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

Mossel Bay Municipality

THE DECISION

At its meeting held on 8 May 2026, the Regulator Executive Committee (REC) considered Mossel Bay Municipality's tariff application. Based on the facts and evidence presented, the REC approved the tariff increases for the 2026/27 financial year, as set out in the Tariff Analysis Section 6 from page 19 of the RfD document.

Based on the available information, public comments and the analysis performed, the REC at its meeting held on 8 May 2026, decided:

1. 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;

2. to note the cost information submitted by the municipality;

3. that the municipality must submit, by 31 January 2027, an audited financial report accounting for all costs that have been noted, to enable the National Energy Regulator of South Africa to perform its independent verification audit; and

4. that the municipality must submit a specific, measurable, achievable, realistic and time-bound (SMART) energy loss reduction report on a quarterly basis, commencing from 30 September 2026, to enable NERSA to closely monitor the implementation thereof.

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ABBREVIATIONS AND ACRONYMS

COS	Cost of Supply
D-form	Distribution form
EPP	Electricity Pricing Policy for the South African Electricity Supply Industry, 2008
ERA	Electricity Regulation Act, 2006
ERTSA	Eskom Retail Tariff Structural Adjustments
FBE	Free Basic Electricity
IBT	Inclining Block Tariff
IDP	Integrated Development Plan
IPP	Independent Power Producer
LED	Local Economic Development
MFMA	Municipal Finance Management Act, 2003
MBM	Mossel Bay Municipality
MTREF	Medium-Term Revenue and Expenditure Framework
NERA	National Electricity Regulation Act, 2004
NERSA	National Energy Regulator of South Africa
NMD	Notified Maximum Demand
OPEX	Operating Expenditure
PAJA	Promotion of Administrative Justice Act, 2000
RCA	Regulatory Clearing Account
SSEG	Small-Scale Embedded Generation
SDBIP	Service Delivery and Budget Implementation Plan

1. INTRODUCTION

1.1. The National Energy Regulator of South Africa (NERSA) receives and considers tariff applications on an annual basis, in accordance with its mandate to regulate prices and tariffs. Municipal tariffs must be approved by NERSA to be implemented on 1 July of each financial year.

1.2. Mossel Bay Municipality (MBM) is situated in the Western Cape. The municipality's customer base is predominantly domestic, with this category accounting for 47.99% of total electricity sales, closely followed by manufacturing at 30.23%. MBM provides qualifying indigent customers with 50 kWh of Free Basic Electricity (FBE) per month and maintains an indigent register. Details of the municipality's customer statistics are set out in Table 1 below.

Table 1: Customer Statistics (Data obtained from 2024/25 D-forms)

Customer categories	***MWh***	***% MWh***	***Customer numbers***
Domestic Prepaid	103 646	39.67	36 051
Domestic Conventional	21 718	8.31	4 241
Agriculture	272	0.10	9
Manufacturing	78 974	30.23	287
Commercial Prepaid	11 522	4.41	1 700
Commercial Conventional	20 724	7.93	586
Other Consumers	593	0.23	10
Street Lighting	1 048	0.40	0
Own Use	5 166	1.98	156
Sold to other departments	17 583	6.73	47
Total	**261 246**	**100**	**43 087**
Free Basic Electricity (FBE)	**7 505**	**6**	**14 101**

1.3. NERSA received MBM's tariff application on 31 March 2026. The application is based on an existing Cost of Supply (COS) study, valid from the 2024/25 to the 2028/29 financial years.

1.4. MBM implemented a 10.81% average price increase in the 2025/26 financial year and is applying for an average price increase of 8.50% for the FY2026/27.

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

1.6. For this application, the municipality confirmed that its council meeting had been held on 31 March 2026. The municipality submitted the council resolution and proof of customer consultation together with the tariff application on 31 March 2026.

1.7. NERSA followed its own public consultation process. On 31 March 2026, NERSA published MBM's tariff application on its website, its various social media platforms,

as well as in national and local newspapers, to solicit written comments from affected parties by 21 April 2026.

1.8. NERSA's decision was made on 8 May 2026, taking into consideration 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 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 NERSA evaluated and determined the municipal electricity tariff application for the 2026/27 municipal financial year.

