NATIONAL ENERGY REGULATOR OF SOUTH AFRICA

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Decision and Reasons for Decision (RfD)

In the matter regarding the

Municipal Tariff Application for the 2026/27 Financial Year

By

Mpofana Local Municipality

THE DECISION

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1. At its meeting held on 11 May 2026, the Regulator Executive Committee (REC) considered Mpofana Municipality's tariff application. Based on the facts and evidence presented, REC approved the tariff increases for the 2026/27 financial year (FY) set out in section 8 of the RFD.

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

   2.1. 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. noted 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 2026; and
   2.4. that the municipality must submit quarterly specific, measurable, achievable, realistic and time-bound (SMART) energy losses reduction progress reports for NERSA to monitor implementation thereof commencing by 30 September 2026.

TABLE OF CONTENTS

THE DECISION 1
ABBREVIATIONS AND ACRONYMS 6
1. INTRODUCTION 7
2. LEGAL AND REGULATORY FRAMEWORK 7
3. FINANCIAL AND TECHNICAL PERFORMANCE 11
4. DETERMINATION OF MPOFANA'S TARIFFS BASED ON THE COS STUDY 12
5. CONCLUSION ON THE COS STUDY 21
6. PUBLIC PARTICIPATION 23
7. THE OBJECTORS AND OTHER INTERVENING PARTIES 23
8. TARIFF ANALYSIS 24
9. CONFIDENTIALITY 26
10. CONCLUSION 26

LIST OF TABLES

Table 1: Customer statistics 7
Table 2: Performance indicators 11
Table 3: Revenue Analysis 12
Table 4: Operational expenditure 16
Table 5: Revenue recovery by customer category 20

LIST OF FIGURES

Figure 1: Five steps of COS study 13
Figure 2: Revenue requirement components 15
Figure 3: Cost breakdown by functions 18
Figure 4: Cost breakdown by cost structure (classification) 19
Figure 5: Costs allocated 19
Figure 6: Rate of design 22

ABBREVIATIONS AND ACRONYMS

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
MLM	Mpofana 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 an annual basis, in accordance with its mandate 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. NERSA received the Mpofana Local Municipality's (Mpofana) tariff application together with its Cost of Supply (COS) study on 31 March 2026. The municipality revised the COS study because of changes in Eskom tariffs.

1.3. Table 2 below shows customer statistics for Mpofana in the 2024/25 financial year (FY). This data is obtained from the latest Distribution form (D-form).

Table 1: Customer statistics

Consumer classification	Sales (MWh)	%MWh	Number of consumers
Domestic (Pre-paid)	2 763	18,22%	3 947
Domestic (Conventional)	3 754	24,76%	26
Commercial (Prepaid)	1 845	12,17%	116
Commercial (Converntional)	1 446	9,54%	59
Manufacturing/Industrial	4 564	30,10%	17
Street lighting and Own use	791	5,22%	N/A
Totals	15 163	100%	4 165
Free Basic Electricity	-	0,00%	0

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

1.5. NERSA's decision was made on 11 May 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 ('the ERA'), the Promotion of Administrative Justice Act, 2000 (Act No. 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 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 2026/27 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 licences and may issue licences 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 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:

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 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. Therefore, public participation processes conducted by the Energy Regulator 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 of the EPP 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 of the EPP 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 NERSA.

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 in respect of the 2026/27 municipal tariff approvals:

a) Written notice of bulk tariffs must be communicated by 6 March 2026.
b) Municipal tariff applications to be submitted by 31 March 2026.
c) Public participation processes to 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 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 contained in this 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 Mpofana, the assessment relied on the D-forms for FY2024/25 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 (AFS). As a result, the data captured in the D-forms is considered reliable for purposes of the tariff analysis.

3.2. Mpofana's percentage deficit regressed from -48.04% in FY2023/24 to a deficit of -66.22% in FY2024/25. The decline in financial performance is mainly attributed to a decrease in revenue due to fewer units sold, a significant increase in OPEX due to investment in ageing network infrastructure and interest on Eskom debt.

3.3. Table 2: Performance indicators below shows that Mpofana's energy losses improved from 63.51% in FY2023/24 to 58.10% in FY2024/25. The municipality indicated that this is mainly due to the installation of smart meters and the improvement in the billing system after the appointment of the panel of service providers. The municipality further increased public awareness of illegal connections.

Table 2: Performance indicators

Indicators	2023-24	2024-25
Percentage Deficit/Surplus	-48.04%	-66.22%
Percentage Energy Losses	63.51%	58.10%

3.4. Based on the above information provided by the municipality from the D-forms, Mpofana's performance requires areas of improvement as evidenced by the significant increase in the deficit.

