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

The City of Cape Town Metropolitan Municipality

THE DECISION

1. At its meeting held on 11 May 2026, the Regulator Executive Committee (REC) considered the City of Cape Town 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) set out in
2. Table 1 below.

Table 1: Summary of the REC Decision

Tariff Category	2026/27 Approved % Increase
1. Domestic	12.93%
2. Llifeline	7.15%
3. Home User	20.41%
4. Residential time-of-use	0.00%
5. Small Power Users 1	17.20%
6. Small Power Users 2	16.95%
7. Small Power Users 3	18.89%
8. Large User Low Voltage Time of Use Tariff	16.55%
9. Large User Medium Voltage Time of Use Tariff	17.77%
10. Large User High Voltage Time of Use Tariff	18,51%
11. Residential: Small-Scale Embedded Generation	3.34%
12. Non-Residential Small-Scale Embedded Generation:	1.61%
13. Wheeling Use of System Charges MV	7.42%

14. Wheeling Use of System Charges HV	7.49%
15. Wheeling Deficit Energy (All Voltage Levels)	9.01%
16. Wheeling Excess Energy Feed-In	0.79%
17. Generation Tariff	9.08%
18. Street Lighting and Traffic Signal	10.45%

3. 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 costs noted 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.

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ABBREVIATIONS

COCT	City of Cape Town Metropolitan Municipality
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 yearly, according to the mandate of the Energy Regulator 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 City of Cape Town Metropolitan Municipality (COCT) is situated in the Western Cape. The municipality's customer base is mostly manufacturing/industrial customers, accounting for 44% of total electricity sales. The municipality provides its indigent customers with a minimum of 60kWh of Free Basic Electricity (FBE) per month if their monthly purchases are equal to or below 250kWh and 25kWh. The details regarding customer statistics are highlighted in Table 2 below.

Table 2: Customer statistics (data obtained from the latest D-forms – 2024/25FY)

Customer categories	***MWh***	***% MWh***	***Customer numbers***
Domestic Prepaid	2 295 751	29.01	560 514
Domestic Conventional	393 145	4.97	59 401
Manufacturing	3 481 684	44.00	1445
Commercial Prepaid	124 242	1.57	12 530
Commercial Conventional	1 485 054	18.77	16 796
Street Lighting	128 648	1.63	0
Sold to other departments	4 127	0.05	229
TOTAL	**7 912 651**	**100.00**	**650 915**

[1]FBE	84 832	3[2]	174 558

1.3. NERSA received COCT's tariff application, together with its revised cost of supply (COS) report based on the cost-plus methodology, on 26 March 2026.

1.4. The COCT is applying for a regulated revenue requirement of R23.271 billion. To achieve this required revenue on NERSA-approved tariffs for 2025/26FY, an average tariff increase from a revised rate of 255.87c/kWh to 305c/kWh is required, which translates into 19.46%. However, the current average price charged by the municipality is 283,45 c/kWh for the 2025/26FY, so the real increase that would be experienced by the customers is 7.74%.

1.5. In accordance with NERSA requirements, all tariff applications must include confirmation that the proposed tariffs were approved by the municipal council and have undergone customer consultation.

1.6. For this application, the municipality has indicated that the draft annual budget was approved by Council on 31 March 2026. The COCT further states that the council will consider the tariffs and public comments thereon before the end of May 2026, as per the requirements of section 75A of the Municipal Systems Act and the Municipal Finance Management Act.

1.7. NERSA followed the notice and comment consultation process. The COCT'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 11 May 2026, considering the written comments received from the affected stakeholders and the analysis performed by NERSA.

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

[2] Percentage of Domestic MWh

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) (MFMA).

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 the 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 the 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 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 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 2025/2026 municipal tariff approvals did not comply with the procedural requirements of section 4 of the PAJA and was therefore unlawful.

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

2.7.4. NERSA subsequently launched a variation application which sought to vary the timelines which were set by the Court on 4 December 2025, considering the practical difficulties which arose as it relates to NERSA's compliance with the Court order. The court, having heard NERSA's application, granted the variation application in respect of the fixed deadlines for the 2026/27 municipal tariff approvals.

2.8. **Court-Directed Timelines**

2.8.1. The timelines below are applicable in respect of the 2026/27 municipal tariff approvals:

a) Written notice of bulk tariffs must be communicated by 6 March 2026.
b) Municipal tariff applications 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 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 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 municipal financial year.

3. FINANCIAL AND TECHNICAL PERFORMANCE

3.1. In evaluating the financial and technical performance of the City of Cape Town, 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. As a result, the data captured in the D-forms is considered reliable for the tariff analysis.

3.2. Table 3 below indicates that the COCT's electricity business recorded a decrease in percentage surplus from 12.60% in the 2023/24 financial year to 9.38% in the 2024/25 financial year.

3.3. Energy losses increased slightly from 10.22% in the 2023/24 financial year to 11.23% in the 2024/25 financial year, as shown in Table 3 below. The municipality is encouraged to maintain energy losses at these relatively low levels.

Table 3: Performance indicators

Performance indicators	***Municipality 2024/25 D-forms Information***	***Municipality 2023/24 D-forms Information***
Percentage surplus: (%)	9.38	12.60[3]
Energy Losses: (%)	11.23	10.22

3.4. Based on the above information, the licensee's electricity department demonstrates satisfactory financial and operational performance, as reflected in the surplus and relatively low energy losses. The recorded surplus indicates sound financial management and effective cost recovery, while the relatively low level of energy losses suggests efficient network operations and maintenance. Collectively, these factors contribute to a stable and sustainable electricity service.

