NATIONAL ENERGY REGULATOR OF SOUTH AFRICA

NATIONAL ENERGY REGULATOR OF SOUTH AFRICA

Decision and Reasons for Decision (RfD)

In the matter regarding the

Municipal Tariff Applications for the 2026/27 Financial Year

by

Gamagara Local Municipality

THE DECISION

At its meeting held on 4 May 2026, the Regulator Executive Committee (REC) considered Gamagara Local Municipality's (GLM) tariff application. Based on the facts and evidence presented, REC approved the tariff increases for the 2026/27 financial year set out below.

a) to approve the tariffs that are based on the Cost of Supply (COS) Report as recommended in the tariff analysis section for implementation by the municipality with effect from 1 July 2026;
b) to note the COS Report submitted by the municipality;
c) that the municipality must submit a report accounting for all the costs that have been noted in its COS study, to enable the National Energy Regulator of South Africa (NERSA) to perform its independent verification/audit process by 31 January 2027; and
d) that the municipality must submit a quarterly progress report Specific, Measurable, Achievable, Realistic and Time-bound (SMART) energy losses reduction progress

reports for NERSA to monitor the implementation thereof by 30 September 2026.

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The whole decision is on NERSA's website:
https://www.nersa.org.za/file/9396/GamagaraMunicipalityReasonsforDecisionforthe2026_27FY.pdf

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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
LM	Local Municipality
MFMA	Municipal Finance Management Act
NERA	National Electricity Regulation Act
NERSA	National Energy Regulator of South Africa
OPEX	Operating Expenditure

1. INTRODUCTION

1.1. The National Energy Regulator of South Africa (NERSA) receives and considers tariff applications on a yearly basis, in accordance with 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 municipality has a population of 53,656, and the rest of the socio-economic information is listed in Table 1 below. The licensee provides 50 kWh Free Basic Electricity (FBE) to 654 indigent customers.

Table 1: Customer base

	2024/25		
Customer categories	***MWh***	***% MWh***	***Customer numbers***
Domestic(Prepaid)	45 353	67%	12 401
Domestic(Conventional)	1 536	2%	752
Agriculture	485	1%	31
Manufacturing	15 986	24%	97
Commercial Prepaid	1 100	2%	48
Commercial Conventional	2 943	4%	46
Street Lighting		0%	
Sold to other departments		0%	
TOTAL	**67 403**	**100%**	**13 375**
Free Basic Electricity	**594**	**1,27%**	**654**

1.3. NERSA received GLM'S tariff application together with its (COS) on 31 March 2026.

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

1.5. NERSA followed the notice and comment consultation process as well as oral presentations. GLM'S tariff applications 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.

1.6. NERSA's decision was made on 10 April 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 municipality 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 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 licenses and may issue licensees 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 authorizes the Energy Regulator to impose license 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 licenses 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 recognizes 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 2025/26 municipal tariff approvals did not comply with the procedural requirements of section 4 of PAJA and was therefore unlawful.

2.7.3. However, recognizing 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 2026/27 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 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 GLM, 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.

GLM'S electricity business operated at a surplus of 4.69% in the 2024/25 financial year, declining from 6.92% in the 2023/24 financial year. The decline in the surplus was primarily driven by increased expenditure, mainly attributable to higher interest charges from Eskom, as well as higher repairs and maintenance costs and rising energy losses.

Table 2 below reflects GLM'S energy losses. The municipality's energy losses increased significantly to 24.41% in the 2024/25 financial year, from 12.46% in the 2023/24 financial year. The elevated level of energy losses is attributable to both technical and non-technical factors, including network inefficiencies, illegal connections, meter bypassing, billing inaccuracies, and unresolved faulty meters.

Table 2: Performance indicators

Performance Indicators: Obtained from the D-Form		
Indicators	**2023/24**	**2024/25**
Percentage Surplus(Deficit)	6.92%	4.69%
Percentage Energy Losses	12.46%	24.41%

3.2. Based on the above information, the municipality's operational and financial performance is not satisfactory. Follow-up engagements are required to obtain and assess strategies aimed at improving performance to acceptable and sustainable levels.

