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

eThekwini Local Municipality

THE DECISION

At its meeting held on 8 May 2026, the Regulator Executive Committee (REC) considered the Ethekwini Metropolitan Municipality's tariff application. Based on the facts and evidence presented, the REC approved the tariff increases for the 2026/27 financial year (FY) the decision is set out on the tariff analysis section 8 on page 21 of the RFD.

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

approve the tariffs that are based on the Cost of Supply (COS) report as recommended in the tariff analysis section for implementation by the licensee with effect from 1 July 2026;

1. note the COS report submitted by the licensee; and
2. that the licensee 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 to perform its independent verification/audit process by 30 September 2026.

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ABBREVIATIONS 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 on a yearly basis, in accordance with its mandate to regulate prices and tariffs. Municipal tariffs must be approved by the Energy Regulator to be implemented on 1 July of each financial year.

1.2. The eThekwini Metropolitan Municipality (eThekwini) is in KwaZulu-Natal.

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

CUSTOMER STATISTICS			
Consumer Classification	**Sales (MWh)**	**%MWh**	**Number of**
Domestic (Pre-paid)	528 744,00	6,03%	472 155
Domestic (Conventional)	2 321 756,00	26,50%	273 452
Commercial (Converntional)	2 301 853,00	26,27%	41829
Manufacturing/Industrial	3 442 736,00	39,29%	1086
Street lighting, Own use.	166 271,00	1,90%	N/A
Totals	**8 761 360**	**100%**	**788 522**
Free Basic Electricity	**65 278**	**4,91%**	

1.3. Industrial customers account for 39.29% of total electricity sales, followed by domestic customers accounting for 32.53%.

1.4. NERSA received eThekwini's tariff application and its Cost of Supply (COS) study on 30 March 2026.

1.5. eThekwini implemented a 12.72% average price increase in 2025/26FY and is applying for an average price increase of 9% for the 2026/27FY.

1.6. For this application, the licensee confirmed that the tariffs applied for are authorised by the Municipal Council, and it undertook customer consultation with no comments received.

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

1.8. NERSA'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 to align with the municipal budgeting process contemplated in the Municipal Finance Management Act, 2003 (Act No. 56 of 2003).

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

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

2.2. Statutory Mandate of the Energy Regulator

2.2.1. NERSA is established as a juristic person in terms of section 3 of NERA. In terms of section 4 of NERA, the Energy Regulator, as the decision-making body, must regulate the electricity industry and execute the functions set out in the ERA. The electricity regulatory mandate of the Energy Regulator is therefore primarily governed by the ERA. Section 3 of the ERA particularly provides that the Energy Regulator is the custodian and enforcer of the national electricity regulatory framework and exercises regulatory authority over activities regulated under the ERA.

2.2.2. In particular:

a) section 4(a)(i) of the ERA provides that the Energy Regulator must consider applications for licences and may issue licences subject to conditions;

b) section 4(a)(ii) of the ERA provides that the Energy Regulator must regulate prices and tariffs; and

c) section 14(1)(d) of the ERA authorises the Energy Regulator to impose licence conditions relating to the setting or approval of prices, charges, rates and tariffs charged by licensees.

2.2.3. Municipalities distributing electricity do so under electricity distribution licences issued by the Energy Regulator and are therefore subject to the tariff approval framework established under the ERA.

2.3. Tariff Determination Principles under the ERA

2.3.1. When determining or approving electricity tariffs, the Energy Regulator must apply the principles contained in section 15(1) of the ERA.

2.3.2. Section 15(1) provides that the Energy Regulator:

a) must enable an efficient licensee to recover the full cost of the licensed activity;
b) must allow for a reasonable return commensurate with the risk of the licensed activity;
c) may provide incentives for continued improvement of technical and economic efficiency;
d) must avoid undue discrimination between customer categories;
e) may permit cross-subsidies of tariffs to certain classes of customers; and
f) may have regard to the need to ensure security of supply, diversity of supply and the promotion of renewable energy.

2.3.3. These statutory requirements form the core legal principles guiding the determination of electricity tariffs within the South African electricity supply industry.

