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

Tokologo Local Municipality

THE DECISION

At its meeting held on 27 May 2026, the Regulator Executive Committee (REC) considered Tokologo Local Municipality (TLM)'S tariff application. Based on the facts and evidence presented, REC approved the tariff increases for the 2026/27 financial year (FY) set out below.

a) to approve the tariffs that are based on the cost drivers as recommended in the tariff analysis section for implementation by the municipality with effect from 1 July 2026;
b) to note the cost drivers submitted by the municipality;
c) that the municipality must submit a report accounting for all the costs that have been noted in its Cost of Supply (COS) study by 31 January 2027, to enable the National Energy Regulator of South Africa (NERSA) to perform its independent verification/audit process; and

d) that the municipality must submit a quarterly progress report on the efficiency improvement measures taken to reduce high energy losses and deficits to enable NERSA to monitor the implementation thereof by 30 September 2026.

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ABBREVIATIONS

COS	Cost of Supply
D-form	Distribution form
ERTSA	Eskom's Retail Tariff Structural Adjustments
FBE	Free Basic Electricity
IBT	Inclining Block Tariff
IPP	Independent Power Producer
MFMA	Municipal Finance Management Act
TLM	Tokologo Local Municipality
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 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. Tokologo Local Municipality (TLM) is situated in the Free State. The customer base of the municipality is mostly domestic customers, accounting for 62% 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)

	2024/25		
Customer categories	***MWh***	***% MWh***	***Customer numbers***
Domestic(Prepaid)	7 676	61%	3 189
Domestic(Conventional)	69	1%	48
Agriculture		0%	
Manufacturing	8	0%	1
Commercial Prepaid	2 284	18%	133
Commercial Conventional	127	1%	22
Street Lighting	1 340	11%	
Sold to other departments	998	8%	3
Other consumers	170	1%	16
TOTAL	**12 674**	**100%**	**3412**
Free Basic Electricity	911	12%	1519

1.3. NERSA received TLM'S tariff application together with its existing COS based on the cost-plus methodology on 31 March 2026.

1.4. TLM implemented an 10.90% average price increase in 2025/26FY and is applying for an average price increase of 22% for the 2026/27FY.

1.5. For this application, the municipality has indicated that the tariff application has been approved by Council. The Council meeting at which this application was approved took place on 31 March 2026 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. TLM'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.

1.7. NERSA's decision was made on 27 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 ("ERA"), the Promotion of Administrative Justice Act, 2000 (Act 3 of 2000) ("PAJA") and the Electricity Pricing Policy for the South African Electricity Supply Industry, 2008 ("EPP").

2.1.2. The approval of municipal electricity tariffs follows the Eskom Multi-year Price Determination and 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 2026/27 municipal financial year.

2.2. Statutory Mandate of the Energy Regulator

2.2.1. NERSA is established as a juristic person in terms of section 3 of the NERA. In terms of section 4 of NERA, the Energy Regulator as the decision-making body, must regulate the electricity industry and execute the functions set out in the ERA. The electricity regulatory mandate of the Energy Regulator is therefore primarily governed by the ERA. Section 3 of the ERA 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. 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 (COS) Studies

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

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

2.6.3. Policy Position 23 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 2025/26FY 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 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 the 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 2026/27FY municipal tariff approvals.

2.8. **Court-Directed Timelines**

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

a) written notice of bulk tariffs by 6 March 2026;
b) municipal tariff applications to be submitted by 31 March 2026;
c) public participation processes to be concluded by 21 April 2026; and
d) the publication of NERSA decisions 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 be communicated by 31 January each year;
b) municipal tariff applications be submitted to NERSA by 20 March each year; and
c) municipal tariff approvals and the tariff reasons for decision document, 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 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 TLM, the assessment relied on the Distribution forms (D-forms) for 2024/25FY 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 purposes of the tariff analysis.