4. Determination Of Gamagara Local Municipality's (GLM)Tariffs Based On The Cost Of Supply Study

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

4.2. GLM utilized the COS study model developed by Sustainable Energy Africa (SEA) to determine its revenue requirements for the 2026/27 financial year and to apportion costs required to service each customer's class in a fair and equitable manner. The study follows the NERSA COS framework and utilizes the latest available audited data which is based on the 2024/25 financial year

4.3. Figure 1: Fives steps of COS below details the five steps considered in the determination of the COS study.

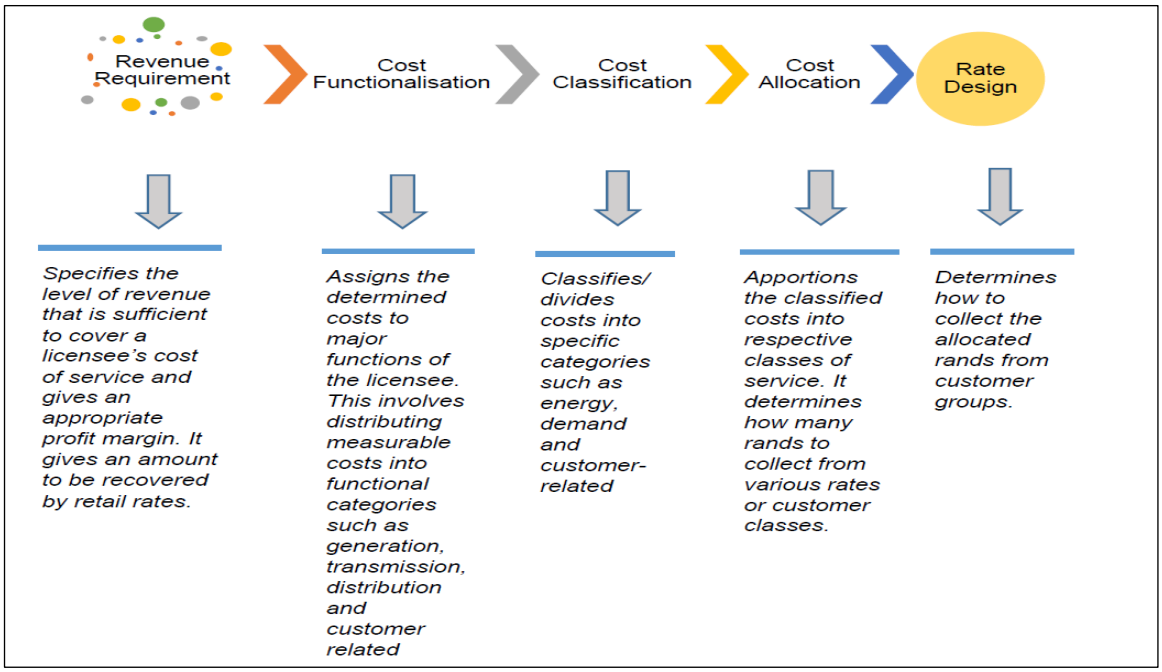


Figure 1: Fives steps of COS

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

4.4.1. Revenue Requirement

4.4.1.1. In order to be fully cost reflective, the licensee's revenue requirements are R278,3 million wires (23%) and Retail (77%) for the 2024/25 financial year. This revenue requirement is made up of the following components:

4.4.1.1.1. Eskom Bulk Purchases composes 73% (excluding cost of losses) of total revenue requirement at an amount of R201,3 million, and this is the largest cost driver of the municipality's electricity department;

4.4.1.1.2. An energy loss allowance of 12% amounting to R33,1 million is provided for; when combined with Eskom bulk energy purchases of 73% (R203,4million), this results in a total of 85% of the total revenue requirement, equivalent to R236,5; and

4.4.1.1.3. Operational expenditure (including depreciation) amounts to R35 million, representing 13% of the total revenue requirement. These costs relate to the operation and maintenance of the network and customer services as shown in Table 3 below.