4. DETERMINATION OF COCT'S TARIFFS BASED ON THE COST OF SUPPLY STUDY

4.1. The process followed in considering and approving COCT's tariff application was supported by a cost of supply study.

4.2. The COCT utilised its own COS study model to determine its revenue requirements for the 2026/27 financial year and to apportion costs required to service each customer's class fairly and equitably. The study it used was based on the 2025/26 actual budgeted costs and was detailed and thorough, but not strictly in accordance with the NERSA COS Framework, in that it looks only at the tariff year. The revenue requirement was based on the budget, and items were first apportioned according to their fixed cost and variable cost, according to three functions, viz., administrative, energy and network costs. Also, whether they fell within the regulatory tariff calculation or not. These costs were then allocated to the various tariff categories, which then resulted in the actual rate design to recover the regulated revenue.

[3] Total Electricity Purchases divided by Total Expenditure

4.3.

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

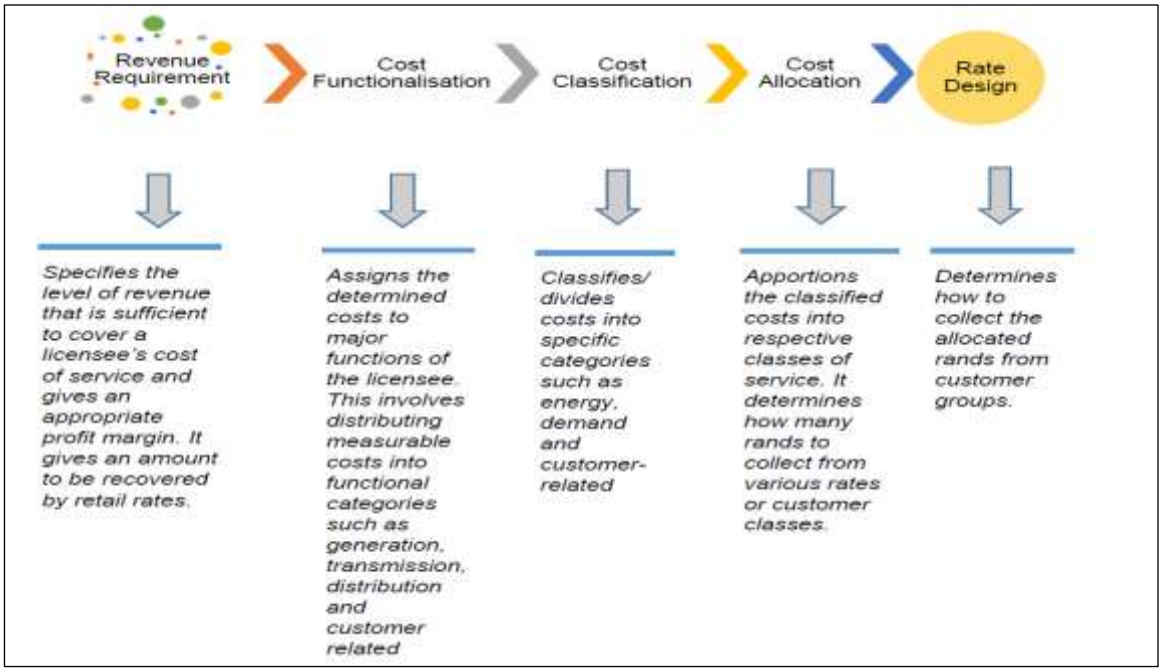


Figure 1: Five steps of COS study

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

4.5.1. **Revenue Requirement**

4.5.1.1. To be fully cost reflective, the licensee's revenue requirement is R23,271 billion. This amount is primarily driven by Eskom purchases, which account for 82%, while operational expenditure makes up the remaining 18%, as highlighted in Table 4 below.

Table 4: Revenue requirement components

Summary - Cost of Supply		Rands	Rands	Rands	Rands	Rands	Rands	Rands	Rands	Rands	Rands
Nature	**Component**	**LL**	**Domestic**	**Home User**	**Residential**	**SPU 1**	**SPU 2**	**SPU Total**	**LPU LV**	**LPU MV**	**Total**
Variable	Admin	7 300 028	8 604 415	30 723 902	46 628 345	27 895 525	1 319 705	29 215 230	252 752	1 863 564	77 959 890
	Energy Post Losses	779 961 660	919 327 093	3 282 653 798	4 981 942 551	2 980 459 663	141 002 134	3 121 461 797	786 463 014	5 611 610 451	14 501 477 813
	Network	106 492 487	153 538 983	461 443 055	721 474 525	724 880 968	213 640 006	938 520 973	225 509 196	313 189 213	2 198 693 908
	Total	893 754 175	1 081 470 491	3 774 820 755	5 750 045 421	3 733 236 156	355 961 845	4 089 198 000	1 012 224 962	5 926 663 228	16 778 131 611
Fixed	Admin	802 838 586	492 236 654	1 346 603 356	2 641 678 596	76 546 052	48 573 132	125 119 185	2 381 506	3 424 441	2 772 603 728
	Energy	14 000 805	19 447 322	58 446 601	91 894 728	91 813 775	27 059 747	118 873 522	28 214 833	39 185 016	278 168 099
	Network	222 765 168	307 834 181	925 158 821	1 455 758 170	1 453 332 139	428 332 237	1 881 664 375	424 424 736	589 444 916	4 351 292 196
	Total	1 039 604 559	819 518 156	2 330 208 778	4 189 331 494	1 621 691 966	503 965 116	2 125 657 082	455 021 075	632 054 372	7 402 064 023
TOTAL REVENUE REQUIREMENT 2026/27		**1 933 358 734**	**1 900 988 647**	**6 105 029 533**	**9 939 376 914**	**5 354 928 122**	**859 926 960**	**6 214 855 082**	**1 467 246 037**	**6 558 717 601**	**24 180 195 634**
REVENUE REQUIREMENT 2025/26											**22 354 334 462**
INCREASE IN REVENUE REQUIREMENT											**8,17%**
Total Revenue From Sales		**948 719 651**	**1 773 490 208**	**6 789 308 673**	**9 511 518 533**	**4 860 746 384**	**448 176 173**	**5 308 922 557**	**1 276 652 908**	**7 174 151 521**	**23 271 245 519**

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 have been made accordingly, as detailed below.

