NATIONAL ENERGY REGULATOR OF SOUTH AFRICA

Decision and Reasons for Decision (RfD)

In the matter regarding the

Municipal Tariff Application for the 2026/27 Financial Year

By

Kareeberg Local Municipality

THE DECISION

At its meeting held on 9 May 2026, the Regulator Executive Committee (REC) considered the Kareeberg Local 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 Table 1 below.

Table 1: Summary of the REC Decision

Tariff Category	2026/27 Approved % Increase
1. Domestic Prepaid	12.08%
2. Domestic Prepaid / Postpaid TOU (60 Amp 1Ph)	12.97%
3. Domestic Prepaid / Postpaid TOU (60 Amp 3Ph)	15.38%
4. Municipal Usage	3.48%
5. Commercial - Small Business Prepaid	23.65%
6. Business Postpaid/Prepaid TOU (60 Amp 1Ph)	20.97%
7. Business Postpaid/Prepaid TOU (60 Amp 3Ph)	20.41%
8. Large Power User 40 kVA or higher	5.50%
9.Non-Standard Tariff	10.00%
Export energy for SSEG's (Nett Users + Needs to be on TOU)	0.00%

Based on the information submitted and the analysis conducted, the REC decided:

a) to approve the tariffs that are 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; and
c) that the municipality must submit a report accounting for all the costs identified in its COS study to enable the National Energy Regulator of South Africa to perform its independent verification or audit process by 31 January 2027.

TABLE OF CONTENTS

The Decision 1
Table of Contents 3
Abbreviations 6
1. Introduction 7
2. Legal and Regulatory Framework 8
3. Financial and Technical Performance 12
4. Determination of Kareeberg's Tariffs Based on the Cost of Supply Study 13
5. Conclusion on the COS Study 21
6. Public Participation 22
7. The Objectors and other Intervening Parties 22
8. The Kareeberg Local Municipality's Analysis and Key Findings 23
9. Tariff Analysis 24
10. Confidentiality 32
11. Conclusion 32

LIST OF TABLES

Table 1: Summary of the REC Decision 1
Table 2: Customer Statistics (Data obtained from the latest D-forms – 2024/25 7
Table 3: Performance Indicators 12
Table 4: Revenue Requirement Components 14
Table 5:Operational Expenditure 15
Table 6: Cost Functionalisation 17
Table 7: Costs Allocated 20
Table 8: Estimated Electricity Revenue and Consumption per customer category 23

LIST OF FIGURES

Figure 1: Five steps of COS 13
Figure 2: Cost Breakdown by Cost Structure (Classification) 18
Figure 3: Revenue Recovery by Customer Category 21
Figure 4: Rate Design 22

ABBREVIATIONS

COS	Cost of Supply
D-FORM	Distribution form
ERTSA	Eskom Retail Tariff Structural Adjustments
FBE	Free Basic Electricity
IBT	Inclining Block Tariff
IPP	Independent Power Producer
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 its mandate of regulating prices and tariffs. Municipal tariffs must be approved by the Energy Regulator and be implemented on 1 July of each financial year.

1.2. The Kareeberg Local Municipality (Kareeberg) is situated in the Northen Cape. The customer base of the municipality is mostly made up of domestic customers in terms of numbers and consumption, accounting for 38.20% of total electricity sales. The municipality provides its indigent customers with 50kWh of Free Basic Electricity (FBE) per month. The municipality also maintains an indigent register. The details regarding customer statistics are highlighted in Table 2 below.

Table 2: Customer Statistics (Data obtained from the latest D-forms – 2024/25)

Customer categories	***MWh***	***% MWh***	***Customer numbers***
Domestic Prepaid	2,104	28.96	1 092
Domestic Conventional	671	9.24	170
Manufacturing	903	12.43	11
Commercial Prepaid	263	3.62	55
Commercial Conventional	1,227	16.89	60
Other Consumers	44	0.61	9
Own Use	2,053	28.26	1
TOTAL	**7,265**	**100%**	**1 398**
Free Basic Electricity (FBE)[1]	757	27.00[2]	322

1.3. NERSA received Kareeberg's tariff application together with its revised Cost of Supply (COS) study on 31 March 2026. The revision of the COS study is primarily driven by significant changes in cost drivers, customer impacts and revenue requirements.

[1] This information is already included in the customer statistics table above under domestic prepaid/conventional category

[2] Percentage of Domestic MWh

1.4. The Kareeberg Local Municipality implemented a 11.72% average price increase in 2025/26 FY and is applying for an average price increase of 13.37% for the 2026/27 FY.

