NATIONAL ENERGY REGULATOR OF SOUTH AFRICA

**NATIONAL ENERGY REGULATOR OF SOUTH AFRICA**

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**Decision and Reasons for Decision (RfD)**

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In the matter regarding the

**Municipal Tariff Applications for the 2026/27 Financial Year**

by

**Mantsopa Local Municipality**

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## THE DECISION

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1. At its meeting held on 30 April 2026, the Regulator Executive Committee (REC) considered Tswelopele Local Municipality's tariff application. Based on the facts and evidence presented, the REC approved the tariff increases for the 2026/27 financial year set out in section 8 (Page 20-26) below.

2. Based on the available information and the analysis performed thus far, the Regulator Executive Committee decided to:

   2.1. to approve the tariffs that are based on the Cost of Supply (COS) report as recommended in the tariff analysis section for implementation by the municipality with effect from 1 July 2026;
   2.2. to note the COS report submitted by the municipality;
   2.3. that the municipality must submit a report accounting for all the costs that have been noted in its COS study, to enable the National Energy Regulator of South Africa (NERSA) to perform its independent verification/audit process by 31 January 2027.
   2.4. The Municipality is required to submit a quarterly smart efficiency plan with improvement measures identified in reducing high energy losses and submit it by 30 September 2026.

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The whole decision is on NERSA's website: https://www.nersa.org.za/file/9288/Mantsopa2027RFD.pdf

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ABBREVIATIONS

| | |
|---|---|
| COS | Cost of Supply |
| D-form | Distribution form |
| ERTSA | Eskom Retail Tariff Structural Adjustments |
| FBE | Free Basic Electricity |
| IBT | Inclining Block Tariff |
| IPP | Independent Power Producer |
| LM | Local Municipality |
| MFMA | Municipal Finance Management Act |
| NERA | National Electricity Regulation Act |
| NERSA | National Energy Regulator of South Africa |
| OPEX | Operating Expenditure |

## 1. INTRODUCTION

1.1. The National Energy Regulator of South Africa (NERSA) receives and considers tariff applications on a yearly basis, in accordance with the mandate of the Energy Regulator to regulate prices and tariffs. Municipal tariffs must be approved by the Energy Regulator to be implemented on 1 July of each financial year.

1.2. The municipality has a population of 53,525 and the rest of the socio-economic information is listed in Table 2 below. The licensee provides 50 kWh Free Basic Electricity to 1,469 indigent customers.

**Table 1: Customer Base**

| | **2024/25** | | | |
|---|---|---|---|---|
| ***Customer categories*** | ***KWh*** | ***% KWh*** | ***Customer numbers*** | ***% Customer numbers*** |
| Domestic (Prepaid) | 6 024 261 | 25.39% | 3,005 | 86.60% |
| Domestic (Conventional) | 1 290 654 | 5.44% | 189 | 5.45% |
| Manufacturing | 12 700 760 | 53.52% | 56 | 1.61% |
| commercial (Prepaid) | 1 730 987 | 7.29% | 96 | 2.77% |
| Commercial (Conventional) | 1 580 240 | 6.66% | 118 | 3.40% |
| Own use | 17,210 | 0.07% | 1 | 0.03% |
| Sold to other departments | 386,836 | 1.63% | 5 | 0.14% |
| **TOTAL** | **23 730 948** | **100%** | **3,470** | **100%** |
| Free Basic Electricity | 700,543 | 9.58% | 1,469 | 42% |

1.3. NERSA received the Mantsopa Local Municipality's (Mantsopa) tariff application together with its COS study on 31 March 2026.

1.4. In accordance with NERSA requirements, all tariff applications must include confirmation that the proposed tariffs have been approved by the municipal council and have undergone customer consultation.

1.5. NERSA followed the notice and comment consultation process as well as oral presentations. On 31 March 2026, NERSA published Mantsopa's tariff application on its website and social media platforms, as well as in national and local newspapers, to solicit written comments from affected parties.

1.6. NERSA's decision was made on 10 April 2026, considering the written comments received from the affected stakeholders and the analysis performed by NERSA.

## 2. Legal and Regulatory Framework

### 2.1. Background

2.1.1. The approval of municipal electricity tariffs constitutes a core regulatory function of the Energy Regulator and must be exercised in accordance with the applicable legislative framework, national policy directives, and court orders. The principal legal instruments governing the exercise of this regulatory authority include the National Energy Regulator Act, 2004 (Act 40 of 2004) ("NERA"), the Electricity Regulation Act, 2006 (Act 4 of 2006) as amended ('the ERA'), the Promotion of Administrative Justice Act, 2000 (Act 3 of 2000) (PAJA), and the Electricity Pricing Policy for the South African Electricity Supply Industry, 2008 (EPP).

2.1.2. The approval of municipal electricity tariffs follows the Eskom Multi-year Price Determination and the Eskom Retail Tariff and Structural Adjustment decision and is undertaken annually to align with the municipal budgeting process contemplated in the Municipal Finance Management Act, 2003 (Act 56 of 2003).

2.1.3. In addition, the municipal tariff approval process has recently been the subject of judicial scrutiny in the High Court of South Africa (Gauteng Division, Pretoria) in AfriForum NPC v National Energy Regulator of South Africa and Others (Case No. 2025/137620), which resulted in structural directives governing the timing and conduct of NERSA's tariff approval process.

2.1.4. This section provides the legal and policy context within which the Energy Regulator evaluated and determined the municipal electricity tariff application for the 2026/27 municipal financial year.

### 2.2. Statutory Mandate of the Energy Regulator

2.2.1. NERSA is established as a juristic person in terms of section 3 of NERA. In terms of section 4 of NERA, the Energy Regulator as the decision-making body must regulate the electricity industry and execute the functions set out in the ERA. The electricity regulatory mandate of the Energy Regulator is therefore primarily governed by the ERA. Section 3 of the ERA particularly provides that the Energy Regulator is the custodian and enforcer of the national electricity regulatory framework and exercises regulatory authority over activities regulated under the ERA.