Table 3*:* Revenue Requirement components

	Total cost (R)			
Revenue Requirement components	**Wires**	**Retail**	**Total**	**% of Total**
Allowable costs	55 912 468	222 415 144	278 327 612	100%
Energy purchases from Eskom - net of cost of losses	-	203 360 335	203 360 335	73%
Energy purchases from Eskom - cost of losses	29 225 414	3 888 988	33 114 402	12%
Other energy purchases	-	-	-	0%
Capital expenditure	-	-	-	0%
Operational expenditure (incl. Depreciation)	21 658 716	13 336 393	34 995 109	13%
Other revenues	- 54 613	- 18 390 132	- 18 444 745	-7%
Surplus	5 082 952	20 219 559	25 302 510	9%
Not allowable costs	15 893 799	23 584 815	39 478 614	
Cost of losses disallowed	15 893 799	23 584 815	39 478 614	
TOTAL COSTS	**71 806 268**	**245 999 959**	**317 806 227**	
	23%	77%		

4.4.1.2. The efficiency of costs for the 2024/25 financial year (base 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.

4.4.1.3. All expenses included in the revenue requirement have been reviewed and verified to ensure that they relate solely to the licensee's electricity function.

Bulk purchases

4.4.1.4. From the submitted COS, GLM applied for bulk purchase expenditure amounting to R201 360 335 million, representing 73% of total costs. The bulk

purchase figure was verified against Eskom invoices for the 2024/25 financial year.

4.4.1.5. To derive the 2026/27 bulk purchase estimate, the 2025/COS amount was escalated by 9.01%, consistent with the approved Eskom Retail Tariff Structural Adjustments (ERTSA).

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

Operational Expenditure

4.4.1.7. GLM has applied for operational expenditure totaling R35 million, representing 13% of overall costs, as reflected in Table 4 above.

4.4.1.8. The approach adopted by GLM in forecasting operational expenditure is considered reasonable, and the amount has therefore been approved as requested.

Surplus

4.4.1.9. GLM has requested a surplus of R25,3 million, calculated using a surplus factor of 9% applied to operating expenditure, inclusive of bulk purchases, for both the wires (23%) and retail (77%) components of the business.

4.4.1.10. The return proposed by GLM is considered reasonable, as it falls below the established target range of 10–20%. This implies that the licensee should scrutinize its operating expenses to enable a tolerable range of surplus.

4.4.1.11. The decision to approve the revenue requirement as submitted will be applied in the subsequent stages, namely Cost Functionalization, Cost Classification, Cost Allocation, and Rate Setting. These stages have been verified and confirmed to align with the approved revenue requirement. Further detail on these stages is provided below.

4.4.2. Cost Functionalisation

4.4.2.1. GLM has categorized its revenue requirement into two primary functional components. The cost structure reflects a clear distinction between the Wires and Retail businesses, with total costs of R55.9 million and R222.4 million, respectively, in accordance with the NERSA COS framework, as illustrated in Figure 2 below. Upon verification, the allocation of costs to these functional components is found to be consistent with the stated revenue requirement.

