NATIONAL ENERGY REGULATOR OF SOUTH AFRICA

Decision and Reasons for Decision (RfD)

In the matter regarding the

Municipal Tariff Applications for the 2026/27 Financial Year

By

Mbizana Local Municipality

THE DECISION

At its meeting held on 30 April 2026, the Regulator Executive Committee (REC) considered Mbizana tariff application. Based on the facts and evidence presented, REC approved the tariff increases for the 2026/27 financial year set out in Table 1 below.

Table 1: Summary of the REC decision

Tariff Category	2026/27 approved % Increase
Domestic pre-paid tariff block Homelight 20A-100A	9.97%
Domestic Conventional Homelight 80A-100A	9.97%
Commercial Prepaid 60A	9.97%
TOU- Large Power User- 300A and above	9.97%
TOU-Three Phase-80A-125A	9.97%
Three Phase- 150A- 250A	9.97%
Single Phase- 80A – 1001A	9.97%
TOU- Basic charges	9.97%
TOU- Network demand Charge	9.97%

Based on the available information and the analysis performed thus far, the Regulator Executive Committee decided at its meeting on 30 April 2026, that:

1. The tariffs that are based on the COS Report are approved as recommended in the tariff analysis section for implementation by the municipality with effect from 1 July 2026.

2. The Cost of Supply Report submitted by the municipality be noted.
3. The municipality is required to submit a report accounting for all the costs that have been noted in its COS study, to enable the Regulator to perform its independent verification/audit process;
4. The municipality must submit a quarterly smart efficiency plan with improvement measures identified in reducing high energy losses and submit by 30 September 2026; and
5. To strengthen the financial health of the electricity business, the municipality must implement strategies to optimize revenue collection and increase operating surplus.

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ABBREVIATIONS

COS	Cost of Supply
D-form	Distribution form
ERTSA	Eskom's Retail Tariff Structural Adjustments
FBE	Free Basic Electricity
IBT	Inclining Block Tariff
IPP	Independent Power Producer
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. Mbizana Municipality is situated in the Eastern Cape. The municipality is made up mostly of Industrial customers, which consume 73.83% of the total electricity sales. The municipality provides its indigent customers with 50kWh of Free Basic Electricity (FBE) per month. The municipality further reports that it maintains an indigent register. The details regarding customer statistics are highlighted in **Error! Reference source not found.**Table 2below.

Table 2: Customer Statistics (Data obtained from the latest D-forms – 2023/24

CONSUMER STATISTICS (OBTAINED FROM 2024-2025 DISTRIBUTION FORMS)			
Consumer Classification	**Sales (KWh)**	**%KWh**	**Number of Consumers**
Domestic (Prepaid)	3 940 645	19,61%	3 005
Domestic (Conventional)	24 418	0,12%	3
Manufacturing/Industrial	14 834 351	73,83%	37
Commercial (Prepaid)	123 544	0,61%	166
Commercial (Conventional)	907 229	4,52%	30
Municipal Consumption & Street Lighting	261 728	1,30%	N/A
TOTAL SALES	**20 091 915**	**100%**	**3 241**
Free Basic Electricity (FBE)	**226 800**	**5,72%**	**378**

1.3. NERSA received Mbizana's tariff application together with its Cost of Supply (COS) on 31 March 2026.

1.4. Mbizana implemented 12.74% average price increase in 2025/26FY and is applying for an average price increase of 9.97% for the 2026/27FY.

1.5. 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.

1.6. The municipality has successfully submitted all requested supporting documentation required for the comprehensive analysis of the tariff application

1.7. NERSA followed the notice and comment consultation process. Mbizana's tariff applications was published on the NERSA website on 31 March 2026, and notices on social media platforms, national and local newspapers to solicit written comments from affected parties.

