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

Kouga Local Municipality

THE DECISION

At its meeting held on 9 May 2026, the Regulator Executive Committee (REC) considered the Kouga Local Municipality's tariff application. Based on the facts and evidence presented, the REC approved the tariff increases for the 2026/27 financial year (FY), as set out in section 8 of this document.

Based on the available information and the analysis performed, the REC decided:

1. 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.
2. to note the COS study submitted by the municipality;
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 or audit process by 31 January 2027; and
4. 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 by 30 September 2026.

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ABBREVIATIONS AND ACRONYMS

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 annually, 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. Kouga Local Municipality (Kouga) is located in the Eastern Cape. The municipality's customer base is mostly residential customers, accounting for 43.86% of total electricity sales. The municipality provides its indigent customers with a minimum of 50kWh of Free Basic Electricity (FBE) per month. The municipality further reports that it maintains an indigent register. The details regarding customer statistics are highlighted in Table 1 below.

Table 1: Customer statistics (data obtained from the latest D-forms – 2024/25FY)

CONSUMER STATISTICS (OBTAINED FROM 2024-2025 DISTRIBUTION FORMS)			
Consumer Classification	**Sales (KWh)**	**%KWh**	**Number of Consumers**
Domestic (Prepaid)	43 194 551	25,15%	12 205
Domestic (Conventional)	32 121 793	18,70%	6 926
Manufacturing / Industrial	74 648 113	43,46%	242
Commercial (Prepaid)	1 830 745	1,07%	514
Commercial (Conventional)	13 091 824	7,62%	587
Street Lighting	2 523 764	1,47%	
Municipal Consumption	4 355 059	2,54%	79
TOTAL SALES	**171 765 848**	**100%**	**20 553**
Free Basic Electricity (FBE)	**3 102 850**	**4,12%**	**5 769**

1.3. NERSA received Kouga's tariff application and its existing cost of supply (COS) study based on the cost-plus methodology on 31 March 2026.

1.4. Kouga is applying for an average price increase of 9.01% for the 2026/27 financial year (FY).

1.5. For this application, the municipality has indicated that the tariff application has been approved by the Council, and the Council resolution has been submitted to NERSA. Proof of customer consultation was also submitted on 31 March 2026.

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

1.7. The Energy Regulator's decision was made on 8 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 in order to align with the municipal budgeting process contemplated in the Municipal Finance Management Act, 2003 (Act No. 56 of 2003).

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

2.1.4. This section provides the legal and policy context within which the Energy Regulator evaluated and determined the municipal electricity tariff application for the 2026/2027 municipal financial year.

2.2. 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. 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. Accordingly, the Energy Regulator must ensure that its tariff determinations are lawful, reasonable and procedurally fair, as required by sections 3 and 6 of PAJA. Procedural fairness requires that affected parties and the public be afforded a reasonable opportunity to make representations before a final decision is taken.

2.4.2. Public participation processes conducted by the Energy Regulator therefore form an essential component of the municipal tariff approval process and are

intended to ensure transparency, accountability and fairness in regulatory decision-making.

2.5. Policy Framework: Electricity Pricing Policy (2008)

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

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

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

2.6. Cost of Supply Studies

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

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

2.6.3. Policy Position 23 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 2025/2026 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 practical difficulties that arose 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) NERSA decisions must be published by 11 May 2026.

2.8.2. Municipal tariff approvals from 2027/28 are to 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 tariff reasons for decision documents 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 be undertaken within a comprehensive regulatory framework consisting of the NERA, ERA, PAJA, EPP and the binding judicial directives issued by the High Court in AfriForum NPC v NERSA (Case No. 2025/137620).

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

3. FINANCIAL AND TECHNICAL PERFORMANCE

3.1. In evaluating the financial and technical performance of Kouga, the assessment relied on the 2024/25 Distribution forms (D-forms) submitted as part of the licensee's tariff application. The information contained in the D-forms was verified against the supporting source documents provided by the municipality, including the trial balance and annual financial statements. As a result, the data captured in the D-forms is considered reliable for tariff analysis.