Table 2: Performance indicators

Performance indicators	***Municipality 2024/25 D-forms Information***	***Municipality 2023/24 D-forms Information***
Percentage surplus: (%)	-97.77	-46.48[1]
Energy Losses: (%)	25.42	18.06

Surplus/Deficit

3.2. The municipality continues to operate at a deficit position, indicating that the expenditure required to operate and maintain the electricity undertaking exceeds the revenue generated from electricity operations. This raises concerns regarding the long-term financial sustainability of the electricity business and may impair the municipality's ability to adequately fund operations, maintenance and future infrastructure investment.

Energy Losses

3.3. Energy losses increased from 18.06% in 2023/24FY to 25.42% in 2024/25FY, which is significantly above prudent and acceptable industry benchmark levels. The increase in losses is attributable to factors such as escalating technical losses, electricity theft, illegal connections, metering inaccuracies, billing inefficiencies and deteriorating network infrastructure.

[1] Total Electricity Purchases divided by Total Expenditure

Table 3: Assessment of Energy Losses and Revenue Impact

	D-Form Input	Energy Loss@12%	Energy Loss@6%
Average Selling Price	274,47		
Sales kWh	11 068 460,92	13 060 221,30	13 950 690,94
Purchases kWh	14 841 160,57	14 841 160,57	14 841 160,57
Losses kWh	3 772 699,65	1 780 939,27	890 469,63
Losses percentage	**25,42%**	**12,00%**	**6,00%**
Additional Energy (kWh)		1 991 760,38	2 882 230,02
Additional Revenue (Rands)		5 466 741,45	7 910 794,11
	D-Form Input	**Energy Loss@12%**	**Energy Loss@6%**
Total Revenue (Rands)	R 43 826 433,75	R 49 293 175,20	R 51 737 227,86
Total Expenses (Rands)	R 85 799 160,61	R 85 799 160,61	R 85 799 160,61
Net Profit (Loss)	R -41 972 726,86	R -36 505 985,41	R -34 061 932,75
Percentage Surplus/Deficit	**-95,77%**	**-74,06%**	**-65,84%**

3.4. The analysis indicates that, should the municipality reduce losses to 12%, energy losses would decrease to approximately 1 780 939,27 kWh. This would result in additional energy sales of approximately 1 991 760,38 kWh, generating additional revenue of approximately R5 466 741,45.

3.5. Furthermore, should losses be reduced to 6%, energy losses would decrease further to approximately 890 469,63 kWh. This reduction would make available approximately 2 882 230,02 kWh for additional sales and generate additional revenue of approximately R7 910 794,11.

3.6. The municipality's D-Form submission reflects total expenditure amounting to R85 799 160,61, against projected revenue of approximately R43 826 433,75, resulting in a net deficit of approximately R41 972 726,86. This represents a deficit margin of approximately 95.77%, indicating severe financial strain within the electricity undertaking.

3.7. Under the 12% loss scenario, the projected deficit decreases to approximately R36 505 985,41, representing a deficit margin of approximately 74.06%. Under the 6% loss scenario, the projected deficit further decreases to approximately R34 061 932,75, equivalent to a deficit margin of approximately 65.84%.

3.8. Although the reduction in losses improves the municipality's financial position, the electricity undertaking continues to operate at a significant deficit under all assessed scenarios. This indicates that the municipality's financial challenges are not only attributable to excessive losses, but also to broader structural cost and revenue recovery constraints.

3.9. The Energy Regulator is therefore of the view that the municipality should implement urgent interventions aimed at reducing losses and improving operational efficiency. Such interventions should include improved maintenance of network infrastructure, replacement of aging equipment, enhanced metering and energy balancing, strengthening of revenue protection measures and improved credit control and debt collection processes.

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

4.1. The licensee submitted its existing COS study which supports the tariffs application which will be approved in 2026/27FY. The licensee's cost of supply study was inclusive of all requirements of NERSA's approved COS framework (i.e. Revenue Requirement, Costs Functionalisation, Costs Classification, Costs Allocation and Rate Setting).