1.8. NERSA's decision was made on 30 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 No. 40 of 2004) ("NERA"), the Electricity Regulation Act, 2006 (Act No. 4 of 2006) as amended ("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 Proce Determination and 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 No. 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 2026/2027 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 the 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:

- Section 4(a)(i) of the ERA provides that the Energy Regulator must consider applications for licences and may issue licences subject to conditions.
- Section 4(a)(ii) of the ERA provides that the Energy Regulator must regulate prices and tariffs.
- Section 14(1)(d) of the ERA authorises the Energy Regulator to impose licence 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 licences 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:

- must enable an efficient licensee to recover the full cost of the licensed activity;
- must allow for a reasonable return commensurate with the risk of the licensed activity;
- may provide incentives for continued improvement of technical and economic efficiency;
- must avoid undue discrimination between customer categories;
- may permit cross-subsidies of tariffs to certain classes of customers; and
- 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 recognizes 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 Cost of Supply methodologies have historically not been consistently applied across the electricity distribution industry.

2.6.3. Policy Position 23 therefore requires electricity distributors to undertake Cost-of-Supply 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 2025/2026 municipal tariff approvals did not comply with the procedural requirements of section 4 of PAJA and was therefore unlawful.

2.7.3. However, recognizing 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 the 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 in respect of the 2026/27 municipal tariff approvals

- written notice of bulk tariffs by 6 March 2026;
- municipal tariff applications to be submitted by 31 March 2026;
- public participation processes to be concluded by 21 April 2026
- the publication of NERSA decisions by 11 May 2026.

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

- written notice of bulk electricity tariffs be communicated by 31 January each year;
- municipal tariff applications be submitted to NERSA by 20 March each year;
- municipal tariff approvals and the tariff reasons for decision document, 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 consisting of 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 2026/2027 municipal financial year.

3. FINANCIAL AND TECHNICAL PERFORMACE

3.1. In evaluating the financial and technical performance of Mbizana, 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 Trial Balance 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. The electricity business unit reported a significant operational deficit of 34.88% for the 2024/25 financial year, representing a sharp decline from the 16.69% in 2023/24 financial year deficit recorded in the previous period. This downward trend is primarily driven by a 2% decrease in total revenue coupled with a 13% surge in total expenditure.

3.3. Table 3 below shows that Mbizana's energy losses have increased significantly, rising from 7.27% in the 2023/24 financial year to 14.97% in 2024/25 financial year. The municipality has identified the root causes as non-technical and administrative, primarily involving illegal connections, meter tampering, and billing inaccuracies. To address these challenges, the following strategic interventions have been implemented:

- Replace undersized and aging conductors, transformers, and switchgear to reduce line losses
- Balance phase loads, optimize feeder routing to minimize voltage drops
- Install capacitor banks and monitor reactive power at substations
- Audit 100% of meters; replace faulty, bypassed, or aged meters with tamper proof smart meters
- Expand prepaid metering to all residential and small commercial consumers
- Educate communities on legal connections and penalties for tampering
- Check Align meter data, customer records, and billing database to eliminate ghost customers
- Use metering monitoring to detect anomalies and unusual consumption patterns

Table 3 Performance indicators

PERFORMANCE INDICATORS: OBTAINED FROM D-FORMS		
INDICATORS	**2024-25FY (Actuals)**	**2023-24 FY (Approved)**
Percentage Surplus (Deficit)	-34,88%	-16,69%
Percentage Energy Losses	14,97%	7,27%

3.4. The municipality's electricity business is currently underperforming, characterized by significant energy losses and a substantial percentage deficit.

By addressing these core issues, the municipality can transform the electricity business from financial liability into a self-sustaining, efficient service.

4. DETERMINATION OF MBIZANA'S TARIFFS BASED ON THE COST OF SUPPLY STUDY

4.1. The process followed in considering and approving Mbizana's tariff application was supported by a cost of supply study. The municipality revised the cost of supply to introduce the following structural changes:

- Introduction of basic charge to mitigate volumetric risk and ensure recovery for fixed network costs
- Time of use (TOU) refinement for new customer category to ensure that rates are aligned with actual energy demand and usage profiles.

4.2. Mbizana 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. Figure 1 below details the five steps considered in the determination of the COS study.