3.2. Table 2 below indicates that Kouga's electricity business recorded an increase in percentage deficit from 1.79% in the 2023/24 financial year to 9.95% in the 2024/25 financial year. This reflects a significant deterioration in the municipality's financial performance and indicates that operating expenditure exceeded operating revenue by a wider margin during the year under review. Total revenue and total expenditure increased by 10% and 18%, respectively. Apart from energy losses, other areas of improvement include bad debts, repairs and maintenance and salaries and wages.

Table 2: Performance indicators

PERFORMANCE INDICATORS: OBTAINED FROM D-FORMS		
INDICATORS	**2024-25FY (Actuals)**	**2023-24 FY (Approved)**
Percentage Surplus (Deficit)	-9,95%	-1,79%
Percentage Energy Losses	14,21%	14,70%

3.3. Energy losses decreased slightly from 12.21% in the 2023/24 financial year to 12.70% in the 2024/25 financial year, as shown in Table 3 below. The municipality provided a loss report and highlighted the following contributing factors:

Technical losses

a) Inherent resistance of conductors
b) Transformers and other electrical equipment.

Non-technical losses

a) Meter tampering
b) Incorrect ratios used on bulk meters,
c) Faulty meters and illegal electricity connections. The problem of meter tampering and illegal connections persists, with regular action taken against defaulters. The municipality has taken an initiative to ensure faulty meters are replaced as soon as they are reported.

3.4. Current losses of 14.21% are far above acceptable norms and materially erode financial sustainability. If losses were capped at 12% and 6%, the municipality would have seen an improved deficit from 9.95% to 7.67% and 1.95%, respectively. Thus, improving its net revenue, as shown in Table 3 below.

Table 3: Energy loss analysis

	D-Form Input	Energy Loss@12%	Energy Loss@6%
Average Selling Price	212,65		
Sales kWh	171 765 848,00	176 195 494,64	188 208 823,82
Purchases kWh	200 222 153,00	200 222 153,00	200 222 153,00
Losses kWh	28 456 305,00	24 026 658,36	12 013 329,18
Losses percentage	**14,21%**	**12,00%**	**6,00%**
Additional Energy (kWh)		4 429 646,64	16 442 975,82
Additional Revenue (Rands)		9 419 643,58	34 965 988,08
	D-Form Input	Energy Loss@12%	Energy Loss@6%
Total Revenue (Rands)	R 445 256 262,00	R 454 675 905,58	R 480 222 250,08
Total Expenses (Rands)	R 489 564 438,00	R 489 564 438,00	R 489 564 438,00
Net Profit (Loss)	R -44 308 176,00	R -34 888 532,42	R -9 342 187,92
Percentage Surplus/Deficit	**-9,95%**	**-7,67%**	**-1,95%**

3.5. Based on the above information, the licensee's electricity department demonstrates growing financial pressure and expenditure challenges. However, the slight reduction in energy losses from 14.70% to 14.21% demonstrates a marginal improvement in operational efficiency within the electricity distribution function. The municipality is required to address operational inefficiencies by reducing high expenditure on its electricity account. These measures are necessary to improve surplus levels and support the municipality's long-term financial sustainability

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

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

4.2. Kouga utilised the 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 apportion costs required to service each customer class 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

4.3.