4.2. Policy position 23 states that, 'Electricity distributors shall undertake COS studies at least every five years, but at least when significant licensee structure changes occur, such as in customer base, relationships between cost components and sales volumes. This must be done according to the approved NERSA standard to reflect changing costs and customer behaviour. The cost-of-service methodology used to derive tariffs must accompany applications to the regulator for changes to tariff structures.

4.3. TLM's 2026/27 tariff application is based on an existing COS study. The study is valid for five years and has been adjusted to reflect key cost drivers for 2026/27FYin line with Section 18.7 of the COS Framework.

4.4. The revenue requirement for TLM's was determined using a cost-plus methodology in accordance with the NERSA COS Framework. Aligned to the NERSA COS Framework: costs were built up from verified bulk purchases (Eskom invoices) and verified electricity-related operating costs (tested against D-Forms, Trial Balance and Audited Financial Statement (AFS).

4.5. The cost to serve recommends an average tariff increase of 75.59% before taking out the inefficiencies and 9,11% after excluding all inefficiencies. The licensee is proposing 22% increase to review its tariffs for 2026/27FY. NERSA recommendation is to increase the tariff by 9.11%.

4.6. Section 18.7 of October 2023 NERSA-approved Cost of Supply Framework states that:

"An adjustment index will be issued to licensees to allow them to submit the tariff applications, which will be used to determine the costs that must

increase with CPI, purchase costs, and other OPEX. Where annual plans, such as repairs and maintenance, and CAPEX plans, have been assessed and approved by NERSA, these can be adjusted based on that."

4.7. In line with section 18.7 mentioned above, table 5 below was developed and the definition of the columns is as follows:

a) Column 1: is the actual 2024/25 licensee performance and is sourced from the D-forms that are based on the audited annual statements;

b) Column 2: is for the 2025/26 revenues and electricity volume that are the base for 2026/27 tariffs. The figures were tested for reasonableness (since at the time of the approval, the figures were estimates) when the Regulator considered and approved the 2026/27 cost of supply base tariffs. Once the financial year ends, the actual figures will be verified using the audited statements;

c) Column 3: is for the licensee's submitted FY 2026/27 budgeted figures to be tested for reasonableness for determining tariffs for the control period under review;

d) Column 4: is for NERSA's recommended adjustments after considering the reasons, facts and evidence the licensee provided to motivate/justify the budgeted figures; and

e) Column 5: is for the NERSA's recommended amounts that sum up to allowable revenues the licensee must recover in 2026/27FY.

4.8. The municipality applied for total allowable revenue amounting to R114 323 076. Following the prudency assessment and adjustments amounting to R43 283 077, the Energy Regulator approved total allowable revenue of R71 039 999.

4.9. The municipality applied for an average tariff increase of approximately 75.59%, mainly driven by the inclusion of Eskom debt interest and the significant financial pressures facing the electricity undertaking. The Energy Regulator noted that the municipality's escalating Eskom debt obligations, together with high energy losses and operational inefficiencies, materially increased the applied revenue requirement.

4.10. In particular, Eskom interest charges amounting to approximately R40 248 215 contributed significantly to the applied increase. The Energy Regulator is of the view that interest charges arising from overdue Eskom accounts constitute inefficient expenditure and should not be passed on to customers through electricity tariffs.