1.5. In accordance with NERSA requirements, all tariff applications must include confirmation of the approval of the proposed tariffs by the Municipal Council and have undergone customer consultation.

1.6. For this application, the municipality has indicated that the tariff application has been approved by Council. The Council meeting which approved the application took place on 26 March 2026 and the resolution was submitted to NERSA. Proof of customer consultation was submitted on 7 May 2026.

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

1.8. NERSA's decision was made on 9 May 2026, considering the written comments received from the affected stakeholders and the analysis performed.

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 (EPP) for the South African Electricity Supply Industry, 2008.

2.1.2. The approval of the 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 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 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 the PAJA. 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. 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 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 Cost of Supply methodologies have historically not been consistently applied across the electricity distribution industry.

2.6.3. Policy Position 23 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 2025/26 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. 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. 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) NERSA decisions must be published 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 tariffs and the tariff reasons for decision documents 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 document demonstrate how the Energy Regulator complied with the legislative, policy and judicial framework in determining the municipal electricity tariff for the 2026/27 financial year.

3. FINANCIAL AND TECHNICAL PERFORMANCE

3.1. In evaluating the financial and technical performance of Kareeberg, 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 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 tariff analysis.

3.2. The Kareeberg Local Municipality's electricity business recorded a surplus of 0.07% in the 2024/25 financial year, representing a significant improvement from the 26.17% deficit recorded in the 2023/24 financial year, as reflected in Table 3 below. This improvement is mainly attributable to higher total income, driven primarily by increased revenue from electricity sales and internal sales revenue.

3.3. The municipality reported energy losses of 10.47% in the 2024/25 financial year, reflecting a significant improvement from the 21.89% recorded in the 2023/24 financial year. The reduction in energy losses is primarily attributed to improved metering accuracy and enhanced energy reconciliation implemented through the Revenue Enhancement Project. As part of the initiative, the municipality installed bulk metering, feeder, transformer and checked metering throughout the electricity network to ensure that all major supply, distribution and consumption points are accurately measured and reconciled against Eskom bulk electricity purchases.

3.4. In addition, a metering audit was conducted, which identified previously unmetered and incorrectly metered connection points within the network. The correction of these metering discrepancies further contributed to the reduction in electricity losses and improved overall revenue recovery.

3.5. The Kareeberg Local Municipality is encouraged to continue implementing measures to reduce and maintain lower levels of energy loss.

Table 3: Performance Indicators

PERFORMANCE INDICATORS: OBTAINED FROM D-FORMS		
Indicators	**2024-25 FY (Actuals)**	**2023-24 FY (Approved)**
Percentage surplus (deficit): (%)	0.07	-26.17[3]
Energy losses: (%)	10.47	21.89

3.6. Based on the above information, the reduction in energy losses indicates improved operational efficiency, better network management and strengthened revenue protection measures within the municipality's electricity business. Despite these improvements, the electricity business remains financially weak, as reflected by a

[3] Total Electricity Purchases divided by Total Expenditure

marginal surplus of only 0.07%. This limited surplus indicates that the licensee's financial position is still exposed to operational and financial risks. Accordingly, the financial performance and sustainability of the electricity business should be closely monitored going forward.

4. DETERMINATION OF THE KAREEBERG LOCAL MUNICIPALITY'S TARIFFS BASED ON THE COST OF SUPPLY STUDY

4.1. The process that the Energy Regulator followed in considering and approving Kareeberg's tariff application was supported by a COS study.