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

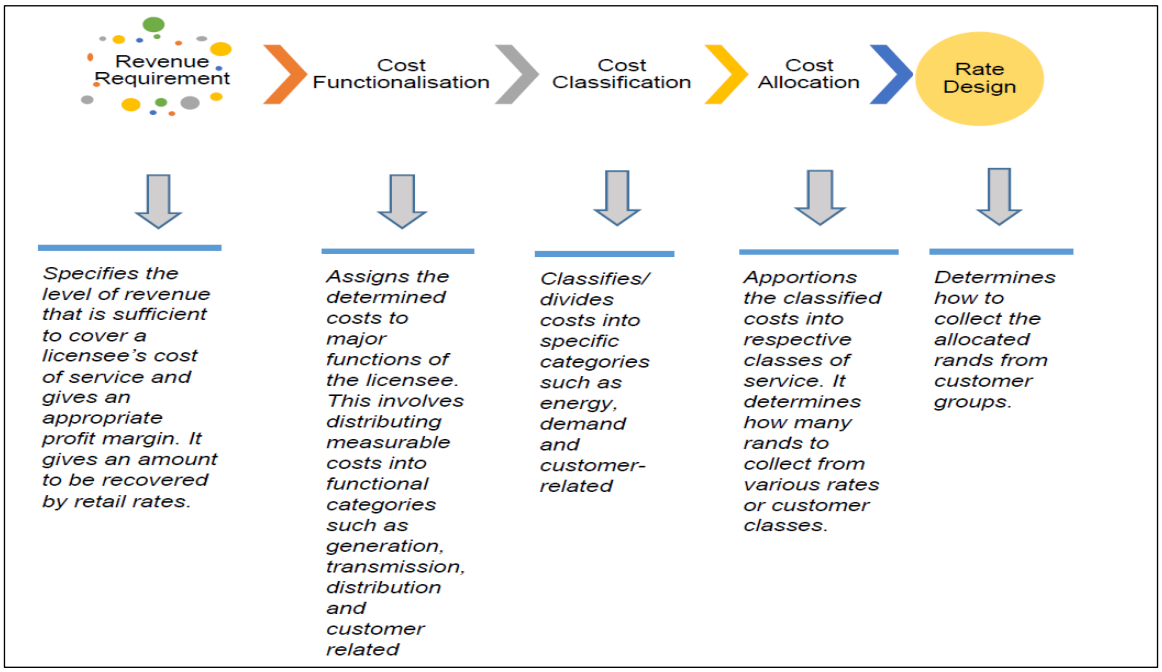


Figure 1: Five steps of COS study

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

Revenue Requirement

4.5.1. In order to be fully cost-reflective, the licensee's revenue requirements are R539.426 million for the 2026/27 financial year. This revenue requirement is predominantly Eskom purchases, accounting for 67%, including energy loss allowance. Operational expenditure accounts for 27%.

Table 4: Revenue requirement components

	Total cost (R)			
Revenue Requirement components	**Wires**	**Retail**	**Total**	**% of Total**
Allowable costs	147 758 699	538 576 669	539 426 388	100%
Energy purchases from Eskom - net of cost of losses	-	340 220 181	340 220 181	63%
Energy purchases from Eskom - cost of losses	34 223 741	12 759 852	46 983 594	9%
Other energy purchases	-	-	-	0%
Capital expenditure	-	-	-	0%
Operational expenditure (incl. Depreciation)	55 260 136	91 648 844	146 908 980	27%
Other revenues	**- 2 283 026**	**- 6 241 760**	**- 8 524 786**	**-2%**
Surplus	5 297 711	8 540 708	13 838 419	3%

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

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

Bulk Purchases

4.5.4. The licensee applied for a bulk purchase expenditure of R340.220 million, which accounts for 67% of the total costs. Bulk purchases were verified against the 2024/25 Eskom invoices.

4.5.5. 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).

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

Operating Expenditure (Including Depreciation)

4.5.7. The licensee applied for the total operational expenditure of R146.909 million for the 2026/27 financial year as reflected in Table 4 above. The approach adopted by Kouga in forecasting operational expenditure is considered reasonable, and the amount has therefore been approved as requested.

Surplus

4.4.8 The municipality applied for a surplus of R13,838 million, which is based on a surplus factor of 3% return on operating expenditure, including bulk purchases for both the wires and retail businesses.

4.4.9 To ensure that the surplus is not excessive or detrimental to consumers and it commensurate with risk, 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.

4.4.10 In applying this provision together with the COS methodology, NERSA must ensure that the licensee recovers costs incurred efficiently and prudently, including a reasonable return, while preventing excessive compensation.