Table 4: Municipality's Revenue Requirement

Energy balance	Unit	Actual FY 2024/25 Costs	FY2025/26 Tariffs Costs per submitted COS	FY2026/27 budgeted Costs as per the Licensee	NERSA Adjustment (considering efficiencies)	FY2026/27 Allowable Revenue
Sales	kWh	11 068 461	11 511 199	11 971 647	-	11 971 647
Eskom bulk purchases	kWh	14 841 161	15 434 807	16 052 199	-	16 052 199
Total Energy Requirements	**kWh**	**14 841 161**	**15 434 807**	**16 052 199**		**16 052 199**
Total Losses	kWh	3 772 700	3 923 608	4 080 552		4 080 552
Technical losses	kWh	1 780 939	1 852 177	1 926 264	-	1 926 264
Non-technical losses	kWh	-1 991 760	-2 071 431	-2 154 288	-	-2 154 288
Allowed losses	%	12,00%	12,00%	12,00%		12,00%
Total Energy losses	%	25,42%	25,42%	25,42%		25,42%
Cost drivers						
Energy purchases from Eskom	Rand	31 268 434	35 245 779	38 421 423	-	38 421 423
total energy purchases		**31 268 434**	**35 245 779**	**38 421 423**	**-**	**38 421 423**
Non-Technical Losses				3 034 861	(3 034 861,34)	
Operational expenditure (incl. Depreciation)	Rand	28 337 039	29 780 025	71 438 811	(40 248 215,33)	31 190 596
General & Other	0	26 387 487	27 723 354	29 020 774	-	29 020 774
Salaries and allowances	Rand	824 627	874 105	900 328		900 328
Materials and supplies	Rand	2 561 097	2 689 152	2 769 826	-	2 769 826
Contracted Services	Rand	3 078 427	3 232 348	3 393 966	-	3 393 966
Salaries, wages and allowances (exclu. Repairs and Mainter	Rand	824 627	874 105	900 328	-	900 328
Current year depreciation	Rand	19 098 709	20 053 644	21 056 326	-	21 056 326
Shared OPEX	Rand	1 949 552	2 056 671	42 418 037	-	2 169 822
General expenses		**1 949 552**	**2 056 671**	**42 418 037**		**2 169 822**
1. Fuel and Oil	Rand	1 347 462	1 414 835	1 485 577		1 485 577
2. Protective Clothing	Rand	482 090	515 836	551 945	-	551 945
3. Telephone &Travelling &subsistance	Rand	120 000	126 000	132 300	-	132 300
Eskom Interest	Rand			40 248 215	(40 248 215,33)	0
Total Expediture before surplus		**59 605 472**	**65 025 803**	**112 895 096**	**-**	**69 612 019**
Surplus	Rand	1 788 164	1 950 774	3 386 853	(1 586 752,00)	501 609
Total Expenditure Including Surplus		61 393 637	66 976 578	116 281 948	-	70 113 628
Other revenues	Rand	**-1 776 301**	**-1 868 140**	**-1 958 884**	**-**	**-1 958 884**
Reconnection fees	Rand	47 847	53 263	53 263	-	53 263
Free Basic Electricity (Equitable share)	Rand	1 728 454	1 814 877	1 905 621	-	1 905 621
Total Allowable Revenus	Rand	59 617 336	65 108 438	114 323 065	(43 283 076,67)	71 039 988
increase required				*75,59%*	*9,11%*	

4.11. It is important to test the efficiency and prudency of the costs in the 2025/26FY since this is the most recently considered revenues in support of the approved tariffs during this period. This forms the basis on which costs for the 2026/27FY will be projected using assumptions to calculate revenue requirements for that year.

4.12. Furthermore, NERSA has verified all expense items included in the revenue requirement 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.

BULK PURCHASES

4.13. The municipality applied for energy purchase costs amounting to R38 421 423. The Energy Regulator assessed the applied bulk purchase costs against the approved Eskom bulk tariffs, projected sales volumes and energy balance information and found the costs to be reasonable.

4.14. However, the assessment identified non-technical losses amounting to R3 034 861. The Energy Regulator is of the view that customers should not bear the full cost of inefficient non-technical losses through electricity tariffs. Consequently, the costs associated with non-technical losses were disallowed from the allowable revenue requirement.

4.15. To get to the 2026/27FY estimate, the licensee provided the year-to-date figures for 2025/26FY, then made an estimate that this cost item would increase by 9.01% in line with the approved Eskom Retail Tariff Structural Adjustments (ERTSA).