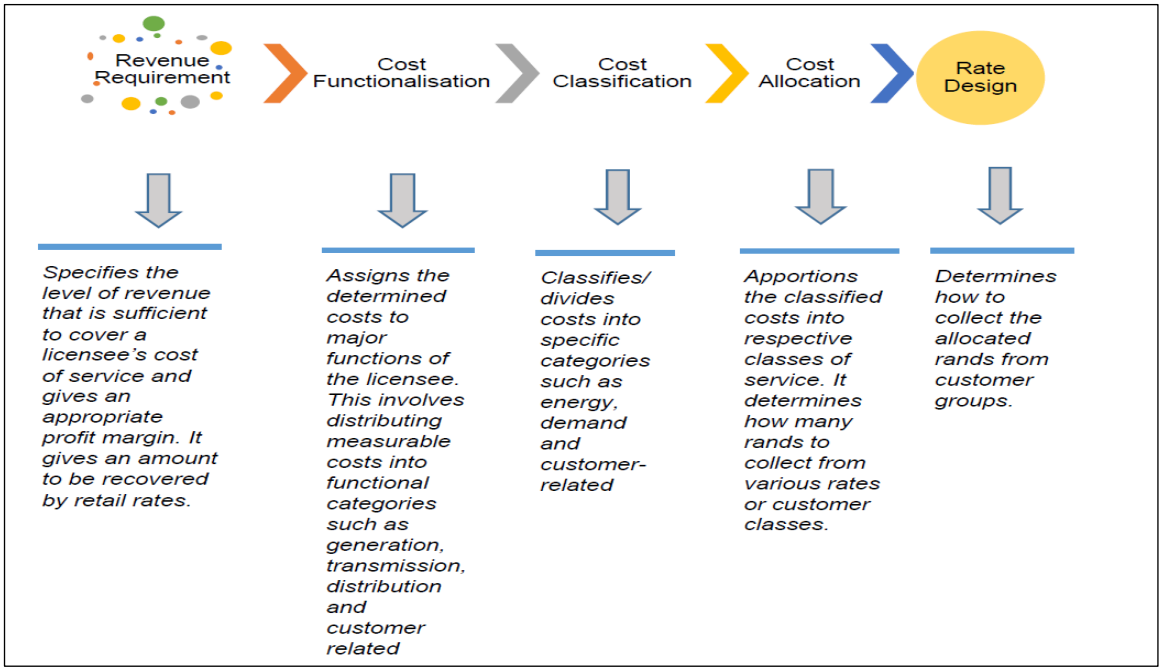


Figure 1: Fives steps of COS

4.4. The following steps are undertaken to analyse the cost of supply study:

Revenue Requirement

Table 4:Revenue Requirement components

Revenue Requirement components	Wires	Retail	Total	% of Total
Allowable costs	61 019 692	113 556 956	124 874 333	100%
Energy purchases from Eskom - net of cost of losses	-	64 861 055	64 861 055	52%
Energy purchases from Eskom - cost of losses	2 970 129	5 585 568	8 555 697	7%
Other energy purchases	-	-	-	0%
Capital expenditure	-	-	-	0%
Operational expenditure (incl. Depreciation)	27 532 593	22 169 723	49 702 315	40%
Other revenues	**- 59 903**	**- 9 537 042**	**- 9 596 946**	**-8%**
Surplus	3 044 282	8 307 930	11 352 212	9%
Not allowable costs	-	-	-	
Cost of losses disallowed	-	-	-	
TOTAL COSTS	**61 019 692**	**113 556 956**	**124 874 333**	

4.4.1 To be fully cost reflective, the licensee's revenue requirements are R124million for the 2026/27 financial year. This revenue requirement is predominantly Eskom purchases accounting for 59% including energy losses allowance. Operational expenditure accounts for 40%.

4.4.2 The efficiency of the costs in the 2024/25 (Base year) financial year has been assessed, as this constitutes the most recent set of actual data. This forms the basis on which costs for the 2026/27 financial year will be projected using assumptions to calculate revenue requirements for that year.

4.4.3 Furthermore, NERSA has verified all expense items included in the revenue requirements to ensure that they relate only to the electricity function of the licensee. In instances where expenses are deemed inflated or unjustified, these have been adjusted accordingly and expanded below.