2.4. Administrative Law Requirements

2.4.1. The approval of municipal electricity tariffs constitutes administrative action as defined in section 1 of 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. Therefore, public participation processes conducted by the Energy Regulator form an essential component of the municipal tariff approval process and are intended to ensure transparency, accountability and fairness in regulatory decision-making.

2.5. Policy Framework: Electricity Pricing Policy (2008)

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

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

2.5.3. Policy Position 2 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 therefore requires electricity distributors to undertake COS studies at least every five years, or when significant structural changes occur in the customer base or cost structure.

2.6.4. Such studies must be conducted in accordance with the methodology approved by NERSA and must accompany tariff structure applications submitted to NERSA.

2.7. Judicial Oversight of the Tariff Approval Process

2.7.1. The municipal tariff approval process administered by NERSA was the subject of litigation in AfriForum NPC v National Energy Regulator of South Africa and Others (Case No. 2025/137620) before the High Court of South Africa, Gauteng Division, Pretoria.

2.7.2. In its final judgment delivered on 4 December 2025, the Court held that NERSA's public participation process relating to the 2025/26 municipal tariff approvals did not comply with the procedural requirements of section 4 of PAJA and was therefore unlawful.

2.7.3. However, recognising the potentially disruptive consequences of setting aside tariff determinations already implemented by municipalities, the Court declined to invalidate the tariffs. Instead, to assist in the timeous and lawful approval of municipal tariffs, the Court issued a structural interdict regulating the municipal tariff approval process going forward.

2.7.4. NERSA subsequently launched a variation application seeking to vary the timelines set by the Court on 4 December 2025, considering the practical difficulties that arose regarding 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) The publication of NERSA decisions by 11 May 2026.

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

a) Written notice of bulk electricity tariffs must be communicated by 31 January each year.
b) Municipal tariff applications must be submitted to NERSA by 20 March each year.
c) Municipal tariff approvals and the tariff reasons for decision document must be approved and published by 5 May of each year.

2.9. Conclusion

2.9.1. The determination of municipal electricity tariffs by the Energy Regulator must therefore be undertaken within a comprehensive regulatory framework consisting of the NERA, ERA, PAJA, EPP and the binding judicial directives issued by the High Court in AfriForum NPC v NERSA (Case No. 2025/137620).

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

3. FINANCIAL AND TECHNICAL PERFORMANCE

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

3.2. eThekwini recorded a percentage deficit of 8.11% in the 2023/24 financial year; this improved to 5.87% in the 2024/25 financial year.

3.3. Table 2 below shows that eThekwini recorded energy losses of 10.88% in the 2023/24 financial year and 11.22% in the 2024/25 financial year.

Table 2: Performance indicators

Outputs:	2024/25	2023/24
Percentage Surplus	-5,87%	-8,11%
Percentage Energy Losses:	11,22	10,88

3.4. Based on the above information, the municipality's performance is satisfactory as the deficit is improving and the energy losses are low.

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

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

4.2. eThekwini 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 uses 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.