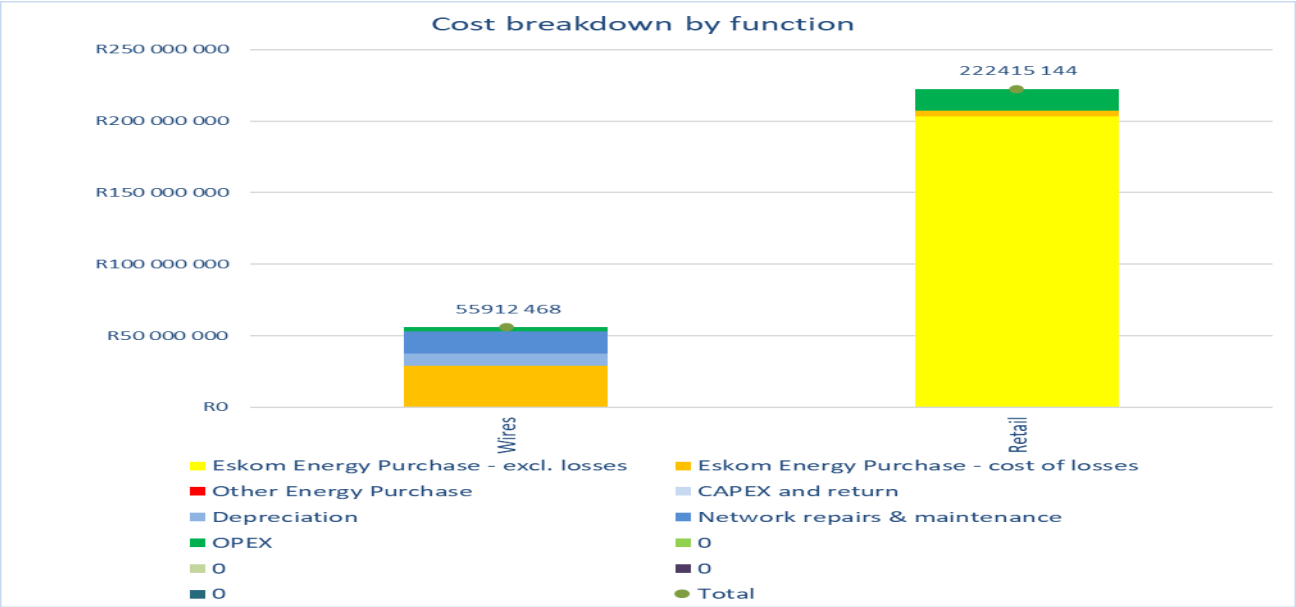


Figure 2*: Costs breakdown by Functions*

4.4.2.2. 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 retail business.

4.4.3. Cost Classification

4.4.3.1. GLM classified its costs into energy, demand, and customer-related cost components, in accordance with the NERSA COS framework. The costs align with revenue requirements and cost functionalization upon verification.

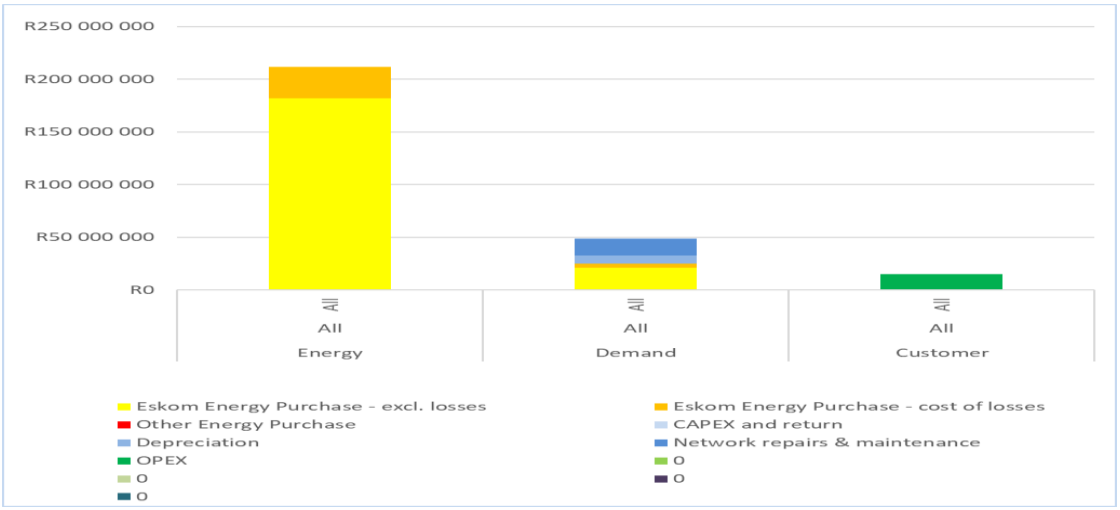


Figure 3*: Costs breakdown by cost structure (Classification)*

4.4.3.2. The cost allocation by driver indicates that the majority of costs are energy-related, accounting for over 80% of total costs. While this is consistent with the municipality's reliance on bulk electricity purchases, it raises concerns regarding the adequacy of demand and customer-related cost recovery.