2.2. NERSA's Statutory Mandate

2.2.1. NERSA is established as a juristic person in terms of section 3 of 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:

- section 4(a)(i) of the ERA provides that the Energy Regulator must consider applications for licences and may issue licences subject to conditions;
- section 4(a)(ii) of the ERA provides that the Energy Regulator must regulate prices and tariffs; and
- 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 NERSA 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 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 NERSA 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 of the EPP 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 for the FY2025/26 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 help ensure municipal tariffs are approved on time and in line with the law, the Court issued a structural interdict to guide the 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 which arose as they relate 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 FY2026/27 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:

- Written notice of bulk tariffs must be given by 6 March 2026.
- Municipal tariff applications must be submitted by 31 March 2026.
- Public participation processes must be concluded by 21 April 2026.
- NERSA decisions must be published by 11 May 2026.

2.8.2. Municipal tariff approvals from the FY2027/28 shall comply with the following timelines:

- Written notice of bulk electricity tariffs must be communicated by 31 January each year.
- Municipal tariff applications must be submitted to NERSA by 20 March each year.
- 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 comprising 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 stated in this document demonstrate how NERSA 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 MBM, 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 purposes of the tariff analysis.

3.2. MBM's electricity business operated at a percentage surplus margin of 8.02%[1] in the 2024/25 financial year, a material fall from 11.06% in the 2023/24 financial year. The decline in surplus is primarily attributed to the licensee's cost pressures outpacing its sales revenue during the reporting period. The revenue growth of 4.78% in the current reporting period has been eroded by expenditure growth of 15.44%. This gap is the core driver of the declining surplus margin, alongside other indicators, such as the credit collection rate, which remains below par relative to the 95% benchmark set in the Service Delivery and Budget Implementation Plan (SDBIP).

3.3. Table 2 below shows that MBM's energy losses, considered high, worsened from 14.11% in the 2023/24 financial year to 16.94% in the 2024/25 financial year. The municipality cited theft, electricity bypassing and meter tampering as some of the contributors to high energy losses. The licensee submitted and implemented its energy loss reduction plan during the reporting period, and it appears to be yielding positive outcomes. Some of the measures identified and actively undertaken to curb its losses include the following:

a) Conduct meter audits
b) Identify and remove illegal connections
c) Identify and replace faulty, tampered and unregistered meters
d) Identify and rectify incorrect tariff codes
e) Identify and correct metering errors
f) Identify and correct billing errors.

Table 2: Performance Indicators

PERFORMANCE INDICATORS: OBTAINED FROM D-FORMS		
Performance Indicator	**FY2023/24 (Approved)**	**2024/25 (Actuals)**
Percentage Surplus (Deficit): (%)	11.06	8.02
Percentage Energy Losses: (%)	14.11	16.94

[1] Percentage Surplus Formula = (Revenue from Electricity Sales Less Total Expenditure) divided by Revenue from Electricity Sales

3.4. Based on the above information, the financial health of the municipality's electricity business remains modestly sustainable, as supported by the operating surplus margin of 8.02%. This position demonstrates that the municipality can cover its operating expenses with a sufficient buffer against financial and operational risks. The licensee ought to implement strong financial controls and its energy loss reduction plans, alongside credit control and debt collection policies, to mitigate the risk of long-term unsustainability.

3.5. Table 3 below provides a revenue impact analysis under two energy loss scenarios: actual (16.94%) and when reduced to 12%.

Table 3: Energy Losses vs Revenue Impact Analysis

Parameters	Current Position FY2024/25	Scenario 1: Losses at 12% (Extrapolated D-Form Info)	Scenario 2: Losses at 6% (Extrapolated D-Form Info)
Energy Losses	16.94%	12%	6%
Surplus / Deficit Margin	8.02%	11.14%	14.66%
Revenue Impact of Energy Losses	R65 175 761.00	R28 545 000.32	R63 207 050.82

3.5.1 Under the current scenario, with actual electricity losses of 16.94%, the licensee records an operating surplus of approximately R65.18 million, which translates to a surplus margin of 8.02%, based on approved D-form inputs. This surplus margin indicates that elevated energy losses continue to place pressure on the financial sustainability of the electricity business, and revenue is sensitive to energy losses.

3.5.2 Based on the scenario analysis one, should electricity losses be reduced to 12%, and assuming constant electricity purchases, operating costs, and tariff structures, total electricity sales revenue is projected to increase due to higher billable energy volumes. Under this scenario, the estimated revenue that could be recovered through loss reduction is estimated to increase by approximately R28.55 million, equivalent to a surplus margin of 11.14%, reflecting improved revenue retention relative to the current position.

3.5.3 Further reduction of energy losses to 6% are expected to strengthen the surplus position by a further R63.21 million, equivalent to a surplus margin of 14.66% subject to the sustainability and effectiveness of the implemented loss-reduction measures.