2.2.2. In particular:

a) Section 4(a)(i) of the ERA provides that the Energy Regulator must consider applications for licenses and may issue licensees subject to conditions;

b) Section 4(a)(ii) of the ERA provides that the Energy Regulator must regulate prices and tariffs; and

c) Section 14(1)(d) of the ERA authorizes the Energy Regulator to impose license conditions relating to the setting or approval of prices, charges, rates, and tariffs charged by licensees.

2.2.3. Municipalities distributing electricity do so under electricity distribution licenses issued by the Energy Regulator and are therefore subject to the tariff approval framework established under the ERA.

## 2.3. Tariff Determination Principles under the ERA

2.3.1. When determining or approving electricity tariffs, the Energy Regulator must apply the principles contained in section 15(1) of the ERA.

2.3.2. Section 15(1) provides that the Energy Regulator:

a) must enable an efficient licensee to recover the full cost of the licensed activity;

b) must allow for a reasonable return commensurate with the risk of the licensed activity;

c) may provide incentives for continued improvement of technical and economic efficiency;

d) must avoid undue discrimination between customer categories;

e) may permit cross-subsidies of tariffs to certain classes of customers; and

f) may have regard to the need to ensure security of supply, diversity of supply and the promotion of renewable energy.

2.3.3. These statutory requirements form the core legal principles guiding the determination of electricity tariffs within the South African electricity supply industry.

## 2.4. Administrative Law Requirements

2.4.1. The approval of municipal electricity tariffs constitutes administrative action as defined in section 1 of the PAJA. Accordingly, the Energy Regulator must ensure that its tariff determinations are lawful, reasonable, and procedurally fair as required by sections 3 and 6 of PAJA. Procedural fairness requires that affected parties and the public be afforded a reasonable opportunity to make representations before a final decision is taken.

2.4.2. Public participation processes conducted by the Energy Regulator therefore form an essential component of the municipal tariff approval process and are intended to ensure transparency, accountability, and fairness in regulatory decision-making.

## 2.5. Policy Framework: Electricity Pricing Policy (2008)

2.5.1. In addition to the statutory framework, the Energy Regulator must have regard to the EPP. The EPP establishes national policy principles for electricity tariff setting, including cost reflectivity, transparency, economic efficiency, and equity.

2.5.2. Policy Position 1 of the EPP provides that the revenue requirement for a regulated licensee must be set at a level that covers the full cost of production, including a reasonable risk-adjusted margin or return on appropriate asset values.

2.5.3. Policy Position 2 states that electricity tariffs must reflect the efficient cost of rendering electricity services accurately and that the average level of tariffs must be set to recover the approved revenue requirement.

## 2.6. Cost of Supply Studies

2.6.1. The EPP recognises that cost reflective tariff structures require a sound understanding of the underlying cost drivers associated with electricity distribution.

2.6.2. Paragraph 8.1 of the EPP notes that COS methodologies have historically not been consistently applied across the electricity distribution industry.

2.6.3. Policy Position 23, therefore, requires electricity distributors to undertake COS studies at least every five years, or when significant structural changes occur in the customer base or cost structure.

2.6.4. Such studies must be conducted in accordance with the methodology approved by NERSA and must accompany tariff structure applications submitted to the Energy Regulator.

## 2.7. Judicial Oversight of the Tariff Approval Process

2.7.1. The municipal tariff approval process administered by NERSA was the subject of litigation in AfriForum NPC v National Energy Regulator of South Africa and Others (Case No. 2025/137620) before the High Court of South Africa, Gauteng Division, Pretoria.

2.7.2. In its final judgment delivered on 4 December 2025, the Court held that NERSA's public participation process relating to the 2025/26 municipal tariff approvals did not comply with the procedural requirements of section 4 of PAJA and was therefore unlawful.

2.7.3. However, recognising the potentially disruptive consequences of setting aside tariff determinations already implemented by municipalities, the Court declined to invalidate the tariffs. Instead, to assist in the timeous and lawful approval of municipal tariffs, the Court issued a structural interdict regulating the municipal tariff approval process going forward.

2.7.4. NERSA subsequently launched a variation application which sought to vary the timelines which were set by the Court on 4 December 2025, considering the practical difficulties which arose as it relates to NERSA's compliance with the Court order. The court having heard NERSA's application, granted the variation

application in respect of the fixed deadlines for the 2026/27 municipal tariff approvals.

## 2.8. Court-Directed Timelines

2.8.1. The timelines below are applicable with respect to the 2026/27 municipal tariff approvals:

a) Written notice of bulk tariffs must be communicated by 6 March 2026.
b) Municipal tariff applications must be submitted by 31 March 2026.
c) Public participation processes must be concluded by 21 April 2026.
d) Publication of NERSA decisions by 11 May 2026.

2.8.2. Municipal tariff approvals from 2027/28 must comply with the following timelines:

a) Written notice of bulk electricity tariffs must be communicated by 31 January each year.
b) Municipal tariff applications must be submitted to NERSA by 20 March each year.
c) Municipal tariff approvals and the tariff reasons for decision document must be approved and published by 5 May of each year.

## 2.9. Conclusion

2.9.1. The determination of municipal electricity tariffs by the Energy Regulator must therefore be undertaken within a comprehensive regulatory framework comprise the NERA, ERA, PAJA, EPP and the binding judicial directives issued by the High Court in AfriForum NPC v NERSA (Case No. 2025/137620).

2.9.2. The reasons that follow in this Reasons for Decision document demonstrate how the Energy Regulator complied with the legislative, policy and judicial framework in determining the municipal electricity tariff for the 2026/27 municipal financial year.