4.4.11 NERSA is satisfied that the surplus applied for by Kouga is reasonable and supports the financial sustainability of the electricity business, Therefore, the applied surplus is considered modest and reasonable having regard to the relevant risk factors, including ageing infrastructure, financial stability requirements, and customer affordability constraints. This is particularly so in the context of a municipal electricity distributor, which, while not operating on a profit-maximising basis, is nonetheless required to maintain financial sustainability and operational viability.

4.4.12 It is therefore recommended that the Energy Regulator approve the allowable revenue as set out in Table 4 above. This revenue is then used in the subsequent steps of cost functionalisation, classification, allocation, and rate design. These steps were verified to be consistent with the approved revenue requirement and are discussed belowhas therefore approved the revenue requirement as submitted.

Cost Functionalisation

4.4.13 The licensee has categorised its revenue requirements of R539.426 million into two main functions: wires (35%) and retail business (65%), which is in line with the NERSA COS Framework, as demonstrated in **Error! Reference source not found.** below. These costs align with revenue requirements upon verification.

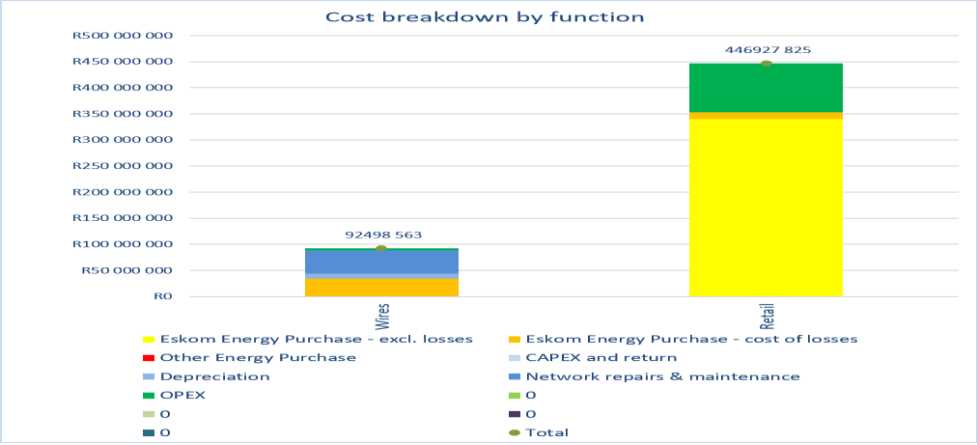


Figure 2: Cost breakdown by functions

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

Cost Classification

4.4.15 The licensee classified its costs into energy, demand and customer-related costs, in line with the NERSA COS Framework. The costs align with revenue requirements and cost functionalisation upon verification.

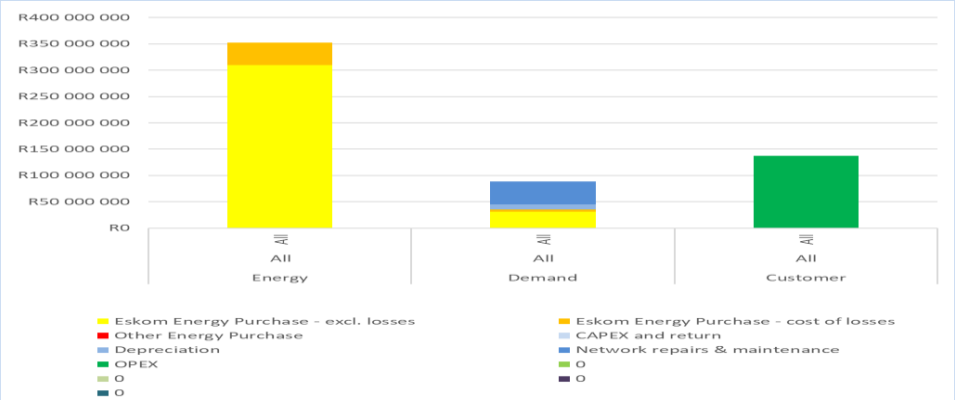


Figure 3: Cost breakdown by cost structure (classification)

4.4.16 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

4.4.17 In this step, the licensee's revenue requirement is allocated between customer categories, which is in line with the NERSA COS Framework, and the costs align with revenue requirements, cost functionalisation and cost classification upon verification.