4.4.3.3. Demand-related costs, which are associated with network capacity and infrastructure, appear to be relatively low. This may result in insufficient recovery of fixed network costs and could distort pricing signals to consumers.

4.4.3.4. Similarly, customer-related costs are minimal, suggesting that fixed charges may not fully reflect the cost of servicing customers, potentially leading to cross-subsidisation

4.4.3.5. The overall cost structure reflects a strong reliance on volumetric (energy-based) cost recovery, with relatively low contributions from demand and customer charges. This imbalance suggests that the current tariff structure may not fully align with cost causation principles.

4.4.3.6. 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. Demand-driven costs are similarly concentrated in the summer period. Customer-driven costs are primarily associated with "Other OPEX," which includes expenses related to the provision of electricity distribution services to customers.

4.4.4. Cost Allocation

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

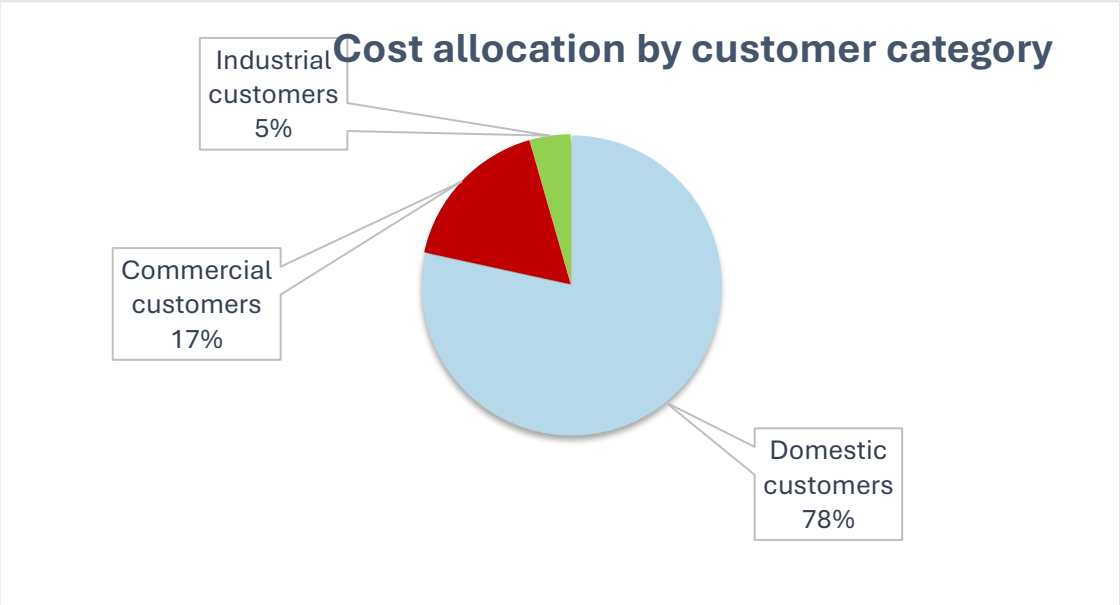


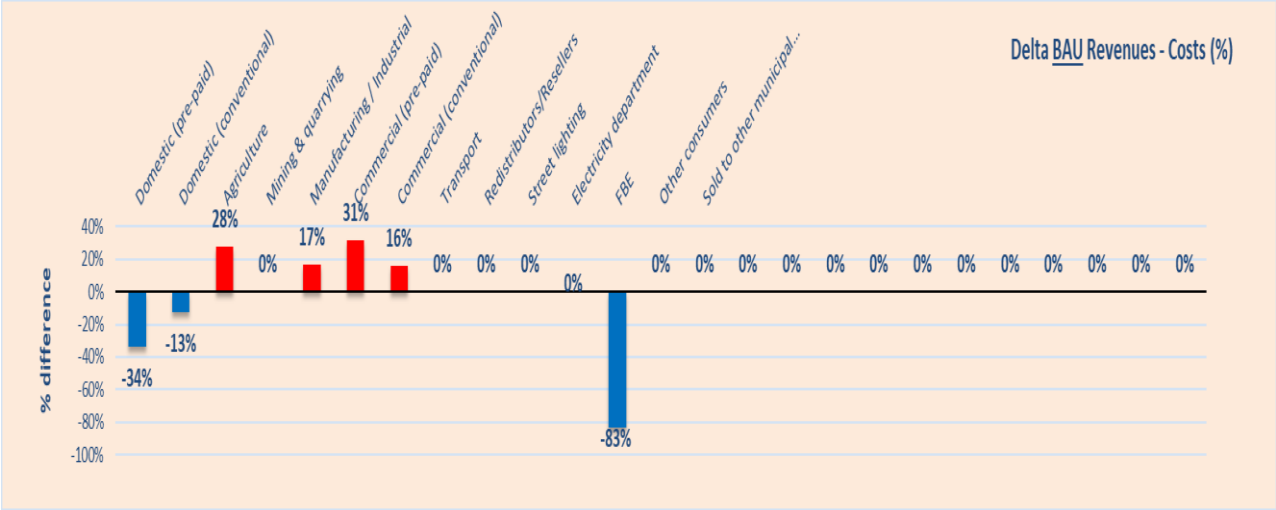
Figure 4: *Costs Allocated*

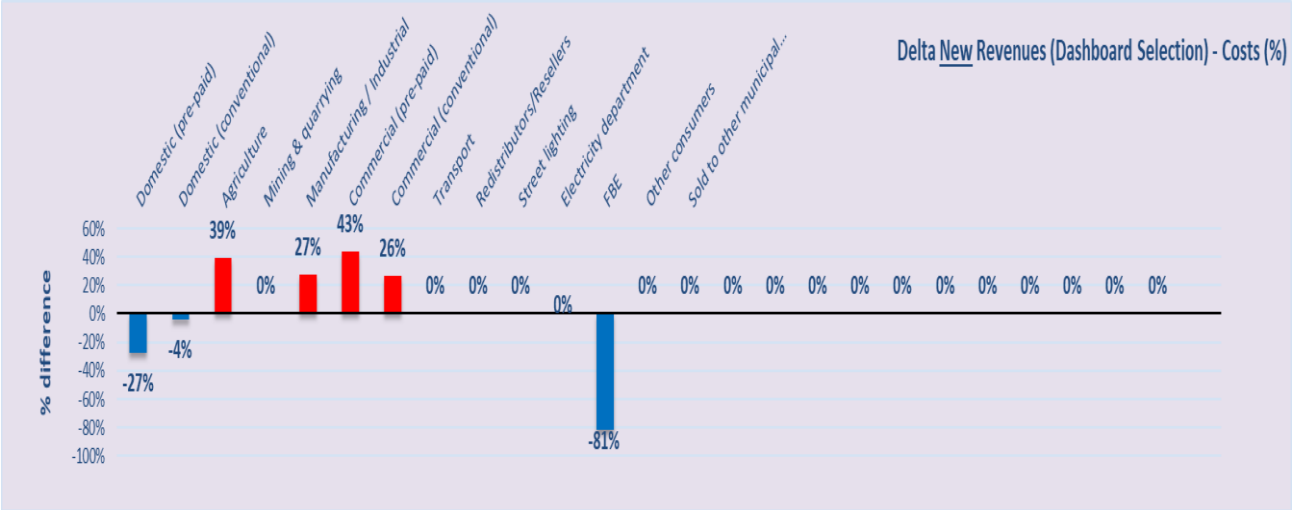
4.4.5. Rate Design

4.4.5.1. Table 5 below reflects the outcome of the COS study, indicating that Domestic, Other Municipal Departments, and industrial time of use customer categories require upward adjustments, while the rest, including commercial customers, warrant decrease. A comparison between the COS and the revenue generated per tariff category highlights the extent of over- or under-recovery within each category, as illustrated in Table 5 below.

4.4.5.2. To achieve full cost-reflectivity, the municipality would be required to implement differentiated tariff adjustments across customer categories mentioned in section 4.4.5.1. However, the municipality has adopted a less aggressive approach, opting instead for a proposed uniform tariff increase of 11.1% across all customer categories.

