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 Application for the 2026/27 Financial Year**

By

**Buffalo City Metropolitan Municipality**

## THE DECISION

At its meeting held on 9 May 2026, the Regulator Executive Committee (REC) considered Buffalo City Municipality's tariff application. Based on the facts and evidence presented, the REC approved the tariff increases for the 2026/27 financial year (FY) the decision is set out on the tariff analysis section 8 on page 24 of the RfD. Based on the information submitted and the analysis conducted, the REC decided:

1. 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;
2. to note the COS Report submitted by the municipality;
3. 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
4. that the municipality must submit quarterly specific, measurable, achievable, relevant and time-bound (SMART) energy losses reduction progress reports for NERSA to monitor the implementation thereof by 30 September 2026.

## TABLE OF CONTENTS

THE DECISION ..... 1
TABLE OF CONTENTS ..... 2
ABBREVIATIONS AND ACRONYMS ..... 5
1. INTRODUCTION ..... 6
2. LEGAL AND REGULATORY FRAMEWORK ..... 7
3. FINANCIAL AND TECHNICAL PERFORMACE ..... 11
4. DETERMINATION OF BUFFALO CITY TARIFFS BASED ON THE COST OF SUPPLY STUDY ..... 13
4.4.1. Revenue Requirement ..... 13
4.4.2. Cost Functionalisation ..... 16
4.4.3. Cost Classification ..... 17
4.4.4. Cost Allocation ..... 19
4.4.5. Rate Design ..... 19
5. CONCLUSION ON THE COS ..... 20
6. PUBLIC PARTICIPATION ..... 21
7. OBJECTORS AND OTHER INTERVENING PARTIES ..... 22
8. TARIFF ANALYSIS ..... 22
9. CONFIDENTIALITY ..... 31
10. CONCLUSION ..... 31

## TABLE OF TABLES

Table 1: Summary of the REC decision.....**Error! Bookmark not defined.**
Table 2: Customer Statistics (Data obtained from the latest D-forms – 2024/25) .....6
Table 3: Performance Indicators.....12
Table 4: Revenue Impact Analysis .....12
Table 4: Revenue Requirement Components .....14

## TABLE OF FIGURES

Figure 1: Fives steps of COS.....13
Figure 2: Cost Breakdown by Function.....17
Figure 3: Cost Breakdown by Cost Structure (Classification).....18
Figure 4: Costs Allocated.....19

## ABBREVIATIONS AND ACRONYMS

| | |
|---|---|
| COS | Cost of Supply |
| D-form | Distribution form |
| ERTSA | Eskom Retail Tariff Structural Adjustments |
| FBE | Free Basic Electricity |
| IBT | Inclining Block Tariff |
| IPP | Independent Power Producer |
| MFMA | Municipal Finance Management Act |
| NERA | National Electricity Regulation Act |
| NERSA | National Energy Regulator of South Africa |
| OPEX | Operating Expenditure |

## 1. INTRODUCTION

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

1.2. Buffalo City Metropolitan Municipality is located in the Eastern Cape. It includes the towns of East London, Bhisho and King William's Town, as well as the large townships of Mdantsane and Zwelitsha. On 18 May 2011 it was separated from the Amathole District Municipality and converted into a Metropolitan Municipality. The area has a well-developed manufacturing base, with the auto industry playing a major role. Daimler AG, through its wholly owned subsidiary Mercedes-Benz South Africa (MBSA), has a large assembly plant located next to the port of East London, which produces a variety of vehicles for export.

1.3. Buffalo City implemented a 12.74% average price increase in the 2025/26 financial year, which was based on a decision taken by the Municipal Mayor, in a meeting between NERSA and the BCMM Mayoral Committee on 24 March 2025. This came after a community uproar about the high increases as a result of the major tariff restructuring in FY2024/25. In the current cycle FY2026/27, the municipality is applying for an average price increase of 14%.

1.4. The details regarding consumer statistics are highlighted in Table 1 below. The municipality is implementing Inclining Block Tariffs (IBTs) fully and is offering 50 kWh of Free Basic Electricity per month to all registered indigent consumers.

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

| CONSUMER STATISTICS (OBTAINED FROM 2024-2025 DISTRIBUTION FORMS) | | | |
|---|---|---|---|
| **Consumer Classification** | **Sales (KWh)** | **%KWh** | **Number of Consumers** |
| Domestic (Prepaid) | 130 242 032 | 14,22% | 133 660 |
| Domestic (Conventional) | 12 827 503 | 1,40% | 4 405 |
| Manufacturing / Industrial | 280 367 257 | 30,60% | 1 018 |
| Commercial (Prepaid) | 141 663 437 | 15,46% | 3 316 |
| Commercial (Conventional) | 324 617 247 | 35,43% | 2 300 |
| Other Consumers (Old Age Homes/ Churches/ Sports ground) | 501 566 | 0,05% | 69 |
| Street Lighting | 10 736 744 | 1,17% | |
| Municipal Consumption | 15 228 723 | 1,66% | 358 |
| **TOTAL SALES** | **916 184 509** | **100%** | **145 126** |
| | | | |
| **Free Basic Electricity (FBE)** | **32 772 340** | **22,91%** | **48 024** |

1.5. NERSA received Buffalo City's tariff application together with its revised Cost of Supply (COS) study on 25 March 2026.

1.6. NERSA followed the notice and comment consultation process. Buffalo City's tariff application was published on the NERSA website on 27 March 2026, as well as on social media platforms and in local and national newspapers to solicit written comments from affected parties.

1.7. NERSA's decision was made on 9 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 NERSA 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 No. 3 of 2000) ('PAJA'), and the Electricity Pricing Policy for the South African Electricity Supply Industry, 2008 ('EPP').

2.1.2. The approval of municipal electricity tariffs follows the Eskom Multi-Year Price Determination and Eskom Retail Tariff and Structural Adjustment decision and is undertaken annually 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 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, NERSA as the decision-making body, must regulate the electricity industry and execute the functions set out in the ERA. NERSA's electricity regulatory mandate 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 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, NERSA 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, NERSA 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 are afforded a reasonable opportunity to make representations before a final decision is taken.