4.2. The Municipality 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.

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

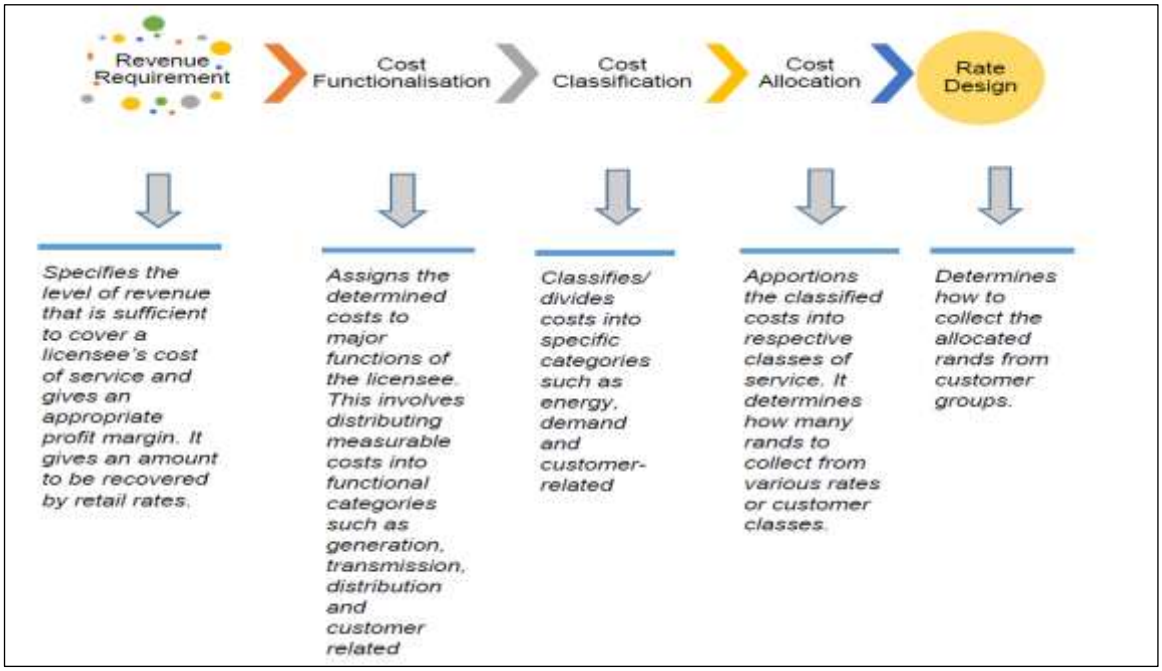


Figure 1: Five steps of COS

4.5. The following steps are undertaken to analyse the Cost of Supply study:

4.5.1. Revenue Requirement

4.5.1.1. To be fully cost-reflective, the licensee's revenue requirement is R39 million for the 2026/27 financial year. This amount is primarily driven by Eskom

purchases, which account for 59%, while operational expenditure makes up the remaining 41%, as highlighted in Table 4 below.

Table 4: Revenue Requirement Components

	Total cost (R)		
Revenue Requirement components	**Wires**	**Retail**	**Total**
Allowable costs	20 253 296	34 419 818	39 910 184
Energy purchases from Eskom - net of cost of losses	-	20 825 487	20 825 487
Energy purchases from Eskom - cost of losses	2 512 168	338 527	2 850 695
Other energy purchases	-	-	-
Capital expenditure	-	-	-
Operational expenditure (incl. Depreciation)	8 450 642	6 312 288	14 762 930
Other revenues	**- 4 747**	**-**	**- 4 747**
Surplus	844 590	631 229	1 475 818
TOTAL COSTS	**20 253 296**	**34 419 818**	**39 910 184**

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

4.5.1.3. 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 were made accordingly, as detailed below.

Bulk purchases

4.5.1.4. The Kareeberg Local Municipality applied for bulk purchase expenditure amounting to R23 million, representing 59% of total costs. The bulk purchase figures were verified against Eskom invoices for the 2024/25 financial year.

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

4.5.1.6. The methodology applied by the Municipality in forecasting bulk purchase costs is deemed reasonable.

4.5.1.7. Accordingly, the bulk purchase expenditure has been recommended for approval. Furthermore, the Municipality did not include Eskom interests charge on the outstanding account. All verifications have been satisfactory to NERSA and therefore this cost has been approved.

Operational Expenditure (including depreciation)

4.5.1.8. Table 5 below presents the operational expenditure extracted from the 2024/25 D-forms and verified against the Audited Financial Statements and Trial Balance.

Table 5: Operational Expenditure

Functions	Wires	Retail	Total OPEX
Depreciation	1 149 134	2 895 908	4 045 042
Network repairs & maintenance	6 609 196	0	6 609 196
Salaries, wages and allowances inclding payments to consultants related to repairs and maintenance	692 313	692 313	1 384 626
General expenses	0	2 724 067	2 724 067
TOTAL			**14 762 930**

4.5.1.9. The Kareeberg Local Municipality has applied for operational expenditure totalling R14 million, for 2026/27 FY representing 37% of overall costs, as reflected in Table 5 above.

4.5.1.10. The licensee's depreciation is calculated on the depreciable amount, using the straight-line method over the estimated useful lives of the assets, other than land and buildings. The resulting Depreciation and Amortisation provisions are consistent with the licensee's total asset base, valued at approximately R106 million as at the 2024/25 FY.

4.5.1.11. The approach taken by the licensee is satisfactory to NERSA to forecast operational expenditure. As a result, this cost has been approved as applied for.

4.5.1.12. The approach adopted by the Municipality in forecasting operational expenditure is considered reasonable and the amount has therefore been approved. However, inefficient cost components—such as 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.