Bulk purchases

4.4.4 The licensee applied for a bulk purchase expenditure of R64million which accounts for 52% of the total costs. Bulk purchases were verified against Eskom invoices in the 2024/25 financial year.

4.4.5 To get to the 2026/27 estimation, the 2025/26 COS amount was adjusted by 9.01% in line with the approved Eskom Retail Tariff Structural Adjustments (ERTSA).

4.4.6 NERSA is satisfied that the approach taken by the licensee to forecast bulk purchases is reasonable. As a result, this cost has been recommended for approval as applied for.

Operational Expenditure

4.4.7 The licensee applied for operational expenditure of R49million, which accounts for 40% of total costs as shown in Table 3 above.

4.4.8 NERSA is satisfied that the approach taken by the licensee to forecast operational expenditure is reasonable. As a result, this cost has been approved as applied for. However, inefficient costs such as NMD exceedance penalties and interest on Eskom debt are removed from the total cost as they are deemed to be within the municipality's control.

Surplus

4.4.9 The licensee applied for a surplus of R11million which is based on a surplus factor of 9% return on operating expenditure including bulk purchases for both the wires and retail businesses.

4.4.10 NERSA is satisfied that the return applied for by the licensee is reasonable as it falls slightly below the 10 - 20% target range, this cost has been approved as applied for.

4.4.11 To ensure that the profit margin is commensurate with the risk, risk considerations were incorporated qualitatively, including:

a) revenue collection risks (non-payment, indigence levels, bad debt);

b) operational risks (energy losses, ageing infrastructure); and

c) financial sustainability requirements.

4.4.12 It is NERSA's decision to allow the revenue requirement as applied for; this revenue requirement will then be used in the next steps which are Cost Functionalization, Classification, Allocation and Rate Setting. These steps have been verified that they match the revenue requirement. These steps are discussed below.

4.4.13 Therefore, the applied surplus margin is considered modest and commensurate with these risks, particularly for a municipal distributor that is not profit-maximising but must remain financially viable.

Cost Functionalisation

4.4.14 The licensee has categorized its revenue requirements of R124 million into wires and retail business which is in line with the NERSA COS framework. These costs align with revenue requirements upon verification.

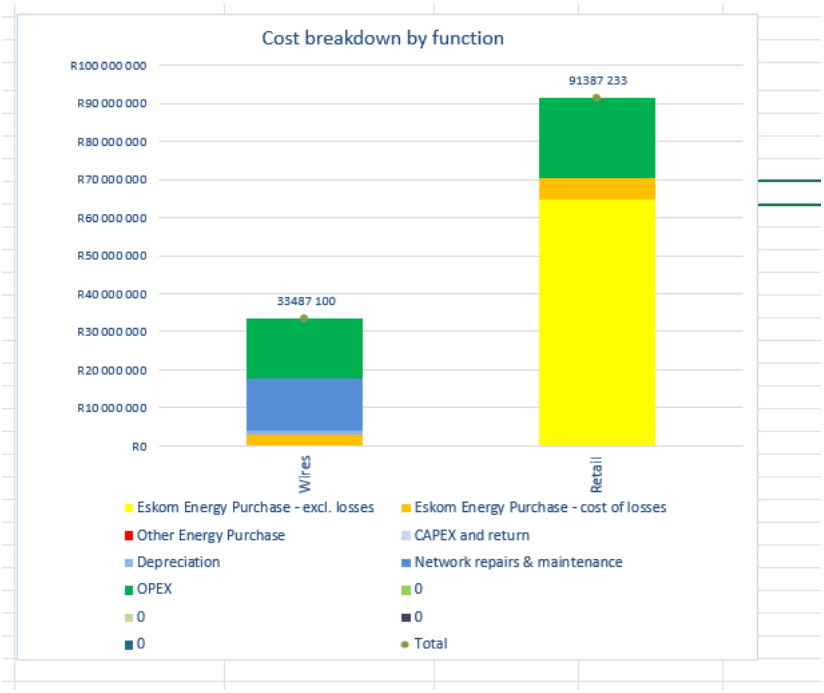


Figure 2: Costs breakdown by Functions

4.4.15 Energy purchases are significant within the cost breakdown and dominate when compared to other costs such as OPEX and Surplus.