4. DETERMINATION OF MOSSEL BAY MUNICIPALITY'S TARIFFS BASED ON THE COST OF SUPPLY ADJUSTED DATA

4.1. The municipality submitted its existing COS study in support of its tariff application approved in the 2026/27 financial year. The municipality'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. Section 18.7 of the Cost of Supply Framework approved by NERSA in October 2023 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.

4.4. In line with section 18.7 mentioned above, Table 4 below was developed, and the definitions of the columns are as follows:

i. Column 1: represents the budgeted FY2024/25 costs submitted by the licensee as part of the COS revenue requirement and approved for tariff determination in FY2024/25.

ii. Column 2: reflects the actual FY2024/25 financial performance of the licensee, sourced from the D-forms and aligned with the audited annual financial statements.

iii. Column 3.1: indicates the variance between the FY2024/25 approved budgeted figures and the audited actual values;

iv. Column 3.2: expresses the same variance in percentage terms. A positive variance indicates that actual expenditure exceeded the approved budget, while a negative variance indicates underspending relative to the budget. In the latter case, a clawback may be applicable, whereas in the former case, a disbursement may be considered, subject to regulatory assessment.

v. Column 4: reflects the FY2025/26 revenue and electricity volume figures used as the baseline for determining the FY2026/27 tariffs (since at the time of the approval, the figures were estimates) when the Energy Regulator considered and approved the 2026/27 COS base tariffs. Once the 2025/26 financial year concludes, the actual figures will be verified against the audited annual financial statements.

vi. Column 5: contains the licensee's submitted FY2026/27 budgeted figures, which are subject to reasonableness testing for purposes of tariff determination for the control period under review.

vii. Column 6: shows the percentage movement between the FY2025/26 baseline figures and the FY2026/27 budgeted amounts and forms the primary basis for proposed tariff adjustments for FY2026/27.

viii. Column 7: is intended for NERSA's recommended adjustments after considering the reasons, facts, and evidence that the licensee has provided to motivate/justify for the approval of the budgeted figures.

ix. Column 8: is intended to capture NERSA's recommended adjustments after considering the reasons, facts, and supporting evidence submitted by the licensee in support of the requested budget figures for the FY2026/27.

4.5. The Total Allowable Revenue of R859.21 million in column 4 is for the 2025/26 tariff review period and is the basis upon which the tariffs are adjusted for approval by the Energy Regulator as shown in Table 4 below.

4.6. The FY2024/25 variance between budgeted and actual Total Allowable Revenue in column 3 reflects lower than planned expenditure and higher than anticipated *other income* offsets, rather than regulatory adjustments. The municipality has incorporated these outcomes into the forward-looking FY2026/27 revenue requirement.

4.7. The COS study is valid for five years; however, municipalities need to reflect the adjustments in their cost drivers for each financial year under the existing COS (i.e. FY2026/27). NERSA utilised the budgeted figures to verify efficiencies and to ensure that municipalities do not over- or under-recover their operating overheads during the FY2026/27 tariff review process.

4.8. In determining the tariff adjustment applicable for the FY2026/27 financial year, the licensee submitted its FY2026/27 cost data, comprising budgeted operating costs plus surplus, as required by NERSA. The total budgeted revenue requirement submitted amounts to R925.70 million for the FY2026/27 tariff review process, inclusive of an energy loss adjustment for 23,627,159 kWh worth of non-technical losses. This results in a 7.74% upward movement in allowable revenue for FY2026/27 relative to the previous financial period. The submitted application reflects a conservative volume forecasting approach by the licensee, coupled with modest operational expenditure growth, and a declining surplus. This could be the licensee's strategy to balance its operational requirements with tariff stability, partially cushioning tariff pressure.