Surplus

4.5.1.13. The Municipality applied a cost-plus methodology and not a rate of return (ROR) approach. Under the cost-plus methodology, the allowable revenue is derived as follows:

a) Efficient and prudent operating expenditure (OPEX)

b) Plus, depreciation (as a proxy for asset consumption and future replacement)

c) Plus, a reasonable surplus margin.

4.5.1.14. The Municipality has requested a surplus of R1,4 million, calculated using a surplus factor of 4% applied to operating expenditure, inclusive of bulk purchases, for both the wires and retail components of the business.

4.5.1.15. To ensure that the surplus is not excessive or detrimental to consumers, verification was undertaken by benchmarking the applied surplus margin of 4% against the established target range of 10–20%, in line with the approved NERSA Cost of Supply framework and the EPP Policy Position 1.

4.5.1.16. The return proposed by the Municipality at 4%, is considered reasonable, although it falls slightly below the established target range of 10–20%.

4.5.1.17. To ensure that the profit margin is commensurate with the level of risk, qualitative risk considerations were incorporated, including revenue collection risks (such as non-payment and bad debts), operational risks (including energy losses and ageing infrastructure) and broader financial sustainability requirements, as well as consideration of customer affordability. All these link to the financial sustainability of the Municipality.

4.5.1.18. The applied surplus margin is considered modest and commensurate with these risks, particularly in the context of a municipal distributor that is not profit-maximising but must remain financially viable. Thus, it is NERSA's decision to allow the revenue requirement as applied for.

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

4.5.2. **Cost Functionalisation**

4.5.2.1. The licensee has categorised its revenue requirement of R39 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 Table 6 below. Upon verification, the allocation of costs to these functional components is found to be consistent with the stated revenue requirement.

Table 6: Cost Functionalisation

	Total Functionalised Costs (R)			
Functions	Wires	Retail	Total	% of Total
Eskom Energy Purchase - excl. losses	-	20 825 487	20 825 487	52%
Eskom Energy Purchase - cost of losses	2 512 168	338 527	2 850 695	7%
Depreciation	1 264 048	3 185 499	4 449 547	11%
Network repairs & maintenance	7 264 894	-	7 264 894	18%
Salaries, wages and allowances including payments to consultants related to repairs and maintenance	761 544	761 544	1 523 088	4%
Other expenses	-	2 692 338	2 692 338	7%
General expenses	-	304 136	304 136	1%
	11 802 653	28 107 530	39 910 184	100%

4.5.2.2. 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

4.5.3. Cost Classification

4.5.3.1. 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.