2.4.2. NERSA's public participation processes 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, NERSA must have regard to the EPP. The EPP establishes national policy principles for electricity tariff setting, including cost reflectivity, transparency, economic efficiency and equity.

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

2.5.3. Policy position 2 states that electricity tariffs must reflect the efficient cost of rendering electricity services accurately and that the average level of tariffs must be set to recover the approved revenue requirement.

## 2.6. Cost of Supply Studies

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

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

2.6.3. Policy position 23 therefore requires electricity distributors to undertake COS studies at least every five years, or when significant structural changes occur in the customer base or cost structure.

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

## 2.7. Judicial Oversight of the Tariff Approval Process

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

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

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

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

## 2.8. Court-Directed Timelines

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

a) Written notice of bulk tariffs by 6 March 2026
b) Municipal tariff applications must be submitted by 31 March 2026
c) Public participation processes must be concluded by 21 April 2026
d) The publication of NERSA decisions by 11 May 2026.

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

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

## 2.9. Conclusion

2.9.1. The determination of municipal electricity tariffs by NERSA 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 NERSA complied with the legislative, policy and judicial framework in determining the municipal electricity tariff for the 2026/27 financial year.

# 3. FINANCIAL AND TECHNICAL PERFORMACE

3.1. In evaluating BCM's financial and technical performance, the assessment relied on the Distribution forms (D-forms) for the 2024/25 financial year that were 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. Buffalo City's electricity business operated at a deficit of 9.91% for the 2024/25 financial year, reflecting an improvement from the 19.01% deficit reported in 2023/24. Total revenue and expenditure increased by 28% and 18%, respectively. However, electricity revenue remains constrained by high bulk purchase. This indicates that the electricity service is not financially sustainable, with costs increasingly exceeding revenue. Furthermore, energy losses resulted in lost electricity sales revenue amounting to R831.4 million (R831,433,819).

3.3. Table 2 below shows that energy losses of 32.19% were recorded for the 2024/25 financial year, up from 20.40% in 2023/24. The technical losses amount to 10%. The municipality has invested a substantial amount of capital into the electrical network.

3.4. The non-technical losses amounted to 22.19%. The losses are due to illegal connections, meter tampering, electrical faults and billing errors. Attempts are currently being made to reduce these losses. A self-funding revenue recovery project proposal is also being considered to target some +180 000 non-purchasing prepayment customers to rehabilitate this income generating revenue stream to the institution.

**Table 2: Performance Indicators**

| PERFORMANCE INDICATORS: OBTAINED FROM D-FORMS | | |
|---|---|---|
| **INDICATORS** | **2024-25FY (Actuals)** | **2023-24 FY (Approved)** |
| Percentage Surplus (Deficit) | -9,91% | -19,01% |
| Percentage Energy Losses | 32,19% | 20,40% |

3.5. Based on the above information, the municipality is required to address operational inefficiencies by reducing high expenditure on its electricity account. These measures are necessary to further improve surplus levels and support the municipality's long-term financial sustainability.

3.6. Table 3 below provides a revenue impact analysis under three energy loss scenarios: actual (32.19%), when reduced to 12% and at 9%.

**Table 3: Revenue Impact Analysis**

| | D-Form Input | Energy Loss@12% | Energy Loss@9% |
|---|---|---|---|
| Average Selling Price | 338,37 | | |
| Sales kWh | 916 184 509,40 | 1 189 043 462,60 | 1 229 579 035,19 |
| Purchases kWh | 1 351 185 752,96 | 1 351 185 752,96 | 1 351 185 752,96 |
| Losses kWh | 435 001 243,56 | 162 142 290,36 | 121 606 717,77 |
| Losses percentage | **32,19%** | **12,00%** | **9,00%** |
| Additional Energy (kWh) | | 272 858 953,20 | 313 394 525,79 |
| Additional Revenue (Rands) | | 923 271 957,78 | 1 060 432 043,69 |
| | D-Form Input | Energy Loss@12% | Energy Loss@6% |
| Total Revenue (Rands) | R 3 367 611 696,85 | R 4 290 883 654,63 | R 4 428 043 740,54 |
| Total Expenses (Rands) | R 3 701 302 628,52 | R 3 701 302 628,52 | R 3 701 302 628,52 |
| Net Profit (Loss) | R -333 690 931,67 | R 589 581 026,11 | R 726 741 112,02 |
| Percentage Surplus/Deficit | **-9,91%** | **13,74%** | **16,41%** |

3.7. Under the current scenario, with actual electricity losses of 32.19%, the licensee records an operating deficit of approximately R333 million, which translates to a deficit level of 9.91%, based on approved D-form inputs. The revenue deficit of R333.7 million (-9.91%), indicates that current tariffs are not cost-reflective under prevailing inefficiencies. This negative surplus margin indicates that elevated energy losses continue to place pressure on the financial sustainability of the electricity business.

3.8. Based on the analysis, should electricity losses be reduced to 12%, and assuming constant electricity purchases, operating costs and tariff structures, the total electricity sales revenue is projected to increase due to higher energy volumes. Under this scenario, the estimated revenue that could be recovered through loss reduction is estimated to increase by approximately R923 million, reflecting improved revenue retention relative to the current position. Further reductions in energy losses are expected to strengthen the surplus position, subject to the sustainability and effectiveness of the implemented loss-reduction measures.

## 4. DETERMINATION OF BUFFALO CITY TARIFFS BASED ON THE COST OF SUPPLY STUDY

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

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

4.3.