Bulk purchases

4.5.1.4. The COCT applied for bulk purchase expenditure amounting to R18,986 billion, representing 82% of total costs. The application reflects bulk purchase cost increases that significantly exceed CPI and general inflationary pressures. The bulk purchase figures were verified against Eskom invoices for the 2024/25 financial year.

4.5.1.5. Bulk purchases are expected to increase by 6.9%. This is below the NERSA-approved Eskom Retail Tariff Structural Adjustments (ERTSA) of 9.01%. The bulk purchases continue to represent the largest expenditure item within COCT's electricity business.

4.5.1.6. The methodology applied by the COCT in forecasting bulk purchase costs is deemed reasonable. Accordingly, the bulk purchase expenditure has been recommended for approval as submitted.

4.5.1.7. It should be noted that the bulk purchases also include purchases from an IPP (Darling Wind Farm) of R200,000 and purchases from Small Scale Embedded Generations customers of R84,968 million.

Operational Expenditure

4.5.1.8. The COCT has applied for operational expenditure totalling R4,284 billion, representing 18% of overall costs, as reflected in Table 4 above.

4.5.1.9. 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 of R543 393 251 are consistent with the licensee's total asset base, valued at approximately R18,978,114,000 as at FY2025/26.

4.5.1.10. The costs have been verified using Annual Financial Statements (AFS) and the Trial Balance. The AFS audited figures for the energy department.

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

4.5.1.12. The approach adopted by COCT in forecasting operational expenditure is considered reasonable, and the amount has therefore been approved as requested. 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 municipality's control.

Surplus

4.5.1.13. The municipality applied a cost-plus methodology. Under the cost-plus methodology, the allowable revenue is derived as follows:

a) Efficient and prudent operating expenditure (OPEX)

b) Depreciation (as a proxy for asset consumption and future replacement)

c) Plus, a reasonable surplus margin.

4.5.1.14. The COCT applied for a Capital Replacement Reserve (CRR) of R401.039 million, which is based on a 2% return on OPEX, including bulk purchases. Therefore, the CRR provision has been included in the approved revenue requirement for the wires and retail components of the business.

4.5.1.15. Although the CRR proposed by the municipality falls below the established target range of 10–20, it is considered reasonable.

4.5.1.16. To ensure that the surplus is not excessive or detrimental to consumers, verification was undertaken by benchmarking the applied surplus margin of 2% against the established target range of 10–20%, in line with the approved NERSA COS Framework, EPP Policy Position 1.

4.5.1.17. Therefore, the applied CRR 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, NERSA decides to allow the revenue requirement as applied for.

4.5.2. **Cost Functionalisation**

4.5.2.1. The licensee has categorised its revenue requirement of R23.27 billion into two primary functional components, namely the fixed (69%) and variable (31%), in accordance with the NERSA COS Framework, as illustrated in table 5 below. Upon verification, the allocation of costs to these functional components is found to be consistent with the stated revenue requirement.

Table 5: Cost functionalisation

Summary - Cost of Supply		Rands	Rands	Rands	Rands	Rands	Rands	Rands	Rands	Rands	Rands
Nature	**Component**	**LL**	**Domestic**	**Home User**	**Residential**	**SPU 1**	**SPU 2**	**SPU Total**	**LPU LV**	**LPU MV**	**Total**
Variable	Admin	7 300 028	8 604 415	30 723 902	46 628 345	27 895 525	1 319 705	29 215 230	252 752	1 863 564	77 959 890
	Energy Post Losses	779 961 660	919 327 093	3 282 653 798	4 981 942 551	2 980 459 663	141 002 134	3 121 461 797	786 463 014	5 611 610 451	14 501 477 813
	Network	106 492 487	153 538 983	461 443 055	721 474 525	724 880 968	213 640 006	938 520 973	225 509 196	313 189 213	2 198 693 908
	Total	893 754 175	1 081 470 491	3 774 820 755	5 750 045 421	3 733 236 156	355 961 845	4 089 198 000	1 012 224 962	5 926 663 228	16 778 131 611
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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 variable business.

4.5.3. Cost Classification

4.5.3.1. The licensee classified its costs into admin, energy, and network-related costs, which are in line with the NERSA COS Framework. The classification is indicated in Table 5 above.

4.5.3.2. 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. The network costs are related to building, operating, maintaining and upgrading the electricity grid. Admin costs are the non-technical operational costs of running the electricity business.

4.5.4. Cost Allocation

4.5.4.1. Table 6 below shows the allocation of the licensee's revenue requirements between customer categories, which is in line with the NERSA COS Framework.

4.5.4.2. The domestic customer category carries the largest proportion of costs (R9.5 billion), followed by Large Power User at R8.0 billion, while the Small Power Users carry the smallest proportion of costs at R5.3 billion.