Table 4: Revenue Requirement Components

Energy Balance	Unit	FY2024/25 Budgeted Costs (COS) (1)	FY2024/25 Actual Costs (2)	FY2024/25 Budget to Actual Variance (R) (3.1)	FY2024/25 Budget to Actual Variance (%) (3.2)	FY2025/26 Tariffs per submitted Municipal Budget (4)	FY2026/27 Budgeted Costs as per the Licensee (5)	FY2025/26 to FY2026/27 Variance (%) (6)	NERSA Adjustment (considering efficiencies) (7)	FY2026/27 Allowable Revenue (8)
Sales	kWh	267 741 234	261 246 660	-	-2%	250 499 613	250 052 841	0%	-	250 052 841
Eskom bulk purchases	kWh	312 132 731	314 531 955	-	1%	317 677 275	311 000 000	-2%	-	311 000 000
Independent Power Producers Conventional	kWh		-	-		-	-		-	-
Independent Power Producers Renewable Energy	kWh		-	-		-	-		-	-
Self Generation	kWh		-	-		-	-		-	-
Other			-	-		-	-		-	-
Total Energy Requirements	**kWh**	**312 132 731**	**314 531 955**	**0**	**1%**	**317 677 275**	**311 000 000**	**-2%**		**311 000 000**
Total Losses	kWh		53 285 295			67 177 662	60 947 159			60 947 159
Technical losses	kWh	37 455 928	37 743 835			38 121 273	37 320 000		-	37 320 000
Non-technical losses	kWh	-6 935 569	-15 541 461			-29 056 389	-23 627 159		-23 627 159	-23 627 159
Allowed losses	%	**12.00%**	**12.00%**			**12.00%**	**12.00%**			**12.00%**
Total Energy losses	%	14.22%	16.94%			21.15%	19.60%			19.60%
Cost Drivers										
Energy purchases from Eskom	Rand	636 147 336	623 138 411	(13 008 925)	-2%	673 278 182	733 469 650	8%	-	733 469 650
Other energy purchases			-	-		-	-	0%	-	-
Total energy purchases	Rand	**636 147 336**	**623 138 411**	**-13 008 925**	**-2%**	**673 278 182**	**733 469 650**	**9%**	**0**	**733 469 650**
Cost of technical losses	Rand	76 337 680	74 776 609	(1 561 071)	-2%	80 793 382	88 016 358	9%	0	88 016 358
Non-Technical Losses	Rand	-14 135 152	-	-	0%	-	-	0%	-	-
Other energy purchases	Rand					-	-		-	-
Capital expenditure	Rand	-	-	-	0%	-	-	0%	-	-
Operational expenditure (incl. Depreciation)	**Rand**	**132 801 989**	**127 725 339**	**(9 607 576)**	**-4%**	**159 982 041**	**170 175 419**	**6%**	**-**	**170 175 419**
General & Other	**Rand**	**66 959 154**	**66 463 076**	**(3 485 702)**	**-1%**	**80 457 904**	**96 914 206**	**20%**	**0**	**96 914 206**
Salaries and allowances	Rand	29 748 133	29 555 365	(192 769)	-1%	32 593 361	34 081 623	5%	-	34 081 623
Materials and supplies	Rand	7 234 713	4 345 323	(2 889 390)	-40%	4 490 885	4 697 407	5%	-	4 697 407
Contracted Services	Rand	5 183 955	3 263 186	(1 920 769)	-37%	3 480 420	3 271 854	-6%	-	3 271 854
Salaries, wages and allowances (excl. Repairs and Maintenance)	Rand	-	780 045	0	#VALUE!	951 637	1 126 938	18%	-	1 126 938
Payments to consultants (operational work)	Rand	-	6 886 455	0	#VALUE!	5 586 599	8 684 284	55%	-	8 684 284
Eskom debts interest	Rand	4 676 876	-	-		0	0		-	-
Current year depreciation	Rand	20 115 477	17 138 799	(2 976 678)	-15%	21 243 683	21 962 189	3%	-	21 962 189
Repairs and Maintenance	Rand	-	0	0					0	
Other creditors interests	Rand	-	4 493 903	4 493 903	#DIV/0!	12 111 319	23 089 912	91%	0	23 089 912
									0	
Shared OPEX	**Rand**	**65 842 835**	**61 262 263**	**(6 121 874)**	**-7%**	**79 524 137**	**73 261 213**	**-8%**	**0**	**73 261 213**
Bad debts (Allowance for Impairment)	Rand	19 042 711	9 915 839	(9 126 872)	-48%	9 227 268	8 500 000	-8%	-	8 500 000
FBE paid to Eskom	Rand	-	0	0	#VALUE!	0	0	#DIV/0!	-	0
Charges from other Municipal Departments	Rand	38 044 957	38 724 418	679 461	2%	57 472 780	56 088 054	-2%	-	56 088 054
General expenses		**8 755 167**	**12 622 005**	**2 325 537**	**44%**	**12 824 089**	**8 673 159**	**-32%**	**0**	**8 673 159**
1.Bulk NMD Charges	Rand		0	-	#DIV/0!	0	0	#DIV/0!	-	0
2. Fleet Costs / Fuel	Rand		1 541 301	-	#DIV/0!	1 749 610	1 830 094	#DIV/0!	-	1 830 094
3.Other Expenses	Rand	8 755 167	2 756 932	(5 998 235)	-69%	2 036 454	2 043 555	0%	-	2 043 555
4. Inventory Consumed	Rand		3 884 551	3 884 551	0%	4 421 901	0	-100%	-	0
5. Impairment Losses / Utilities	Rand		4 252 794	4 252 794	#DIV/0!	4 297 176	4 763 918	11%	-	4 763 918
6. Employee Related Cost / Travel, S&T	Rand		14 439	14 439	#DIV/0!	92 200	35 592	-61%		35 592
7. Safety Equipment and Protective Clothing	Rand		171 988	171 988	#DIV/0!	226 748	0	-100%		0
	Rand		-			-			0	0
Total Expediture before surplus	Rand	845 287 005	825 640 359	(24 177 572)	-2%	914 053 605	991 661 426	**8%**	0	991 661 426
Surplus	Rand	126 793 051	65 175 761	(61 617 290)	-49%	55 597 453	46 672 849	**-16%**	-	46 672 849
Total Expenditure including Surplus	**Rand**	**972 080 056**	**890 816 120**	**(85 794 862)**	**-8%**	**969 651 057**	**1 038 334 276**	**7%**	**-**	**1 038 334 276**
Other Income	Rand	**-96 347 751**	**-106 441 011**	**(10 093 260)**	**0%**	**-110 438 112**	**-112 630 735**	**2%**	**0**	**-112 630 735**
5. Other Revenue - Illegal Connections	Rand		-	-		-	-		-	-
Total Allowable Revenue	**Rand**	**875 732 305**	**784 375 109**	**(95 888 122)**	**-10%**	**859 212 945**	**925 703 541**	**8%**	**-**	**925 703 541**
Increase Required							***8.50%***			***8.50%***