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

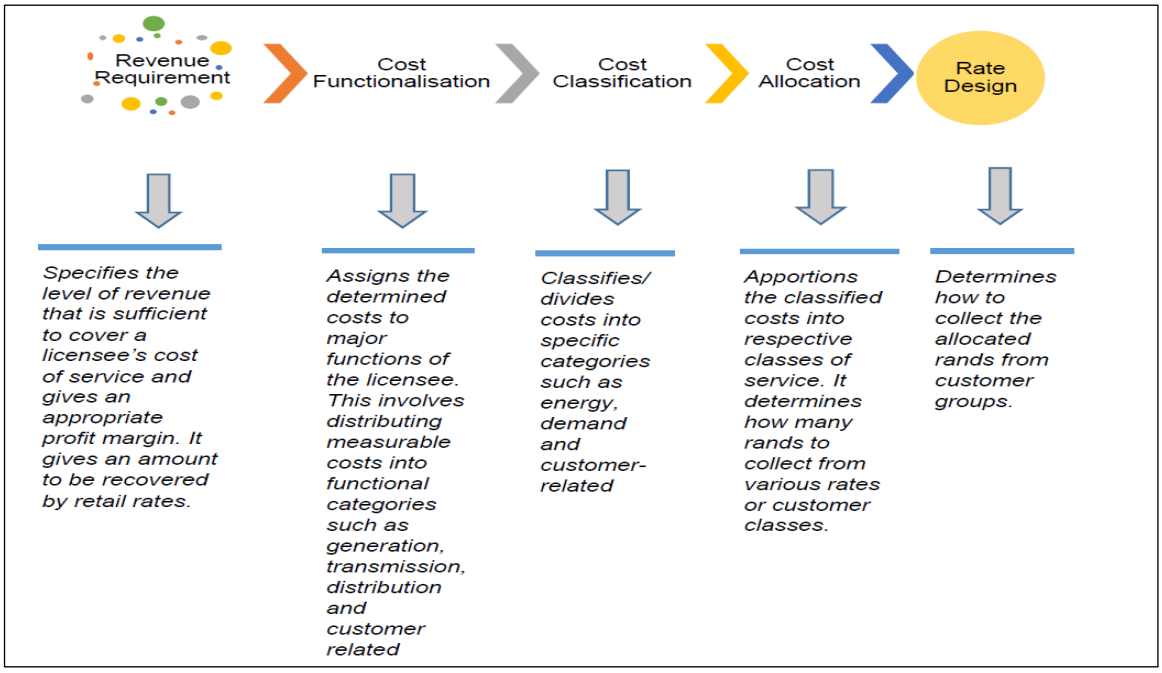



**Figure 1: Fives steps of COS**

4.5. The following steps are undertaken to analyse the cost of supply study.

### 4.5.1. Revenue Requirement

4.5.1.1. In order to be fully cost reflective, the licensee's revenue requirements are R3 716 600 634 million, divided into wires (54%) and retail (46%), for the 2024/25 financial year. This revenue requirement consists of the components outlined below.

4.5.1.2. Eskom Bulk Purchases constitutes 48% (excluding cost of losses) of the total revenue requirement at an amount of R1 783 625 468, and this is the largest cost driver of the municipality's electricity department.

4.5.1.3. An energy loss allowance of 12%, amounting to R335 706 753, has been provided for. When combined with Eskom bulk energy purchases (net of losses) of 48% (R1 783 625 468), these components constitute approximately 57% of the total revenue requirement, equivalent to R2 119 332 221.

4.5.1.4. Operational expenditure (including depreciation) amounts to R1 374 422 372, representing 37% of the total revenue requirement. These costs relate to the operation and maintenance of the network and customer services. The costs are highlighted in Table 4 below.

**Table 1: Revenue Requirement Components**

| | Total cost (R) | | | |
|---|---|---|---|---|
| **Revenue Requirement components** | **Wires** | **Retail** | **Total** | **% of Total** |
| **Allowable costs** | 1 909 948 190 | 1 806 652 444 | 3 716 600 634 | 100% |
| Energy purchases from Eskom - net of cost of losses | - | 1 783 625 468 | 1 783 625 468 | 48% |
| Energy purchases from Eskom - cost of losses | 797 242 146 | - 461 535 393 | 335 706 753 | 9% |
| Other energy purchases | - | - | - | 0% |
| Capital expenditure | 215 822 787 | - | 215 822 787 | 6% |
| Operational expenditure (incl. Depreciation) | 899 360 154 | 475 062 218 | 1 374 422 372 | 37% |
| Other revenues | - 2 476 896 | - 13 574 248 | - 16 051 144 | 0% |
| Surplus | - | 23 074 399 | 23 074 399 | 1% |
| **Not allowable costs** | 410 622 923 | 137 108 593 | 547 731 516 | |
| Cost of losses disallowed | 410 622 923 | 137 108 593 | 547 731 516 | |
| **TOTAL COSTS** | **2 320 571 113** | **1 943 761 037** | **4 264 332 149** | |
| | **54%** | **46%** | | |

4.5.1.5. 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.

4.5.1.6. 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**

4.5.1.7. Buffalo City applied for a bulk purchase expenditure of R2.1 billion which accounts for 57% of total costs. Bulk purchases were verified against Eskom invoices in the 2024/25 financial year.

4.5.1.8. To derive the 2026/27 bulk purchase estimate, the licensee projected the year-to-date costs for 2025/26 and increased this cost item by 9.01% in line with the approved Eskom Retail Tariff Structural Adjustments (ERTSA).

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

**Operational Expenditure**

4.5.1.10. Buffalo City applied for operational expenditure of R1.37 billion, which accounts for 37% of total costs, as reflected in Table 4 above.

4.5.1.11. The approach adopted by Buffalo City in forecasting operational expenditure is considered reasonable and the amount has therefore been approved as requested. However, inefficient cost components – such as NMD exceedance penalties amounting to R5,8 million (FY2024/25) and interest incurred on Eskom-related debt (R732 700) – have been excluded from the total, as these items fall within the control of the municipality.

**Surplus**

4.5.1.12. The municipality used a cost-plus methodology. Under the cost-plus methodology, allowable revenue is determined by adding the following together:

a) Efficient and prudent operating expenditure (OPEX)
b) Depreciation (serving as an estimate of asset consumption and future replacement needs)
c) A reasonable surplus margin.

