NATIONAL ENERGY REGULATOR OF SOUTH AFRICA

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The Decision and Reasons for Decision

In the matter regarding the

Municipal Tariff Applications for the 2026/27 Financial Year

By

Ga-Segonyana Local Municipality (GLM)

THE DECISION

At its meeting held on 6 May 2026, the Regulator Executive Committee (REC) considered the Ga-Segonyana Local Municipality's tariff application. Based on the facts and evidence presented, REC approved the tariff increases for the 2026/27 financial year as set out on the tariff analysis section 7 below.

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

a) to approve the tariffs based on the Cost of Supply (COS) study, as recommended in the tariff analysis section, for implementation by the Municipality with effect from 1 July 2026;
b) to note the COS study submitted by the Municipality;
c) that 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 by 31 January 2027; and
d) that the Municipality must submit quarterly progress reports on the efficiency improvement measures taken to reduce high energy losses and deficits to enable NERSA to monitor the implementation.

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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
GLM	Ga-Segonyana 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), in accordance with its statutory mandate regulate electricity prices and tariffs, assesses tariff applications submitted by Licensees on an annual basis. As part of this process, municipal electricity tariffs must be approved by the Energy Regulator prior to implementation, which typically takes effect on 1 July of each financial year.

1.2. The Ga-Segonyana Local Municipality (The Municipality), located in Northern Cape Province, has 18 150 customers. with the Municipality's electricity sales profile is largely driven by domestic customers, who contributed 39.34% of total electricity sales in the 2024/25 financial year, while commercial customers accounted for 36.56%.

1.3. The Municipality provides Free Basic Electricity (FBE) of 50 kWh per month to registered indigent customers, in line with national policy objectives aimed at ensuring access to basic energy services for low-income households. Detailed customer statistics and consumption patterns are reflected in Table 1 below.

Table 1: Customer Statistics (Data obtained from the latest D-forms – 2024/25FY

Customer categories	***MWh***	***% MWh***	***Customer numbers***
Domestic(Prepaid)	25 617	35.71	9 620
Domestic(Conventional)	2 606	3.63	1 561
Manufacturing	16 469	22.96	692
Commercial	26 228	36.56	5 997
General(other consumers)	823	1.15	280
TOTAL	**71 743**	**100.00**	**18 150**
FBE	**33**	**0.12**	**664**

1.4. NERSA received the Municipality's tariff application, together with its Cost of Supply (CoS), on 31 March 2026.

1.5. The Cost of Supply study confirms the existence cross-subsidisation, with Commercial and Industrial customers effectively subsidising Residential customers. The Municipality indicated that the increase for commercial and industrial tariffs is lower compared to other customers. This is to try to reduce cross subsidy or burden other customers hence the different increases across tariffs.

1.6. The Municipality implemented an average price increase of 11.33% in the 2025/26 financial year and is applying for an average price increase of 6.94% for the 2026/27 financial year.

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

1.8. The Energy Regulator's decision was made on 6 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 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 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. NERSA's Statutory Mandate

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. Therefore, NERSA's electricity regulatory mandate is 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, the Energy Regulator exercises this authority through the powers conferred by ERA:

- 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; and
- 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 NERSA 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 that guide the determination of electricity tariffs in 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 Electricity Pricing Policy (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 accurately reflect the efficient cost of providing electricity services, and that the average tariff level 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 whenever 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 seeking to vary the timelines set by the Court on 4 December 2025, in light of the practical difficulties arising in relation 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 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 NERSA 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 stated in this Reasons for Decision document demonstrate how NERSA 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 PERFORMACE

3.1. Level of reliability of information

3.1.1. In evaluating the financial and technical performance, NERSA relied on the 2024/25 Distribution forms (D-forms) information provided in analysing the Licensee's tariff application. The D-forms' information was validated by NERSA against the relevant source documents submitted by the municipality (i.e. the trial balance/audited annual financial statement [AFS]). Hence, the information provided in the D-forms is considered reasonable for the analysis of the tariffs.

3.1.2. Table 3 below shows GLM's Technical and financial performance:

Table 2: Technical and financial performance

Performance indicators	***2023/24***	***2024/25***
*Percentage surplus/(Deficit): **(%)***	9.47	8.76
*Energy Losses: (**%**)*	20.87	7.76

3.2. Percentage Surplus

3.2.1. Ga-Segonyana Local Municipality recorded a surplus of 8.76% in the 2024/25 financial year, compared to a surplus of 9.47% in the 2023/24 financial year. Despite the marginal decline in the surplus margin, the Municipality remained financially sustainable.