Table 3: Revenue Analysis

	D-Form Input	Energy Loss@12%	Energy Loss@6%
Average Selling Price	356,20		
Sales kWh	15 165 945,00	31 852 104,24	34 023 838,62
Purchases kWh	36 195 573,00	36 195 573,00	36 195 573,00
Losses kWh	21 029 628,00	4 343 468,76	2 171 734,38
Losses percentage	**58,10%**	**12,00%**	**6,00%**
Additional Energy (kWh)		16 686 159,24	18 857 893,62
Additional Revenue (Rands)		59 435 731,63	67 171 401,65
	D-Form Input	Energy Loss@12%	Energy Loss@6%
Total Revenue (Rands)	R 75 310 507,00	R 134 746 238,63	R 142 481 908,65
Total Expenses (Rands)	R 125 184 041,00	R 125 184 041,00	R 125 184 041,00
Net Profit (Loss)	R -49 873 534,00	R 9 562 197,63	R 17 297 867,65
Percentage Surplus/Deficit	**-66,22%**	**7,10%**	**12,14%**

3.5. The licensee has the potential to improve the deficit to 7.10% if energy losses are limited to 12% and the surplus could potentially increase to 12.14% if the energy losses are reduced to 6%.

4. DETERMINATION OF MPOFANA'S TARIFFS BASED ON THE COS STUDY

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

4.2. Mpofana utilised the COS model developed by Sustainable Energy Africa (SEA) to determine its revenue requirements for FY2026/27 and to apportion costs required to service each customer class in a fair and equitable manner. The municipality applied the cost-plus methodology in conducting its COS study. The COS study was submitted to NERSA for FY2024/25 and was based on audited financial statements for FY2024/25. The study follows the NERSA COS Framework and uses the latest available audited data, which is based on FY2024/25. The asset value is – R 189 358 378 (2024/25 D-form and AFS), Depreciation – R 276 508 000 (2026/27 budget), profit margin/surplus – R7 355 164 (2026/27 budget). The depreciation and surplus are highlighted in Figure 2 and Table 5.

4.3.

4.4. below details the five steps considered in the determination of the COS study.

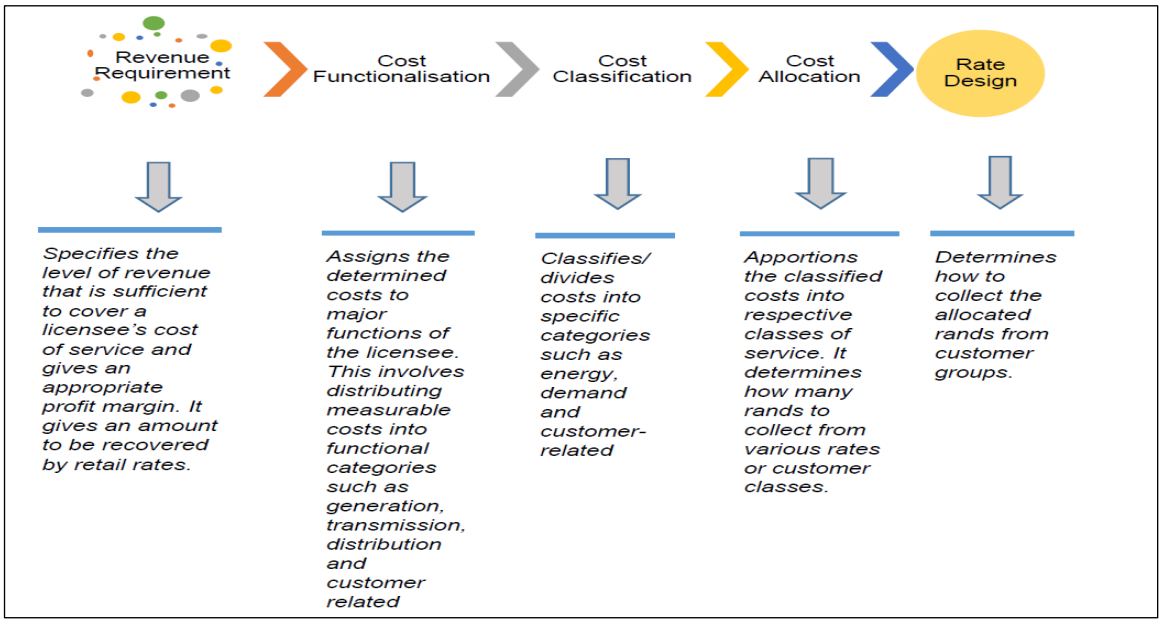


Figure 1: Five steps of COS study

4.5. Section 18.7 of the COS Framework requires that tariff adjustments:

4.5.1. be informed by cost of supply outcomes;

4.5.2. progressively move tariffs towards cost-reflectivity; and

4.5.3. be implemented in a structured and transparent manner, including phased adjustments where required.

4.6. In its tariff application, the licensee has considered and applied these requirements as follows:

4.6.1. The tariff application is based on a COS model incorporating financial, technical and customer data inputs.

4.6.2. Bulk purchase costs were assumed to increase year on year by 8.74%, which is below the approved 9,01% Eskom bulk tariff adjustment.

4.6.3. Controllable electricity OPEX was adjusted using CPI-linked assumptions.

4.6.4. Adjustments were supported by source documents and reasonability checks (D-forms, trial balance and AFS).

4.7. This ensures that tariff adjustments are grounded in cost-reflective principles.

4.7.1. The licensee has proposed a phased implementation to achieve full-cost recovery.

4.7.2. This approach aligns with section 18.7, which allows for gradual tariff realignment to mitigate tariff shocks and maintain affordability for vulnerable customer groups.