4.5.1.13. Buffalo City has requested a surplus of R23 074 399, calculated using a surplus factor of 1% applied to operating expenditure, for both the wires and retail components of the business.

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

4.5.1.15. The return proposed by the Municipality at 1%, is considered reasonable, although it falls below the established target range of 10–20%.

4.5.1.16. To ensure that the profit margin is commensurate with the level of risk, qualitative risk considerations were incorporated, including revenue collection risks (such as non-payment and bad debts), operational risks (including the high energy losses and ageing infrastructure) and broader financial sustainability requirements, as well as consideration of customer affordability. All these link to the financial sustainability of the Municipality.

4.5.1.17. Therefore, the applied surplus margin is considered modest and commensurate with these risks, particularly in the context of a municipal distributor that is not profit-maximising but must remain financially viable. Thus, it is NERSA's decision to allow the revenue requirement as applied for.

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

### 4.5.2. **Cost Functionalisation**

4.5.2.1. The licensee has categorised its revenue requirement of R3.7 billion into two primary functional components, namely the wires business (51%) and the retail business (49%), in accordance with the NERSA COS Framework, as illustrated in Figure 2 below. On verification, the allocation of costs to these functional components is found to be consistent with the stated revenue requirement.

| | Total Functionalised Costs (R) | | |
|---|---|---|---|
| Functions | Wires | Retail | Total |
| Eskom Energy Purchase - excl. losses | - | 1 783 625 468 | 1 783 625 468 |
| Eskom Energy Purchase - cost of losses | 797 242 146 | - 461 535 393 | 335 706 753 |
| Other Energy Purchase | - | - | - |
| CAPEX and return | 215 822 787 | - | 215 822 787 |
| Depreciation | 188 119 169 | 2 715 764 | 190 834 933 |
| Network repairs & maintenance | 220 281 363 | - | 220 281 363 |
| Other OPEX | 488 482 726 | 481 846 605 | 970 329 331 |
| | | | |
| | 1 909 948 190 | 1 806 652 444 | 3 716 600 634 |
| | | | TRUE |

**Figure 2: Cost Breakdown by Function**

4.5.2.2. These costs, on 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.

### 4.5.3. Cost Classification

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

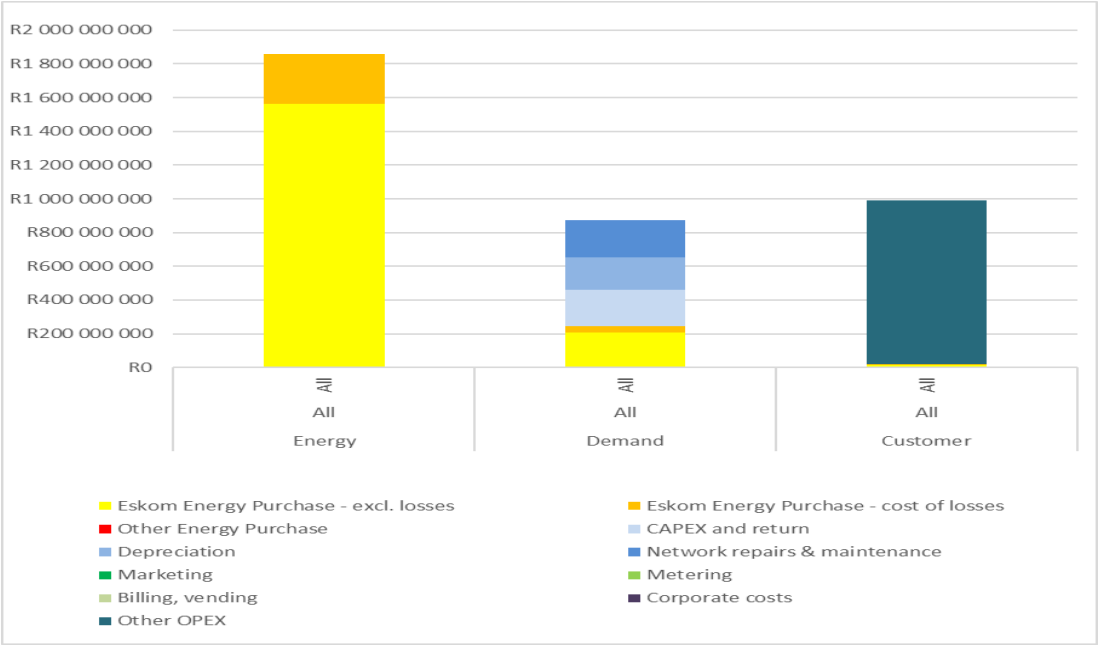



**Figure 3: Cost Breakdown by Cost Structure (Classification)**

4.5.3.2. The cost breakdown by component indicates that the energy-related costs constitute the largest portion of the total revenue requirement, significantly outweighing both demand- and customer-related costs.

4.5.3.3. The energy cost component is dominated by bulk energy purchases from Eskom (excluding losses), with an additional contribution from the cost of losses. This confirms that the municipality's cost structure is highly energy-intensive and largely variable in nature, making it sensitive to changes in bulk tariffs and consumption levels.

4.5.3.4. The demand-related costs are comparatively smaller and mainly consist of network repairs and maintenance, depreciation, and limited capital-related costs (CAPEX and return).

4.5.3.5. 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.

4.5.3.6. 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.