# 3. Financial and Technical Performance

3.1. In evaluating the financial and technical performance of Mantsopa Local Municipality, the assessment relied on the Distribution forms (D-forms) for the 2024/25 financial year submitted as part of the licensee's tariff application. The information contained in the D-forms was verified against the supporting source documents provided by the municipality, including the Mscoa, Billing/Revenue report and Annual Financial Statements. As a result, the data captured in the D-forms is considered reliable for the purposes of the tariff analysis.

3.2. Mantsopa Local Municipality's electricity business operated at a percentage deficit of 54.55% in the 2024/25 financial year increasing from a deficit of 40.17% in the 2023/24 financial year. The deficit was mainly due to surge on expenses resulting

mainly from Eskom interest and partly repairs and maintenance together with increasing energy losses.

3.3. Table 3 below reflects Mantsopa Local Municipality energy losses. The municipality's energy losses amounted to 21.81% in 2024/25 financial year from 25.36% in 2023/24 financial year. High energy losses are due to network inefficiencies (technical) and illegal connections, meter bypassing, billing inaccuracy as well as unattended faulty meters.

**Table 3: Performance Indicators**

| Performance Indicators: Obtained from the D-Form | | |
|---|---|---|
| **Indicators** | **2023/24** | **2024/25** |
| Percentage Surplus (Deficit) | -40.17% | -54.55% |
| Percentage energy Losses | 25.36% | 21.81% |

3.4. If the energy losses were capped at 12% the municipality's deficit would have decreased effectively, changing the deficit from -54.55% to -35.99%. The forgone revenue will be R11 386 079.

3.5. Losses capped at 6%, the deficit would have decreased from -54.55% to a deficit of -28.93% and the foregone revenue of R16 573 503.

3.6. However, if the municipality had zero Eskom interest and had maintained the energy losses at 6%, it would have operated with a surplus of 15.92%. The municipality must continue implementing the plan submitted to NERSA to reduce the energy losses and should also pay its Eskom account to avoid interest.

3.7. This will assist in improving its financial and technical viability. NERSA will monitor to assess the implementation and effectiveness thereof enhancement of network maintenance and monitoring.

**Table 4: Energy Loss Analysis**

| | **D-Form Input** | **Energy Loss@12%** | **Energy Loss@6%** | **Zero Eskom Debts Interest** |
|---|---|---|---|---|
| Average Selling Price c/KWh | 324.53 | | | |
| Sales kWh | 24 730 948.00 | 28 239 471.43 | 29 837 932.08 | 29 837 932.08 |
| Purchases kWh | 31 628 208 | 31 628 208.00 | 31 628 208.00 | 31 628 208.00 |
| Losses kWh | 6 897 260.00 | 3 388 736.57 | 1 790 275.92 | 1 790 275.92 |
| Losses percentage | 21.81% | 12.00% | 6.00% | 6.00% |
| Additional Energy (kWh) | | 3 508 523.43 | 5 106 984.08 | 5 106 984.08 |
| Additional Revenue (Rands) | | 11 386 078.81 | 16 573 502.89 | 16 573 502.89 |
| | D-Form Input | Energy Loss@12% | Energy Loss@ 6% | Energy Loss@ 6% |
| Total Revenue (Rands) | 83 407 122.22 | 94 793 201.04 | 99 980 625.12 | 111 366 703.93 |
| Total Expenses (Rands) | 128 906 957.48 | 128 906 957.48 | 128 906 957.48 | 93 636 800.13 |
| Net Profit (Loss) | -45 499 835.26 | -34 113 756.44 | -28 926 332.36 | 17 729 903.80 |
| Percentage Surplus/Deficit | **-54.55%** | **-35.99%** | **-28.93%** | **15.92%** |

3.8. Based on the above information, inefficiencies on operating expenses continue to put pressure on the financial sustainability of the electricity business. The continued increase in losses indicates weaknesses in revenue protection, network management, metering and operational efficiency. Had these losses been effectively managed and reduced, the municipality's financial position and surplus levels would have improved considerably. The municipality will therefore be engaged further to implement urgent loss-reduction interventions, strengthen technical and non-technical loss management measures, and improve operational efficiencies to restore the sustainability of its electricity business.

3.9. Accordingly, the analysis supports the need for the municipality to prioritise:

a) implementation of credible loss-reduction strategies;

b) strengthening of revenue protection measures; and

c) improvement of metering and billing systems;

## 4. Determination of Mantsopa Tariffs Based on the Cost of Supply Study

4.1. The process followed in considering and approving Mantsopa's tariff application was supported by a COS study.

4.2. Mantsopa utilised the COS study model developed by Sustainable Energy Africa (SEA) to determine its revenue requirements for the 2026/27 financial year and to apportion costs required to service each customer's class in a fair and equitable manner. The study follows the NERSA COS framework and utilises the latest available audited data, which is based on the 2024/25 financial year.

4.3. **Error! Reference source not found.** below details the five steps considered in the determination of the COS study.