4.9. It is important to test the efficiency and prudency of the costs in the FY2025/26, as this represents the most recently considered revenue in support of the approved tariffs during this period. This forms the basis on which costs for the FY2026/27 have been projected, using assumptions to calculate revenue requirements for that year.

4.10. 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

4.11. For the 2026/27 financial year, the licensee has applied for a bulk purchase expenditure of R733.47 million, which accounts for 79% of total costs inclusive of the 12% energy loss allowance[2]. Bulk purchases were verified against Eskom invoices in the 2024/25 financial year.

4.12. To arrive at the FY2026/27 estimate, the licensee projected the full-year amount for the FY2025/26 and then estimated that this cost item would increase by 9.01% in line with the approved Eskom Retail Tariff Structural Adjustments (ERTSA).

4.13. Analysed Eskom bills showed no Notified Maximum Demand (NMD) exceedance penalties had been charged. Furthermore, the municipality did not include the Eskom interest charges on the outstanding account. All verifications have been satisfactory to NERSA, and therefore, this cost has been approved as applied for.

Operating Expenditure (including depreciation)

4.14. The licensee seeks an Operational Expenditure of R170.18 million for the 2026/27 financial year including depreciation. This represents 16% of the Total Costs, adjusted upward from R159.98 million in the 2025/26 financial year. This translates to a 6.37% escalation from the previous year. This appears to be a structural cost pass-through increase, driven almost entirely by Eskom tariffs and inflation.

4.15. The licensee's depreciation is calculated on the depreciable amount, using the straight-line method over the estimated useful lives of the assets. The asset base is valued at approximately R560 million as at FY2024/25, as reported in its D-forms and verified against its audited AFS and supporting financial information. The resulting depreciation and amortization provisions amounted to R17.1 million in FY2024/25, R21.2 million in FY2025/26 and projected at R21.9 million for the 2026/27 financial year.

4.16. 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.

[2] The Cost of Technical Losses line item is best understood as an analytical measure used to quantify the cost impact of network losses. As these costs are already embedded within Eskom bulk purchase costs, the separate disclosure is for transparency and analytical purposes only and neither represents an additional recoverable cost nor constitutes additional expenditure.

Surplus

4.17. The licensee is projecting a surplus position of R46.67 million, which is based on a 4% return on OPEX, including bulk purchases, and decreased by 16.05% from the previous year relative to total expenditure. The projected surplus provides a modest liquidity buffer to support cash flow stability and absorb short-term cost shocks. However, its reduced level limits flexibility to address unforeseen load-related revenue shortfalls or deferred maintenance, thereby elevating operational and financial sustainability risks if adverse conditions materialise.