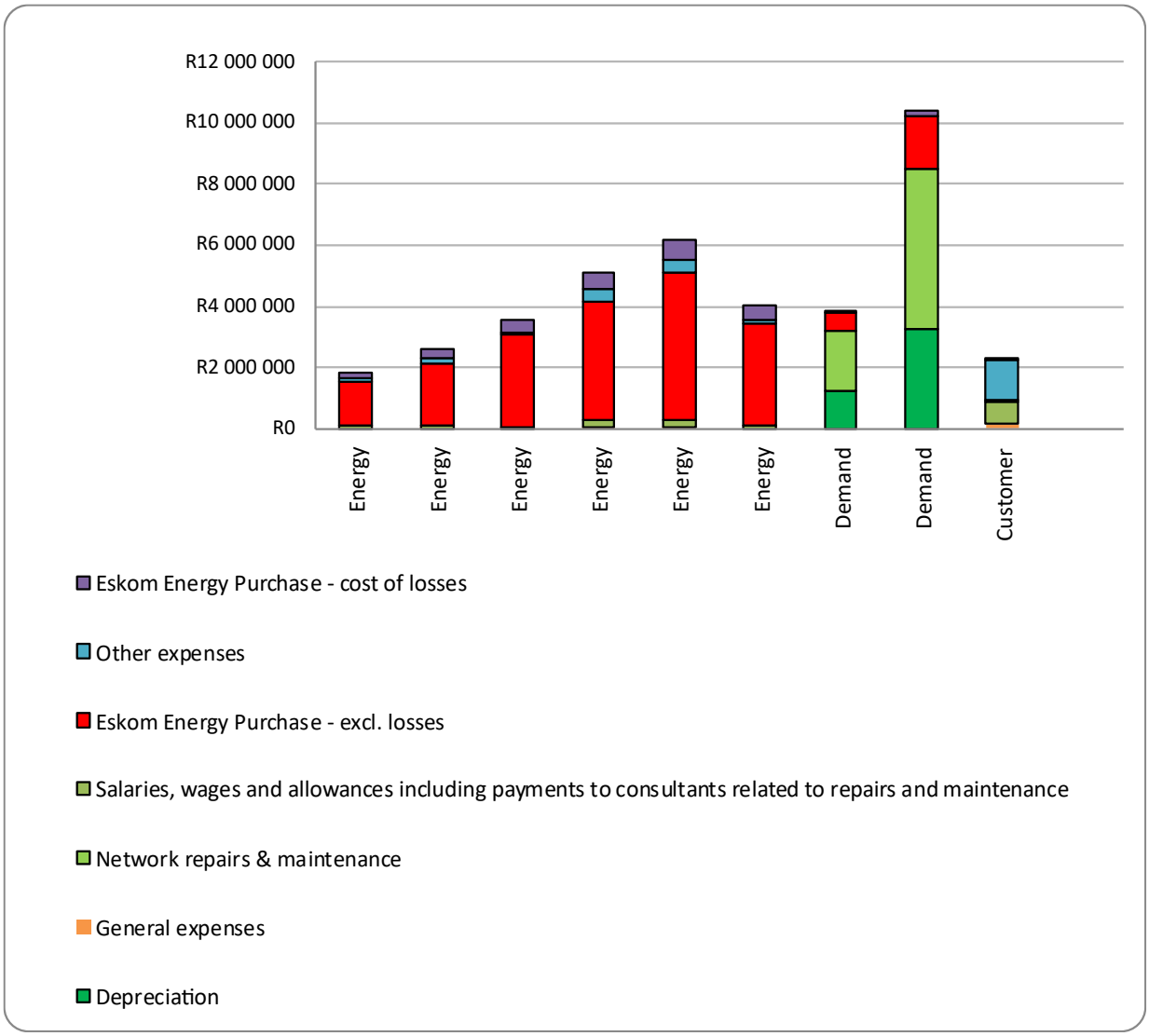


Figure 2: Cost Breakdown by Cost Structure (Classification)

4.5.3.2. The Cost of Supply classification for the Kareeberg Local Municipality indicates that the Municipality's electricity distribution costs are primarily driven by bulk electricity purchases from Eskom. The energy-related cost categories show a steady increase in expenditure, with Eskom energy purchases excluding losses representing the largest component across most classifications. Costs associated with electricity losses, repairs and maintenance and general operational expenses contribute a comparatively smaller portion to the overall energy cost structure. This demonstrates the Municipality's strong dependence on external electricity procurement as the principal cost driver within the electricity supply function.

4.5.3.3. The demand-related cost categories reflect the highest overall expenditure levels in the graph, exceeding R10 million in one classification category. These costs are largely associated with depreciation, salaries and wages and network-related operational activities required to maintain the electricity infrastructure and ensure reliable supply capacity. The prominence of

depreciation and staffing costs suggests that a substantial portion of the municipality's electricity expenditure is linked to maintaining and operating the distribution network rather than only the direct purchase of electricity. This highlights the importance of effective asset management and operational efficiency in controlling future electricity supply costs.

4.5.3.4. Customer-related costs constitute the smallest portion of the total cost of supply and mainly comprise administrative and support functions such as billing, customer service and revenue management. Although relatively low in comparison to energy and demand costs, these expenses remain essential for the effective operation of the electricity distribution service. Overall, the cost classification indicates that the Kareeberg Local Municipality's electricity tariffs and financial sustainability are heavily influenced by Eskom bulk supply charges, infrastructure-related operational costs and the ongoing maintenance of the electricity distribution network.

4.5.4. Cost Allocation

4.5.4.1. 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.

4.5.4.2. As indicated in Table 7 below, the domestic customer category carries the largest proportion of costs, followed by the commercial customers.

4.5.4.3. Differences in the results between the customer categories are mainly driven by differences in voltage of connection point, load factors, coincidence factors and average specific consumption.

Table 7: Costs Allocated

Business area:	Wires	Retail	Total
Customer Categories			
Domestic Prepaid Low (Intended for Indigent)	4 494 810	9 975 015	14 469 825
Domestic Postpaid/Prepaid TOU (60 Amp 1Ph)	947 358	1 879 457	2 826 814
Domestic Postpaid/Prepaid TOU (60 Amp 3Ph)	211 795	452 783	664 578
Small Business, pre-paid (60 Amp 1Ph)	592 746	1 252 351	1 845 096
Business Postpaid/Prepaid TOU (60 Amp 1Ph)	1 430 642	3 697 409	5 128 051
Business Postpaid/Prepaid TOU (60 Amp 3Ph)	1 837 012	4 510 228	6 347 240
Large Power Users: Time of Use Tariff (> 40 KVA 3	2 073 450	5 099 674	7 173 123
Municipal Usage	214 841	1 240 614	1 455 455
Availability charges	-	-	-
Energy Exports- Surplus PV (SSEG)	-	-	-
	11 802 653	28 107 530	39 910 184

4.5.5. Rate Design

4.5.5.1. Figure 3 below reflects the outcome of the COS study, indicating that most customer categories require upward adjustments. 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 figure 3 below.