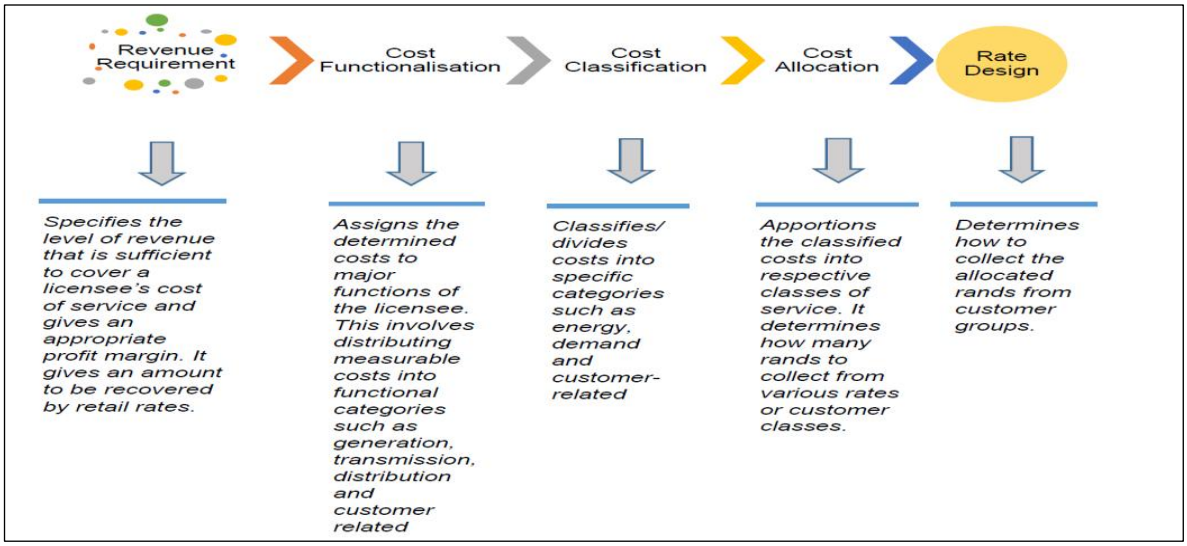



**Figure 1: Fives Steps of COS Study**

4.4. The following steps are undertaken to analyse the COS study:

### 4.4.1. Revenue Requirement

4.4.1.1. In order to be fully cost reflective, the licensee's revenue requirements are R224 102 960 million (wires [14%] and Retail [86%]) for the 2024/25 financial year. This revenue requirement is made up of the following components:

a) Eskom Bulk Purchases composes 59% (excluding cost of losses) of total revenue requirement at an amount of R131 248 794 million and this is the largest cost driver of the municipality's electricity department.

b) Energy Loss Allowance of 12% (norm) amounting to R16 654 550 million. When combined with Eskom purchases: 59% + 7% = 66% and totals of R147 903 344 million of total revenue requirement.

c) Operational Expenditure (OPEX) 28% of total Value: R61 948 145 million. This includes salaries, maintenance, repairs, administration and others.

d) The remaining 6% includes depreciation, return on assets and others.

**Table 5*:* Revenue Requirement Components**

| | Total cost (R) | | | |
|---|---|---|---|---|
| **Revenue Requirement components** | **Wires** | **Retail** | **Total** | **% of Total** |
| **Allowable costs** | 30 578 791 | 193 524 169 | 224 102 960 | 100% |
| Energy purchases from Eskom - net of cost of losses | - | 131 248 794 | 131 248 794 | 59% |
| Energy purchases from Eskom - cost of losses | 7 539 123 | 9 115 428 | 16 654 550 | 7% |
| Other energy purchases | - | - | - | 0% |
| Capital expenditure | - | - | - | 0% |
| Operational expenditure (incl. Depreciation) | 20 315 499 | 41 632 645 | 61 948 145 | 28% |
| Other revenues | - 55 721 | - 6 065 804 | - 6 121 525 | -3% |
| Surplus | 2 779 890 | 17 593 106 | 20 372 996 | 9% |
| **TOTAL COSTS** | **30 578 791** | **193 524 169** | **224 102 960** | |
| | 14% | 86% | | |

4.4.1.2. The efficiency of costs for the 2024/25 financial year (base year) has been assessed, as this constitutes the most recent set of actual data. This assessment serves as the baseline for projecting costs for the 2026/27 financial year, applying stated assumptions to determine the revenue requirement for that period.

4.4.1.3. All expenses included in the revenue requirement have been examined to confirm that they pertain exclusively to the licensee's electricity function.

**Bulk Purchases**

4.4.1.4. From the submitted COS study, Mantsopa applied for bulk purchase expenditure amounting to R131 248 794 million, representing 59% of total costs. The bulk purchase figure was verified against Eskom invoices for the 2024/25 financial year.

4.4.1.5. To derive the 2026/27 bulk purchase estimate, the 2025/26 COS amount was escalated by 9.01%, consistent with the approved Eskom Retail Tariff Structural Adjustments (ERTSA).

4.4.1.6. The methodology applied by Mantsopa in forecasting bulk purchase costs is deemed reasonable. Accordingly, the bulk purchase expenditure has been recommended for approval as submitted.

**Operational Expenditure**

4.4.1.7. Mantsopa has applied for operational expenditure totalling R61 948 145 million, representing 28% of overall costs, as reflected in Table 3 above.

4.4.1.8. The approach adopted by Mantsopa in forecasting operational expenditure is considered reasonable, and the amount has therefore been approved as requested.

**Surplus**

4.4.1.9. Mantsopa has requested a surplus of R15 million, calculated using a surplus factor of 9% applied to operating expenditure, inclusive of bulk purchases, for both the wires (14%) and retail (86%) components of the business.

4.4.1.10. The return proposed by Mantsopa is considered reasonable, as it falls below the established target range of 10–20%. This implies that the licensee should scrutinize its operating expenses to enable tolerable range on surplus.

4.4.1.11. The decision to approve the revenue requirement as submitted will be applied in the subsequent stages, namely Cost Functionalisation, Cost Classification, Cost Allocation and Rate Setting. These stages have been verified and confirmed to align with the approved revenue requirement. Further detail on these stages is provided below.

### 4.4.2. Cost Functionalisation

4.4.2.3. Mantsopa has categorised its revenue requirement of R224 102 960 million into two primary functional components, namely the wires business (14%) and the retail business (86%), in accordance with the NERSA COS framework, as illustrated in Figure 2 below. Upon verification, the allocation of costs to these functional components is found to be consistent with the stated revenue requirement.