### 4.5.4. Cost Allocation

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

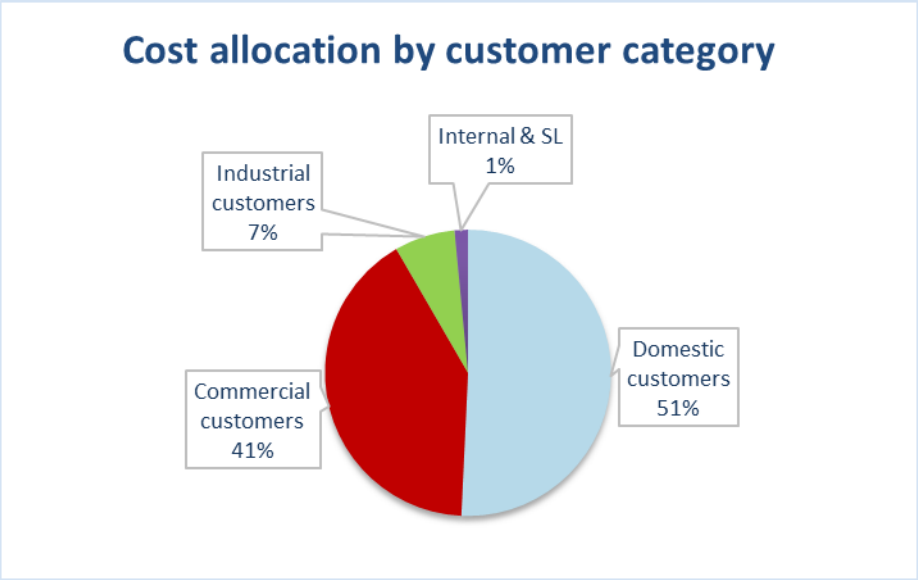



**Figure 4: Costs Allocated**

### 4.5.5. Rate Design

4.5.5.1. Table 5 below reflects the outcome of the COS study, indicating that certain customer categories require upward adjustments, while others warrant decreases. A comparison between the cost of supply and the revenue generated per tariff category highlights the extent of over- or under-recovery within each category, as illustrated in Table 5 below.

4.5.5.2. The analysis indicates that the domestic customer categories are not cost-reflective and are operating at a significant under-recovery level. In particular, the domestic (prepaid) indigent category reflects an under-recovery of 57%, while the domestic prepaid category reflects an under-recovery of 32%.

4.5.5.3. This indicates that the revenues generated from these categories are substantially below the cost to supply electricity, resulting in a funding gap. The shortfall is effectively recovered through cross-subsidisation from other customer categories, primarily non-domestic consumers.

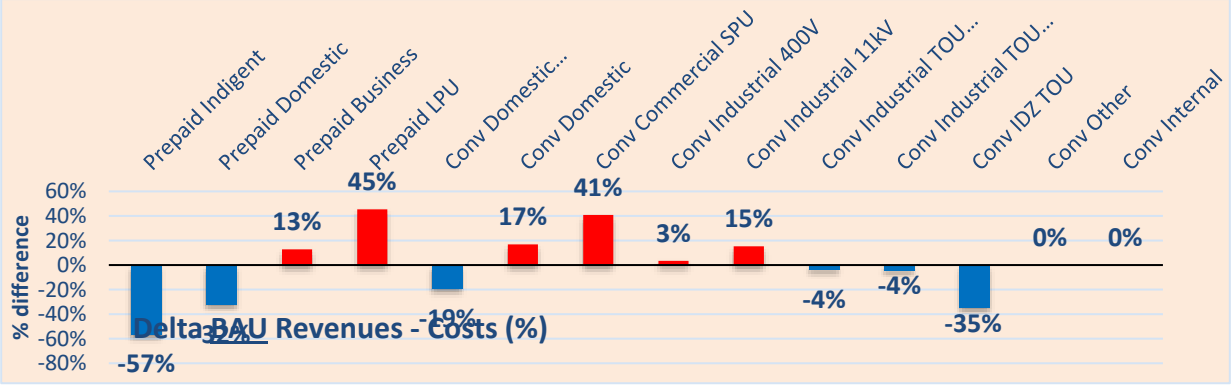
4.5.5.4. While NERSA acknowledges that a degree of cross-subsidisation is permissible to support affordability objectives, the magnitude of the under-

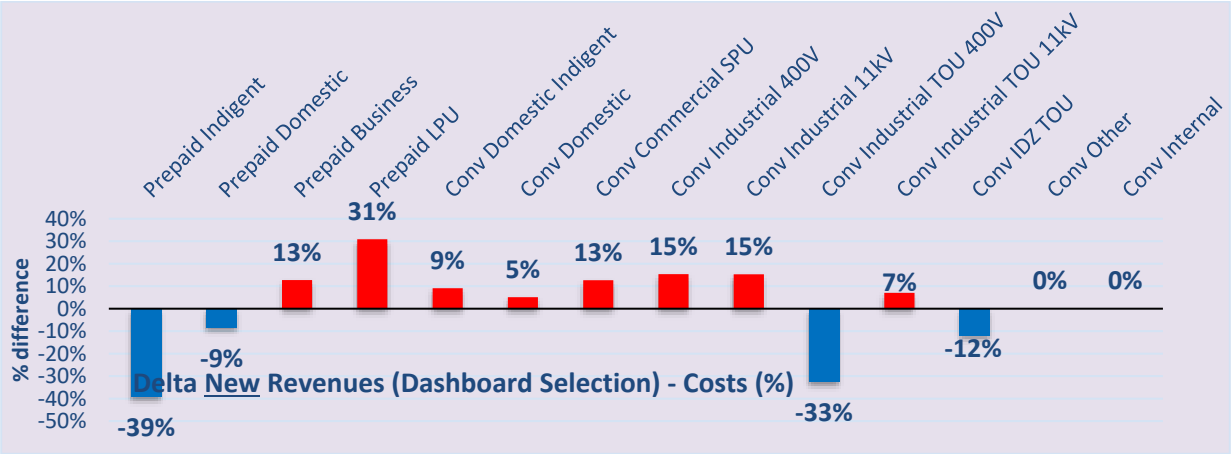
recovery in the domestic categories is significant and may not be sustainable in the long term.

4.5.5.5. The municipality is therefore encouraged to progressively align domestic tariffs with cost-reflective levels, while ensuring that support to indigent customers is appropriately targeted and transparently funded.

4.5.5.6. To achieve full cost reflectivity, the municipality would be required to implement differentiated tariff adjustments across customer categories mentioned in the section.