3.3. Energy Losses

3.3.1. The Municipality reduced energy losses from 20.87% in the 2023/24 financial year to 7.79% in the 2024/25 financial year, reflecting the effectiveness of its loss-reduction measures. The Municipality further indicated that it conducts meter audits using internal staff to identify meter tampering, illegal connections, and incorrect meter configurations, thereby supporting accurate billing and revenue protection.

3.3.2. In addition, the Municipality has appointed a service provider to conduct inspections of prepaid electricity meters. These interventions are expected to strengthen revenue protection, improve billing accuracy, and support the maintenance of energy losses within acceptable benchmark levels.

4. DETERMINATION OF GLM'S TARIFFS BASED ON THE COST OF (COS) SUPPLY STUDY

4.1.1. The process that the Energy Regulator followed in considering and approving the Municipality's tariff application was supported by a Cost of Supply (COS) study.

4.1.2. The Municipality utilised the revised COS study model developed by Sustainable Energy Africa (SEA) and various other stakeholders to determine its revenue requirements for the 2026/27 financial year and

to allocate costs required to service each customer category in a fair and equitable manner. The study diligently follows the NERSA COS Framework and utilises the latest available audited data which is based on the 2024/25 financial year

4.1.3.

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

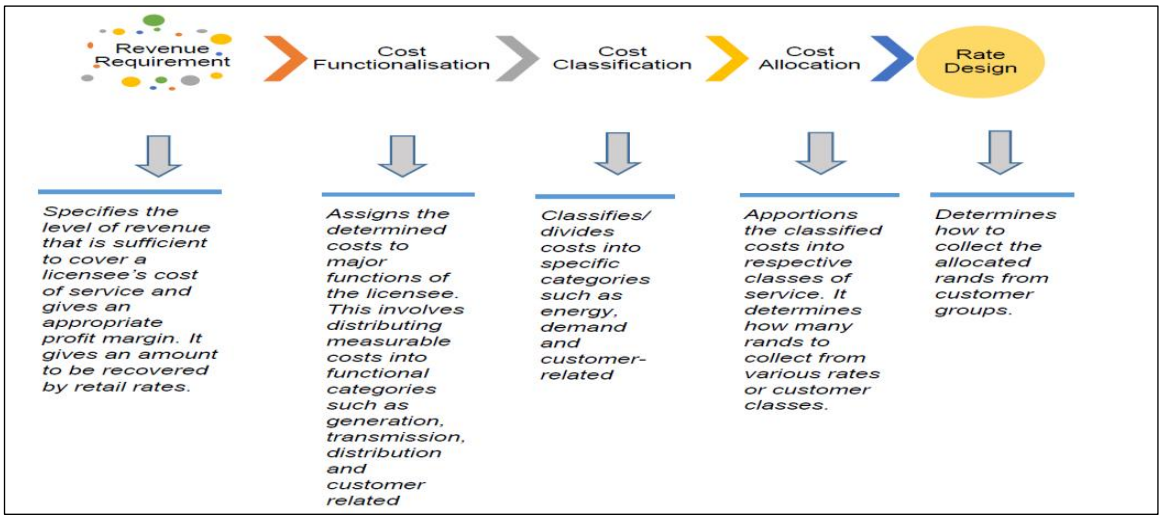


Figure 1: Fives steps of COS

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

Revenue Requirement

4.1.6. the Licensee's allowable revenue requirement for the 2026/27 financial year amounts to R290 093 748, as detailed in Table 3 below.

Table 3: Revenue Requirement components

	Total cost (R)			
Revenue Requirement components	**Wires**	**Retail**	**Total**	**% of Total**
Allowable costs	143 661 328	215 604 923	290 093 748	100%
Energy purchases from Eskom - net of cost of losses	-	185 423 138	185 423 138	64%
Energy purchases from Eskom - cost of losses	18 159 640	8 067 634	26 227 273	9%
Other energy purchases	-	-	-	0%
Capital expenditure	-	-	-	0%
Operational expenditure (incl. Depreciation)	58 401 195	10 771 309	69 172 504	24%
Other revenues	**- 52 939**	**- 907 968**	**- 960 907**	**0%**
Surplus	8 752 238	1 479 501	10 231 740	4%
Not allowable costs	3 786 853	3 123 347	6 910 199	
Cost of losses disallowed	3 786 853	3 123 347	6 910 199	
TOTAL COSTS	**147 448 181**	**218 728 270**	**297 003 947**	
	50%	74%		

4.1.7. It is important to test the efficiency of the costs in the 2024/25 financial year since this is the most recent available actual data. This forms the basis on which costs for the 2026/27 financial year will be projected using assumptions to calculate revenue requirements.