Figure 5 ***Revenue Recovery by customer category***





4.4.5.3. The analysis of the delta between Business-as-Usual (BAU) revenues and allocated costs indicates significant variances across customer categories. Certain customer groups, including industrial and commercial customers, reflect substantial over-recovery, while others, particularly segments of domestic customers and internal municipal consumption, are materially under-recovering.

4.4.5.4. The magnitude of these variances, ranging from approximately -83% to +31%, highlights the presence of considerable cross-subsidisation within the tariff structure. While some level of cross-subsidisation may be justified on socio-economic grounds, the current extent appears excessive and not fully aligned with the principles of cost reflectivity.

4.4.5.5. Of particular concern is the significant under-recovery associated with internal municipal electricity consumption, which may indicate inefficiencies in cost allocation or tariff application.

4.4.5.6. The current tariff structure may therefore result in distorted pricing signals, potentially impacting customer behaviour, especially among large industrial users, and undermining the long-term sustainability of the revenue base.

5. Conclusion on the COS

5.1. While the outcome of the COS study indicated an average tariff adjustment of a 29.2% for a licensee to achieve full cost-reflectivity, a municipality may elect to implement such adjustments on a phased basis, including applying an increase below the COS-derived level.

5.1.1. The Municipality should consider phasing in the required tariff increases over a multi-year period rather than implementing the full adjustments immediately. This will help to:

5.1.1.1. Eliminate the remaining revenue shortfall;

5.1.1.2. Achieve full alignment with cost-of-supply principles; and

5.1.1.3. Ensure the long-term financial sustainability of the electricity service.

5.2. In addition, the licensee may take into account its ability to meet financial obligations, including payments to Eskom, as well as the broader affordability constraints faced by customers, in determining the appropriate trajectory for tariff adjustments.

5.3. This approach is intended and will ensure safeguarding of the municipality's revenue base and support its financial sustainability, in line with applicable legislative requirements.

5.4. The COS study is based on forecast assumptions and, as such, does not guarantee that the projected outcomes will materialise. Accordingly, the licensee retains the discretion to review the results and determine its own revenue requirements to ensure financial sustainability. In this regard, the municipality will be required to submit a report accounting for all costs that remain unverified.

5.5. The COS study results indicate a required increase of 29.2% to reach cost reflectivity, as illustrated in Figure 5 below.

5.6. The licensee applied for a tariff increase of 9.7% for the 2026/27 financial year, which is aligned with the outcomes of the COSstudy. Although the COS indicates a cost-reflective tariff adjustment of 29.2%, the proposed increase remains substantially below this level, suggesting a phased approach toward cost-reflectivity. This approach may be aimed at mitigating the immediate impact on

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https://www.nersa.org.za/file/9396/GamagaraMunicipalityReasonsforDecisionforthe2026_27FY.pdf