Cost Classification

4.4.16 Energy purchases and the cost of losses make up the energy driven costs, with the highest amount of costs incurred during the Low season and standard TOU- mostly due to the low season covering a greater portion of the year. Demand driven costs are depreciation, network repairs and maintenance, along with energy purchase demand related costs. The period of greatest demand driven costs is during the Low Season.

4.4.17 Finally, customer driven costs are incurred through offering electricity distribution services to the customers which include salaries.

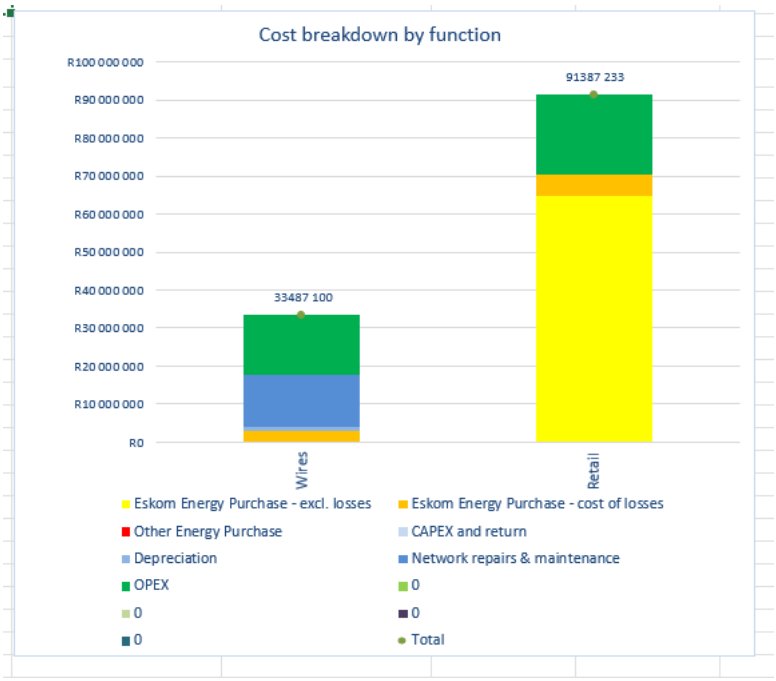


Figure 3: Costs breakdown by cost structure

Cost Allocation

4.4.18 The domestic customer category carries the largest proportion of costs, followed by the commercial customers. Industrial customers and internal electricity requirements result in the lowest proportion of costs.

4.4.19 Difference in results between customer classes mainly driven differences in voltage of connection point, load factors, coincidence factors, average specific consumption.