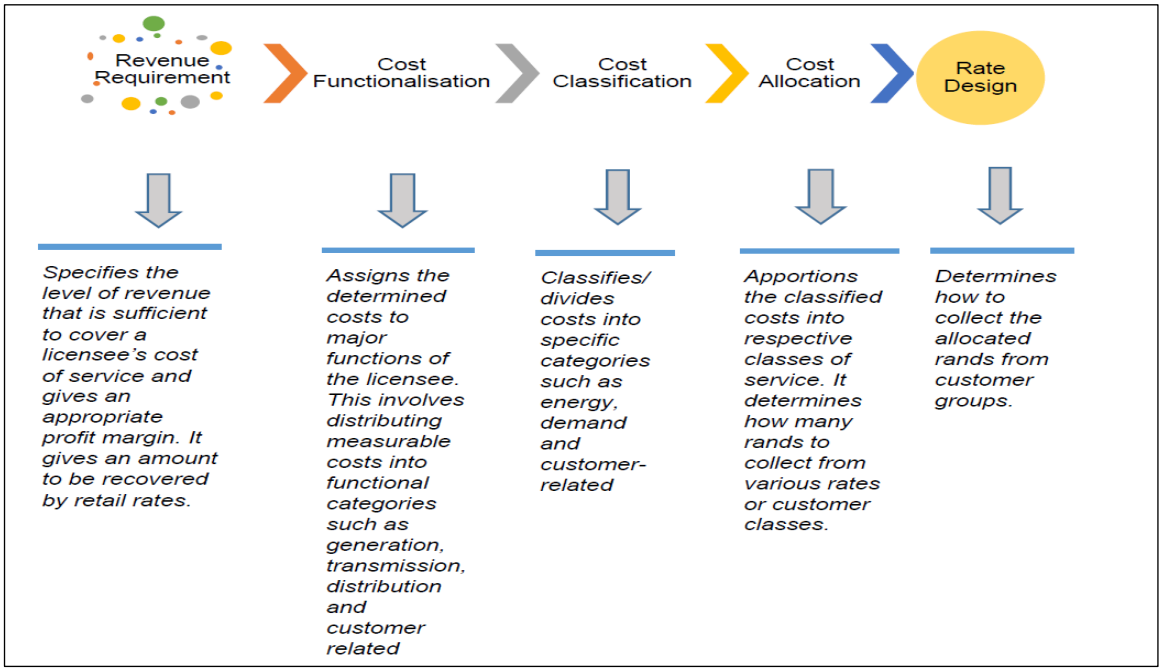


Figure 1: Five steps of COS study

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

4.5.1. be informed by COS outcomes;

4.5.2. progressively move tariffs towards cost reflectivity; and

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

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

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

4.6.2. Bulk purchase costs were updated using the approved 8.76% Eskom bulk tariff adjustment.

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

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

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

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

Revenue Requirement

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

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

4.8.3. eThekwini submitted a COS study detailing revenue requirement of R25 787 046 806 for the 2026/27 financial year. As shown in Table 3 below, this revenue requirement is dominated by Eskom purchases accounting for 75%, including an energy losses allowance. Operational expenditure (including depreciation) accounts for 18%.

Table 3: eThekwini revenue requirement

	Total cost (R)					
Revenue Requirement components	Wires	Retail	Applied for 2026/27	NERSA Adjustments	NERSA Decision 2026/27	% of Total
Allowable costs	3 394 758 364	22 392 288 442	25 787 046 806	-	25 787 046 806	100%
Energy purchases from Eskom - net of cost of losses	-	15 195 938 870	15 195 938 870	-	15 195 938 870	59%
Energy purchases from Eskom - cost of losses	-	4 218 983 321	4 218 983 321	-	4 218 983 321	16%
Other energy purchases	-	-	-	-	-	0%
Capital expenditure	700 000 000	-	700 000 000	-	700 000 000	3%
Operational expenditure (incl. Depreciation)	2 777 427 702	1 771 367 378	4 548 795 080	-	4 548 795 080	18%
Other revenues	**- 82 669 338**	**- 61 489 152**	**- 144 158 490**	-	**- 144 158 490**	**-1%**
Surplus	-	1 267 488 025	1 267 488 025	-	1 267 488 025	5%
Not allowable costs	-	-	-	-	-	
Cost of losses disallowed	-	-	-	-	-	
TOTAL COSTS	3 394 758 364	22 392 288 442	25 787 046 806	-	25 787 046 806	
	13%	87%				

4.8.3.1. 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.

4.8.4. 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 on below.

Bulk Purchases

4.8.5. eThekwini's COS study projects a bulk purchase expenditure of R19 414 922 191, which accounts for 75% of total costs when including the 12% energy losses allowance. Bulk purchases were verified against the 2024/25 Eskom invoices.

4.8.6. The licensee projected its bulk purchases for the 2026/27 financial year using the 2025/26 Eskom tariffs as a base and made the following assumptions: sales decline of 2.5%, and a bulk purchase cost increase of 9.01% for the 2026/27 financial year, which is in line with the approved Eskom Retail Tariff Structural Adjustments (ERTSA).

Operational Expenditure

4.8.7. eThekwini's COS study projects operational expenditure totalling R4 548 795 080, representing 18% of overall costs. Table 4 below provides a breakdown of this expenditure.