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

4.8.1. **Revenue Requirement**

4.8.1.1. The revenue requirement step specifies the level of revenue that is sufficient to cover a licensee's cost of service and appropriate margin. It is an indication of the amount to be recovered from the approved tariffs.

4.8.1.2. The municipality applied a cost-plus methodology in the determination of its revenue requirement, and did not utilise a Rate of Return (ROR) approach. Accordingly, no Regulatory Asset Base (RAB) was determined or applied.

4.8.1.3. Under the cost-plus framework, the allowable revenue comprises the following:

4.8.1.3.1. Efficient and prudent operating expenditure (OPEX) of R 19 063 366 before surplus.

4.8.1.3.2. Depreciation, as a proxy for asset consumption and future asset replacement of R276 508.

4.8.1.3.3. A reasonable surplus margin applied to the total cost of R7 355 164.

4.8.1.4. To ensure that the applied surplus is not excessive and remains within acceptable regulatory bounds, the following validation procedures were undertaken:

4.8.1.4.1. The applied surplus margin of 9% was benchmarked against the 10–20% range prescribed in the approved NERSA COS Framework, as supported by the EPP Policy Position 1, D-forms, and trial balance.

4.8.1.4.2. The margin was further assessed against the municipality's risk profile to ensure alignment with the principle of cost reflectivity and financial sustainability.

4.8.1.5. Risk factors considered include the following:

4.8.1.5.1. Revenue collection risk, with current collection levels at approximately 42%, reflecting exposure to non-payment, bad debts and indigents.

4.8.1.5.2. Operational risk, including energy losses of approximately 58.10% and ageing network infrastructure.

4.8.1.5.3. Financial sustainability requirements, including the need to maintain adequate cash flows for ongoing operations and infrastructure investment.

4.8.1.6. Based on the above, the applied surplus margin of 9% is considered conservative, justified, and commensurate with the municipality's risk profile, while remaining within the acceptable parameters of the NERSA COS Framework. This approach supports the financial viability of the electricity distribution function without imposing undue burden on consumers.

4.8.1.7. Mpofana submitted a COS study detailing a revenue requirement of R80.91 million for FY2026/27. This revenue requirement is based mainly on Eskom purchases, accounting for 54%, while operational expenditure accounts for 24%.

	Total cost (R)			
Revenue Requirement components	Wires	Retail	Total	% of Total
Allowable costs	16 928 603	63 978 204	80 906 807	100%
Energy purchases from Eskom - net of cost of losses	-	43 855 073	43 855 073	54%
Energy purchases from Eskom - cost of losses	5 316 602	5 316 602	10 633 205	13%
Other energy purchases	-	-	-	0%
Capital expenditure	-	-	-	0%
Operational expenditure (incl. Depreciation)	10 073 037	8 990 329	19 063 366	24%
Other revenues	-	-	-	0%
Surplus	1 538 964	5 816 200	7 355 164	9%
Not allowable costs	17 060 880	17 060 880	34 121 761	
Cost of losses disallowed	17 060 880	17 060 880	34 121 761	
TOTAL COSTS	33 989 484	81 039 085	115 028 568	
	30%	70%		

Figure 2: Revenue requirement components

4.8.1.8. The efficiency of costs for FY2024/25 has been assessed, as this constitutes the most recent set of actual data. This assessment serves as the baseline for projecting costs for FY2026/27, applying stated assumptions to determine the revenue requirement for that period.

4.8.1.9. All expenses included in the revenue requirement have been examined to confirm that they pertain exclusively to the licensee's electricity function. Where any amounts were found to be inflated or insufficiently substantiated, adjustments have been effected accordingly, as detailed below.

Bulk Purchases

4.8.2. Mpofana's COS study projects a bulk purchase expenditure of R54.49 million, which accounts for 54% of total costs when excluding the 13% energy losses allowance. Bulk purchases were verified against Eskom invoices in FY2024/25.

4.8.3. The licensee projected its bulk purchases for FY2026/27 using FY2025/26 Eskom tariffs as a base and made the following assumptions: sales growth of

0% and a bulk purchase cost increase of 8.74% for the FY2026/27, which is below the approved Eskom Retail Tariff Structural Adjustments (ERTSA).

Operational Expenditure

4.8.4. Mpofana's COS study projects operational expenditure totalling R19.06 million, representing 24% of overall costs. Table 5 below provides a breakdown of this expenditure.

Table 4: Operational expenditure

Functions	Total OPEX	Wires	Retail
Depreciation	276 508	276 508	
Network and repairs	8 000 000	8 000 000	
Other expenses	10 786 858	1 796 529	8 990 329
Total	**19 063 366**	**10 073 037**	**8 990 329**

4.8.5. Only the portion of shared costs directly attributable to the electricity service was allocated to the revenue requirement. This ensures that electricity consumption is charged solely for costs associated with the provision of electricity services.

4.8.6. Inefficient cost components – such as Notified Maximum Demand (NMD) exceedance penalties and interest incurred on Eskom-related debt – have been excluded from the total, as these items fall within the control of the municipality. The municipality's accounts with Eskom are up to date, with exceedances recorded under the NMD, with outstanding arrears of R0 for FY2024/25.