4.5.5.2. To achieve full cost reflectivity, the Municipality would need to implement differentiated tariff adjustments across customer categories. However, a less aggressive approach has been adopted, with differentiated increases applied across the various categories and an average tariff increase of 13.37%.

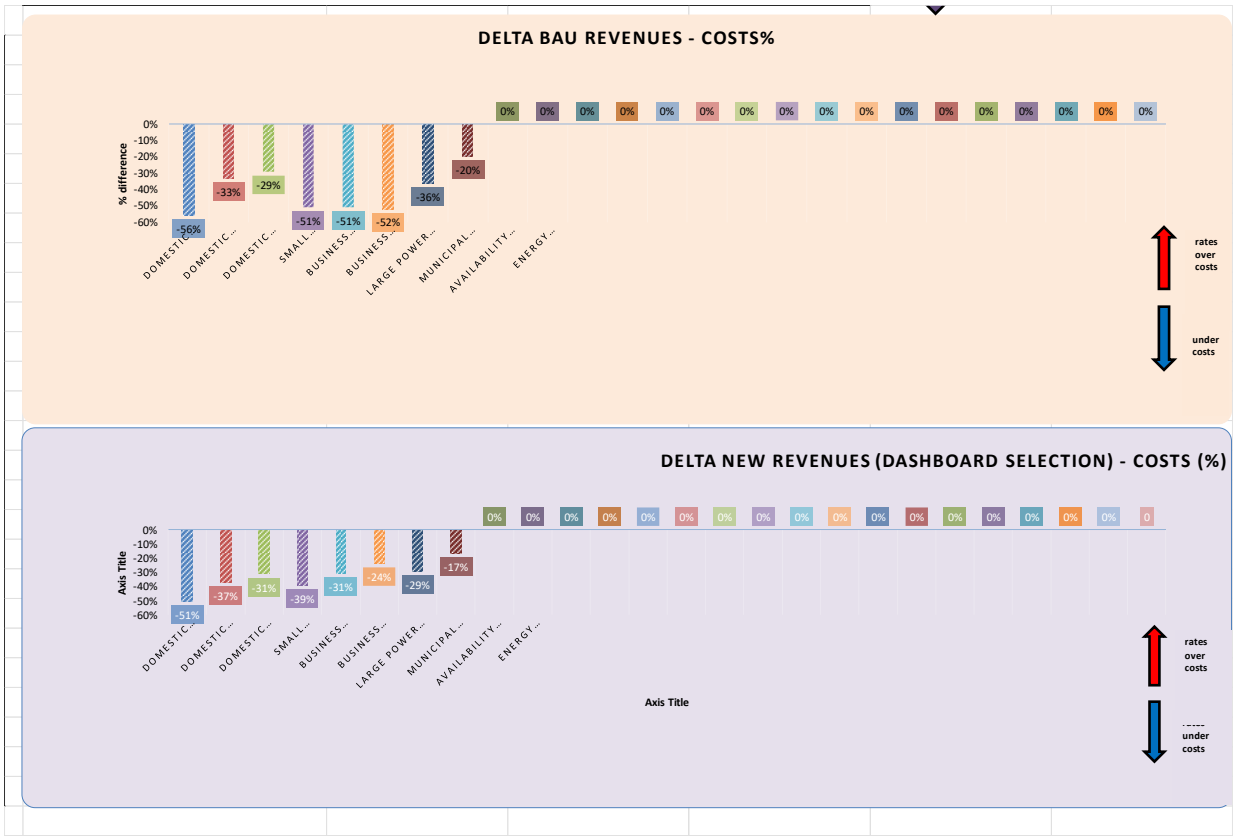


Figure 3: Revenue Recovery by Customer Category

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. The licensee retains the discretion to review the results and determine its own revenue requirements to

Page 22 withheld by Unmapped Dataworks.

This page is part of the decision's record of public participation,
objections or comments, which names members of the public.
We do not republish it.

The whole decision is on NERSA's website:
https://www.nersa.org.za/file/9263/KareebergMunicipality_ReasonsforDecisionontariffapplicationpr

Page 23 withheld by Unmapped Dataworks.

This page is part of the decision's record of public participation,
objections or comments, which names members of the public.
We do not republish it.

The whole decision is on NERSA's website:
https://www.nersa.org.za/file/9263/KareebergMunicipality_ReasonsforDecisionontariffapplicationpr

encourage consumers to shift electricity usage away from peak demand periods and to improve overall demand-side management.