4.16. All verifications have been satisfactory to NERSA and therefore this cost has been approved as applied for.

OPERATING EXPENDITURE (INCLUDING DEPRECIATION)

4.17. The municipality applied for operational expenditure amounting to R71 438 812 for 2026/27FY. Following the prudency assessment undertaken by the Energy Regulator, adjustments amounting to R40 248 215 relating to Eskom interest were made, resulting in approved operational expenditure of R31 190 596, as reflected in Table 6 below.

Table 5:Operating expenditures

Cost drivers	Units	2024/25FY Actuals	2024/25FY Budgeted	2026/27FY Applied	NERSA Adjustments	2026/27FY Recommended
General costs and other	**R**	**26 387 487**	**27 723 354**	**29 020 775**	**-**	**29 020 774**
Salaries and allowances	R	824627	874105	900 328		900 328
Materials and supplies	R	2561097	2689152	2 769 826	-	2 769 826
Contracted Services	R	3078427	3232348	3 393 966	-	3 393 966
Salaries, wages and allowances (exclu. Repai	R	824627	874105	900 328	-	900 328
Current year depreciation	R	19 098 709	20 053 644	21 056 326	-	21 056 326
Shared OPEX	**R**	**1949552**	**2056671,4**	**42 418 037**	**(40 248 215,00)**	**2 169 822**
1. Fuel and Oil	R	1 347 462	1 414 835	1 485 577		1 485 577
2. Protective Clothing	R	482 090	515 836	551 945	-	551 945
3. Telephone &Travelling &subsistance	R	120000	126000	132 300		132 300
4. Eskom Interest	R	0	0	40 248 215	(40 248 215,00)	-
Total Opex	**R**	**28 337 039**	**29 780 026**	**71 438 812**	**(40 248 215,00)**	**31 190 596**

GENERAL COSTS AND OTHER

4.18. The municipality applied for general costs and other expenditure amounting to R29 020 775. The applied costs include salaries and allowances, materials and supplies, contracted services and depreciation.

4.19. The Energy Regulator assessed the submitted costs against historical actual expenditure, budgeted amounts and supporting financial information. The costs were found to be reasonable, prudently incurred and directly attributable to the electricity undertaking. Accordingly, the costs were allowed substantially as applied for, resulting in recommended expenditure of R29 020 774.

SHARED OPERATING EXPENDITURE

4.20. The municipality applied for shared operating expenditure amounting to R42 418 037. The shared costs comprise fuel and oil, protective clothing, telephone and travelling subsistence, as well as Eskom interest charges.

4.21. Following the assessment of the supporting information submitted by the municipality, the Energy Regulator made adjustments amounting to R40 248 215 relating to interest on the Eskom account. Consequently, the recommended shared operating expenditure was adjusted to R2 169 822.

DEPRECIATION

4.22. The Energy Regulator notes that depreciation forms an important component of operational expenditure as it provides for the recovery of the cost of electricity infrastructure over its useful life. Adequate depreciation provision is necessary to ensure the sustainability of the electricity undertaking and to support future refurbishment and replacement of aging network assets.

SURPLUS/PROFIT MARGIN

4.23. The municipality applied for a surplus amounting to R3 386 853 for 2026/27FY. Following assessment of the municipality's financial position, affordability considerations and the prudency of the applied costs, the Energy Regulator made an adjustment amounting to R1 586 752, resulting in an approved surplus of R501 609, representing 1% of the total costs for 2026/27FY, as reflected in Table 6 above.

4.24. The Energy Regulator is of the view that, under the current financial conditions, the municipality's ability to generate an adequate surplus is severely constrained. The approved surplus was therefore limited to a level considered reasonable and affordable to customers while taking into account the municipality's financial challenges.

4.25. The municipality's current financial position exposes the electricity undertaking to several risks, including:

a) inadequate cash flow to fund day-to-day operations and maintenance;
b) inability to adequately maintain and refurbish aging infrastructure;
c) increased network failures and deterioration in quality of supply;
d) escalating debt obligations and reliance on external funding;
e) weakening liquidity and financial sustainability; and
f) increased risk of future tariff shocks to consumers due to deferred cost recovery.