4.1.8. 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

4.1.9. The Licensee applied for a bulk purchase expenditure of R211 650 411 which accounts for 73% of the total costs. Bulk purchases were verified against Eskom invoices in the 2024/25 financial year.

4.1.10. In order 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).

Operational Expenditure

4.1.11. The Municipality applied for operational expenditure amounting to R69 172 504, representing 24% of the total costs for the 2026/27 financial year, as reflected in Table 4 below.

Table 4: Operating expenditures

Cost drivers	Units	2024/25FY Actuals	2025/26FY Budgeted	2026/27FY Applied	NERSA Adjustments	2026/27FY Recommended
General costs and other	**R**	**36 542 959**	**54 324 374**	**56 597 691**	**-**	**56 597 691**
Salaries and allowances	R	9 466 292	10 034 270	10 535 983	-	10 535 983
Contracted Services	R	15 614 575	16 551 450	17 213 507	-	17 213 507
Payments to consultants (operational work)	R		15 614 575	16 239 158	-	16 239 158
Eskom debts interest	R	24 281	-			
Current year depreciation	R	11 437 811	12 124 080	12 609 043	-	12 609 043
Shared OPEX	**R**	**3 496 323**	**12 091 166**	**12 574 813**		**12 574 813**
Bad debts (Allowance for Impairment)	**R**	236 010	8 622 890	8 967 806		8 967 806
General Expenses	**R**	3 260 313	3 468 276	3 607 007		3 607 007
Total Opex	**R**	**40 039 282**	**66 415 540**	**69 172 504**	**-**	**69 172 504**

4.1.12. The difference between contracted services and consultants is mainly based on the nature and purpose of the service provided:

i. Contracted Services (Payments) refers to services outsourced to external service providers to perform operational or technical functions on behalf of the Municipality. These are usually ongoing or project-based services. e.g. Meter reading, security services, maintenance work, revenue collection, IT support and grass cutting to name a few.

ii. Payments to consultants (Operational Work) refers to payments made to professional experts or specialists who provide advisory, technical, analytical, or professional support services. Consultants usually provide expertise rather than performing routine operational functions. E.g. Engineers, financial advisors, legal consultants, tariff or COS specialists, auditors and project management consultants to name a few.

Surplus

4.1.13. The Licensee has provided for a surplus amount of R10 231 740, representing 4% of the allowable revenue requirement. While the surplus is relatively modest, it provides a prudent operating margin to mitigate financial risks associated with the electricity business, including revenue collection shortfalls, unexpected increases in operating costs, and infrastructure maintenance requirements. The surplus further enhances the financial resilience of the electricity undertaking and supports its ability to maintain service delivery and network reliability without placing undue reliance on future tariff increases.