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

Table 6: Costs allocated

Summary - Cost of Supply		Rands	Rands	Rands	Rands	Rands	Rands	Rands	Rands	Rands	Rands
Nature	**Component**	**LL**	**Domestic**	**Home User**	**Residential**	**SPU 1**	**SPU 2**	**SPU Total**	**LPU LV**	**LPU MV**	**Total**
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	Network	222 765 168	307 834 181	925 158 821	1 455 758 170	1 453 332 139	428 332 237	1 881 664 375	424 424 736	589 444 916	4 351 292 196
	Total	1 039 604 559	819 518 156	2 330 208 778	4 189 331 494	1 621 691 966	503 965 116	2 125 657 082	455 021 075	632 054 372	7 402 064 023
TOTAL REVENUE REQUIREMENT 2026/27		**1 933 358 734**	**1 900 988 647**	**6 105 029 533**	**9 939 376 914**	**5 354 928 122**	**859 926 960**	**6 214 855 082**	**1 467 246 037**	**6 558 717 601**	**24 180 195 634**
REVENUE REQUIREMENT 2025/26											**22 354 334 462**
INCREASE IN REVENUE REQUIREMENT											**8,17%**
Total Revenue From Sales		**948 719 651**	**1 773 490 208**	**6 789 308 673**	**9 511 518 533**	**4 860 746 384**	**448 176 173**	**5 308 922 557**	**1 276 652 908**	**7 174 151 521**	**23 271 245 519**

4.5.5. Rate Design

4.5.5.1. Table 7 below illustrates that the SPU (Small Power Users) 2 and the Lifeline (LL) customers are the most undercharged customer categories by 46.87% and 48.43%, respectively. The licensee is over-recovering from the Domestic Home User group and LPU MV customers by 14.54% and 14.85%, respectively. Significant under-recovery in LL, SPU Total and LPU LV tariffs.

4.5.5.2. To achieve full cost reflectivity, the municipality would be required to implement differentiated tariff adjustments across customer categories. A cross-subsidy framework is needed to adequately address the cross-subsidy issue in a fair and transparent manner.

Table 7: COS results with cost-reflective units

Summary - Cost of Supply		Rands	Rands	Rands	Rands	Rands	Rands	Rands	Rands	Rands	Rands
Nature	**Component**	**LL**	**Domestic**	**Home User**	**Residential**	**SPU 1**	**SPU 2**	**SPU Total**	**LPU LV**	**LPU MV**	**Total**
Variable	Admin	7 300 028	8 604 415	30 723 902	46 628 345	27 895 525	1 319 705	29 215 230	252 752	1 863 564	77 959 890
	Energy Post Losses	779 961 660	919 327 093	3 282 653 798	4 981 942 551	2 980 459 663	141 002 134	3 121 461 797	786 463 014	5 611 610 451	14 501 477 813
	Network	106 492 487	153 538 983	461 443 055	721 474 525	724 880 968	213 640 006	938 520 973	225 509 196	313 189 213	2 198 693 908
	Total	893 754 175	1 081 470 491	3 774 820 755	5 750 045 421	3 733 236 156	355 961 845	4 089 198 000	1 012 224 962	5 926 663 228	16 778 131 611
Fixed	Admin	802 838 586	492 236 654	1 346 603 356	2 641 678 596	76 546 052	48 573 132	125 119 185	2 381 506	3 424 441	2 772 603 728
	Energy	14 000 805	19 447 322	58 446 601	91 894 728	91 813 775	27 059 747	118 873 522	28 214 833	39 185 016	278 168 099
	Network	222 765 168	307 834 181	925 158 821	1 455 758 170	1 453 332 139	428 332 237	1 881 664 375	424 424 736	589 444 916	4 351 292 196
	Total	1 039 604 559	819 518 156	2 330 208 778	4 189 331 494	1 621 691 966	503 965 116	2 125 657 082	455 021 075	632 054 372	7 402 064 023
TOTAL REVENUE REQUIREMENT 2026/27		**1 933 358 734**	**1 900 988 647**	**6 105 029 533**	**9 939 376 914**	**5 354 928 122**	**859 926 960**	**6 214 855 082**	**1 467 246 037**	**6 558 717 601**	**24 180 195 634**
REVENUE REQUIREMENT 2025/26											**22 354 334 462**
INCREASE IN REVENUE REQUIREMENT											**8,17%**
Total Revenue From Sales		**948 719 651**	**1 773 490 208**	**6 789 308 673**	**9 511 518 533**	**4 860 746 384**	**448 176 173**	**5 308 922 557**	**1 276 652 908**	**7 174 151 521**	**23 271 245 519**
Other Non-tariff Revenue Sources		**48 265 291**	**56 889 449**	**203 135 933**	**308 290 673**	**184 435 670**	**8 725 440**	**193 161 111**	**48 667 605**	**358 830 727**	**908 950 115**
TOTAL EXCHANGE REVENUE		**996 984 942**	**1 830 379 657**	**6 992 444 606**	**9 819 809 205**	**5 045 182 055**	**456 901 613**	**5 502 083 668**	**1 325 320 512**	**7 532 982 248**	**24 180 195 634**
Estimated Subsidy (Received)/Paid		**-936 373 793**	**-70 608 990**	**887 415 073**	**-119 567 709**	**-309 746 067**	**-403 025 347**	**-712 771 414**	**-141 925 524**	**974 264 647**	**0**
Percentage Subsidy on Cost		**-48,43%**	**-3,71%**	**14,54%**	**-1,20%**	**-5,78%**	**-46,87%**	**-11,47%**	**-9,67%**	**14,85%**	**0,00%**