Table 4: Operational expenditure[1]

	Actual 2024/25	Budget 2025/26	Applied for 2026/27	NERSA Adjustments	NERSA Decision 2026/27
Network OPEX	R 3 201 425 096	R 2 552 004 280	R 2 560 188 460	R -	R 2 560 188 460
Salaries and allowances	R 1 047 336 230	R 998 268 190	R 1 128 432 460	R -	R 1 128 432 460
Materials and supplies	R 794 330 075	R 313 919 100	R 326 794 310	R -	R 326 794 310
Contracted Services	R 996 683 217	R 850 727 050	R 680 409 730	R -	R 680 409 730
Salaries, wages and allowances (exclu. Rep	R -	R -	R -	R -	R -
Payments to consultants (operational work)	R 6 848 685	R 11 325 570	R 14 755 490	R -	R 14 755 490
Eskom debts' interests	R -	R -	R -	R -	R -
Other creditors interests	R 281	R -	R -	R -	R -
Current year depreciation	R 356 226 608	R 377 764 370	R 409 796 470	R -	R 409 796 470
Retail OPEX	R 320 049 434		R 568 868 190	R -	R 568 868 190
General & Other	R 716 193 650	R 803 236 790	R 905 163 510	R -	R 905 163 510
Salaries and allowances	R 325 706 317	R 314 883 740	R 453 433 730	R -	R 453 433 730
Materials and supplies	-R 2 831 884	R 1 864 290	R 1 813 430	R -	R 1 813 430
Contracted Services	R 81 404 588	R 123 524 200	R 92 879 800	R -	R 92 879 800
Salaries, wages and allowances (exclu. Rep	R -	R -	R -	R -	R -
Payments to consultants (operational work)	R 74 057 816	R 117 942 470	R 93 882 680	R -	R 93 882 680
Eskom debts' interests	R -	R -	R -	R -	R -
Other creditors interests	R 148 618 424	R 139 067 270	R 141 474 770	R -	R 141 474 770
Current year depreciation	R 89 238 389	R 105 954 820	R 121 679 100	R -	R 121 679 100
NMD exceedance penalties	R -	R -	R -	R -	R -
0	R -	R -	R -	R -	R -
Shared OPEX	R 1 117 265 801	R 929 555 740	R 514 574 920	R -	R 514 574 920
Total	**R 5 354 933 981**	**R 4 284 796 810**	**R 4 548 795 080**	**R -**	**R 4 548 795 080**

4.8.8. The operating expenditure comprises:

4.8.8.1. Network operating expenditure of R2 560 188 460;

4.8.8.2. Retail operating expenditure of R568 868 190;

4.8.8.3. General and other expenditure of R905 163 510; and

4.8.8.4. Shared expenditure of R514 574 920.

4.8.9. The approach adopted by eThekwini in forecasting operational expenditure is considered reasonable, and the amount has therefore been recommended as requested. Furthermore, the licensee is not incurring inefficient costs such as Notified Maximum Demand (NMD) exceedance penalties and interest incurred on Eskom-related debt.

Surplus

4.8.10. eThekwini's revenue requirement includes a surplus of R1 267 488 025, calculated using a surplus factor of 6% applied to operating expenditure, inclusive of bulk purchases, for both the wires and retail components of the electricity business.

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

[1] COS tool Comm & Fin Forecasts (Year 2)

4.8.11.1. The applied surplus margin of 10% was benchmarked against the 10–20% range prescribed in the approved NERSA COS Framework, as supported by the EPP Policy Position 1.

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

4.8.12. Risk factors considered include the following:

4.8.12.1. Revenue collection risk, with current collection levels above 86%, reflecting minimum exposure to non-payment.

4.8.12.2. Operational risk, including energy losses of approximately 11.22%, signifying a well-maintained network infrastructure.

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

4.8.13. Based on the above, the applied surplus margin of 10% is considered conservative, justified and commensurate with the licensee's risk profile, while remaining within the acceptable parameters of the NERSA COS Framework. This approach supports the financial viability of the electricity distribution function without imposing undue burden on consumers.