4.26. The Energy Regulator therefore emphasises the need for urgent corrective measures aimed at improving the financial sustainability of the electricity undertaking. Failure to address the municipality's high loss levels and continued deficit position may further compromise the sustainability and reliability of electricity service delivery.

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

5. PUBLIC PARTICIPATION

5.1. NERSA received TLM's tariff application on 31 March 2026 and published both the application and COS on the NERSA website, social media platforms (Facebook, X and LinkedIn) and national and local newspapers, along with an invitation to stakeholders to submit written comments by 21 April 2026 in line with the Court judgement of 20 February 2026.

6. THE OBJECTORS AND OTHER INTERVENING PARTIES

6.1. NERSA did not receive any objections stakeholders from affected by the closing date of 21 April 2026.

7. TARIFF ANALYSIS

OVERALL KEY FINDINGS

7.1. The Energy Regulator assessed the tariff structure against the principles of cost-reflectivity, affordability and transparency.

7.2. The assessment concluded that the municipality's applied tariffs were not fully supported by the approved allowable revenue requirement due to:

a) inefficient expenditure;
b) excessive energy losses;
c) Eskom debt interest charges; and
d) operational inefficiencies.

7.3. Accordingly, adjustments were made to ensure that only prudent and efficient costs are recoverable through tariffs. The Energy Regulator recommend an average tariff increase of 9.11% for 2026/27FY, instead of the municipality's proposed increase of approximately 22%.

7.4. The approved increase is considered sufficient to:

a) enable recovery of prudently incurred costs;
b) support continued electricity service delivery;
c) improve affordability for consumers; and
d) protect customers from bearing the full impact of inefficient expenditure and financial mismanagement.

7.5. The municipality is encouraged to strengthen financial management, improve revenue collection, reduce technical and non-technical losses, enhance energy balancing practices and implement cost containment measures to improve the long-term sustainability of the electricity undertaking.

8. TARIFF ANALYSIS AND RECOMMENDATIONS

<u>Domestic Tariffs</u>

ALL THE BELOW MENTIONED TARIFFS EXCLUDES VAT	Tariff	Tariff	%	%	Tariff	Tariff	%	%	Tariff	Tariff
	2025/26 Financial year Approved	2025/26 Financial year Approved	2026/27 Financial year % proposed	2026/27 Financial year % proposed	2026/27 Financial year Application	2026/27 Financial year Application	2026/27 Financial year Recommended	2026/27 Financial year Recommended	2026/27 Financial year Recommended	2026/27 Financial year Recommended
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
		June to Aug				June to Aug				June to Aug
Pre-paid; (E009)										
0 - 50 (first 50 units)	2,4546	2,5174	26%	26%	**3,0928**	**3,1720**	9,11%	9,11%	**2,6782**	**2,7468**
51 - 350 (next 300 units)	3,1561	3,2371	26%	26%	**3,9766**	**4,0788**	9,11%	9,11%	**3,4436**	**3,5320**
351 - 600 (next 250 units)	4,0157	4,5534	26%	26%	**5,0598**	**5,7372**	9,11%	9,11%	**4,3816**	**4,9682**
> 600	4,3156	5,0352	26%	26%	**5,4377**	**6,3443**	9,11%	9,11%	**4,7088**	**5,4939**
Domestic; (E001)										
0 - 50 (first 50 units)	2,2266	2,3776	19%	19%	**2,6496**	**2,8293**	9,11%	9,11%	**2,4294**	**2,5942**
51 - 350 (next 300 units)	2,8714	3,0573	19%	19%	**3,4170**	**3,6382**	9,11%	9,11%	**3,1330**	**3,3358**
351 - 600 (next 250 units)	3,6415	4,3004	19%	19%	**4,3334**	**5,1175**	9,11%	9,11%	**3,9732**	**4,6922**
> 600	3,9120	4,7554	19%	19%	**4,6553**	**5,6590**	9,11%	9,11%	**4,2684**	**5,1887**
Basic Charge: R/Month	344,36	344,36	19%	19%	**409,79**	**409,79**	9,11%	9,11%	**375,73**	**375,73**