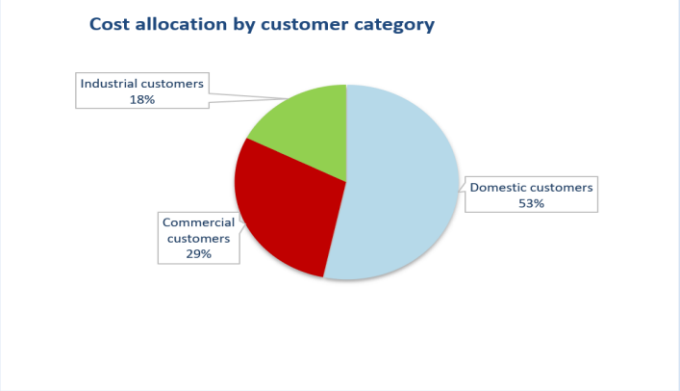


Figure 4: Costs allocated

Rate Design

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

4.4.19 In order for the municipality to reach full cost reflectivity, the municipality is required to increase tariffs for the different customer categories as demonstrated below. In doing so, it will increase some categories more than others to manage the cross-subsidies in the system. However, the municipality has opted for a uniform tariff increase of 9.01%. After the proposed changes are implemented, the under- and over-recoveries per tariff category are presented as shown in the second graph of Figure 5.

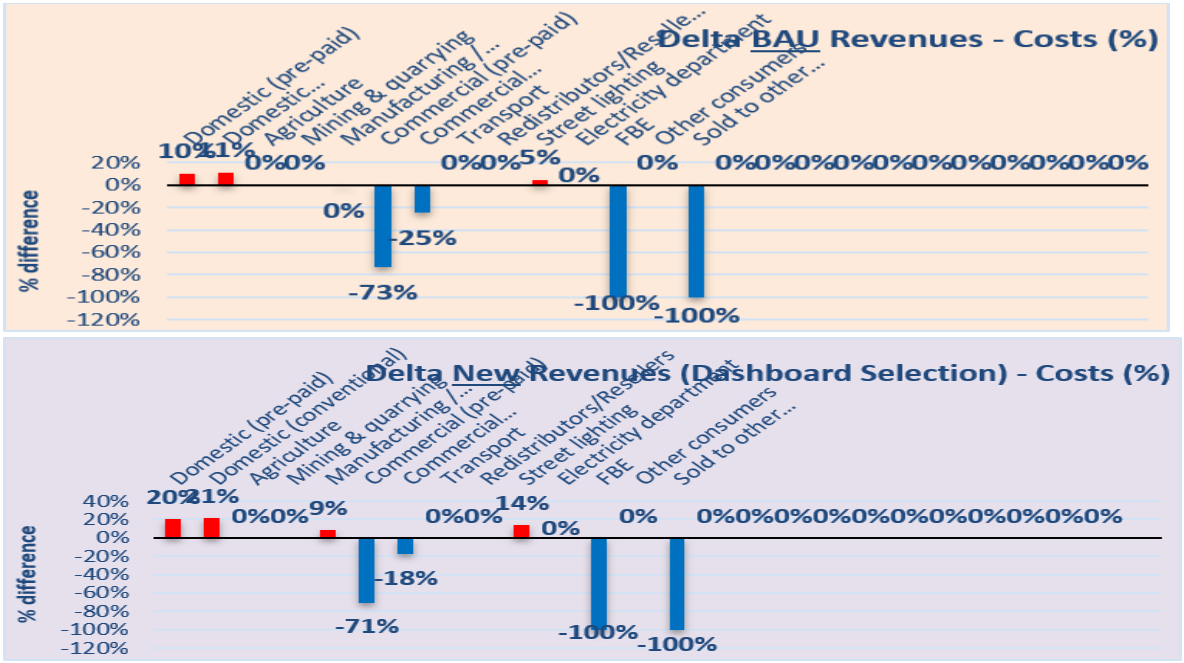


Figure 5: Revenue recovery by customer category

5. CONCLUSION ON COSTS TO SERVE

5.1. While the COS outcome indicates that achieving full cost reflectivity would require a tariff increase of approximately 6.7% (R533.171 million). The above increase of 9.01% is recommended for the municipality to generate additional revenue primarily to improve its ability to service the Eskom bulk supply account and meet its growing bulk electricity purchase obligations.