8.3. The business and large power user categories contribute a significant portion of the municipality's projected electricity revenue despite representing a smaller number of consumers. The introduction of TOU tariffs for these customer groups is expected to improve cost recovery, reduce peak demand pressure on the network and align tariffs more closely with the actual COS. Overall, the proposed tariff structure supports improved financial sustainability, tariff equity and more efficient electricity usage across all customer categories.

9. TARIFF ANALYSIS

1. Domestic Prepaid (old	***2025/26 Approved***	***2026/27 Proposed***	***Proposed% Increase***	***2026/27 Recommended***	***Recommended % Increase***
Block 1 (0 - 50kWh) (c/kWh)	172,53	Discontinued	Discontinued	Discontinued	Discontinued
Block 2 (51 - 350 kWh) [c/kWh]	222,90	Discontinued	Discontinued	Discontinued	Discontinued
Block 3 (351 - 600kWh) (c/kWh)	314,83	Discontinued	Discontinued	Discontinued	Discontinued
Block 4 (>250 kWh) (c/kWh)	365,20	Discontinued	Discontinued	Discontinued	Discontinued

2. Domestic Prepaid	***2025/26 Approved***	***2026/27 Proposed***	***Proposed% Increase***	***2026/27 Recommended***	***Recommended % Increase***
Block 1 (0 - 100kWh) (c/kWh)	208,72	208,00	-0.34%	208,00	-0.34%
Block 2 (101 - 250 kWh) (c/kWh)	222,90	298,79	34.05%	298,79	34.05%
Block 3 (>250 kWh) (c/kWh)	365,20	499,75	36.84%	499,75	36.84%
Average	220,98	247,69	12.08%	247,69	12.08%

3. Domestic Prepaid / Postpaid TOU (60 Amp 1Ph)	***2025/26 Approved***	***2026/27 Proposed***	***Proposed% Increase***	***2026/27 Recommended***	***Recommended % Increase***
Low Energy charge Peak (c/kWh)	New	436,50	New	436,50	New
Low Energy charge Standard (c/kWh)	New	238,01	New	238,01	New
Low Energy charge Off Peak v(c/kWh)	New	238,01	New	238,01	New
High Energy charge Peak (c/kWh)	New	774,09	New	774,09	New
High Energy charge Standard (c/kWh)	New	285,47	New	285,47	New
High Energy charge Off Peak (c/kWh)	New	238,01	New	238,01	New
Basic charge (R/month)	New	260,82	New	260,82	New

4. Domestic Prepaid / Postpaid TOU (60 Amp 3Ph)	***2025/26 Approved***	***2026/27 Proposed***	***Proposed% Increase***	***2026/27 Recommended***	***Recommended % Increase***
Low Energy charge Peak (c/kWh)	New	436,50	New	436,50	New
Low Energy charge Standard (c/kWh)	New	238,01	New	238,01	New
Low Energy charge Off Peak v(c/kWh)	New	253,35	New	253,35	New
High Energy charge Peak (c/kWh)	New	774,09	New	774,09	New
High Energy charge Peak (c/kWh)	New	305,47	New	305,47	New
High Energy charge Off Peak (c/kWh)	New	245,02	New	245,02	New
Basic charge (R/month)	New	657,18	New	657,18	New

5. Municipal Usage	***2025/26 Approved***	***2026/27 Proposed***	***Proposed% Increase***	***2026/27 Recommended***	***Recommended % Increase***
Energy charge (c/kWh)	28,.82	300,94	3.84%	300,94	3.84%

6. Commercial - Small Business Prepaid	***2025/26 Approved***	***2026/27 Proposed***	***Proposed% Increase***	***2026/27 Recommended***	***Recommended % Increase***
Energy charge (c/kWh)	285,38	352,87	23.65%	352,87	23.65%

7. Commercial - Small Business Conventional	***2025/26 Approved***	***2026/27 Proposed***	***Proposed% Increase***	***2026/27 Recommended***	***Recommended % Increase***
Energy charge (c/kWh)	285,38	Discontinued	Discontinued	Discontinued	Discontinued
Basic charge (R/month)	768,63	Discontinued	Discontinued	Discontinued	Discontinued

8. Business Postpaid/Prepaid TOU (60 Amp 1Ph)	***2025/26 Approved***	***2026/27 Proposed***	***Proposed% Increase***	***2026/27 Recommended***	***Recommended % Increase***
Low Energy charge Peak (c/kWh)	New	472,91	New	472,91	New
Low Energy charge Standard (c/kWh)	New	284,25	New	284,25	New
Low Energy charge Off Peak v(c/kWh)	New	284,25	New	284,25	New
High Energy charge Peak (c/kWh)	New	782,72	New	782,72	New
High Energy charge Standard (c/kWh)	New	284,25	New	284,25	New
High Energy charge Off Peak (c/kWh)	New	284,25	New	284,25	New
Basic charge (R/month)	New	306,18	New	306,18	New