**Table 5: Revenue Recovery by Customer Category**




## 5. CONCLUSION ON THE COS

5.1. While the outcome of the COS study indicated an average tariff adjustment of a 13.5% 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.

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charges (approximately -20%), alongside differentiated adjustments in energy charges across TOU periods.

8.6. The reduction in fixed and demand charges is noted and supports improved affordability and reduced fixed cost burden, while the rebalancing of energy charges across peak, standard, and off-peak periods enhances cost reflectivity by aligning tariffs with system demand and energy cost drivers. Notably, increases in certain TOU periods are offset by decreases in others, indicating a reallocation of cost recovery rather than a uniform escalation, which is consistent with TOU pricing principles.

8.7. The COS confirms the presence of inter-tariff cross-subsidies, with commercial/industrial customers subsidising residential customers. Such cross-subsidisation is permitted and expected within municipal tariff structures, particularly to protect vulnerable households. The municipality's commitment to a phased transition to cost-reflective tariffs aligns with NERSA's approach of avoiding tariff shock while improving allocative efficiency over time. The municipality must develop a fair and transparent cross-subsidy framework.

| | DETAILS OF TARIFFS APPLIED FOR | | | | |
|---|---|---|---|---|---|
| | 2025/26 Approved | 2026/27 Proposed | % Increase | Recommended Tariff | Recommended % Increase |
| **1. Indigent Domestic Prepayment/Credit Three-Part Block Tariff** | | | | | |
| **Scale 1 C** | | | | | |
| Part 1 - First 50 kWh. Charge per kWh | Free | Free | | | |
| Part 2 - Charge per kWh | 2,56 | 2,86 | 11,72% | 2,86 | 11,72% |
| Part 3 - Charge per kWh > 300 kWh purchased per month | 3,01 | 3,37 | 11,89% | 3,37 | 11,89% |
| | | | | | |
| **2. Pensioners Domestic Prepayment Three-Part Tariff (credit and prepayment metering)** | | | | | |
| **Scale 1 C – 3** | | | | | |
| Part 1 – Charge per kWh | New | 3,12 | New | 3,12 | New |
| Part 2 – Basic Monthly Service Charge | New | Nil | New | Nil | New |
| Part 3 – Charge per kWh > 300 kWh purchased per month | New | 3,37 | New | 3,37 | New |
| | | | | | |
| | | | | | |
| **3. Social housing development projects (credit and prepayment metering)** | | | | | |
| **Scale 1 C – 4** | | | | | |
| Part 1 – Prepayment Charge per kWh up to 200 kWh | New | 3,12 | New | 3,12 | New |
| Part 2 – Credit Charge per kWh | New | 4,05 | New | 4,05 | New |
| Part 3 – Prepayment Charge per kWh > 200 kWh purchased per month | New | 3,37 | New | 3,37 | New |
| | | | | | |
| **4. Scale 1 B** | | | | | |
| Part 1 – Charge per kWh – First 2000 kWh | 3,01 | 3,37 | 11,89% | 3,368 | 11,89% |
| Part 2 – Charge per kWh > 2000 kwh purchased | 3,20 | 3,55 | 10,80% | 3,550 | 10,80% |
| Part 3 – Basic Monthly Service Charge | 423,90 | 461,00 | 8,75% | 461,000 | 8,75% |
| | | | | | |
| **5. Scale 2 B** | | | | | |
| **Small Power Prepayment Users, Domestic and Commercial 50kVA. Max 70A Three Phase** | | | | | |
| Part 1 – Charge per kwh | 3,61 | 3,774 | 4,54% | 3,774 | 4,54% |
| Part 2 – Basic Monthly Service Charge | 1167,00 | 1095,70 | -6,11% | 1 095,700 | -6,11% |
| | | | | | |

| | DETAILS OF TARIFFS APPLIED FOR | | | | |
|---|---|---|---|---|---|
| | **2025/26 Approved** | **2026/27 Proposed** | **% Increase** | **Recommended Tariff** | **Recommended % Increase** |
| **6. Prepayment Large Power User** | | | | | |
| **Scale 3C –** Large Power Users (80kVA up to 150kVA Commercial / Industrial), Min 100A | | | | | |
| Max 216A | | | | | |
| Charge per kWh | 3,87 | 3,826 | -1,14% | 3,826 | -1,14% |
| Part 2 – Basic charge per month or part thereof (payable whether or not any electricity is used) | 2537,78 | 2163,00 | -14,77% | 2 163,000 | -14,77% |
| *** Note – This tariff is not available for new services as these will have to apply for a 3A tariff** | | | | | |
| | | | | | |
| **7. Credit Metering** | | | | | |
| **Scale 1A – Domestic and Commercial 1phase Supply (70A)** | | | | | |
| Part 1 – Charge per kWh supplied | 3,48 | 3,885 | 11,64% | 3,885 | 11,64% |
| Part 2 – Basic charge per month or part thereof (payable whether or not any electricity is used) | 748,59 | 514,30 | -31,30% | 514,300 | -31,30% |
| | | | | | |
| **8. Scale 2A – Small Power Users Domestic and Commercial 50kVA. 70A Three Phase** | | | | | |
| Part 1 – Charge per kWh supplied | 4,80 | 4,456 | -7,17% | 4,456 | -7,17% |
| Part 2 – Basic charge per month or part thereof (payable whether or not any electricity is used) | Not applied | Not applied | | | |
| Part 3 – Charge per max KVA used per month | Not applied | Not applied | | | |
| | | | | | |
| **9. Scale 3A – Large Power Users – (80kVA–800kVA) and above. Supply at a nominal voltage of 400V** | | | | | |
| Service charge per month or part thereof (payable whether or not any electricity is used) | 6087,96 | 5767,80 | -5,26% | 5 767,800 | -5,26% |
| Demand charge per month per kVA of the maximum demand supplied in the month. | 405,86 | 443,50 | 9,27% | 443,500 | 9,27% |
| An energy charge for all electricity supplied in the month **(per kWh)**. | 2,10 | 2,116 | 0,76% | 2,116 | 0,76% |
| | | | | | |