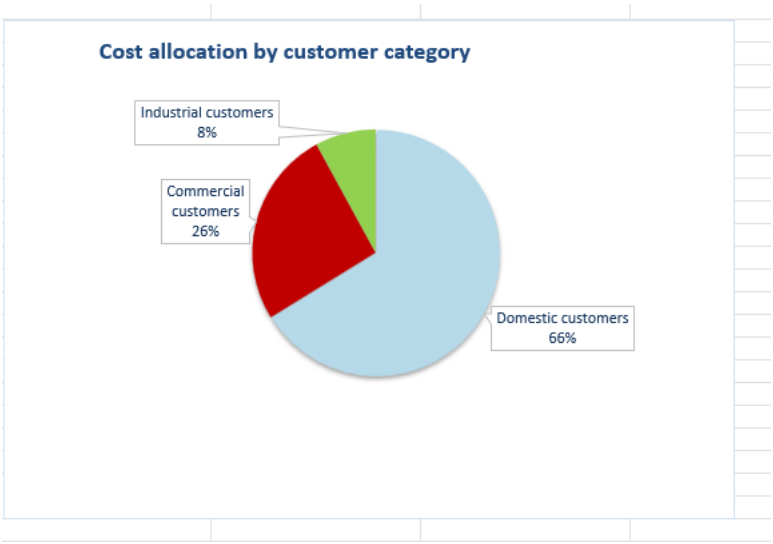


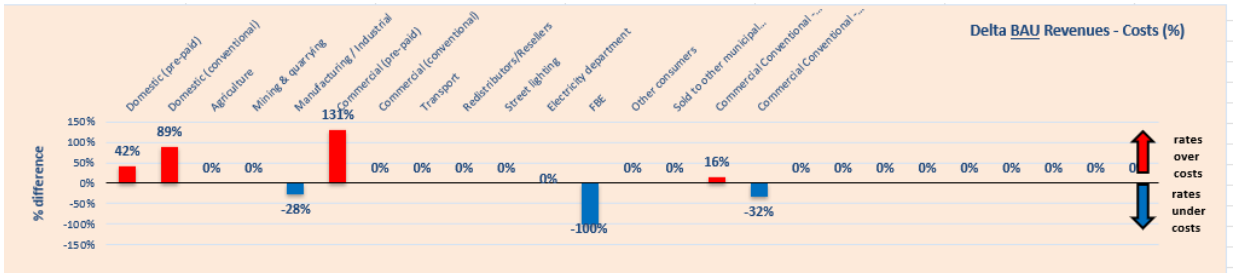
Figure 4: Costs Allocation

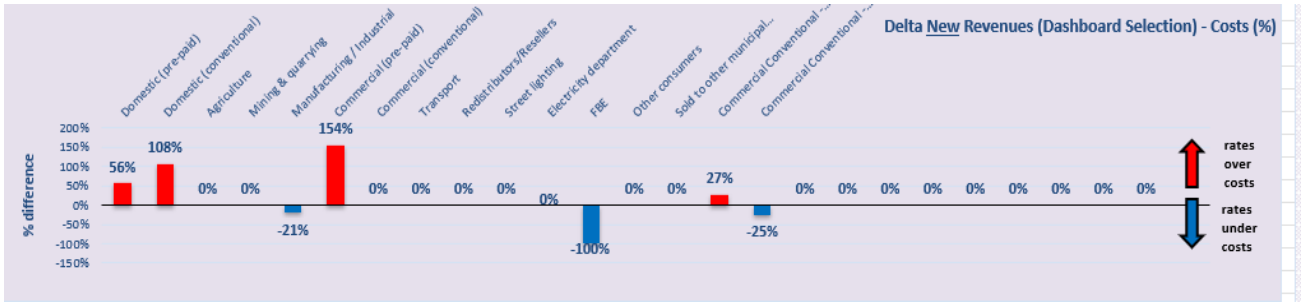
Rate Design

4.4.20 Figure 5 below shows the outcome of the COS study, showing that certain customer categories should increase while others should decrease. Comparing these costs to the income per tariff category reveals the over- or under-recovery per tariff category, as shown in the figure below.

4.4.21 For the municipality to reach full cost reflectivity, the municipality is required to increase tariffs for the different customer categories as demonstrated below. In doing so, it will increase some categories more than others to manage the cross-subsidies in the system. However, the municipality has opted for a uniform tariff increase of 9.97%. After the proposed changes are implemented, the under- and over-recovery per tariff category are presented as shown in the second graph of Figure 5.

Figure5: Rate design





5. CONCLUSION ON THE COS

5.1. The Cost of Supply (COS) outcome indicates that achieving full cost reflectivity would require a tariff increase of approximately 10%. However, the municipality proposes a lower increase of 9.97%, adopting a phased approach to mitigate the potential negative impacts of higher tariffs on customer affordability and electricity demand.