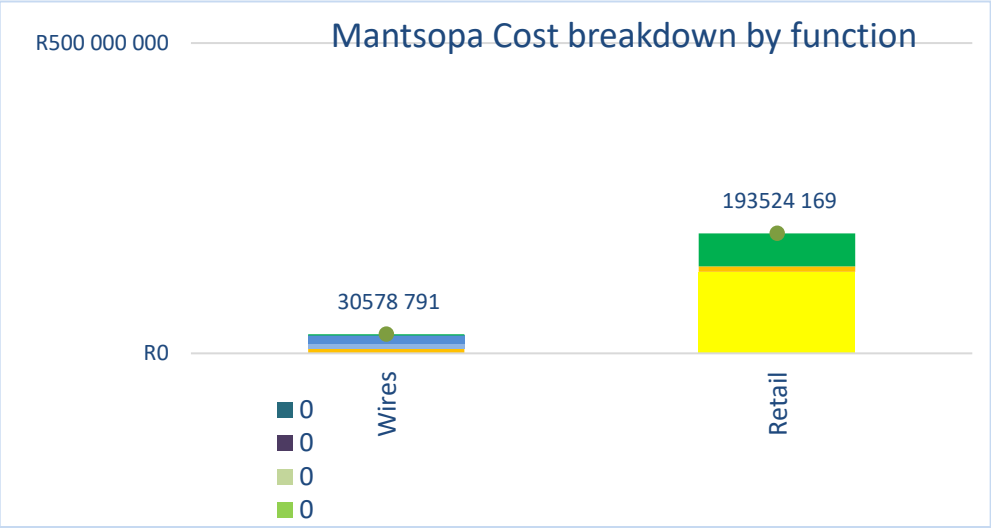



**Figure 2: Cost Breakdown by Functions**

4.4.2.4. These costs, upon verification, are consistent with the approved revenue requirements. Network repairs and maintenance constitute the predominant cost drivers within the wires business, while energy purchases represent the primary cost driver within the retail business.

### 4.4.3. Cost Classification

4.4.3.3. Mantsopa classified its costs into energy, demand, and customer related cost components, in accordance with the NERSA COS framework. The costs align with revenue requirements and cost functionalisation upon verification.

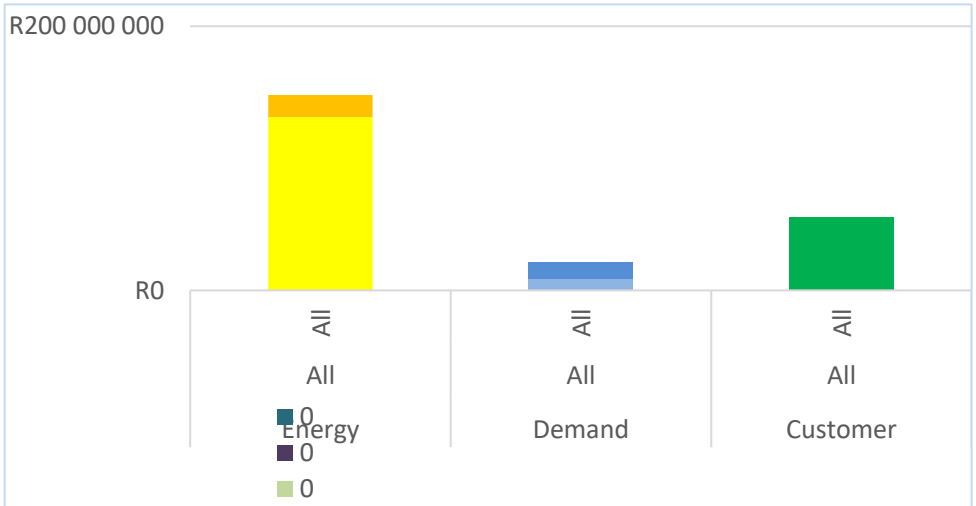



**Figure 3*:* Cost Breakdown by Cost Structure (Classification)**

4.4.3.4. Energy purchases constitute energy-driven costs, with the highest expenditure incurred during the summer period under the standard time-of-use structure, largely due to the longer duration of the summer season. Demand-driven costs are similarly concentrated in the summer period. Customer-driven costs are primarily associated with 'Other OPEX'" which includes expenses related to the provision of electricity distribution services to customers.

### 4.4.4. Cost Allocation

4.4.4.3. In this step, the licensee's revenue requirement is allocated across customer categories, in accordance with the NERSA COS framework. Upon verification, the allocation is found to be consistent with the stated revenue requirement and aligned with the principles of cost allocation.

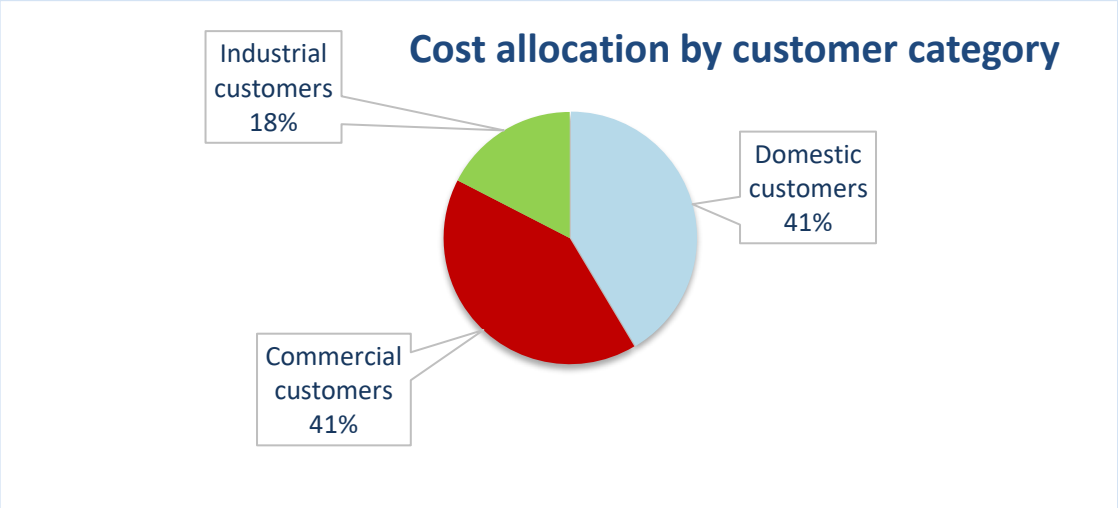



**Figure 4: Costs Allocated**

### 4.4.5. Rate Design

4.4.5.3. Table 4 below reflects the outcome of the COS study, indicating that domestic, bulk supply, flat business prepaid, and departmental flat rate customer categories require upward adjustments, while the rest including sport club customers warrant decrease. A comparison between the COS and the revenue generated per tariff category highlights the extent of over- or under-recovery within each category, as illustrated in Table 4 below.