Recovery of Costs											
Nature	**Recovery Basis**	**LL**	**Domestic**	**Home User**	**Residential**	**SPU 1**	**SPU 2**	**SPU Total**	**LPU LV**	**LPU MV**	
Service Charge	R/Customer/Day	11,99	12,35	12,40	12,26	26,13	18,50	23,17	144,53	139,97	
Energy	c/kWh	194,7327	194,7327	194,7327	194,7327	194,7327	194,7327	194,7327	192,9890	186,7655	
Energy Demand	R/kVA Measured	23,6768	23,6768	23,6768	23,6768	23,6768	23,6768	23,6768	220,01	43,93	
Network Demand	R/kVA AC	49,53	47,47	47,47	47,77	47,47	47,47	47,47	44,56	22,28	

5. CONCLUSION ON THE COS STUDY

5.1. While the COS study outcome reflected that the revenue requirement for the 2026/27FY was 8.17% more than the revenue applied for in the FY2025/26. To achieve this, the municipality is applying for an average tariff increase of 19% on the NERSA-approved tariffs for FY2025/26. This would result in cost reflectivity in that the tariffs would then yield the required revenue.

5.2. The licensee applied for a completely new set of tariffs in 2025/26FY, and not simply an evolution of those that were previously charged to customers. According to the COCT, the electricity tariffs for 2025/26 were the first step in a multi-year process to migrate to a more unbundled, cost-reflective tariff structure to future-proof the COCT's Electrical Utility financially. This continues into the 2026/27 tariffs.

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the City's COS study, which resulted in the approval on 20 June 2025, of an increase of 12.80% of the electricity tariff for the 2025/26 tariff cycle. NERSA has filed its record and is finalising its answering affidavit.

8.3. The Energy Regulator notes the existence of this pending litigation. However, the institution of review proceedings does not suspend the operation of the impugned decision, nor does it limit or fetter the Energy Regulator's statutory mandate to regulate electricity tariffs on an ongoing basis.

8.4. In terms of sections 4(a)(ii), 14 and 15 of the ERA, the Energy Regulator is expressly empowered and obliged to determine and approve electricity tariffs for licensed distributors on an annual basis. This statutory obligation is further reinforced by the Municipal Finance Management Act, 2003 (Act No. 56 of 2003), which requires municipalities to adopt budgets and tariffs within prescribed time frames.

8.5. The annual determination of municipal tariffs is a prospective (forward-looking) regulatory function directed at ensuring the continued financial viability, operational sustainability and regulatory oversight of licensed electricity distributors. Any failure to determine tariffs for a forthcoming financial year would result in regulatory uncertainty and may adversely affect municipal budgeting processes, service delivery obligations and compliance with applicable legislative frameworks.

8.6. In fulfilling this mandate, the Energy Regulator is entitled to rely on the most recent approved and implemented tariff determinations as a lawful and operative baseline. Accordingly, the 2025/26FY municipal tariff determinations constitute the applicable base against which the 2026/27 tariff determinations are assessed.

8.7. The utilisation of a prior tariff determination as a base year reflects established regulatory practice and does not constitute a reconsideration of, or pronouncement on, the validity of any previous decision that may be subject to judicial review.

8.8. This reasons for decision (RfD) document is confined to the determination of municipal electricity tariffs for the 2026/27FY and does not seek to pre-empt, determine or otherwise interfere with matters currently before the courts.

8.9. All NERSA's tariff decisions in respect of the COCT have not been set aside. Therefore, the principle of using NERSA-approved tariffs to analyse the COCT's tariff application stands. Using the COCT's tariff base in the analysis of the tariff application would be tantamount to NERSA reviewing its own decisions, whereas the court has not yet pronounced on the review applications.

9. COCT TARIFF ANALYSIS AND KEY FINDINGS

9.1. This section sets out the key considerations, findings, customer impacts, and revenue implications arising from the COCT's tariff application. The analysis considers compliance with NERSA tariff-setting principles and COS requirements, the financial sustainability of the COCT electricity business, the impact of Eskom bulk electricity purchase increases, the effect of tariff restructuring on different customer categories, customer affordability and social protection considerations, as well as the long-term sustainability risks associated with declining electricity sales volumes and increasing levels of embedded generation.

9.2. The application reflects significant financial pressure within the municipal electricity distribution business. These pressures arise from rising Eskom bulk electricity purchase costs, revenue under-recovery experienced during previous tariff periods, declining electricity sales volumes, growth in small-scale embedded generation (SSEG), increasing operational and infrastructure-related costs and the need to improve tariff cost reflectivity.

Revenue Adequacy and Financial Sustainability

9.3. The COCT raised concerns regarding revenue adequacy and the long-term financial sustainability of the electricity service. The municipality indicated that previous tariff approval outcomes resulted in revenue under-recovery relative to its approved revenue requirement.

9.4. Insufficient revenue recovery may adversely affect infrastructure maintenance, asset replacement programmes, service reliability, financial sustainability and future tariff stability. It is, therefore, important to balance customer affordability considerations with the need to ensure prudent cost recovery and the continued operational sustainability of the electricity distribution business.

9.5. The COCT proposed significant tariff restructuring measures aimed at improving cost reflectivity and correcting historical tariff distortions. While the restructuring may result in uneven tariff impacts across customer categories, including higher-than-average increases for certain customers, NERSA considered whether the restructuring remained aligned with approved COS principles and whether the changes were transparent and appropriately justified. NERSA further considered the proposed implementation measures to be reasonable and proportionate.

9.6. The application further reflects ongoing declines in electricity sales volumes. As network and infrastructure costs remain largely fixed, declining sales volumes may result in increasing tariff burdens being carried by the remaining customer base.