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Block 4 (>600 kWh)	411.32	452.33	9.97%	452.33	9.97%	*The COS indicates that Prepaid customers are currently receiving electricity services at a price below cost meaning they are being cross subsidized .an increase of 9.97% is allowed to enable the municipality to broaden its income base, supporting the ongoing delivery of essential basic services*
Basic Charge (R/Month)	new	461.65	9.97%	461.65	9.97%	*The proposed increase of 9.97% will enable the municipality to broaden its income base, supporting the ongoing delivery of essential basic services*

Domestic Conventional Homelight 80-100A	**2025/26 Approved**	**2026/27 Proposed**	**% Increase**	**Recommended Tariff**	**Recommended % increase**	**Analysis and key findings**
Block 1 (0-50) kWh	193.02	212.26	9.97%	212.26	9.97%	*The proposed increase of 9.97% will*

						enable the municipality to broaden its income base, supporting the ongoing delivery of essential basic services
Block 2 (51-350) kWh	248.17	272.91	9.97%	272.91	9.97%	*The proposed increase of 9.97% will enable the municipality to broaden its income base, supporting the ongoing delivery of essential basic services*
Block 3 (351-600kWh)	349.27	384.09	9.97%	384.09	9.97%	*The proposed increase of 9.97% willenable the municipality to broaden its income base, supporting the ongoing delivery of essential basic services*
Block 4 (>600 kWh)	411.32	452.33	9.97%	452.33	9.97%	*The proposed increase of 9.97% is allowed to enable the municipality to broaden its income base, supporting the ongoing delivery of essential basic services*
Basic Charge (R/Month)80A-100A	419.80	461.65	9.97%	461.65	9.97%	*The proposed increase of 9.97% will enable the municipality to broaden its income base, supporting the ongoing delivery of essential basic services*

Commercial Tariffs

Commercial Prepaid 60A	2025/26 Approved	2026/27 Recommended	% Increase	Recommended Tariff	Recommended % increase	Analysis and key findings
Block 1 (0-50) kWh	193.02	212.26	9.97%	212.26	9.97%	*The COS indicates that commercial prepaid is paying above cost of electricity. The increase of 9.97% will enable the municipality to broaden its income base, supporting the ongoing delivery of essential basic services*
Block 2 (51-350) kWh	248.17	272.91	9.97%	272.91	9.97%	*The COS indicates that commercial prepaid is paying above cost of electricity. The increase of 9.97% will enable the municipality to broaden its income base, supporting the ongoing delivery of essential basic services*
Block 3 (351-600kWh)	349.27	384.09	9.97%	384.09	9.97%	*The COS indicates*

						that commercial prepaid is paying above cost of electricity. The increase of 9.97% will enable the municipality to broaden its income base, supporting the ongoing delivery of essential basic services
Block 4 (>600 kWh)	411.32	452.33	9.97%	452.33	9.97%	*The COS indicates that commercial prepaid is paying above cost of electricity. The increase of 9.97% will enable the municipality to broaden its income base, supporting the ongoing delivery of essential basic services*
Basic Charge (R/Month)	1 458.70	1 604.13	9.97%	1 604.13	9.97%	*The COS indicates that commercial prepaid is paying above cost of electricity. The*

						increase of 9.97% will enable the municipality to broaden its income base, supporting the ongoing delivery of essential basic services

TOU Large Power User 300 &above	**2025/26 Approved**	**2026/27 Proposed**	**% Increase**	**Recommended Tariff**	**Recommended % increase**	**Analysis and key findings**
Peak	316.80	348.38	9.97%	348.38	9.97%	*The COS study indicates that TOU tariffs are close to cost reflectivity and an increase of 9.97% will strengthen the municipality's revenue enhancement strategy and ensure financial sustainability*
Standard	225.40	247.87	9.97%	247.87	9.97%	*The COS study indicates that TOU tariffs are close to cost reflectivity and an increase of 9.97% will strengthen the municipality's revenue enhancement strategy and ensure*

						financial sustainability
Off Peak	187.90	206.63	9.97%	206.63	9.97%	*The COS study indicates that TOU tariffs are close to cost reflectivity and an increase of 9.97% will strengthen the municipality's revenue enhancement strategy and ensure financial sustainability*