4.8.7. All the other expenses have been grouped under 'other expenses'. The other operating expenses, including charges from other municipal departments, have been checked to ensure that they relate only to the electricity function. Furthermore, all these expenses have been projected to grow in line with inflation.

Surplus

4.8.8. Mpofana's revenue requirement includes a surplus of R7.36 million, calculated using a surplus factor of 9% applied to operating expenditure, inclusive of bulk purchases, for both the wires and retail components of the electricity business. This figure excludes inefficient or non-allowable costs, including interest on Eskom-related debt for its bulk electricity account (R21 455 065) and penalties arising from NMD exceedances (R0). These exclusions were verified against Eskom invoices.

4.8.9. The applied surplus margin of 9% was benchmarked against the established target range of 10–20% on the approved NERSA COS Framework, EPP Policy Position 1, D-form and trial balance.

4.8.10. To ensure that the profit margin commensurate with the risk, risk considerations were incorporated qualitatively, including the following:

4.8.10.1.1. Revenue collection risks (non-payment, indigent levels, bad debts). The municipality has budgeted to write off bad debt of R0 for FY2026/27.

4.8.10.1.2. Operational risks remain a concern, particularly in relation to energy losses and ageing infrastructure. For FY2026/27, municipal energy losses are projected at 13.00%.

4.8.10.1.3. Financial sustainability requirements.

4.8.11. In recommending a surplus, NERSA relied on section 15(1)(a) of the ERA under the tariff principles, which specifies that the tariffs set by the Regulator 'must enable an efficient licensee to recover the full cost of its licensed activities, including a reasonable margin or return'.

4.8.12. In applying the ERA, NERSA is required to ensure that Mpofana recovers efficient costs and a reasonable return, while preventing excessive compensation. The return proposed by Mpofana is considered reasonable, as it falls within the established target range of 10–20%. Consequently, the requested amount has been recommended as applied for.

4.8.13. The recommended revenue requirement will be applied in the subsequent COS steps, namely cost functionalisation, cost classification, cost allocation and rate setting. These steps have been verified and confirmed to align with the approved revenue requirement. Further details of these steps are provided below.

Cost Functionalisation

4.8.14. The licensee has categorised its revenue requirement of R80.91 million into two primary functional components, namely the **wires business (30%)** and the **retail business (70%)**, in accordance with the NERSA COS Framework, as illustrated in Figure 3 below. Upon verification, the allocation of costs to these functional components is found to be consistent with the stated revenue requirement.

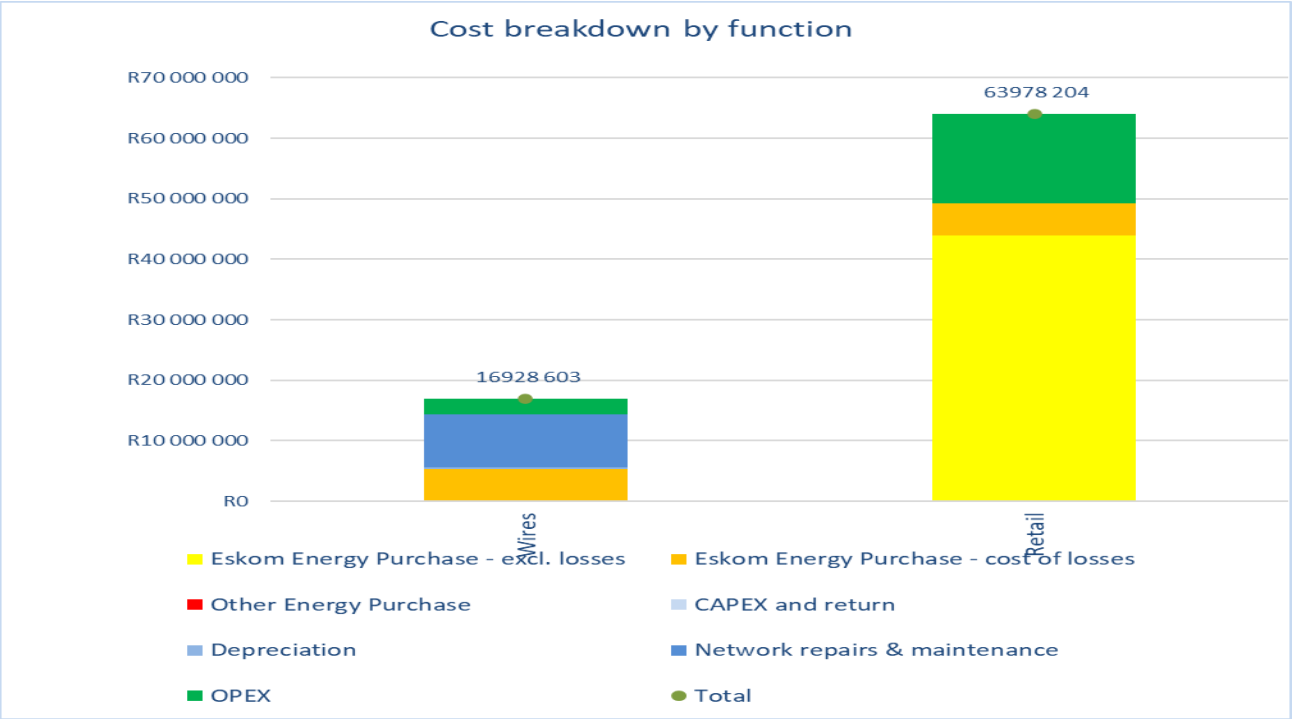


Figure 3: Cost breakdown by functions

4.8.15. 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.