4.18. The surplus position represents the critical financial buffer against several risks, allowing the municipality to maintain service delivery without resorting to emergency borrowing.

4.19. The considerations that went into the municipality's surplus allowance included factors that support both cost reflectivity and financial sustainability, and the associated risk factors include financial liquidity and operational risks.

4.20. NERSA is of the view that the return applied for by the licensee is reasonable to keep the licensee just about sustainable, though it falls below the 10-20% target range as determined in the COS Methodology. The surplus level complies with the applicable principles, and it is justified in the manner in which MBM manages the risks associated with its service delivery. Thus, it is NERSA's decision to allow the revenue requirement as applied for.

Conclusion on Costs to Serve

4.21. While the COS study outcome reflected an average tariff increase of 41.00% for the licensee to achieve full cost reflectivity, the municipality adopted a multi-year phase-in approach to implement tariff increases below the COS outcome. Some of the considerations for this decision include the licensee's requirement to maintain a sustainable tariff level to drive the demand for its electricity services.

4.22. Significantly higher tariffs could negatively impact the licensee by reducing customer demand and sales. The licensee also considered its ability to service its Eskom account and the broader affordability impact on customers in determining the pace of its tariff adjustments.

4.23. This approach will help protect the municipality's revenue base and support its financial sustainability, as required by legislation.

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This supports financial viability, compliance with MFMA cost-recovery principles, and continued investment in the distribution network, whilst keeping tariff increases within a sound and transparent range.

6.1.6. Rejection or downward adjustment of the proposed tariffs would result in a revenue shortfall of approximately R66 million, forcing the electricity trading service into under-recovery. This would likely necessitate deferred maintenance, accelerated cash erosion, or reliance on non-electricity revenues to subsidise the function, thereby risking fiscal sustainability and regulatory compliance. Over time, such an outcome would increase the risk of infrastructure failures, higher future tariff shocks, and adverse audit findings. Approval of the application, therefore, represents the most prudent option to balance consumer protection with long-term service stability.

Municipal Impact Analysis

6.1.7. Table 6 below illustrates the municipal impact in the event of either approval or rejection of its application.

Table 6: Municipal Impact

Application Item	Assessment
Profile	Industrial-commercial hub, petrochemical & port activity (PetroSA, etc.).
Proposed Increase	8.50%
Cost of Supply Results	41.00%
Customer Impact	Industrial users risk load reduction or self-supply, and this may hamper MBM's electricity business.
Revenue Impact (Approved)	Will present partial recovery, with approximately 32% under-recovery gap.
Revenue Impact (Rejected)	Would result in declining electricity revenue despite stable economic activity as rising opex and bulk supply costs will not be offset through tariffs.
Regulatory Considerations	Municipality needs to achieve balancing between farm viability and cost recovery.

Clawback / disbursement mechanism

6.1.8. It is important to note that currently, there is no formal Regulatory Clearing Account (RCA) mechanism for municipalities. Although the FY2024/25 tariffs were set to recover costs based on approved forecasts, the lower actual expenditure resulted in a lower allowable revenue outcome in the year under review. Accordingly, (i) in the absence of a clawback or disbursement mechanism, the FY2024/25 over-recovery cannot be automatically clawed back; and (ii) the impact is addressed through forward-looking tariff determinations, subject to prudency, affordability, and actual cash collection assessments. The proposed 8.50% tariff increase is therefore forward-looking, and not retrospective, as discussed in section 4.6 above.

6.2. **TARIFF ANALYSIS**

1. Domestic Supply: Single Phase 2 Part [30A, 45A and 60A] (Tariff 1.A)	***2025/26 Approved***	***Proposed % Increase***	***2026/27 Proposed***	***2026/27 Recommended***	***% Increase***
Tariff Blocks	***c/kWh***				
Fixed Monthly Charge (R/ month/ 1 phase Ampere)	7.1985	8.50%	7.8104	7.8104	8.50%
Energy Charge (c/kWh)	268.89	8.50%	291.75	291.75	8.50%

2. Domestic: Indigent, Level 1 (Tariff 1.C)	***2025/26 Approved***	***Proposed % Increase***	***2026/27 Proposed***	***2026/27 Recommended***	***% Increase***
Tariff Blocks	***c/kWh***				
Block 1 (0 - 50kWh)	0.00	0%	0.00	0.00	0%
Block 2 (51 - 350 kWh)	253.99	10.50%	280.66	280.66	10.50%
Block 3 (351 - 600kWh)	335.62	8.50%	364.15	364.15	8.50%
Block 4 (>600 kWh)	404.01	8.50%	438.36	438.36	8.50%