TOU-Three Phase-80A-125A	**2025/26 Approved**	**2026/27 Proposed**	**% Increase**	**Recommended Tariff**	**Recommended % increase**	**Analysis and key findings**
Peak	487.40	535.99	9.97%	535.99	9.97%	*The COS study indicates that TOU tariffs are close to cost reflectivity and an increase of 9.97% will strengthen the municipality's revenue enhancement strategy and ensure financial sustainability*
Standard	324.90	357.29		357.29	9.97%	*The COS study indicates that TOU tariffs are close to cost reflectivity*

			9.97%			*and an increase of 9.97% will strengthen the municipality's revenue enhancement strategy and ensure financial sustainability*
Off Peak	249.30	274.16	9.97%	274.16	9.97%	*The COS study indicates that TOU tariffs are close to cost reflectivity and an increase of 9.97% will strengthen the municipality's revenue enhancement strategy and ensure financial sustainability*

Three Phase- 150A- 250A	2025/26 Approved	2026/27 Proposed	% Increase	Recommended Tariff	Recommended % increase	Analysis and key findings
Peak	new	428.80	9.97%	428.80	New	*The increase of 9.97% will strengthen the municipality's revenue enhancement strategy and ensure financial sustainability*
Standard	new	285.83	9.97%	285.83	New	*The increase of 9.97% will strengthen the municipality's revenue enhancement strategy and ensure financial sustainability*
Off peak	new	219.32	9.97%	219.32	New	*The increase of 9.97% will strengthen the municipality's revenue enhancement strategy and ensure financial sustainability*

Single Phase- 80A – 100A	2025/26 Approved	2026/27 Proposed	% Increase	Recommended Tariff	Recommended % increase	Analysis and key findings
Peak	487.40	535.99	9.97%	535.99	9.97%	*The increase of 9.97% will strengthen the municipality's revenue enhancement strategy and ensure financial sustainability*
Standard	324.90	357.29	9.97%	357.29	9.97%	*The increase of 9.97% will strengthen the municipality's revenue enhancement strategy and ensure financial sustainability*
Off peak	249.30	274.16	9.97%	274.16	9.97%	*The increase of 9.97% will strengthen the municipality's revenue enhancement strategy and ensure financial sustainability*

TOU- Basic charges	2025/26 Approved	2026/27 Proposed	% Increase	Recommended Tariff	Recommended % increase	Analysis and key findings
Large Power User-300A and above	2 636.30	2 899.13	9.97%	2 899.13	9.97%	*The increase of 9.97% will strengthen the municipality's revenue enhancement strategy and ensure financial sustainability*

Three Phase 80A- 125A	1 458.70	1 604.13	9.97%	1 604.13	9.97%	*The increase of 9.97% will strengthen the municipality's revenue enhancement strategy and ensure financial sustainability*
Three phase 150-250A	new	2 483.20	9.97%	2 483.20	9.97%	*The increase of 9.97% will strengthen the municipality's revenue enhancement strategy and ensure financial sustainability*
Single Phase 80A-100A	1 458.70	1604.13	9.97%	1 604.13	9.97%	*The increase of 9.97% will strengthen the municipality's revenue enhancement strategy and ensure financial sustainability*
Domestic (Conventional) 80-100A	419.80	461.65	9.97%	461.65	9.97%	*The increase of 9.97% will strengthen the municipality's revenue enhancement strategy and ensure financial sustainability*
Domestic (prepaid)	new	461.65	9.97%	461.65	9.97%	*The increase of 9.97% will strengthen the municipality's revenue enhancement strategy and*

						ensure financial sustainability

TOU-Network demand Charge	**2025/26 Approved**	**2026/27 Proposed**	**% Increase**	**Recommended Tariff**	**Recommended % increase**	**Analysis and key findings**
Large Power User – 300 and above	175.30	192.78	9.97%	192.78	9.97%	*The increase of 9.97% will strengthen the municipality's revenue enhancement strategy and ensure financial sustainability*
Three phase 150A- 250A	new	154.22	9.97%	154.22	New	*The increase of 9.97% will strengthen the municipality's revenue enhancement strategy and ensure financial sustainability*

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 and approve Mbizana's tariff application for 2026/27 financial year.

End.