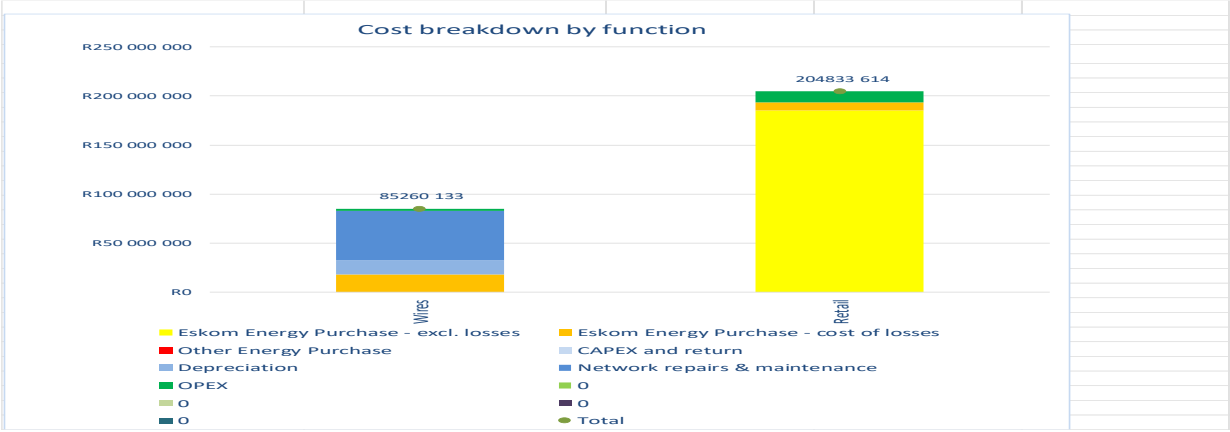
4.1.14. In recommending a surplus, NERSA relied on section 15(1)(a) of the Electricity Regulation Act, which provides that tariffs must enable an efficient Licensee to recover the full cost of its licensed activities, including a reasonable margin or return. In applying this provision, together with the Cost of Supply (COS) methodology, NERSA is required to ensure that the Municipality recovers efficiently and prudently incurred costs, including a reasonable return, while preventing excessive compensation.

4.1.15. A core regulatory requirement under the COS Framework is that only efficient and prudently incurred costs may be passed through to tariffs. In compliance with this principle:

Cost Functionalisation

4.1.16. The Licensee has categorised its revenue requirements of R290 093 748 into two main functions: wires and retail business, which is in line with the NERSA COS Framework as demonstrated in figure 2 below. These costs align with revenue requirements upon verification.

Figure 2: Costs breakdown by Functions

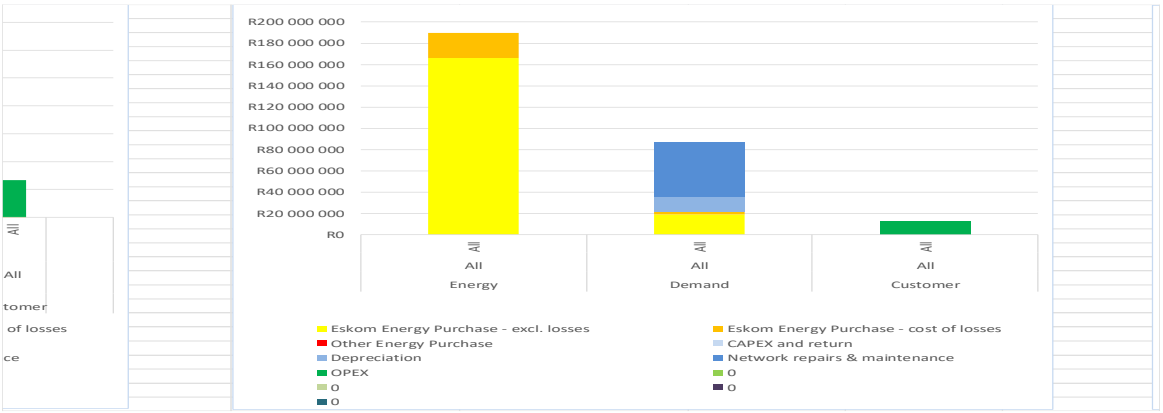


4.1.17. These costs align with revenue requirements upon verification. Network repairs and maintenance dominate the wires business while the energy purchases are the primary cost driver for the retail business.

Cost Classification

4.1.18. The Licensee classified its costs into energy, demand and customer-related costs, which is in line with the NERSA COS Framework. The costs align with revenue requirements and cost functionalization upon verification.

Figure 3: Cost Classification



4.1.19. Energy purchases constitute energy-driven costs, with the highest expenses occurring during summer under standard time of use, mainly because summer spans a larger portion of the year. Demand-driven costs are also predominantly incurred in summer. Customer-driven costs are primarily attributed to "Other OPEX," which