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

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

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

Cost Functionalisation

4.8.17. The licensee has categorised its revenue requirement into two primary functional components, namely the wires business (23%) and the retail business (77%), in accordance with the NERSA COS Framework, as illustrated in Figure

2 below. Upon verification, the allocation of costs to these functional components is found to be consistent with the stated revenue requirement.

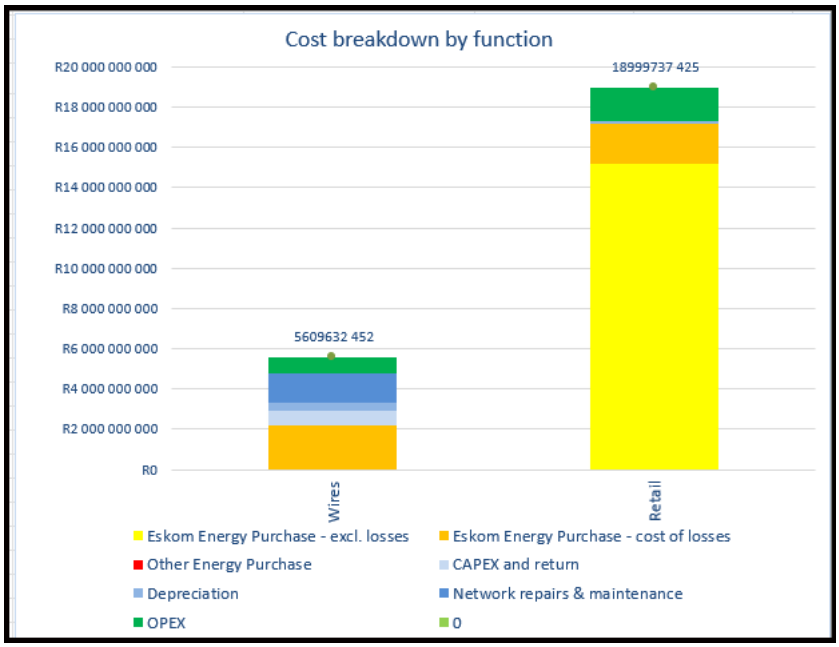


Figure 2*:* Cost breakdown by functions

4.8.18. These costs, upon verification, are consistent with the approved revenue requirements. Network repairs and maintenance are the predominant cost drivers within the wires business, while energy purchases represent the primary cost driver within the retail business.

Cost Classification

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

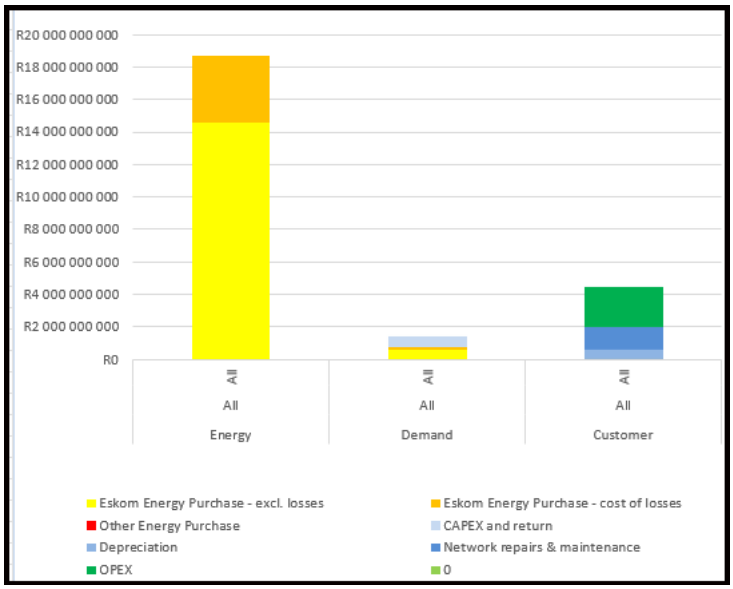


Figure 3*:* Cost breakdown by cost structure (classification)

4.8.20. Energy purchases constitute energy-driven costs, with the highest expenditure incurred during the summer period under the standard time-of-use structure, largely due to the longer duration of the summer season, as shown in Figure 3 above. Demand-driven costs are similarly concentrated in the summer period. Customer-driven costs are primarily associated with 'Other OPEX', which includes expenses related to the provision of electricity distribution services to customers.