4.4.5.4. To achieve full cost reflectivity, the municipality would be required to implement differentiated tariff adjustments across customer categories mentioned in section 4.4.5.1. However, the municipality has adopted a less aggressive approach, opting instead for a proposed uniform tariff increase of 11% across all customer categories.

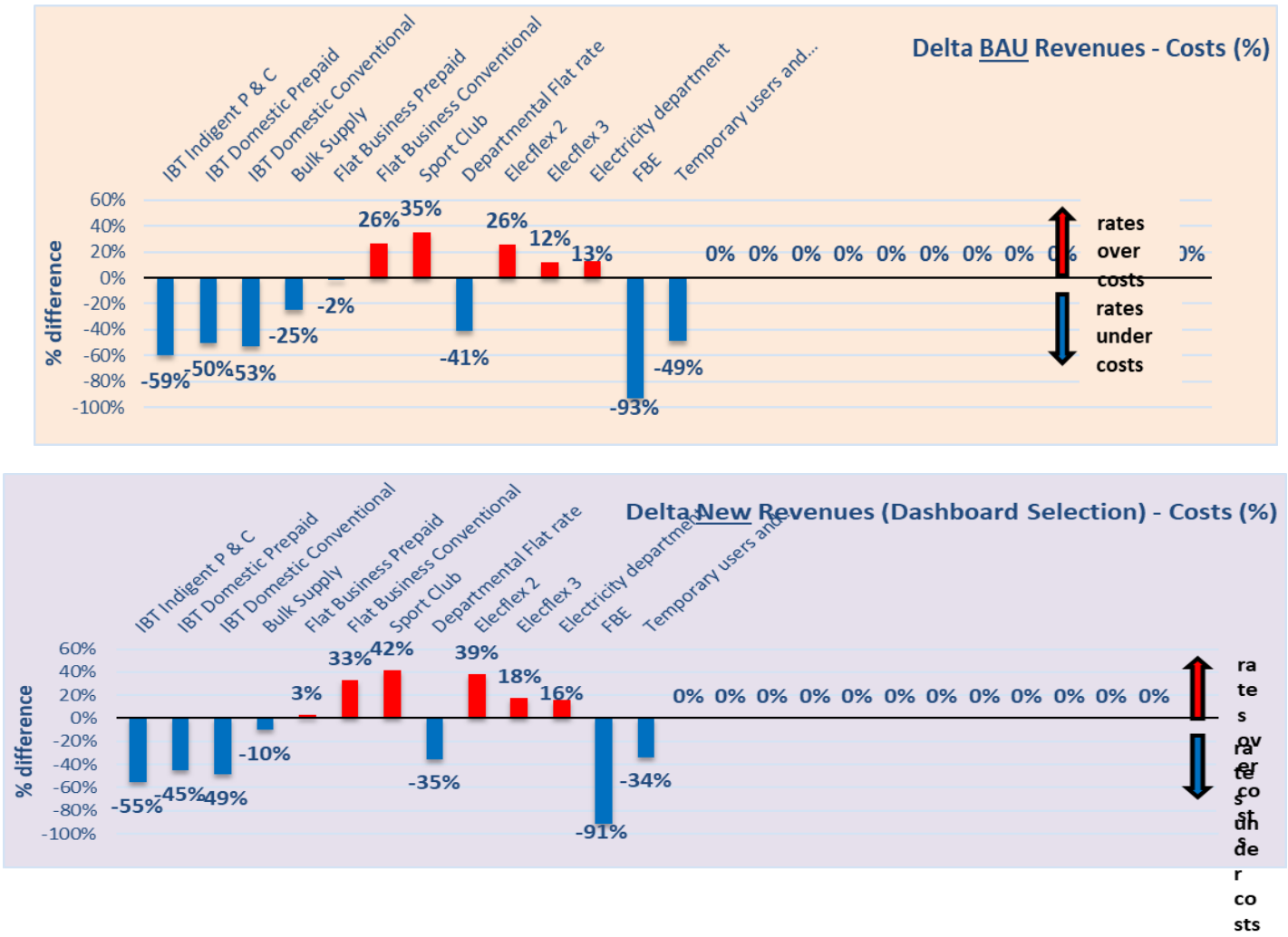



**Figure 4: Revenue Recovery by Customer Category**

## 5. Conclusion on the COS Study

5.1. While the outcome of the COS study indicated an average tariff adjustment of a 16% to 100% on mainly domestic and industrial time of use customer for a licensee to achieve full cost reflectivity, a municipality may elect to implement such adjustments on a phased basis, including applying an increase below the COS-derived level.

5.2. The Municipality should consider phasing in the required tariff increases over a multi-year period rather than implementing the full adjustments immediately. This assist help to:

5.2.1. reduce the financial burden on households and businesses;

5.2.2. allow customers time to adjust to higher tariffs; and

5.2.3. maintain revenue stability while gradually moving towards cost reflectivity.