| | DETAILS OF TARIFFS APPLIED FOR | | | | |
|---|---|---|---|---|---|
| | **2025/26 Approved** | **2026/27 Proposed** | **% Increase** | **Recommended Tariff** | **Recommended % Increase** |
| *Alternative 3A flat rate kWh tariff for bulk suppled complexes (business and residential) | | 4,70 | | 4,700 | |
| *Note – Used where electricity reselling takes place to off-set the inability of the resellers to collect the KVA portion of their BCMM account | | | | | |
| | | | | | |
| **10. Scale 3B – Large Power Users – 1MVA and above. Supply at a nominal voltage of 11kV** | | | | | |
| Basic charge per month or part thereof (payable whether or not any electricity is used) | 28185,00 | 20991,40 | -25,52% | 20 991,400 | -25,52% |
| Demand charge per month per kVA of the maximum demand supplied in the month. | 422,78 | 418,70 | -0,97% | 418,700 | -0,97% |
| An energy charge for all electricity supplied in the month **(per kWh)**. | 1,61 | 1,659 | 3,04% | 1,659 | 3,04% |
| | | | | | |
| **11. EL0301B *Alternative 3B flat rate kWh tariff for bulk suppled complexes (business and residential) where electricity** | NEW | 3,32 | | 3,32 | NEW |
| *Note: Used where electricity reselling takes place to off-set the inability of the resellers to collect the KVA portion of their BCMM account | | | | | |
| | | | | | |
| **12. SMALL- AND LARGE-SCALE EMBEDDED GENERATION TARIFFS** | | | | | |
| ***Note 1: SSEG and LSEG are NET billing tariffs and the credited exported energy cannot exceed the total imported energy for that month. The credited*** | | | | | |
| ***feed-in energy will be deducted from the energy procured from BCMM to off-set the billed kWh summary total.*** | | | | | |
| | | | | | |
| Note 2: Customers can apply for a feed-in tariff on any applied electricity tariff structure and will be compensated for this energy exported back to BCMM. Customers who install any SSEG/LSEG system or who want to be compensated for exported energy, must register their SSEG/LSEG system via the online SSEG registration portal, viz https://apply.sseg.org.za and once approved, a new export rate will be billed, in addition to the applied tariff. All compensated export energy must not exceed imported energy totals. | | | | | |

| | DETAILS OF TARIFFS APPLIED FOR | | | | |
|---|---|---|---|---|---|
| | **2025/26 Approved** | **2026/27 Proposed** | **% Increase** | **Recommended Tariff** | **Recommended % Increase** |
| **13. Feed-in tariff for SSEG/LSEG approved installations** | | | | | |
| (This is a bi-directional (import/export) three-part tariff structure) | | | | | |
| Energy exported by customer to the BCMM electricity grid | | | | | |
| * Billed in addition to other tariff components of the applied tariff | | | | | |
| Eskom Off-peak and standard periods during high and low season billing | New tariff | -1,90 | | -1,90 | New tariff |
| Eskom Peak period during high season billing (Jun–Aug) | New tariff | -3,00 | | -3,00 | New tariff |
| | | | | | |
| **16. Scale 4 – Time-of-Use** | | | | | |
| **Scale 4A – Time-of-Use at 400V** | | | | | |
| Basic charge per month or part thereof (payable whether or not any electricity is used) | 7046,12 | 4437,10 | -37,03% | 4 437,100 | -37,03% |
| **Monthly maximum Demand Charges during peak or standard periods (R/kVA/m)** | | | | | |
| During low demand months | 258,58 | 206,10 | -20,30% | 206,100 | -20,30% |
| During high demand months | 285,35 | 227,50 | -20,27% | 227,500 | -20,27% |
| **Active Energy Charges / kwh** | | | | | |
| Low Demand (Sept – May) | 3,73 | 3,488 | -6,49% | 3,488 | -6,49% |
| | 2,69 | 3,125 | 16,17% | 3,125 | 16,17% |
| | 2,06 | 2,416 | 17,28% | 2,416 | 17,28% |
| High Demand (June – Aug) | 6,73 | 4,359 | -35,23% | 4,359 | -35,23% |
| | 2,99 | 3,708 | 24,01% | 3,708 | 24,01% |
| | 2,19 | 3,473 | 58,58% | 3,473 | 58,58% |
| Reactive Energy Charge. Standard 30-minute integrating periods. (R.cents/kvarh) | 0,33 | 0,330 | 0,00% | 0,330 | 0,00% |
| | | | | | |
| **17. Scale 4C – Time-of-Use at 11KV** | | | | | |
| Basic charge per month or part thereof (payable whether or not any electricity is used) | 58043,17 | 8993,00 | -84,51% | 8 993,000 | -84,51% |