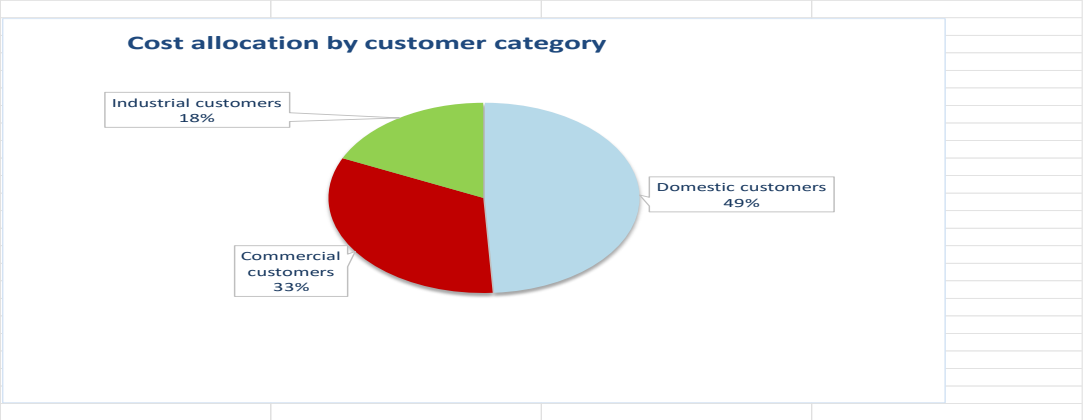
encompasses expenses related to providing electricity distribution services to customers.

Cost Allocation

4.1.20. In this step, the Licensee's revenue requirements are allocated between customer categories, which is in line with the NERSA COS Framework and the costs align with revenue requirements, cost functionalization and cost classification upon verification.

4.1.21. All shared municipal costs were ring fenced and strictly allocated to the electricity distribution function using the D-form cost allocation methodology, consistent with COS requirements. Verification against the Trial Balance and Audited AFS confirmed that only electricity related costs were included in the revenue requirement;

Figure 4: **Allocation of costs between customer categories**



4.1.22. The domestic customer category accounts for the largest share of allocated costs at 49%, followed by commercial customers at 33%, while industrial customers account for 18% of the total costs. The variation in cost allocation across customer categories is primarily driven by differences in supply characteristics, including connection voltage levels, load factors, coincidence factors, and average consumption patterns.

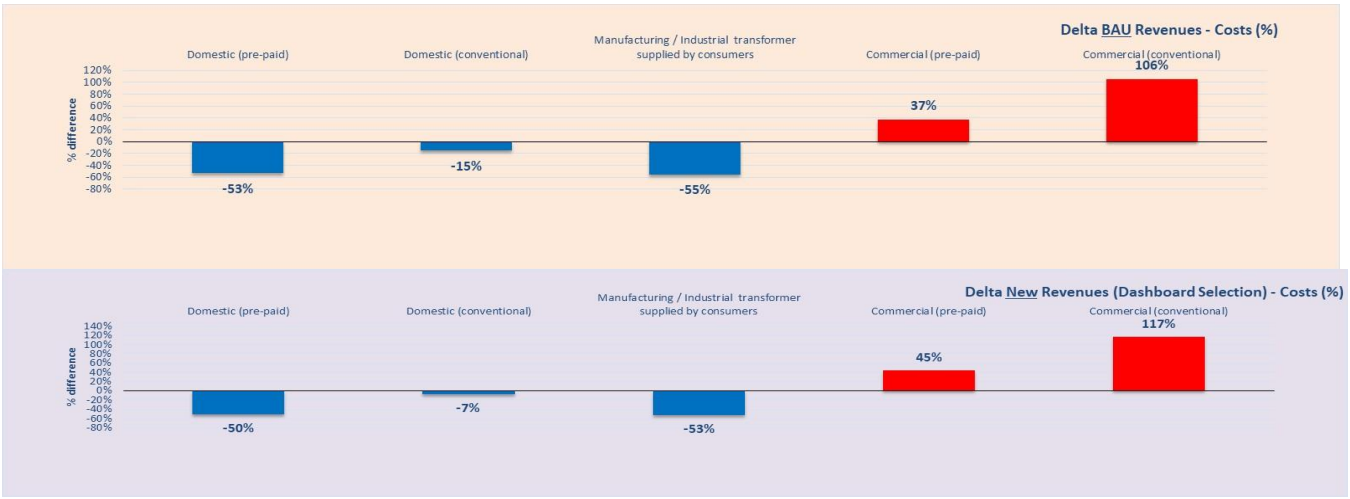
Rate Design

4.1.23. The Cost of Supply analysis demonstrates the total costs against revenue impact of the various tariffs. Figure 5 below compares the current tariff components with the costs for the same tariff

components and indicates that certain rates should increase and others decrease.