4.8.16. The verification of costs included in the COS model was undertaken using both the NERSA D-forms and the municipality's audited AFS for FY2024/25.

Cost Classification

4.8.17. The licensee has 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.

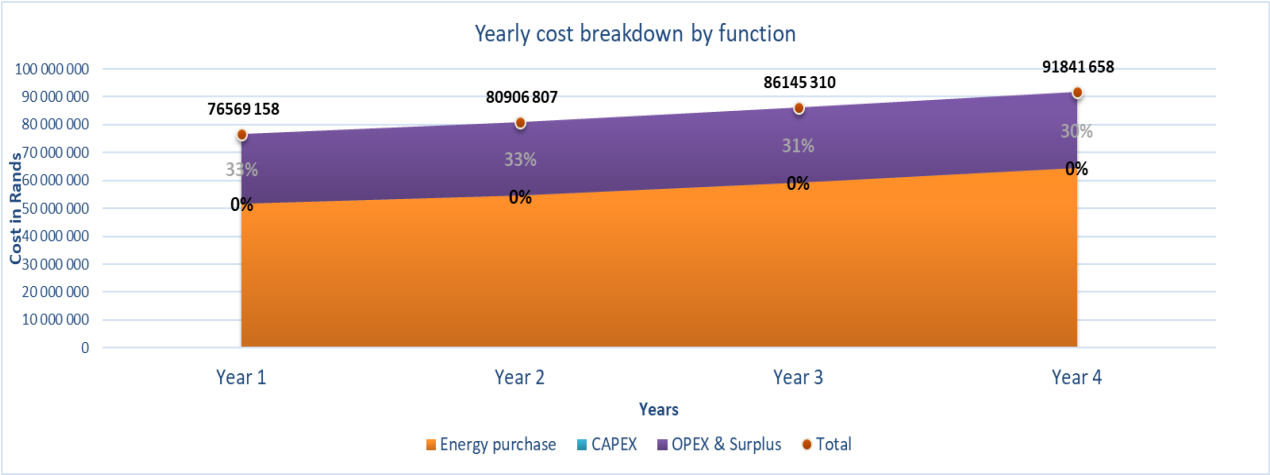


Figure 4: Cost breakdown by cost structure (classification)

4.8.18. 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.

Cost Allocation

4.8.19. 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.

