUs and create additional tariffs for small power users (SPUs). This complexity would not only burden customers but also complicate the administration and implementation of tariffs.

Moreover, such detailed differentiation would require a new Cost of Supply study and introduce losses associated with both busbar and line connections. Customers may also request to be connected at the busbar to avoid higher tariffs, but this is not feasible for all connections. Additionally, this differentiation would lead to municipal points connected to lines paying more than those connected at the busbar, creating further disparities.

Eskom appreciates SALGA's support for maintaining the current voltage categories and acknowledges that SALGA is not proposing the creation of additional categories. This support is valued as Eskom continues its efforts to streamline and rationalise tariffs while ensuring fair cost distribution.

## 9. Explanation of costing for Homepower and Homelight tariffs

Homepower and Homelight are Standard Tariffs which belong to the costing category for Pods with voltage supply of less than 500 V and location being urban.
They do not have actual or forecasted sales volumes by time-of-use and their demand (UC) is not metered. ToU representative profiles, ADMDs and load-factors obtained from a research study were used.

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) is assumed for the UC. The UC in the forecasted sales volumes is a non-coincident demand.
The results from cost allocation are average unit costs separately identifiable 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).

**Conclusion**

Eskom is committed to an inclusive tariff restructuring process that ensures fairness, efficiency, and alignment with regulatory policies. We support many of the proposals raised by SALGA, but it is important to recognise that the first step is to align our tariffs with the updated cost-to-serve study, as the current tariffs were last updated in 2012. This alignment will inform future tariff developments, and Eskom will continue to take a phased approach to minimise customer impact and ensure sustainable revenue recovery.

We welcome continued collaboration with SALGA, NERSA, and other stakeholders to refine and implement these changes in a manner that balances customer affordability with operational sustainability.