4.1.24. Comparing these costs to the income per tariff category reveals the over- or under- recovery per tariff category, as shown in Figures 5. When reading this graph, it is important to note that it is presented in % terms and not absolute Rand terms.

Figure 5: Revenue Recovery by customer category



4.1.25. The Licensee is not proposing any structural changes to its tariffs.

CONCLUSION ON THE COS

4.1.26. The COS study results suggest a 13.7% increase as illustrated in Table 5 below. However, the municipality is proposing an average increase of 6.7% increase to review its tariffs for the 2026/27 financial year. Some of the considerations for this decision include the Licensee's requirement to maintain a sustainable tariff level to stimulate demand, ability to cover Eskom bulk electricity costs and ensure customer affordability while maintaining long-term financial stability.

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Domestic Prepaid						**Analysis and key findings**
Block 1 (0-200 kWh)	210,26	9.50%	230,23	230,23	9.50%	The increase is consistently applied across domestic conventional, prepaid, and lifeline tariffs, maintaining the inclining block tariff (IBT) structure. The adjustment remains closely aligned to cost drivers, with only a minimal margin above bulk cost. The 9.50% increase is near cost-reflective, balancing customer affordability and cost recovery, with limited demand impact and modest financial benefit to the Licensee.
Block 2 (>200 kWh)	339,64	9.50%	371,91	371,91	9.50%	
Domestic Lifeline						**Analysis and key findings**
Block 1 (0-200 kWh)	210,26	9.50%	230,23	230,23	9.50%	The increase is consistently applied across domestic conventional, prepaid, and lifeline tariffs, maintaining the inclining block tariff (IBT) structure. The adjustment remains closely aligned to cost drivers, with only a minimal margin above bulk cost. The 9.50% increase is near cost-reflective, balancing customer affordability and cost recovery, with limited demand impact and modest financial benefit to the Licensee.
Block 2 (>200 kWh)	339,64	9.50%	371,91	371,91	9.50%	

Tariffs	Approved Tariffs FY 2025/26	FY 2026/27 Proposed % increase	FY 2026/27 Proposed tariffs	Recommended Tariffs FY 2026/27	FY 2026/27 recommended % Increase	Analysis and key findings
Domestic: Availability charge (any property that is not connected to the main service)						
Basic Charge: R/month	239,03	9.50%	261,74	261,74	9.50%	The proposed 5.70% increase is well below the Eskom bulk increase of 9.01%, resulting in a below cost-reflective adjustment with an under-recovery of approximately 3.31%. The 5.70% increase supports industrial affordability and competitiveness but introduces a significant revenue gap for the Licensee, reflecting a trade-off between economic support and cost recovery.

Commercial

Commercial conventional 60 Amps						
Basic Charge: R/month	1161,04	5.70%	1227,22	1227,22	5.70%	The proposed 5.70% increase is significantly below the Eskom bulk increase of 9.01%, resulting in a below cost-reflective adjustment with an under-recovery of approximately 3.31%. The proposed 5.70% increase is significantly below the Eskom bulk increase of 9.01%, resulting in a below cost-reflective adjustment with an under-recovery of approximately 3.31%.
Energy charge: c/kWh	299,27	5.70%	316,32	316,32	5.70%	

Commercial Prepaid						
Availability Charge: R/month	610,73	5.70%	645,55	645,55	5.70%	The proposed 5.70% increase is significantly below the Eskom bulk increase of 9.01%, resulting in a below cost-reflective adjustment with an under-recovery of approximately 3.31%. The proposed 5.70% increase is significantly below the Eskom bulk increase of 9.01%, resulting in a below cost-reflective adjustment with an under-recovery of approximately 3.31%.
Energy charge: c/kWh	370,03	5.70%	391,12	391,12	5.70%	

Tariffs	**Approved Tariffs FY 2025/26**	**FY 2026/27 Proposed % increase**	**FY 2026/27 Proposed tariffs**	**Recommended Tariffs FY 2026/27**	**FY 2026/27 recommended % Increase**	**Analysis and key findings**
Organ of state: Conventional						
Availability Charge: R/month	1161,04	5.70%	1227,22	1227,22	5.70%	The proposed 5.70% increase is significantly below the Eskom bulk increase of 9.01%, resulting in a below cost-reflective adjustment with an under-recovery of approximately 3.31%. The proposed 5.70% increase is significantly below the Eskom bulk increase of 9.01%, resulting in a below cost-reflective adjustment with an under-recovery of approximately 3.31%.
Energy charge: c/kWh	299,27	5.70%	316,32	316,32	5.70%	