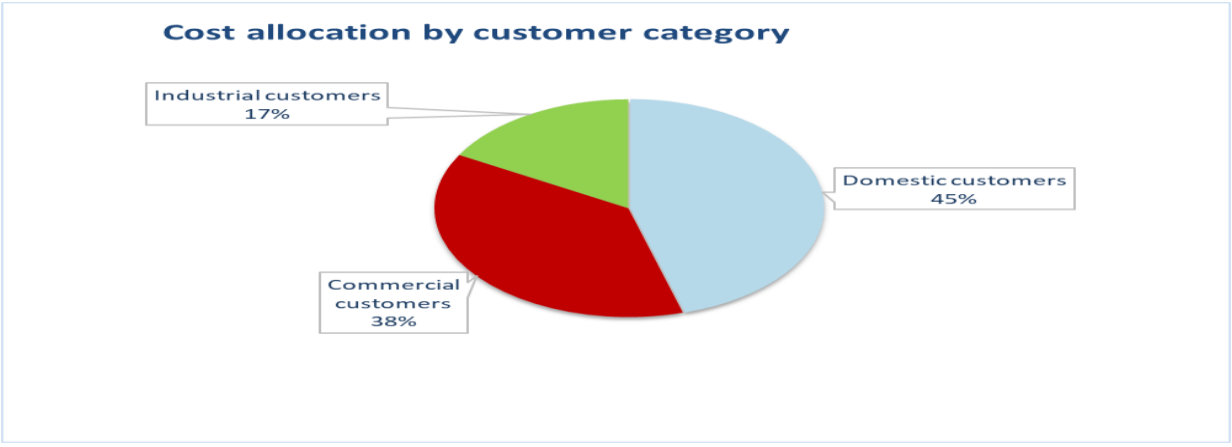


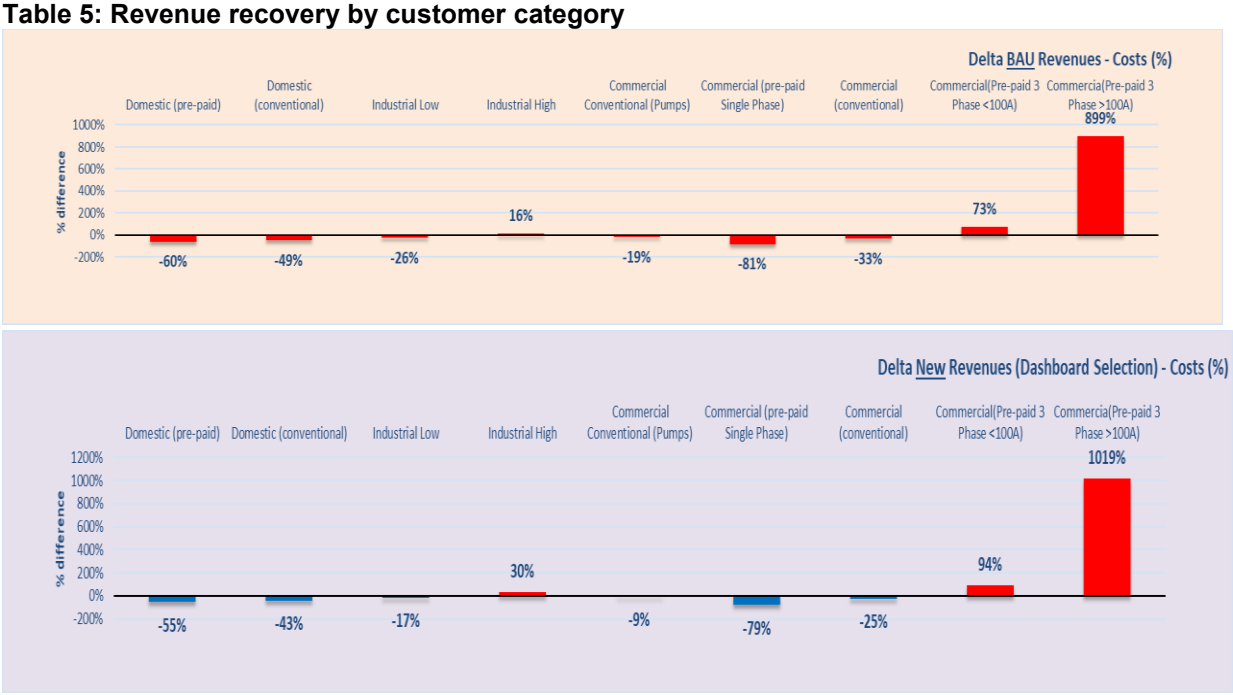
Figure 5: Costs allocated

Rate Design

4.8.20. Table 6 below reflects the outcome of the COS study, indicating that certain customer categories require upward adjustments, while others warrant decreases. A comparison between the cost of supply and the revenue generated per tariff category highlights the extent of over- or under-recovery within each category, as illustrated in Table 6 below.

4.8.21. To achieve full cost reflectivity, the municipality would be required to implement differentiated tariff adjustments across customer categories.

Table 5: Revenue recovery by customer category



4.8.22. The COS study confirms the presence of cross-subsidisation between customer categories. Certain categories are under-recovering (receiving a subsidy), while others are over-recovering (providing the subsidy). Commercial customers are cross-subsidising residential and municipal customer categories, which is consistent with typical municipal tariff structures.

4.8.23. Based on the revenue outputs of the COS main model, a tariff increase of 12% is required by the municipality. However, the municipality has resolved to implement differentiated tariff increases of above 12% in some of the tariff categories. This impacts customers in the inclining block tariff category. The municipality is moving to a flat seasonal tariff, particularly for domestic prepaid and domestic conventional customers. However, in terms of the NERSA analysis, the recommendation is an approval of tariffs by an adjusted 12% increase across the different tariff categories, with the previously approved NERSA tariffs used as a base, as indicated in the tariffs analysis section below. This approach seeks to enhance revenue collection while minimising the financial impact on customers, particularly indigent households and low-income households. This approach ensures that cross-subsidies are not removed abruptly, thereby avoiding undue tariff shocks and mitigating adverse impacts

on vulnerable consumers. At the same time, it facilitates a managed, transparent and gradual transition towards tariffs that are cost-reflective, equitable and aligned with the NERSA principles.

5. CONCLUSION ON THE COS STUDY

5.1. While the outcome of the COS study may indicate an average tariff adjustment of a certain percentage 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. This approach may be informed by a range of considerations, including the need to maintain tariff sustainability to support ongoing demand for electricity services. Excessive tariff increases may adversely affect consumption levels, thereby impacting revenue stability.

5.3. In addition, the licensee may consider 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 to safeguard 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 61.00% to reach the overall cost-reflectivity, as illustrated in Figure 6 below. The licensee has proposed a differentiated tariff increase of above 12% and a 12.00% increase in other tariff categories to ensure municipal financial sustainability. Based on the available information, the municipality is expected to remain financially sustainable under the recommended tariff increase of 12%.

5.7. The outcome of the COS study indicates that the municipality requires a tariff increase of 61.00% to achieve efficient cost reflectivity, as shown in Figure 6 below.