9.7. Table 9 below indicates the tariffs that are based on the approved cost-of-supply methodology. The projected sales volumes and revenue recovery for the two years are reflected in the table below, together with the corresponding average tariffs for each year.

Table 9: Revenue impact analysis

	ENERGY		REVENUE	
	2025/26	2026/27	2025/26	2026/27
Home User	1 741 057 050	1 701 500 772	R5 955 515 241	R6 789 308 673
Domestic	487 591 490	476 515 604	R1 609 703 555	R1 773 490 208
Lifeline	413 675 036	404 278 200	R859 658 092	R948 719 651
Small Power 1	1 545 176 501	1 544 864 226	R4 161 302 621	R4 860 746 384
Small Power 2	73 007 196	73 085 757	R363 403 863	R448 176 173
Large User LV	410 657 317	407 648 052	R1 073 189 496	R1 276 652 908
Large User MV	3 029 776 117	3 005 626 577	R5 681 995 527	R7 174 151 521
TOTAL	7 700 940 708	7 613 519 188	R19 704 768 394	R23 271 245 519

Customer Impact Analysis

9.8. The COS methodology applied by the COCT appears to be rigorous and comprehensive, resulting in a high likelihood that the proposed tariffs will recover the required revenue with minimal over- or under-recovery. The proposed tariffs are therefore

considered to be cost-reflective and capable of enabling the licensee to recover its efficient costs, as required in terms of section 15 of the ERA.

9.9. Although concerns may arise regarding the potential impact on customers, the actual customer impact is expected to be lower than the headline increase reflected in the NERSA-approved tariffs. In practice, customers are already paying tariffs that differ from the approved benchmark tariffs, and the effective impact is estimated to be approximately 7.48% rather than 19.46%. Based on the facts and evidence before the Regulator Executive Committee, the tariffs should be approved as applied for.

10. TARIFF ANALYSIS

10.1. Consumption Tariffs

1. Residential: Lifeline	2025/26 NERSA Approved	2025/26 Actual	2026/27 COS	% Increase COS to NERSA	% Increase COS to Actual	NERSA 2026/27 Recommended	% Increase NERSA Recommended
Tariff Blocks							
Block 1 (0 - 600kWh) (c/kWh)	207.81	216.18	234.67	12.93%	3.59%	234.67	12.93%
Block 2 (>600kWh) (c/kWh)	207.81	216.18	234.67	12.93%	3.59%	234.67	12.93%

2. Residential: Domestic	2025/26 NERSA Approved	2025/26 Actual	2026/27 COS	% Increase COS to NERSA	% Increase COS to Actual	NERSA 2026/27 Recommended	% Increase NERSA Recommended
Tariff Blocks							
Service and Wires Charge (R/month)	59.90	59.90	65.02	8.54%	8.55%	65.02	8.54%
Service and Wires Charge (R/day)	New	1.97	2.14	New		2.14	New
Block 1 (0 - 600kWh) (c/kWh)	308.58	320.92	348.37	12.90%	2.48%	348.37	12.90%
Block 2 (>600kWh) (c/kWh)	370.21	385.10	418.03	12.92%	3.44%	418.03	12.92%

3. Residential: Home User	2025/26 NERSA Approved	2025/26 Actual	2026/27 COS	% Increase COS to NERSA	% Increase COS to Actual	NERSA 2026/27 Recommended	% Increase NERSA Recommended
Tariff Blocks	***c/kWh***						
Block 1 (0 - 600kWh) (c/kWh)	264.60	274.59	298.07	12.65%	12.65%	298.07	12.65%
Block 2 (>600kWh) (c/kWh)	365.20	365.20	396.43	8.55%	8.55%	396.43	8.55%
Service and Wires Charge (R/month)	263.51	339.89	368.96	40.02%	40.02%	368.96	40.02%

4. Residential Time of Use	2025/26 NERSA Approved	2025/26 Actual	2026/27 COS	% Increase COS to NERSA	% Increase COS to Actual	NERSA 2026/27 Recommended	% Increase NERSA Recommended
Administration Charge (R/month)	New	New	344.49	New	New	344.49	New
Capacity Charge (R/month)			250.85	New	New	250.85	New
Energy Charge per meter - TOU (c/kWh)							
High Demand (June to August):							
Peak	New	New	781.07	New	New	781.07	New
Standard	New	New	321.12	New	New	321.12	New
Off-peak	New	New	261.69	New	New	261.69	New
Low Demand (September to May)							
Peak	New	New	363.95	New	New	363.95	New
Standard	New	New	309.22	New	New	309.22	New
Off-peak	New	New	261.69	New	New	261.69	New

5. Commercial: Small Power User 1 (High consumption - >1300 kWh / month)	2025/26 NERSA Approved	2025/26 Actual	2026/27 COS	% Increase COS to NERSA	% Increase COS to Actual	NERSA 2026/27 Recommended	% Increase NERSA Recommended
Service and Wires Charge (R/month)	3 030.60	3 872.95	4 204.18	38.72%	8.55%	4 204.18	38.72%
Service and Wires Charge (R/day)	New	99.56	138.11	New		138.11	New
Energy charge c/kWh	227.70	236.75	257.00	12.87%	-8.17%	257.00	12.87%

6. Commercial: Small Power User 2 (Low consumption - <1300 kWh / month)	2025/26 NERSA Approved	2025/26 Actual	2026/27 COS	% Increase COS to NERSA	% Increase COS to Actual	NERSA 2026/27 Recommended	% Increase NERSA Recommended
Service and Wires Charge (R/month)	239.49	282.68	306.86	28.13%	8.55%	306.86	28.13%
Service and Wires Charge (R/day)	New	New	10.08	New		10.08	New
Energy charge c/kWh	453.70	512.92	556.79	22.72%	4.67%	556.79	22.72%