Organ of state: Prepaid						
Availability Charge: R/month	610,62	5.70%	645,43	645,43	5.70%	The proposed 5.70% increase is significantly below the Eskom bulk increase of 9.01%, resulting in a below cost-reflective adjustment with an under-recovery of approximately 3.31%. The proposed 5.70% increase is significantly below the Eskom bulk increase of 9.01%, resulting in a below cost-reflective adjustment with an under-recovery of approximately 3.31%.
Energy charge: c/kWh	370,03	5.70%	391,12	391,12	5.70%	

Industrial

Tariffs	**Approved Tariffs FY 2025/26**	**FY 2026/27 Proposed % increase**	**FY 2026/27 Proposed tariffs**	**Recommended Tariffs FY 2026/27**	**FY 2026/27 recommended % Increase**	**Analysis and key findings**
INDUSTRIAL: Transformer supplied by consumer						
Basic Charge: R/month	4313,63	5.70%	4559,51	4559,51	5.70%	
Energy charge: c/kWh	168,03	6.15%	178,36	178,36	6.15%	The proposed 5.70% increase is well below the Eskom bulk increase of 9.01%, resulting in a below cost-reflective adjustment with an under-recovery of approximately 3.31%.
Demand Charge (R/kVA)	470,23	4.12%	489,60	489,60	4.12%	

INDUSTRIAL: Transformer supplied by Municipality	**Approved Tariffs FY 2025/26**	**FY 2026/27 Proposed % increase**	**FY 2026/27 Proposed tariffs**	**Recommended Tariffs FY 2026/27**	**FY 2026/27 recommended % Increase**	**Analysis and key findings**
Basic Charge: R/month	6260,28	5.70%	6617,11	6617,11	5.70%	The 5.70% increase supports industrial affordability and competitiveness but introduces a significant revenue gap for the Licensee, reflecting a trade-off between economic support and cost recovery.
Energy charge: c/kWh	168,74	5.70%	178,36	178,36	5.70%	
Demand Charge (R/kVA)	463,19	5.70%	489,60	489,60	5.70%	

Tariffs	**Approved Tariffs FY 2025/26**	**FY 2026/27 Proposed % increase**	**FY 2026/27 Proposed tariffs**	**Recommended Tariffs FY 2026/27**	**FY 2026/27 recommended % Increase**	**Analysis and key findings**
Industrial Resellers:						
Basic Charge: R/month	3878,78	5.70%	4099,87	4099,87	5.70%	The 5.70% increase supports industrial affordability and competitiveness but introduces a significant revenue gap for the Licensee, reflecting a trade-off between economic support and cost recovery.
Energy charge: c/kWh	168,74	5.70%	178,36	178,36	5.70%	
Demand Charge (R/kVA)	471,23	5.70%	498,09	498,09	5.70%	

Tariffs	Approved Tariffs FY 2025/26	FY 2026/27 Proposed % increase	FY 2026/27 Proposed tariffs	Recommended Tariffs FY 2026/27	FY 2026/27 recommended % Increase	Analysis and key findings
Commercial: (any property that is not connected to the main service)						
Basic Charge: R/month	616,24	5.70%	651,36	651,36	5.70%	The 5.70% increase benefits industrial TOU customers through lower cost pressures and improved competitiveness but creates a significant revenue shortfall for the Licensee, highlighting a trade-off between economic support and cost recovery, especially in peak pricing structures.
Time of Use Large power users (>500kVA)						
Basic Monthly: R/month	2505,14	5.70%	2647,93	2647,93	5.70%	
Energy charges:						
Peak c/kWh	534,41	5.70%	564,87	564,87	5.70%	
Standard c/kWh	237,32	5.70%	250,84	250,84	5.70%	
Off-peak c/kWh	126,11	5.69%	133,29	133,29	5.69%	
Demand charge: R/kVA	345,36	5.70%	365,05	365,05	5.70%	

8. CONFIDENTIALITY

8.1. None.

9. CONCLUSION

9.1. From a conspectus of the facts and evidence presented to the REC, supporting information, stakeholder inputs, and applicable legal framework, it is appropriate to consider and approve the Municipality tariff application as set out in this Reasons for Decision for the 2026/27 financial year.

End.