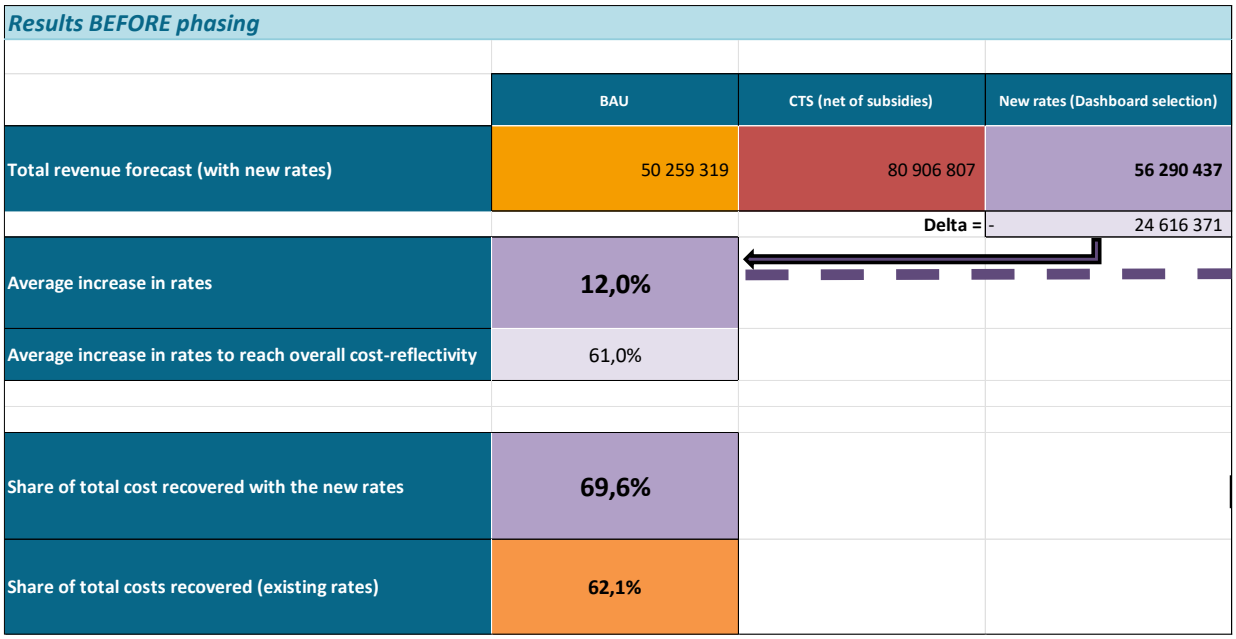


Figure 6: Rate of design

5.8. The licensee has applied an across the board 12.00% tariff increase, which is below the increase required for full cost reflectivity. NERSA conducted an analysis and recommended an applied tariff increase of 12.00% across all categories, in line with the COS Framework for customer protection and municipal financial sustainability. NERSA's analysis indicates that the recommended tariff increases are sustainable for Mpofana. The municipality did not demonstrate the economic and social impact on the affected stakeholders, nor did it demonstrate proof of public consultation on applying differentiated tariff categories which exceed the 12% tariff increase. It is on this basis that NERSA's analysis limited the tariff increases to 12%.

5.9. While the COS study outcome reflected an average tariff increase of 61.00% for the licensee to achieve full cost reflectivity, the municipality adopted a phased-in approach to implement tariff increases below the COS outcomes. Some of the considerations for this decision include the licensee's requirement to maintain a sustainable tariff level to drive the demand for its electricity services. Significantly higher tariffs could negatively impact the licensee by reducing customer demand and sales. The licensee also considered the ability to service its Eskom account and broader affordability impact on customers when determining the pace of its tariff adjustments.

5.10. This approach will help protect the licensee's revenue base and support its financial sustainability, as required by legislation.

5.11. The COS study is based on forecast values; therefore, until audited actual figures are used, the true requirement for cost reflectivity cannot be determined with 100% certainty. It is for this reason that the municipality will be requested to submit a