Cost Allocation

4.8.21. In this step, the licensee's revenue requirement is allocated across customer categories in accordance with the NERSA COS framework. Upon verification, the allocation is found to be consistent with the stated revenue requirement and aligned with the principles of cost allocation.

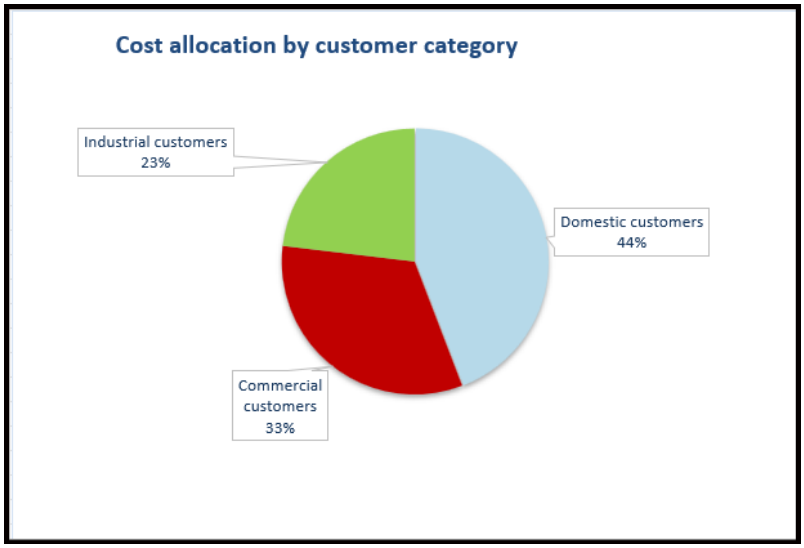


Figure 4: Costs allocated

Rate Design

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

4.8.23. To achieve full cost reflectivity, the municipality would be required to implement differentiated tariff adjustments across customer categories. However, the municipality has adopted a less aggressive approach, opting for a uniform tariff increase of 10.5% across all customer categories. The municipality has cross-subsidisation within its tariffs; as a result, the municipality will be requested to develop a cross-subsidy framework to ensure that its cross-subsidisation is fair and transparent.

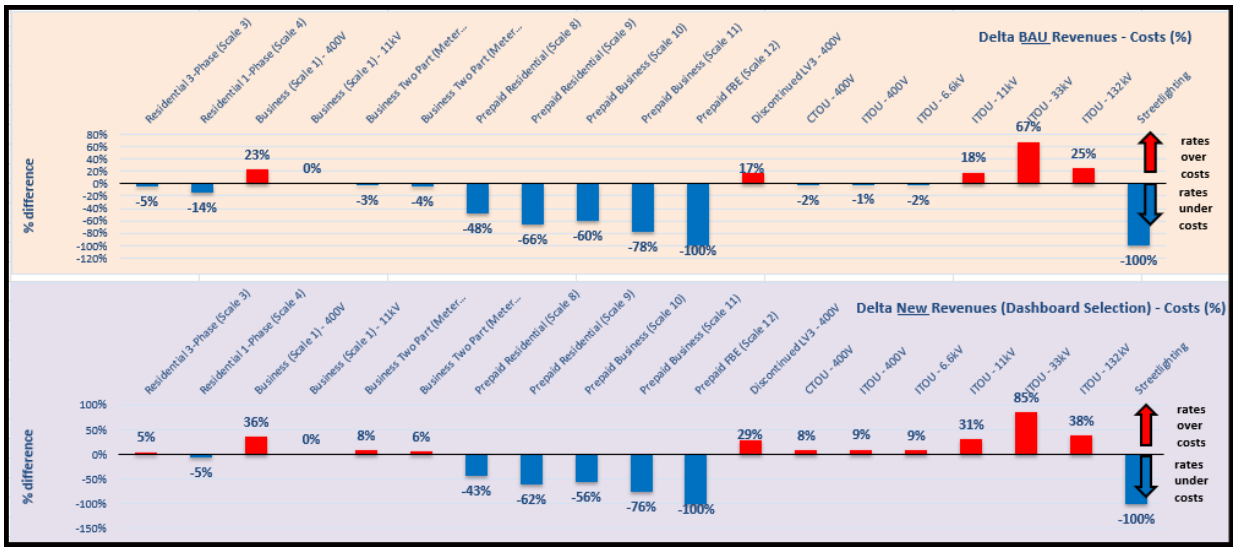


Figure 5: Revenue recovery by customer category

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.