8. Tariff Analysis:

Table 4: Schedule of Tariffs

Domestic Prepaid						
Tariff blocks	**2025/26 Approved**	**Proposed % Increase**	**2026/27 Proposed**	**2026/27 Proposed**	**2026/27 Recommended % Increase**	**Analysis and Key Findings**
Block 1 (0 - 50 kWh)	176,404	9,7%	193,52	193,52	9,7%	The recommended tariffs are considered sufficient to cover the revenues required.
Block 2 (51 – 350 kWh)	223,790	9,7%	245,50	245,50	9,7%	
Block 3 (351 – 600 kWh)	320,012	9,7%	351,05	351,05	9,7%	
Block 4 (>600kWh)	376,360	9,7%	412,87	412,87	9,7%	
Domestic Conventional	**2025/26 Approved**	**Proposed % Increase**	**2026/27 Proposed**	**2026/27 Proposed**	**2026/27 Recommended % Increase**	**Analysis and Key Findings**
Tariff blocks	**R/kWh**					
Block 1 (0 – 50 kWh)	175,488	9,7%	192,51	192,51	9,7%	The recommended tariffs are considered sufficient to cover the revenues required.
Block 2 (51 – 350 kWh)	224,256	9,7%	246,01	246,01	9,7%	
Block 3 (351 – 600 kWh)	320,006	9,7%	351,05	351,05	9,7%	
Block 4 (>600kWh)	376,372	9,7%	412,88	412,88	9,7%	
				-		
Basic charge (R/month)	221,106	9,7%	242,55	242,55	9,7%	
Commercial Prepaid (Single Phase)	**2025/26 Approved**	**Proposed % Increase**	**2026/27 Proposed**	**2026/27 Proposed**	**2026/27 Recommended % Increase**	**Analysis and Key Findings**
Basic charge:	256,22	9,7%	281,07	281,07	9,7%	The recommended tariffs are considered sufficient to cover the revenues required.
Energy charge:	373,27	9,7%	409,48	409,48	9,7%	
Commercial Prepaid (Three Phase)	**2025/26 Approved**	**Proposed % Increase**	**2026/27 Proposed**	**2026/27 Proposed**	**2026/27 Recommended % Increase**	
Basic charge:	256,22	9,7%	281,07	281,07	9,7%	
Energy charge:	372,58	9,7%	408,72	408,72	9,7%	
Commercial Conventional (Single phase)	**2025/26 Approved**	**Proposed % Increase**	**2026/27 Proposed**	**2026/27 Proposed**	**2026/27 Recommended % Increase**	**Analysis and Key Findings**
Basic charge:	540,73	9,7%	593,18	593,18	9,7%	tariffs are considered
Energy charge:	335,14	9,7%	367,65	367,65	9,7%	sufficient to cover the
Commercial Conventional below 100A / Three phase	**2025/26 Approved**	**Proposed % Increase**	**2026/27 Proposed**	**2026/27 Proposed**	**2026/27 Recommended % Increase**	**Analysis and Key Findings**
Basic charge:	782,67	9,7%	858,59	858,59	9,7%	tariffs are considered
Energy charge:	300,35	9,7%	329,49	329,49	9,7%	sufficient to cover the
Government Schools >100A	**2025/26 Approved**	**Proposed % Increase**	**2026/27 Proposed**	**2026/27 Proposed**	**2026/27 Recommended % Increase**	**Analysis and Key Findings**
Basic charge:	795,60	9,7%	872,77	872,77	9,7%	tariffs are considered
Energy charge:	296,91	9,7%	325,71	325,71	9,7%	sufficient to cover the
Agricultural Conventional	**2025/26 Approved**	**Proposed % Increase**	**2026/27 Proposed**	**2026/27 Proposed**	**2026/27 Recommended % Increase**	**Analysis and Key Findings**
Basic charge:	1 886,14	9,7%	2 069,10	2 069,10	9,7%	tariffs are considered
Energy charge:	236,11	9,7%	259,01	259,01	9,7%	sufficient to cover the
Industrial Tariffs	**2025/26 Approved**	**Proposed % Increase**	**2026/27 Proposed**	**2026/27 Proposed**	**2026/27 Recommended % Increase**	**Analysis and Key Findings**
Basic charge:	1 493,13	9,7%	1 637,96	1 637,96	9,7%	tariffs are considered
Demand Charge:	189,49	9,7%	207,87	207,87	9,7%	sufficient to cover the
Energy charge:	248,48	9,7%	272,58	272,58	9,7%	revenues required.
Departmental/ Municipality	**2025/26 Approved**	**Proposed % Increase**	**2026/27 Proposed**	**2026/27 Proposed**	**2026/27 Recommended % Increase**	**Analysis and Key Findings**
Basic charge:	256,22	9,7%	281,07	281,07	9,7%	
Energy charge:	390,72	9,7%	428,62	428,62	9,7%	
Street Lights	**2025/26 Approved**	**Proposed % Increase**	**2026/27 Proposed**	**2026/27 Proposed**	**2026/27 Recommended % Increase**	**Analysis and Key Findings**
Energy charge:	255,22	9,7%	279,98	279,98	9,7%	

9. CONFIDENTIALITY

9.1. None.

10. CONCLUSION

10.1. On a conspectus of the facts and evidence presented to the REC, it is appropriate to approve GLM'S tariff application for the 2026/27 financial year.

End.