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1. Domestic Tariffs						
1.1 Domestic High Conventional	***2025/26 Approved***	**% Increase**	***2026/27 Proposed***	**2026/27 Recommended**	**Recommended % Increase**	**Analysis and Key Findings**
Block 1 (0 - 50kWh)	194,53		-	217,87	12,00%	Recommend approval of adjusted tariffs, NERSA previously approved tariff used as a base.
Block 2 (51-350 kWh)	250,17		-	280,19	12,00%	
Block 3 (351-600 kWh)	352,11			394,36	12,00%	
Block 4 (>600 kWh)	414,65		-	464,41	12,00%	
Basic Charge (R/month)	101,00	13,86%	115,00	113,12	12,00%	
1.2 Domestic Prepaid	***2025/26 Approved***	**% Increase**	***2026/27 Proposed***	**2026/27 Recommended**	**Recommended % Increase**	**Analysis and Key Findings**
Block 1 (0 - 50kWh)	194,52		-	217,86	12,00%	Recommend approval of adjusted tariffs, NERSA previously approved tariff used as a base.
Block 2 (51-350 kWh)	250,17		-	280,19	12,00%	
Block 3 (351-600 kWh)	352,11		-	394,36	12,00%	
Block 4 (> 600 kWh)	414,65		-	464,41	12,00%	
1.3 Free Basic	***2025/26 Approved***	**% Increase**	***2026/27 Proposed***	**2026/27 Recommended**	**Recommended % Increase**	**Analysis and Key Findings**
Block 1 (0 - 50kWh)	0,00		-	-	-	Recommend approval of adjusted tariffs, NERSA previously approved tariff used as a base.
Block 2 (51-350 kWh)	250,17		-	280,19	12,00%	
Block 3 (351-600 kWh)	352,11		-	394,36	12,00%	
Block 4 (> 600 kWh)	414,65		-	464,41	12,00%	
2. Commercial Tariffs						
2.1 Commercial Credit Meter	***2025/26 Approved***	**% Increase**	***2026/27 Proposed***	**2026/27 Recommended**	**Recommended % Increase**	**Analysis and Key Findings**
Basic Charge (R/month)	278,58	-	-	312,01	12,00%	Recommend approval of adjusted tariffs, NERSA previously approved tariff used as a base.
Energy Charge c/kWh	391,90	12%	438,93	438,93	12,00%	
2.2 Commercial Prepaid	***2025/26 Approved***	**% Increase**	***2026/27 Proposed***	**2026/27 Recommended**	**Increase**	**Analysis and Key Findings**
Basic Charge	245,80	-	-	275,30	12%	Recommend approval of adjusted tariffs, NERSA previously approved tariff used as a base.
Energy Charge c/kWh	425,28	-	-	476,31	12%	
3. Industrial Tariffs						
3.1 Industrial Low Voltage-400V	**2025/26 Approved**	**% Increase**	**2026/27 Proposed**	**2026/27 Recommended**	**Recommended % Increase**	**Analysis and Key Findings**
Basic Charge (R/month)	19 693,47	9%	21 504,00	21 504,00	9%	Recommend approval of adjusted tariffs, NERSA previously approved tariff used as a base.
Notified Demand Charge R/kVA	120,44	10%	133,00	133,00	10%	
Actual Demand Charge R/kVA	59,06	22%	72,00	66,15	12%	
3.2 Energy Charge High Season	**2025/26 Approved**	**% Increase**	**2026/27 Proposed**	**2026/27 Recommended**	**Recommended % Increase**	**Analysis and Key Findings**
Peak (c/kWh)	916,70	15%	1053,90	1 026,70	12%	Recommend approval of adjusted tariffs, NERSA previously approved tariff used as a base.
Standard (c/kWh)	305,48	1%	309,40	342,14	12%	
Off-Peak (c/kWh)	174,62	25%	218,10	195,57	12%	
3.3 Energy Charge Low Season	**2025/26 Approved**	**% Increase**	**2026/27 Proposed**	**2026/27 Proposed**	**Recommended % Increase**	**Analysis and Key Findings**
Peak (c/kWh)	326,34	15%	375,10	365,50	12,00%	Recommend approval of adjusted tariffs, NERSA previously approved tariff used as a base.
Standard (c/kWh)	232,05	1%	235,00	259,90	12,00%	
Off-Peak (c/kWh)	174,62	25%	218,10	195,57	12,00%	
3.4 Industrial Low Voltage-11 000V-Summer Season	**2025/26 Approved**	**% Increase**	***2026/27 Proposed***	**2026/27 Recommended**	**Recommended % Increase**	**Analysis and Key Findings**
Basic Charge (R/month)	19 092,02	14%	21 672,90	21 383,06	12,00%	Recommend approval of adjusted tariffs, NERSA previously approved tariff used as a base.
Network Access Charge kVA	56,82	21%	68,82	63,64	12,00%	
Network Demand Charge kVA	71,72	13%	81,00	80,33	12,00%	
3.5 Energy Charge Summer Season	**2025/26 Approved**	**% Increase**	**2026/27 Proposed**	**2026/27 Recommended**	**Recommended % Increase**	**Analysis and Key Findings**
Peak (c/kWh)	236,91	58%	375,10	265,34	12%	Recommend approval of adjusted tariffs, NERSA previously approved tariff used as a base.
Standard (c/kWh)	168,50	39%	235,00	188,72	12%	
Off-Peak (c/kWh)	113,30	92%	218,10	126,90	12%	
3.6 Industrial Low Voltage-11 000V-Winter Season	**2025/26 Approved**	**% Increase**	**2026/27 Proposed**	**2026/27 Recommended**	**Recommended % Increase**	**Analysis and Key Findings**
Basic Charge (R/month)	19 319,37	11%	21 455,55	21 455,55	11%	Recommend approval of adjusted tariffs, NERSA previously approved tariff used as a base.
Network Access Charge kVA	68,18	17%	80,10	76,36	12%	
Actual Demand Charge kVA	79,55	14%	90,40	89,10	12%	
3.7 Energy Charge Winter Season	**2025/26 Approved**	**% Increase**	**2026/27 Proposed**	**2026/27 Recommended**	**Recommended % Increase**	**Analysis and Key Findings**
Peak (c/kWh)	669,66	57%	1053,90	750,02	12%	Recommend approval of adjusted tariffs, NERSA previously approved tariff used as a base.
Standard (c/kWh)	218,78	41%	309,40	245,03	12%	
Off-Peak (c/kWh)	126,77	72%	218,10	141,98	12%	

9. CONFIDENTIALITY

None.

10. CONCLUSION

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

10.2. All tariffs shall be limited to 12.00% as per the COS study for customer protection and municipal financial sustainability.

End.