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Commercial Prepaid Tariff Scale10, 11 & 14	2025/26 Approved	2026/27 Proposed	% Increase	Recommended Tariff	% Increase	Key Analysis and Findings
Energy charge (c/kWh)	411,17	448,18	9,00%	448,18	9,00%	

Scale 2 (Meter 002): Business and General Obsolete tariff	2025/26 Approved	2026/27 Proposed	% Increase	Recommended Tariff	% Increase	Key Analysis and Findings
Energy charge (c/kWh)	160,15	174,56	9,00%	174,56	9,00%	
Supplementary charge (c/kWh)	381,12	415,42	9,00%	415,42	9,00%	
Basic charge (R/month)	500,87	545,95	9,00%	545,95	9,00%	

Scale 2 (Meter 021): Business and General Obsolete tariff	2025/26 Approved	2026/27 Proposed	% Increase	Recommended Tariff	% Increase	Key Analysis and Findings
Off-peak energy charge (c/kWh)	160,15	174,56	9,00%	174,56	9,00%	0,10
Peak energy charge (c/kWh)	541,28	590,00	9,00%	590,00	9,00%	0,10
Basic charge (R/month)	500,87	545,95	9,00%	545,95	9,00%	0,10

Residential Time of Use (TOU)	2025/26 Approved	2026/27 Proposed	% Increase	Recommended Tariff	% Increase	Key Analysis and Findings
Basic charge **(R/month)**	258,81	282,10	9,00%	282,10	9,00%	
Energy Charges						

Peak **(c/kWh)**	480,57	523,82	9,00%	523,82	9,00%	
Standard (**c/kWh)**	240,09	261,70	9,00%	261,70	9,00%	
Off-peak **(c/kWh)**	177,83	193,83	9,00%	193,83	9,00%	

Commercial Time of Use (TOU)	**2025/26 Approved**	**2026/27 Proposed**	**% Increase**	**Recommended Tariff**	**% Increase**	**Key Analysis and Findings**
Basic charge **(R/month)**	680,02	741,22	9,00%	741,22	9,00%	
Low Season Energy Charges						
Peak **(c/kWh)**	316,82	345,33	9,00%	345,33	9,00%	
Standard **(c/kWh)**	254,87	277,81	9,00%	277,81	9,00%	
Off-peak **(c/kWh)**	148,26	161,60	9,00%	161,60	9,00%	
High Season Energy Charges						
Peak **(c/kWh)**	642,15	699,94	9,00%	699,94	9,00%	
Standard (**c/kWh)**	321,30	350,22	9,00%	350,22	9,00%	
Off-peak **(c/kWh)**	156,52	170,61	9,00%	170,61	9,00%	
Demand charge **(R/kVA)**	137,04	149,38	9,00%	149,38	9,00%	

Industrial Time of Use (TOU)	**2025/26 Approved**	**2026/27 Proposed**	**% Increase**	**Recommended Tariff**	**% Increase**	**Key Analysis and Findings**
Basic charge **(R/month)**	7186,53	8079,99	12,43%	8079,99	12,43%	
Low Season Energy Charges						
Peak **(c/kWh)**	245,68	265,92	8,24%	265,92	8,24%	
Standard (**c/kWh)**	138,14	149,52	8,24%	149,52	8,24%	