Commercial Tariffs

Churches & Old Age Homes (E006 & E011)										
Unit Charge: kWh	3,6415	3,7040	19%	19%	**4,3334**	**4,4078**	9,11%	9,11%	**3,9732**	**4,0415**
Basic Charge: Per Month	272,23	272,23	19%	19%	**323,95**	**323,95**	9,11%	9,11%	**297,03**	**297,03**
Commercial (Prepaid Single Phase) Business (E014)										
Unit Charge: kWh	3,9280	3,9895	17%	17%	**4,5958**	**4,6677**	9,11%	9,11%	**4,2859**	**4,3530**
Commercial (Conventional Single Phase) Business (E002)										
Unit Charge: kWh	3,8455	3,9125	21%	21%	**4,6530**	**4,7342**	9,11%	9,11%	**4,1958**	**4,2690**
Basic Charge: Per Month	926,82	926,82	21%	21%	**1 121,46**	**1 121,46**	9,11%	9,11%	**1 011,26**	**1 011,26**
Commercial (Prepaid Three Phase) Business (E015)										
Unit Charge: kWh	3,9280	3,9895	17%	17%	**4,5958**	**4,6677**	9,11%	9,11%	**4,2859**	**4,3530**
Commercial (Conventional Three Phase) Business (E016)										
Unit Charge: kWh	4,0623	4,1259	21%	21%	**4,9154**	**4,9924**	9,11%	9,11%	**4,4324**	**4,5018**
Basic Charge: Per Month	926,82	926,82	21%	21%	**1 121,46**	**1 121,46**	9,11%	9,11%	**1 011,26**	**1 011,26**
Government (E004, E005 & E010)										
Unit Charge: Per kWh Single Phase	4,0623	4,1259	21%	21%	**4,9154**	**4,9924**	9,11%	9,11%	**4,4324**	**4,5018**
Unit Charge: Per kWh Three Phase	4,0623	4,1259	21%	21%	**4,9154**	**4,9924**	9,11%	9,11%	**4,4324**	**4,5018**
Basic Charge: Per Month	964,30	964,30	21%	21%	**1 166,80**	**1 166,80**	9,11%	9,11%	**1 052,14**	**1 052,14**

Industria Tariffs

Industrial supply (E012 & E013)										
Unit Charge: Per kWh	1,6175	1,7487	25%	25%	**2,0218**	**2,1859**	9,11%	9,11%	**1,7648**	**1,9080**
Demand Charge: Per kVA	436,53	610,57	25%	25%	**545,66**	**763,21**	9,11%	9,11%	**476,30**	**666,19**
Basic Charge: Per Month	2 268,77	2 268,77	25%	25%	**2 835,96**	**2 835,96**	9,11%	9,11%	**2 475,46**	**2 475,46**
Industrial - Bulk (E007 & E008)										
Unit Charge: Per kWh	2,0765	2,5793	25%	25%	**2,5957**	**3,2241**	9,11%	9,11%	**2,2657**	**2,8143**
Demand Charge: Per kVA	350,03	434,03	25%	25%	**437,53**	**542,54**	9,11%	9,11%	**381,91**	**473,57**
Basic Charge: Per Month	1 201,93	1 349,64	25%	25%	**1 502,42**	**1 687,05**	9,11%	9,11%	**1 311,43**	**1 472,60**

9. CONFIDENTIALITY

9.1. None.

10. CONCLUSION

10.1. The Energy Regulator, having considered TLM's application, supporting information, stakeholder inputs and applicable legal framework, approve the tariff adjustments as set out in this Reasons for Decision.

End