7. Commercial: Small Power User 3 (Very Low consumption - <250 kWh / month)	2025/26 NERSA Approved	2025/26 Actual	2026/27 COS	% Increase COS to NERSA	% Increase COS to Actual	NERSA 2026/27 Recommended	% Increase NERSA Recommended
Energy charge c/kWh	571.58	625.99	679.53	18.89%	5.35%	679.53	18.89%

8. Large User Low Voltage Time of Use	2025/26 NERSA Approved	2025/26 Actual	2026/27 COS	% Increase COS to NERSA	% Increase COS to Actual	NERSA 2026/27 Recommended	% Increase NERSA Recommended
Service charge (R/month)	2 321.35	2 321.35	2 519.88	8.55%	8.55%	2 519.88	8.55%
Energy Charge per meter - TOU (c/kWh)							
High Demand (June to August):							
Peak	659.18	685.93	742.64	12.66%	1.87%	742.64	12.66%
Standard	191.85	191.85	207.86	8.35%	-11.53%	207.86	8.35%
Off-peak	119.77	136.93	148.43	23.93%	-17.56%	148.43	23.93%

Low Demand (September to May)							
Peak	229.89	300.55	325.52	41.60%	-5.28%	325.52	41.60%
Standard	160.64	179.76	195.96	21.98%	-12.07%	195.96	21.98%
Off-peak	104.68	136.93	148.42	41.78%	-17.56%	148.42	41.78%
Energy demand charge R/kVA/month	234.69	234.69	254.76	-18.83%	8.55%	254.76	-18.83%
Network capacity charge R/kVA NMD/month	35.81	35.81	39.00	8.91%	8.91%	39.00	8.91%

9. Large User Medium Voltage Time of Use	**2025/26 NERSA Approved**	**2025/26 Actual**	**2026/27 COS**	**% Increase COS to NERSA**	**% Increase COS to Actual**	**NERSA 2026/27 Recommended**	**% Increase NERSA Recommended**
Service charge (R/month)	2 404.57	2 404.57	2 610.22	8.55%	8.55%	2 610.22	8.55%
Energy Charge per meter - TOU (c/kWh)							
High Demand (June to August):							
Peak	637.93	663.80	718.68	12.66%	1.66%	718.68	12.66%
Standard	185.67	185.67	201.16	8.34%	-12.07%	201.16	8.34%
Off-peak	119.77	132.52	143.64	19.93%	-18.21%	143.64	19.93%
Low Demand (September to May)							
Peak	229.89	290.85	315.02	37.03%	-5.67%	315.02	37.03%
Standard	160.64	173.97	189.64	18.05%	-12.64%	189.64	18.05%
Off-peak	104.68	132.52	143.64	37.22%	-18.21%	143.64	37.22%
Energy demand charge R/kVA/month	75.89	75.89	82.38	8.56%	8.55%	82.38	8.56%
Network capacity charge R/kVA NMD/month	3.74	17.47	19.15	9.60%	9.62%	19.15	9.60%

10. Large User High Voltage Time of Use	2025/26 NERSA Approved	2025/26 Actual	2026/27 COS	% Increase COS to NERSA	% Increase COS to Actual	NERSA 2026/27 Recommended	% Increase NERSA Recommended
Service charge (R/month)	2 404.57	2 404.57	2 610.22	8.55%	8.55%	2 610.22	8.55%
Energy Charge per meter - TOU (c/kWh)							
High Demand (June to August):							
Peak	612.08	638.58	692.41	13.12%	1.57%	692.41	13.12%
Standard	178.61	178.61	193.80	8.50%	-12.59%	193.80	8.50%
Off-peak	113.41	127.48	138.39	22.03%	-18.88%	138.39	22.03%
Low Demand (September to May)							
Peak	219.31	279.80	303.50	38.39%	-6.01%	303.50	38.39%
Standard	152.72	167.36	182.70	19.63%	-13.19%	182.70	19.63%
Off-peak	98.93	127.48	138.39	39.89%	-18.88%	138.39	39.89%
Energy demand charge R/kVA/month	73.01	73.01	78.67	7.75%	7.75%	78.67	7.75%
Network capacity charge R/kVA NMD/month	3.56	16.81	18.28	413.43%	8.74%	18.28	8.74%

10.2. Generation Tariffs

11. Residential: Small-Scale Embedded Generation	2025/26 NERSA	2025/26 Actual	2026/27 Proposed	Proposed % Increase 2026/27	NERSA 2026/27 Recommended	NERSA 2026/27 Recommended % increase
	c/kWh					
SSEG Feed-in Tariff (c/kWh)	101.23	101.23	107.98	6.67%	107.98	6.67%
SSEG Feed-in Incentive (c/kWh)	25.00	25.00	25.00	0.00%	25.00	0.00%

12. Non-Residential Small-Scale Embedded Generation	2025/26 NERSA	2025/26 Actual	2026/27 Proposed	Proposed % Increase 2026/27	NERSA 2026/27 Recommended	NERSA 2026/27 Recommended % increase
SSEG Feed-in Tariff 1 (c/kWh)	90.17	90.17	96.18	6.67%	96.18	6.67%
SSEG Feed-in Tariff 2 (c/kWh)	71.37	71.37	768.46	-4.08%	768.46	-4.08%
High Demand (June to August):						
Peak	586.62	586.62	625.73	6.67%	625.73	6.67%
Standard	133.84	133.84	135.65	1.35%	135.65	1.35%
Off-peak	83.51	83.51	91.18	9.19%	91.18	9.19%
Low Demand (September to May)						
Peak	233.45	233.45	243.47	4.29%	243.47	4.29%
Standard	123.76	123.76	124.74	0.79%	124.74	0.79%
Off-peak	83.51	83.51	81.18	-2.79%	81.18	-2.79%
SSEG Feed-in Incentive c/kWh	25.00	25.00	25.00	0.00%	25.00	0.00%