Off-peak **(c/kWh)**	98,66	106,79	8,24%	106,79	8,24%	
High Season Energy Charges						
Peak **(c/kWh):**	592,00	640,77	8,24%	640,77	8,24%	
Standard (**c/kWh):**	148,00	160,19	8,24%	160,19	8,24%	
Off-peak **(c/kWh):**	98,66	106,79	8,24%	106,79	8,24%	
Network access charge **(R/kVA)**:	53,00	60,81	14,74%	60,81	14,74%	
Demand charge **(R/kVA):**	154,35	176,51	14,36%	176,51	14,36%	
Ancillary service charge (c/kWh)	0,35	0,38	8,57%	0,38	8,57%	
Legacy Charge	19,51	21,27	9,02%	21,27	9,02%	
Electrification and rural network subsidy (c/kWh)	5,02	5,47	8,96%	5,47	8,96%	

Residential Net-Billing	**2025/26 Approved**	**2026/27 Proposed**	**% Increase**	**Recommended Tariff**	**% Increase**	**Key Analysis and Findings**
Basic charge (R/kVA)	70,07	76,83	9,65%	76,83	9,65%	
Energy charge (c/kWh)	147,46	160,52	8,86%	160,52	8,86%	

Commercial Net-Billing	**2025/26 Approved**	**2026/27 Proposed**	**% Increase**	**Recommended Tariff**	**% Increase**	**Key Analysis and Findings**
Basic charge (R/kVA)	145,32	161,58	11,19%	161,58	11,19%	
Energy charge (c/kWh)	112,62	122,60	8,86%	122,60	8,86%	

TOU Net-Billing	2025/26 Approved	2026/27 Proposed	% Increase	Recommended Tariff	% Increase	Key Analysis and Findings
Low Season Energy Charges						
Peak **(c/kWh)**	245,68	265,92	8,24%	265,92	8,24%	
Standard **(c/kWh)**	138,14	149,52	8,24%	149,52	8,24%	
Off-peak **(c/kWh)**	98,66	106,79	8,24%	106,79	8,24%	
High Season Energy Charges						
Peak **(c/kWh)**	592,00	640,77	8,24%	640,77	8,24%	
Standard (**c/kWh)**	148,00	160,19	8,24%	160,19	8,24%	
Off-peak **(c/kWh)**	98,66	106,79	8,24%	106,79	8,24%	
132 kV Basic charge (R/kVA)	4,88	5,32	9,02%	5,32	9,02%	
33 kV Basic charge (R/kVA)	6,37	6,94	8,95%	6,94	8,95%	
11kV Basic charge (R/kVA)	22,50	24,53	9,02%	24,53	9,02%	
6.6 kV Basic charge (R/kVA)	27,95	30,47	9,02%	30,47	9,02%	
400V Basic charge (R/kVA)	47,80	52,11	9,02%	52,11	9,02%	

Wheeling Internal	2025/26 Approved	2026/27 Proposed	% Increase	Recommended Tariff	% Increase	Key Analysis and Findings
Basic charge **(R/month)**	N/A	11911,67	New App	11911,67	New App	
Low Season Energy Charges						
Peak **(c/kWh)**	N/A	293,04	New App	293,04	New App	
Standard (**c/kWh)**	N/A	176,64	New App	176,64	New App	
Off-peak **(c/kWh)**	N/A	133,91	New App	133,91	New App	

High Season Energy Charges						
Peak **(c/kWh)**	N/A	667,89	New App	667,89	New App	
Standard **(c/kWh)**	N/A	187,31	New App	187,31	New App	
Off-peak **(c/kWh)**	N/A	133,91	New App	133,91	New App	

Wheeling External	**2025/26 Approved**	**2026/27 Proposed**	**% Increase**	**Recommended Tariff**	**% Increase**	**Key Analysis and Findings**
Basic charge **(R/month)**	N/A	11911,67	New App	11911,67	New App	
Low Season Energy Charges						
Peak **(c/kWh)**	N/A	As per Eskom Credits	New App	As per Eskom Credits	New App	As per Eskom Credits
Standard (**c/kWh)**	N/A		New App		New App	
Off-peak **(c/kWh)**	N/A		New App		New App	
High Season Energy Charges						
Peak **(c/kWh)**	N/A	As per Eskom Credits	New App	As per Eskom Credits	New App	As per Eskom Credits
Standard (**c/kWh):**	N/A		New App		New App	
Off-peak **(c/kWh):**	N/A		New App		New App	

9. CONFIDENTIALITY

9.1. None.

10. CONCLUSION

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

End.