5.2. The increase above the COS outcome suggests that the municipality's current financial position may not be sufficient to sustainably cover Eskom payments, especially where there are existing arrears, rising bulk purchase costs, high energy losses, or weak revenue collection levels. In this context, the additional 3.01% increase can be viewed as a measure aimed at strengthening cash flow, reducing pressure on the Eskom account and improving the municipality's financial sustainability.

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https://www.nersa.org.za/file/9322/KougaMunicipality-ReasonsforDecisionontariffApplicationFY202

Block 2 (51 - 350 kWh)	238,87	9,01%	260,40	260,40	9,01%
Block 3 (351 -600kWh)	340,81	9,01%	371,52	371,52	9,01%
Block 4 (>600 kWh)	410,09	9,01%	447,04	447,04	9,01%
Basic Charge (R/month)	334,30	9,01%	364,42	364,42	9,01%

3. Domestic High Prepayment 60A 3Phase	**2025/26 Approved**	**Proposed % Increase**	**2026/27 Proposed**	**2026/27 Recommended**	**Recommended % Increase**
Tariff Blocks	c/kWh	9,01%	c/kWh	c/kWh	9,01%
Block 1 (0 - 50kWh)	182,94	9,01%	199,43	199,43	9,01%
Block 2 (51 - 350 kWh)	238,87	9,01%	260,40	260,40	9,01%
Block 3 (351 -600kWh)	340,81	9,01%	371,52	371,52	9,01%
Block 4 (>600 kWh)	410,09	9,01%	447,04	447,04	9,01%
Basic Charge (R/month)	936,01	9,01%	1020,35	1020,35	9,01%

4. Domestic High Conventional 60A 1Phase	**2025/26 Approved**	**Proposed % Increase**	**2026/27 Proposed**	**2026/27 Recommended**	**Recommended % Increase**
Tariff Blocks	c/kWh	9,01%	c/kWh	c/kWh	9,01%
Block 1 (0 - 50kWh)	182,94	9,01%	199,43	199,43	9,01%
Block 2 (51 - 350 kWh)	238,87	9,01%	260,40	260,40	9,01%
Block 3 (351 -600kWh)	340,81	9,01%	371,52	371,52	9,01%
Block 4 (>600 kWh)	410,09	9,01%	447,04	447,04	9,01%
Basic Charge (R/month)	417,86	9,01%	455,51	455,51	9,01%

5. Domestic High Conventional 60A 3Phase	**2025/26 Approved**	**Proposed % Increase**	**2026/27 Proposed**	**2026/27 Recommended**	**Recommended % Increase**
Tariff Blocks	c/kWh	9,01%	c/kWh	c/kWh	9,01%
Block 1 (0 - 50kWh)	182,94	9,01%	199,43	199,43	9,01%
Block 2 (51 - 350 kWh)	238,87	9,01%	260,40	260,40	9,01%
Block 3 (351 -600kWh)	340,81	9,01%	371,52	371,52	9,01%
Block 4 (>600 kWh)	410,09	9,01%	447,04	447,04	9,01%
Basic Charge (R/month)	1170,03	9,01%	1275,45	1275,45	9,01%

6. Commercial Conventional 60A 1Phase	2025/26 Approved	Proposed % Increase	2026/27 Proposed	2026/27 Recommended	Recommended % Increase
Tariff Blocks	c/kWh	9,01%	c/kWh	c/kWh	9,01%
Energy Charge: c/kWh	292,28	9,01%	318,61	318,61	9,01%
Basic Charge (R/month)	915,79	9,01%	998,30	998,30	9,01%