3. Domestic: Indigent, Level 2 (Tariff 1.C)	***2025/26 Approved***	***Proposed % Increase***	***2026/27 Proposed***	***2026/27 Recommended***	***% Increase***
Tariff Blocks	***c/kWh***				
Block 1 (0 - 50kWh)	0.00	0%	0.00	0.00	0%
Block 2 (51 - 350 kWh)	253.99	10.50%	280.66	280.66	10.50%
Block 3 (351 - 600kWh)	335.62	8.50%	364.15	364.15	8.50%
Block 4 (>600 kWh)	404.01	8.50%	438.36	438.36	8.50%

4. Domestic: Three Phase (15A, 30A, 45A, 60A, 90A): SSEG Feed-in (Tariff 1.D and 1.G)	***2025/26 Approved***	***Proposed % Increase***	***2026/27 Proposed***	***2026/27 Recommended***	***% Increase***
Tariff Blocks	***c/kWh***				
Import Charges					
Fixed Network Charge (R/month 3 phase Ampere)	16.5652	8.50%	17.9652	17.9652	8.50%
Energy Charge - Consumption (c/kWh)	253.30	8.50%	274.83	274.83	8.50%
Domestic: Single Phase, SSEG Feed-in (Tariff 1.F)					
Import Charges					
Fixed Network Charge (R/month 1 phase Ampere)	7.1985	8.50%	7.8104	7.8104	8.50%
Energy Charge - Consumption (c/kWh)	268.89	8.50%	291.75	291.75	8.50%
Export Charges					
Energy Charge - Generation (c/kWh)	129.19	8.50%	140.17	140.17	8.50%

5. Commercial: 1 Phase 2 Part (Tariff 2.A)	***2025/26 Approved***	***Proposed % Increase***	***2026/27 Proposed***	***2026/27 Recommended***	***% Increase***
Tariff Blocks	***c/kWh***				
Fixed Monthly Charge (R/ month/ Ampere)	14.4087	8.40%	15.6261	15.6261	8.40%
Energy Charge (c/kWh)	232.60	8.50%	252.37	252.37	8.50%

6. Commercial: 3 Phase 2 Part (Tariff 2.C)	***2025/26 Approved***	***Proposed % Increase***	***2026/27 Proposed***	***2026/27 Recommended***	***% Increase***
Tariff Blocks	***c/kWh***				
Fixed Monthly Charge (R/ month/ 3-phase Ampere)	33.1304	8.50%	35.9304	35.9304	8.50%
Energy Charge (c/kWh)	222.71	8.50%	241.65	241.65	8.50%

7. Commercial: Single Phase: SSEG (Tariff 2.E)	***2025/26 Approved***	***Proposed % Increase***	***2026/27 Proposed***	***2026/27 Recommended***	***% Increase***
Tariff Blocks	***c/kWh***				
Import Charges					
Fixed Network Charge (R/month 3 phase Ampere)	14.4087	8.40%	15.6261	15.6261	8.40%
Energy Charge - Consumption (c/kWh)	232.60	8.50%	252.37	252.37	8.50%
Export Charges					
Energy Charge - Generation (c/kWh)	129.19	8.50%	140.17	140.17	8.50%

8. Commercial: Three Phase: SSEG (Tariff 2.F)	***2025/26 Approved***	***Proposed % Increase***	***2026/27 Proposed***	***2026/27 Recommended***	***% Increase***
Tariff Blocks	***c/kWh***				
Import Charges					
Fixed Network Charge (R/month 3 phase Ampere)	33.1304	8.50%	35.9304	35.9304	8.50%
Energy Charge - Consumption (c/kWh)	222.71	8.50%	241.65	241.65	8.50%
Export Charges					
Energy Charge - Generation (c/kWh)	129.19	8.50%	140.17	140.17	8.50%

9. Light Industrial (40 kVA - 100 kVA) (Scale 3)	***2025/26 Approved***	***Proposed % Increase***	***2026/27 Proposed***	***2026/27 Recommended***	***% Increase***
Tariff Blocks	***c/kWh***				
Fixed Monthly Charge (R/ kVA/ month)	1,987.8261	8.50%	2,155.8261	2,155.8261	8.50%
Demand Charge (R/KVA) - min 40kVA	392.3391	8.50%	425.6957	425.6957	8.50%
Energy Charge (c/kWh)	193.02	8.50%	209.43	209.43	8.50%
Energy Charge - Generation (c/kWh)	129.19	8.50%	140.17	140.17	8.50%