| DETAILS OF TARIFFS APPLIED FOR | | | | | |
|---|---|---|---|---|---|
| **Monthly maximum Demand Charges during peak or standard periods (R/kVA/m)** | **2025/26 Approved** | **2026/27 Proposed** | **% Increase** | **Recommended Tariff** | **Recommended % Increase** |
| During low demand months | 168,11 | 201,00 | 19,56% | 201,000 | 19,56% |
| During high demand months | 450,80 | 539,30 | 19,63% | 539,300 | 19,63% |
| **Active Energy Charges / kwh** | | | | | |
| Low Demand (Sept - May) Peak | 2,47 | 2,983 | 20,77% | 2,983 | 20,77% |
| Standard | 1,63 | 1,756 | 7,73% | 1,756 | 7,73% |
| Off Peak | 1,30 | 1,206 | -7,23% | 1,206 | -7,23% |
| High Demand (June - Aug) Peak | 4,48 | 5,411 | 20,78% | 5,411 | 20,78% |
| Standard | 1,76 | 1,896 | 7,73% | 1,896 | 7,73% |
| Off Peak | 1,31 | 1,216 | -7,18% | 1,216 | -7,18% |
| Reactive Energy Charge. Standard periods. 30-minute integrating period. | 0,30 | 0,30 | 0,00% | 0,300 | 0,00% |
| | | | | | |
| **18. *Business relief tariff for financially distressed businesses or old age homes** | | | | | |
| Basic charge per month or part thereof (payable whether or not any electricity is used) | New Tariff | | | | |
| Demand charge per month per kVA of the maximum demand supplied in the month. | New Tariff | | | | |
| An energy charge for all electricity supplied in the month **(per kWh)**. | New Tariff | 3,00 | | 3,00 | New Tariff |
| | | | | | |
| **20. Scale TOU – IDZ (Eskom municipal TOU tariff with a 2,5% surcharge)** | | | | | |
| | | | | | |
| Refer to the Eskom tariff book for the applied Eskom Municflex tariff for municipalities will apply for Zone 3, >600 km & < 900 km at 11KV. | | | | | |
| 2,5% Surcharge (IE all costs depicted in Eskom's munic flex tariff X 2,5%) as approved by Council, in Percentage | 0,025 | 0,025 | | 0,025 | |
| | | | | | |
| **Note 1: Only the IDZ is approved for this reduced tariff at transmission zone >600 km <900 km at (66KV–132KV)** | | | | | |

| DETAILS OF TARIFFS APPLIED FOR | | | | | |
|---|---|---|---|---|---|
| **Note 2: The relevant Eskom billing tariff will apply** | **2025/26 Approved** | **2026/27 Proposed** | **% Increase** | **Recommended Tariff** | **Recommended % Increase** |
| | | | | | |
| **21. Scale 5 – Streetlighting** | | | | | |
| A Basic charge per streetlighting luminaire per month, plus | 26,86 | | | | |
| A Demand charge per month per KW Installed plus | 335,00 | | | | |
| Energy charge: Streetlighting | 3,28 | 3,56 | 8,54% | 3,560 | 8,54% |
| Energy Charge-Traffic Signals: for all electricity supplied in a month | 3,44 | 3,56 | 3,49% | 3,560 | 3,49% |
| | | | | | |
| **22. Scale 6 – Temporary and Itinerant (Max 50KVA supply, Single- or Three-phase prepayment meter only)** | | | | | |
| Charge per kWh supplied | 11,00 | 11,00 | | 11,00 | 0,00% |
| | | | | | |
| **23. Scale 8 – Sports field Lighting and Schools** | | | | | |
| Energy Charge | | | | | |
| First 2000 kWh | 5,12 | | | | |
| Next 8000kWh | 3,76 | | | | |
| Above 10 000 kWh | 5,35 | | | | |
| Minimum charge per month, or part thereof | 0,00 | | | | |
| kWh rate | New flat rate | 4,00 | | 4,00 | NEW |

| | | | | | | |
|---|---|---|---|---|---|---|
| **24 ELECTRICITY WHEELING TARIFFS** | | | | | | |
| **Note - Please refer to the wheeling policy for approved account reconciliation methodology and qualifying criteria** | | | | | | |
| | | | | | | |
| Wheeling between Generators within and outside of the BCMM electricity networks to BCMM consumers will be allowed on a pilot basis. This will only be done in line with the BCMM Wheeling guideline and approval by the GM: Electricity. The wheeling will be done to ensure revenue neutrality for BCMM. The consumers must be on one of the relevant BCMM TOU tariffs and an additional basic charge will apply to the respective consumers. Generators within the BCMM network will be charged at the standard TOU tariff in respect of their own consumption. Basic charge (additional to applicable tariff payable by the consumer – off-taker) : R 114,75 per month. A use of system charge will be payable for consumers or off-takers or generators within the BCMM Municipality network. In cases of wheeling from a generator outside of the BCMM network through Eskom, any additional charges relating to the wheeling will be charged to the off-taker | | | | | | |
| | | | | | | |
| All generators connected and wheeling energy through Eskom's transmission networks and Eskom | | | | | | |
| credit the city at the designated Eskom Point of Delivery, The following active energy only charges | | | | | | |
| will be credited per kWh generated and wheelerd at the related TOU period to the designated | | | | | | |
| off-taker once received from Eskom with the following charges: | | | | | | |
| | | | | | | |
| **ESKOM WEPS rates excluding losses (for Municipalities for the 2026/27 period) ;** | | | | | | |
| | | | | | | |
| **Note: ESKOM WEPS rates are obtained from the ESKOM tariff book and the updated ESKOM tariff will** | | | | | | |
| | | | | | | |
| All generators connected and wheeling energy within the City's distribution networks | | | | | | |
| the following active energy charges only will be credited to the designated off-taker with the | | | | | | |
| following charges: | | | | | | |
| | | | | | | |
| **25. BCMM Connected Generator** | | | | | | |
| | | | | | | |
| **High Season (Jun - Aug)** | | | | | | |
| Peak (R/kWh) | Refer ESKOM Tariff book | | | | | |
| Standard (R/kWh) | Refer ESKOM Tariff book | | | | | |
| Off - Peak (R/kWh) | Refer ESKOM Tariff book | | | | | |
| | | | | | | |
| **Low Season ((Sep-May)** | | | | | | |
| Peak (R/kWh) | Refer ESKOM Tariff book | | | | | |
| Standard (R/kWh) | Refer ESKOM Tariff book | | | | | |
| Off - Peak (R/kWh) | Refer ESKOM Tariff book | | | | | |
| | | | | | | |
| ***Note : Offtakers will still be charged for maximum demand and a basic charge on the applied tariff structure*** | | | | | | |

## 9. CONFIDENTIALITY

9.1. None.

## 10. CONCLUSION

10.1. NERSA, having considered the Buffalo City Metropolitan Municipality's application, the supporting information, stakeholder inputs and applicable legal framework, approves the tariff adjustments as set out in this Reasons for Decision document.

***End.***