7. Commercial Conventional 60A 3Phase	*2025/26 Approved*	*Proposed % Increase*	*2026/27 Proposed*	*2026/27 Recommended*	*Recommended % Increase*
Tariff Blocks	*c/kWh*	*9,01%*	*c/kWh*	*c/kWh*	*9,01%*
Energy Charge: c/kWh	*292,28*	*9,01%*	*318,61*	*318,61*	*9,01%*
Basic Charge (R/month)	*2564,67*	*9,01%*	*2795,75*	2795,75	*9,01%*

8. Commercial Conventional 100A 3Phase	2025/26 Approved	Proposed % Increase	2026/27 Proposed	2026/27 Recommended	Recommended % Increase
Tariff Blocks	c/kWh	9,01%	c/kWh	c/kWh	9,01%
Energy Charge: c/kWh	292,28	9,01%	318,61	318,61	9,01%
Basic Charge (R/month)	4273,70	9,01%	4658,76	4658,76	9,01%

9. Commercial Prepaid 60A 1&3 Phase	2025/26 Approved	Proposed % Increase	2026/27 Proposed	2026/27 Recommended	Recommended % Increase
Tariff Blocks	c/kWh	9,01%	c/kWh	c/kWh	9,01%
Energy Charge: c/kWh	404,14	9,01%	440,55	440,55	9,01%

10. Industrial Normal Bulk Low Voltage (<500)	2025/26 Approved	Proposed % Increase	2026/27 Proposed	2026/27 Recommended	Recommended % Increase
Tariff Blocks	c/kWh	9,01%	c/kWh	c/kWh	9,01%
Energy Charge: c/kWh	149,75	9,01%	163,25	163,25	9.01
Basic Charge (R/month)	1681,95	9,01%	1833,49	1833,49	9,01%
Demand Charge (R/kVA)					
Network Demand	440,94	9,01%	480,67	480,67	9,01%
Network Access	66,39	9,01%	72,37	72,37	12,74 %

11. Industrial Normal Bulk High Voltage (>500 & <66kV)	2025/26 Approved	Proposed % Increase	2026/27 Proposed	2026/27 Recommended	Recommended % Increase
Tariff Blocks	c/kWh	9,01%	c/kWh	c/kWh	9,01%
Energy Charge: c/kWh	148,24	9,01%	161,60	161,60	9,01%
Basic Charge (R/month)	1681,63	9,01%	1833,14	1833,14	9,01%
Demand Charge (R/kVA)					
Network Demand	405,67	9,01%	442,22	442,22	9,01%
Network Access	61,09	9,01%	66,60	66,60	9,01%

TOU (Megaflex)

12. Low Voltage (<500V)	2025/26 Approved	Proposed % Increase	2026/27 Proposed	2026/27 Recommended	Recommended % Increase
	c/kWh	9,01%	c/kWh	c/kWh	9,01%
Basic Charge (R/month)	1 681,64	9,01%	1833,16	1833,16	9,01%
Demand Charge (R/kVA)					
Network Demand	77,00	9,01%	83,94	83,94	9,01%
Network Access	66,39	9,01%	72,37	72,37	9,01%
Low Season					
Peak	263,88	10,00%	290,27	290,27	10.00%
Standard	187,53	9,01%	204,43	204,43	9,01%
Off-Peak	125,91	9,01%	137,25	137,25	9,01%
High Season					
Peak	769,81	9,01%	839,17	839,17	9,01%
Standard	246,45	9,01%	268,65	268,65	9,01%
Off-Peak	142,50	9,01%	155,34	155,34	9,01%
Reactive Energy	32,59	9,01%	35,53	35,53	9,01%