10. Bulk Supply (>100 kVA) (Scale 4)	***2025/26 Approved***	***Proposed % Increase***	***2026/27 Proposed***	***2026/27 Recommended***	***% Increase***
Tariff Blocks	***c/kWh***				
Fixed Monthly Charge (R/ kVA/ month)	4,969.5652	8.50%	5,389.5652	5,389.5652	8.50%
Demand Charge (R/kVA) - min 100KVA	488.5130	8.50%	530.0435	530.0435	8.50%
Energy Charge (c/kWh)	156.73	8.50%	170.06	170.06	8.50%
Energy Charge - Generation (c/kWh)	129.19	8.50%	140.17	140.17	8.50%

11. Special Bulk Supply (Scale 5)	***2025/26 Approved***	***Proposed % Increase***	***2026/27 Proposed***	***2026/27 Recommended***	***% Increase***
Tariff Blocks	***c/kWh***				
Fixed Monthly Charge (R/month)	4,969.5652	8.50%	5,389.5652	5,389.5652	8.50%
Network Access Charge (R/ kVA/ month)	20.0000	8.50%	21.7000	21.7000	8.50%
Energy Charge (c/kWh)					
Off-Peak	125.37	8.50%	136.03	136.03	8.50%
Standard	308.48	8.50%	334.70	334.70	8.50%
Peak	539.39	8.50%	585.24	585.24	8.50%
Energy Charge - Generation (c/kWh)	129.19	8.50%	140.17	140.17	8.50%

12. PetroSA: Klipheuwel & Desalination Plant (Scale 6)	***2025/26 Approved***	***Proposed % Increase***	***2026/27 Proposed***	***2026/27 Recommended***	***% Increase***
Tariff Blocks	***c/kWh***				
Fixed Monthly Charge (R/ kVA/ month)	4,969.5652	8.50%	5,389.5652	5,389.5652	8.50%
Demand Charge (R/kVA)	483.6174	8.50%	524.7304	524.7304	8.50%
Energy Charge (c/kWh)	146.84	8.50%	159.33	159.33	8.50%

13. Agricultural Supply (Scale 7)	***2025/26 Approved***	***Proposed % Increase***	***2026/27 Proposed***	***2026/27 Recommended***	***% Increase***
Tariff Blocks	***c/kWh***				
Energy Charge <2000 units (c/kWh)	443.73	8.50%	481.45	481.45	8.50%
Energy Charge >2000 units (c/kWh)	353.02	8.50%	383.03	383.03	8.50%
Energy Charge - Generation (c/kWh)	129.19	8.50%	140.17	140.17	8.50%

14. Agricultural Supply (Scale 8), Water Pumping Only, Off-Peak	***2025/26 Approved***	***Proposed % Increase***	***2026/27 Proposed***	***2026/27 Recommended***	***% Increase***
Tariff Blocks	***c/kWh***				
Energy Charge (c/kWh)	240.83	8.50%	261.30	261.30	8.50%

15. Street Lighting (Scale 9)	***2025/26 Approved***	***Proposed % Increase***	***2026/27 Proposed***	***2026/27 Recommended***	***% Increase***
Tariff Blocks	***c/kWh***				
Energy Charge: Municipality & Private Street Lighting Metered (c/kWh)	229.30	8.50%	248.80	248.80	8.50%
Energy Charge: Municipality & Private Street Lighting Not Metered (c/kWh)	0.00	0%	0.00	0.00	0%
Fixed Monthly Charge (R/light)	230.3043	8.50%	249.8870	249.8870	8.50%

16. Sports fields Lighting, Prepaid (Scale 10)	***2025/26 Approved***	***Proposed % Increase***	***2026/27 Proposed***	***2026/27 Recommended***	***% Increase***
Tariff Blocks	***c/kWh***				
Energy Charge: (c/kWh)	253.30	8.50%	274.83	274.83	8.50%

17. Availability Fees	***2025/26 Approved***	***Proposed % Increase***	***2026/27 Proposed***	***2026/27 Recommended***	***% Increase***
Tariff Blocks	***c/kWh***				
Availability Charge: Vacant Erven (R/month)	561.4847	8.50%	609.2139	609.2139	8.50%

7. CONFIDENTIALITY

7.1. None.

8. CONCLUSION

8.1. From a conspectus of the facts and evidence presented to the REC, it is appropriate to consider and approve Mossel Bay Municipality's tariff application for the 2026/27 financial year.

End.