13. Wheeling Use of System Charges MV	2025/26 NERSA	2025/26 Actual	2026/27 Proposed	Proposed % Increase 2026/27	NERSA 2026/27 Recommended	NERSA 2026/27 Recommended % increase
Service charge (R/month)	4 809.14	4 809.14	5 220.44	8.55%	5 220.44	8.55%
Energy Charge per meter - TOU (c/kWh)						
High Demand (June to August):						
Peak	115.74	115.74	121.24	4.76%	121.24	4.76%
Standard	48.66	48.66	51.81	6.47%	51.81	6.47%
Off-peak	41.17	41.17	44.06	7.02%	44.06	7.02%
Low Demand (September to May)						
Peak	63.41	63.41	67.09	5.80%	67.09	5.80%
Standard	46.09	46.09	50.24	9.01%	50.24	9.01%
Off-peak	41.17	41.17	44.06	7.02%	44.06	7.02%
Energy demand charge R/kVA/month	75.89	75.89	82.38	8.56%	82.38	8.56%
Network capacity charge R/kVA NMD/MEC	17.47	17.47	19.15	9.60%	19.15	9.60%

14. Wheeling Use of System Charges HV	2025/26 NERSA	2025/26 Actual	2026/27 Proposed	Proposed % Increase 2026/27	NERSA 2026/27 Recommended	NERSA 2026/27 Recommended % increase
Service charge (R/month)	4 809.14	4 809.14	5 220.44	8.55%	5 220.44	8.55%
Energy Charge per meter - TOU (c/kWh)						
High Demand (June to August):						
Peak	90.52	90.52	94.97	4.92%	94.97	4.92%
Standard	41.63	41.63	44.45	6.78%	44.45	6.78%
Off-peak	36.13	36.13	38.81	7.41%	38.81	7.41%
Low Demand (September to May)						

Peak	52.36	52.36	55.57	6.14%	55.57	6.14%
Standard	39.48	39.48	43.30	9.69%	43.30	9.69%
Off-peak	36.13	36.13	38.31	7.41%	38.31	7.41%
Energy demand charge R/kVA/month	73.01	73.01	78.67	7.75%	78.67	7.75%
Network capacity charge R/kVA NMD/MEC	16.81	16.81	18.38	8.73%	18.38	8.73%

15. Wheeling Deficit Energy (All Voltage Levels)	**2025/26 NERSA**	**2025/26 Actual**	**2026/27 Proposed**	**Proposed % Increase 2026/27**	**NERSA 2026/27 Recommended**	**NERSA 2026/27 Recommended % increase**
Service charge (R/day)	0.00	0.00	0.00	0.00%	0.00	0.00%
Energy Charge per meter - TOU (c/kWh)						
High Demand (June to August):						
Peak	548.06	548.06	597.44	9.01%	597.44	9.01%
Standard	137.01	137.01	149.35	9.01%	149.35	9.01%
Off-peak	91.35	91.35	99.58	9.01%	99.58	9.01%
Low Demand (September to May)						9.01%
Peak	227.44	227.44	247.93	9.01%	247.93	9.01%
Standard	127.88	127.88	139.40	9.01%	139.40	9.01%
Off-peak	91.35	91.35	99.58	9.01%	99.58	9.01%
Energy demand charge R/kVA/month	0.00	0.00	0.00	0.00%	0.00	0.00%
Network capacity charge R/kVA NMD/month	0.00	0.00	0.00	0.00%	0.00	0.00%

16. Wheeling Excess Energy Feed-In	2025/26 NERSA	2025/26 Actual	2026/27 Proposed	Proposed % Increase 2026/27	NERSA 2026/27 Recommended	NERSA 2026/27 Recommended % increase
Energy Charge per meter - TOU (c/kWh)						
High Demand (June to August):						
Peak	501.90	501.90	538.04	7.20%	538.04	7.20%
Standard	112.64	112.64	113.71	0.95%	113.71	0.95%
Off-peak	69.41	69.41	66.58	-4.07%	66.58	-4.07%
Low Demand (September to May)						
Peak	198.28	198.28	207.06	4.43%	207.06	4.43%
Standard	104.00	104.00	104.29	0.28%	104.29	0.28%
Off-peak	69.41	69.41	66.58	-4.07%	66.58	-4.07%

17. Generator Tariff	2025/26 NERSA	2025/26 Actual	2026/27 Proposed	Proposed % Increase 2026/27	NERSA 2026/27 Recommended	NERSA 2026/27 Recommended % increase
Service Charge (R/month)	2 404.57	2 404.57	2 610.22	8.55%	2 610.22	8.55%
Network Capacity Charge (R/kVA MEC/month)	17.47	17.47	19.15	9.60%	19.15	9.60%

18. Street Lighting and Traffic Signal	2025/26 NERSA	2025/26 Actual	2026/27 Proposed	Proposed % Increase 2026/27	NERSA 2026/27 Recommended	NERSA 2026/27 Recommended % increase
Energy charge: R/100 W per burning hour	0.3549	0.3611	0.3920	10.45%	0.3920	10.45%

11. CONFIDENTIALITY

11.1. None.

12. CONCLUSION

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

End.