13. High Voltage (=>500V & <66kV)	2025/26 Approved	Proposed % Increase	2026/27 Proposed	2026/27 Recommended	Recommended % Increase
	c/kWh	9,01%	c/kWh	c/kWh	9,01%
Basic Charge (R/month)	1 681,64	9,01%	1833,16	1833,16	9,01%
Demand Charge (R/kVA)					
Network Demand	70,85	9,01%	77,23	77,23	9,01%
Network Access	61,09	9,01%	66,60	66,60	9,01%
Energy (c/kWh)					
Low Season					
Peak	249,41	13,30%	282,59	282,59	13,30%
Standard	177,24	9,01%	193,21	193,21	9,01%
Off-Peak	119,02	9,01%	129,74	129,74	9,01%
High Season					
Peak	727,58	9,01%	793,13	793,13	9,01%
Standard	232,94	9,01%	253,93	253,93	9,01%
Off-Peak	134,70	9,01%	146,84	146,84	9,01%
Reactive Energy	32,59	9,01%	35,53	35,53	9,01%

Small Scale Embedded Generation (SSEG)

SSEG FEED-IN RATES

14. Net billing Export	2025/26 Approved	Proposed % Increase	2026/27 Proposed	2026/27 Recommended	Recommended % Increase
Net billing Export (c/kWh)	88,35	9,01%	96,31	96,31	9,01%
Basic charge (R/month)	417,86	20,00%	501,43	501,43	20,00%

15.SSEG TOU FEED-IN TARIFF High Voltage (=>500V & <66kV)	2025/26 Approved	Proposed % Increase	2026/27 Proposed	2026/27 Recommended	Recommended % Increase
	c/kWh	9,01%	c/kWh	c/kWh	9,01%
Basic Charge (R/month)	1 681,64	9,01%	1833,16	1833,16	9,01%
Demand Charge (R/kVA)					
Network Demand	70,85	9,01%	77,23	77,23	9,01%
Network Access	61,09	9,01%	66,60	66,60	9,01%
Energy (c/kWh)					
Low Season					
Peak	212,00	-50,00%	106,00	106,00	9,01%
Standard	150,65	-50,00%	75,33	75,33	9,01%
Off-Peak	101,16	-50,00%	50,58	50,58	9,01%
High Season					
Peak	618,44	-50,00%	309,22	309,22	9,01%
Standard	198,01	-50,00%	99,00	99,00	9,01%
Off-Peak	114,50	-50,00%	57,25	57,25	9,01%

16. SSEG Tariff - Low Voltage (<500V)	2025/26 Approved	Proposed % Increase	2026/27 Proposed	2026/27 Recommended	Recommended % Increase
	c/kWh	9,01%	c/kWh	c/kWh	9,01%
Basic Charge (R/month)	1 898,58	9,01%	2069,64	2069,64	9,01%
Demand Charge (R/kVA)					
Network Demand	66,39	9,01%	72,37	72,37	9,01%
Network Access	77,00	9,01%	83,94	83,94	9,01%
Energy (c/kWh)					
Low Season					
Peak	224,30	-50,00%	112,15	112,15	-50,00%
Standard	159,40	-50,00%	79,70	79,70	-50,00%
Off-Peak	107,02	-50,00%	53,51	53,51	-50,00%
High Season					
Peak	654,34	-50,00%	327,17	327,17	-50,00%
Standard	209,48	-50,00%	104,74	104,74	-50,00%
Off-Peak	121,13	-50,00%	60,56	60,56	-50,00%

17. Wheeling Energy Credit (-NEGATIVE) (Customer Tariff)	2025/26 Approved	Proposed % Increase	2026/27 Proposed	2026/27 Recommended	Recommended % Increase
Energy (c/kWh)					
High Season					
Peak	109,14	9,01%	118,97	118,97	9,01%
Standard	34,94	9,01%	38,09	38,09	9,01%
Off peak	20,21	9,01%	22,03	22,03	9,01%
Low season					
Peak	37,41	9,01%	40,78	40,78	9,01%
Standard	26,59	9,01%	28,99	28,99	9,01%
Off peak	17,85	9,01%	19,46	19,46	9,01%
Wheeling Admin charge	683,96	9,01%	745,58	745,58	9,01%

9. CONFIDENTIALITY

9.1. None.

10. CONCLUSION

10.1. The Energy Regulator, having considered Kouga's tariff application, supporting information, stakeholder inputs and applicable legal framework, approves the tariff adjustments, as set out in this reasons for decision document.

End