5.3. In addition, the licensee may take into account its ability to meet financial obligations, including payments to Eskom, as well as the broader affordability constraints faced by customers, in determining the appropriate trajectory for tariff adjustments.

5.4. This approach is intended and will ensure safeguarding of the municipality's revenue base and support its financial sustainability, in line with applicable legislative requirements.

5.5. The COS study is based on forecast assumptions and, as such, does not guarantee that the projected outcomes will materialise. Accordingly, the licensee retains the discretion to review the results and determine its own revenue requirements to ensure financial sustainability. In this regard, the municipality will be required to submit a report accounting for all costs that remain unverified.

5.6. The COS study results indicate a required increase of 33.2% to reach cost reflectivity, as illustrated in Figure 4 below. A 33.2% cost reflectivity was resulting from the licensee wrongly billing industrial customers on time of use. In recovering cost reflectivity, the licensee introduced fixed charges to the industrial time of use in order to implement tariffs towards cost reflectivity as reflected in in figure 5 below.

5.7. The licensee applied for an increase of 11% for the 2026/27 financial year. The 11% increase applied for was not based on the COS study but on the overall municipal revenue-generating services. It is for this reason that the licensee is expected to implement the 11% tariff increase, as per the proposed average increase in rates, to ensure financial sustainability from its electricity revenue ringfenced account, as per the COS study.

| | BAU | CTS (net of subsidies) | New rates (Dashboard selection) |
|---|---|---|---|
| **Total revenue forecast (with new rates)** | 167 067 468 | 222 553 229 | **185 472 742** |
| | | **Delta =** | - 37 080 487 |
| **Average increase in rates** | **11,0%** | | |
| **Average increase in rates to reach overall cost-reflectivity** | 33,2% | | |
| **Share of total cost recovered with the new rates (by the end of the transition period)** | **83,3%** | | |
| **Share of total costs recovered (existing rates)** | **75,1%** | | |

**Figure 5: Rate Design**

5.8. In its evaluation and assessment of the tariff applications, the following principles are applied:

5.8.1. Costs were assessed for reasonableness and accuracy, noting that certain cost items were considered excessive and insufficiently substantiated by the licensees.

5.8.2. The costs will be subject to a detailed audit and independent verification process, to be undertaken under the direction of NERSA at a later stage.

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| | | | | | | |
|---|---|---|---|---|---|---|
| **Tariff II: IBT - Domestic (Pre-paid or Conventional)** | **2025/26 Approved** | **Proposed % Increase** | **2026/27 Proposed** | **2026/27 Recommended** | **Recommended % Increase** | **Analysis and Key findings** |
| **SUMMER** | | | | | | |
| Block 1 (0-350kWh) | 2.4198 | 11.00% | R 2,686 | R 2,686 | 11.00% | N/A |
| Block 2 (351-600kWh) | 3.4049 | 11.00% | R 3,779 | R 3,779 | 11.00% | N/A |
| Block 3 (>600kWh) | 3.9737 | 11.00% | R 4,411 | R 4,411 | 11.00% | N/A |
| | | | | | | |
| **WINTER** | | | | | | |
| Block 1 (0-350kWh) | 2.5101 | 11.00% | R 2,786 | R 2,786 | 11.00% | N/A |
| Block 2 (351-600kWh) | 3.5337 | 11.00% | R 3,922 | R 3,922 | 11.00% | N/A |
| Block 3 (>600kWh) | 4.0857 | 11.00% | R 4,535 | R 4,535 | 11.00% | N/A |
| | | | | | | |
| **Tariff III: Business Flat Rate (Pre-Paid or Conventional)** | **2025/26 Approved** | **Proposed % Increase** | **2026/27 Proposed** | **2026/27 Recommended** | **Recommended % Increase** | **Analysis and Key findings** |
| Basic Charge | R 815.82 | 11.00% | R 905,559 | R 905,559 | 11.00% | N/A |
| **SUMMER** | | | | | | |
| Business, Schools, Guest Houses Pre-paid | R 3,9951 | 11.00% | R 4,435 | R 4,435 | 11.00% | N/A |
| Business, Schools, Guest Houses Conventional | R 3,9951 | 11.00% | R 4,435 | R 4,435 | 11.00% | N/A |
| Schools, Hostels, Sports clubs, Guest houses | R 3,9889 | 11.00% | R 4,428 | R 4,428 | 11.00% | N/A |
| | | | | | | |
| **WINTER** | | | | | | |
| Business, Schools, Guest Houses Pre-paid | R 4,1073 | 11.00% | R 4,559 | R 4,559 | 11.00% | N/A |
| Business, Schools, Guest Houses Conventional | R 4,1073 | 11.00% | R 4,559 | R 4,559 | 11.00% | N/A |
| Schools, Hostels, Sports clubs, Guest houses | R 4,1073 | 11.00% | R 4,559 | R 4,559 | 11.00% | N/A |
| | | | | | | |
| **Tariff III: Departmental** | **2025/26 Approved** | **Proposed % Increase** | **2026/27 Proposed** | **2026/27 Recommended** | **Recommended % Increase** | **Analysis and Key findings** |
| Departmental - Summer | R 3,9247 | 11.00% | R 4,356 | R 4,356 | 11.00% | N/A |