9. Business Postpaid/Prepaid TOU (60 Amp 3Ph)	***2025/26 Approved***	***2026/27 Proposed***	***Proposed% Increase***	***2026/27 Recommended***	***Recommended % Increase***
Low Energy charge Peak (c/kWh)	New	472,91	New	472,91	New
Low Energy charge Standard (c/kWh)	New	284,25	New	284,25	New
Low Energy charge Off Peak v(c/kWh)	New	284,25	New	284,25	New
High Energy charge Peak (c/kWh)	New	782,72	New	782,72	New
High Energy charge Standard (c/kWh)	New	284,25	New	284,25	New
High Energy charge Off Peak (c/kWh)	New	284,25	New	284,25	New
Basic charge (R/month)	New	831,60	New	831,60	New

10. Large Power User	***2025/26 Approved***	***2026/27 Proposed***	***Proposed% Increase***	***2026/27 Recommended***	***Recommended % Increase***
Energy charge (c/kWh)	245,78	Discontinued	Discontinued	Discontinued	Discontinued
Basic charge (R/month)	768,63	Discontinued	Discontinued	Discontinued	Discontinued
Basic charge (R/month)	138,53	Discontinued	Discontinued	Discontinued	Discontinued

11. Delta School	***2025/26 Approved***	***2026/27 Proposed***	***Proposed% Increase***	***2026/27 Recommended***	***Recommended % Increase***
Energy charge (c/kWh)	251,86	Discontinued	Discontinued	Discontinued	Discontinued
Basic charge (R/month)	768,63	Discontinued	Discontinued	Discontinued	Discontinued
Demand charge (R/kVA)	138,53	Discontinued	Discontinued	Discontinued	Discontinued

12. Industrial Tariff (Abattoir)	***2025/26 Approved***	***2026/27 Proposed***	***Proposed% Increase***	***2026/27 Recommended***	***Recommended % Increase***
Energy charge (c/kWh)	251,86	Discontinued	Discontinued	Discontinued	Discontinued
Basic charge (R/month)	768,63	Discontinued	Discontinued	Discontinued	Discontinued
Demand charge (R/kVA)	138,53	Discontinued	Discontinued	Discontinued	Discontinued

13. Large Power User 40 kVA or higher	***2025/26 Approved***	***2026/27 Proposed***	***Proposed% Increase***	***2026/27 Recommended***	***Recommended % Increase***
Low Energy charge Peak (c/kWh)	New	396,12	New	396,12	New
Low Energy charge Standard (c/kWh)	New	260,37	New	260,37	New
Low Energy charge Off Peak v(c/kWh)	New	240,33	New	240,33	New
High Energy charge Peak (c/kWh)	New	782,19	New	782,19	New
High Energy charge Standard (c/kWh)	New	364,51	New	364,51	New
High Energy charge Off Peak (c/kWh)	New	225,85	New	225,85	New
Basic charge (R/month)	New	5,400.00	New	5 400.00	New
Demand Charge (R/kVA)	New	33.83	New	33.83	New
Access Charge (R/kVA)	New	71.97	New	71.97	New

14. Non-Standard Tariff	***2025/26 Approved***	***2026/27 Proposed***	***Proposed% Increase***	***2026/27 Recommended***	***Recommended % Increase***
Availability charge (R/month)	256,56	282,22	10%	282,22	10%

15. Export energy for SSEG's (Nett Users + Needs to be on TOU)	***2025/26 Approved***	***2026/27 Proposed***	***Proposed% Increase***	***2026/27 Recommended***	***Recommended % Increase***
Low Energy charge Peak (c/kWh)	New	233,21	New	233,21	New
Low Energy charge Standard (c/kWh)	New	131,12	New	131,12	New
Low Energy charge Off Peak v(c/kWh)	New	93.68	New	93.68	New
High Energy charge Peak (c/kWh)	New	561,91	New	561,91	New
High Energy charge Peak (c/kWh)	New	140,49	New	140,49	New
High Energy charge Off Peak (c/kWh)	New	93.68	New	93.68	New

10. CONFIDENTIALITY

10.1. None.

11. CONCLUSION

11.1. The Energy Regulator, having considered the Kareeberg Local Municipality's application, supporting information, stakeholder inputs and applicable legal framework, approves the tariff adjustments as set out in this document.

End.