| | | | | | | |
|---|---|---|---|---|---|---|
| Departmental - Winter | R 3,9247 | 11.00% | R 4,356 | R 4,356 | 11.00% | N/A |
| **Tariff IV: Vacant stand/ Unbuilt Erven** | **2025/26 Approved** | **Proposed % Increase** | **2026/27 Proposed** | **2026/27 Recommended** | **Recommended % Increase** | **Analysis and Key findings** |
| Basic Charge (R/month): | R 238,9000 | 11.00% | R 265,179 | R 265,179 | 11.00% | N/A |
| Energy charge (c/kWh): Summer | R 1,7477 | 11.00% | R 1,940 | R 1,940 | 11.00% | N/A |
| Energy charge (c/kWh): Winter | R 2,3331 | 11.00% | R 2,590 | R 2,590 | 11.00% | N/A |
| | | | | | | |
| **Tariff V: Bulk supply** | **2025/26 Approved** | **Proposed % Increase** | **2026/27 Proposed** | **2026/27 Recommended** | **Recommended % Increase** | **Analysis and Key findings** |
| **SUMMER** | | | | | | |
| Basic Charge (R/month): | R 815,8190 | 11.00% | R 905,559 | R 905,559 | 11.00% | N/A |
| Demand Charge (R/kVA) | R 255,2349 | 11.00% | R 283,311 | R 283,311 | 11.00% | N/A |
| Energy charge: Summer | R 1,6574 | 11.00% | R 1,840 | R 1,840 | 11.00% | N/A |
| | | | | | | |
| **WINTER** | | | | | | |
| Basic Charge (R/month): | R 815,8190 | 11.00% | R 905,559 | R 905,559 | 11.00% | N/A |
| Demand Charge (R/kVA) | R 255,2349 | 11.00% | R 283,311 | R 283,311 | 11.00% | N/A |
| Energy charge (c/kWh): Winter | R 2,0255 | 11.00% | R 2,248 | R 2,248 | 11.00% | N/A |
| | | | | | | |
| **Tariff VI: Elecflex 1** | **2025/26 Approved** | **Proposed % Increase** | **2026/27 Proposed** | **2026/27 Recommended** | **Recommended % Increase** | **Analysis and Key findings** |
| Basic Monthly: | R 5 927,74 | 11.00% | R 6 579,791 | R 6 579,791 | 11.00% | N/A |
| Network Access charge KVA | R 80,3824 | 11.00% | R 89,224 | R 89,224 | 11.00% | N/A |
| Demand Charge | R 224,0117 | 11.00% | R 248,653 | R 248,653 | 11.00% | N/A |
| Energy charges: | | | | | | |
| **SUMMER** | | | | | | |
| Peak | R 2,7642 | 11.00% | R 3,068 | R 3,068 | 11.00% | N/A |
| Standard | R 1,8133 | 11.00% | R 2,013 | R 2,013 | 11.00% | N/A |
| Off-peak | R 1,7107 | 11.00% | R 1,899 | R 1,899 | 11.00% | N/A |
| | | | | | | |
| **WINTER** | | | | | | |
| Peak | R 5,4398 | 11.00% | R 6,038 | R 6,038 | 11.00% | N/A |
| Standard | R 2,7862 | 11.00% | R 3,093 | R 3,093 | 11.00% | N/A |
| Off-peak | R 2,0565 | 11.00% | R 2,283 | R 2,283 | 11.00% | N/A |
| **Tariff VI: Elecflex 2** | **2025/26 Approved** | **Proposed % Increase** | **2026/27 Proposed** | **2026/27 Recommended** | **Recommended % Increase** | **Analysis and Key findings** |

| | | | | | | |
|---|---|---|---|---|---|---|
| Basic Monthly: | R 4 237,48 | 11.00% | R 4 703,606 | R 4 703,606 | 11.00% | N/A |
| Network Access charge KVA | R 96,2679 | 11.00% | R 106,857 | R 106,857 | 11.00% | N/A |
| Demand Charge | R 261,2323 | 11.00% | R 289,968 | R 289,968 | 11.00% | N/A |
| Energy charges: | | | | | | |
| **SUMMER** | | | | | | |
| Peak | R 2,9819 | 11.00% | R 3,310 | R 3,310 | 11.00% | N/A |
| Standard | R 1,9561 | 11.00% | R 2,171 | R 2,171 | 11.00% | N/A |
| Off-peak | R 1,7263 | 11.00% | R 1,916 | R 1,916 | 11.00% | N/A |
| | | | | | | |
| **WINTER** | | | | | | |
| Peak | R 5,8602 | 11.00% | R 6,505 | R 6,505 | 11.00% | N/A |
| Standard | R 2,9982 | 11.00% | R 3,328 | R 3,328 | 11.00% | N/A |
| Off-peak | R 2,7483 | 11.00% | R 3,051 | R 3,051 | 11.00% | N/A |
| | | | | | | |
| **Tariff VI: Elecflex 3** | **2025/26 Approved** | **Proposed % Increase** | **2026/27 Proposed** | **2026/27 Recommended** | **Recommended % Increase** | **Analysis and Key findings** |
| Basic Monthly: | R 3 303,09 | 11.00% | R 3666,424 | R 3 666,424 | 11.00% | N/A |
| Network Access charge KVA | R 100,5658 | 11.00% | R 111,628 | R 111,628 | 11.00% | N/A |
| Demand Charge | R 282,1601 | 11.00% | R 313,198 | R 313,198 | 11.00% | N/A |
| Energy charges: | | | | | | |
| **SUMMER** | | | | | | |
| Peak | R 3,1338 | 11.00% | R 3,479 | R 3,479 | 11.00% | N/A |
| Standard | R 2,0536 | 11.00% | R 2,279 | R 2,279 | 11.00% | N/A |
| Off-peak | R 1,8379 | 11.00% | R 2,040 | R 2,040 | 11.00% | N/A |
| | | | | | | |
| **WINTER** | | | | | | |
| Peak | R 5,8660 | 11.00% | R 6,511 | R 6,511 | 11.00% | N/A |
| Standard | R 2,9894 | 11.00% | R 3,318 | R 3,318 | 11.00% | N/A |
| Off-peak | R 2,7977 | 11.00% | R 3,105 | R 3,105 | 11.00% | N/A |

## 9. CONFIDENTIALITY

9.1. None.

## 10. CONCLUSION

10.1. From a conspectus of the facts and evidence presented to the REC, it is appropriate to consider the review of Mantsopa's tariff application for the 2026/27 financial year.

***End.***