NATIONAL ENERGY REGULATOR OF SOUTH AFRICA

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**Decision and Reasons for Decision (RfD)**

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In the matter regarding the

**Municipal Tariff Applications for the 2026/27 Financial Year**

By

**Ulundi Local Municipality**

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## THE DECISION

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1. At its meeting held on 6 May 2026, the Regulator Executive Committee (REC) considered Ulundi Municipality's tariff application. Based on the facts and evidence presented, REC approved the tariff increases for the 2026/27 financial year (FY) set out in section 8 of the RFD.

2. Based on the available information and the analysis performed thus far, the Regulator Executive Committee decided at its meeting on 6 May 2026, that:

   2.1. The tariffs that are based on the COS Report are approved as recommended in the tariff analysis section for implementation by the municipality with effect from 1 July 2026.
   2.2. The Cost of Supply Report submitted by the municipality be noted.
   2.3. The municipality is required to submit a report accounting for all the costs that have been noted in its COS study, to enable the Regulator to perform its independent verification/audit process by 31 January 2027; and
   2.4. The municipality is required to submit quarterly Specific Measurable Achievable Realistic and Time-bound (SMART) energy losses reduction progress reports

for the Regulator to monitor implementation thereof commencing from 30 September 2026. .

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## ABBREVIATIONS

| | |
|---|---|
| COS | Cost of Supply |
| D-Form | Distribution form |
| ERTSA | Eskom's Retail Tariff Structural Adjustments |
| FBE | Free Basic Electricity |
| IBT | Inclining Block Tariff |
| IPP | Independent Power Producer |
| ULM | Ulundi 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. NERSA received Ulundi's tariff application together with its Cost of Supply (COS) on 31 March 2026. The municipality revised the COS because of changes in Eskom tariffs.

1.3. The table 2 below shows customer statistics of Ulundi for 2024/25 financial year (FY). This data is obtained from the latest D-Form.

**Table 1: Customer Statistics**

| CUSTOMER STATISTICS | | | |
|---|---|---|---|
| **Consumer classification** | **Sales (MWh)** | **%MWh** | **Number of consumers** |
| Domestic (Pre-paid) | 15 407,00 | 39,40% | 9 763 |
| Commercial (Prepaid) | 1 530,00 | 3,91% | 437 |
| Commercial (Conventional) | 20 919,00 | 53,49% | 441 |
| Own use and street lighting | 1 252,00 | 3,20% | N/A |
| **Totals** | **39 108,00** | **100%** | **10 641** |
| | | | |
| **Free Basic Electricity** | **193** | **1,25%** | **322** |

1.4. NERSA followed the notice and comment consultation process. Ulundi's tariff application was published on the NERSA website on 31 March 2026, on social media platforms and national and local newspapers to solicit written comments from affected parties.

1.5. NERSA's decision was made on 6 May 2026, considering the written comments received from the affected stakeholders and the analysis performed by NERSA.

## 2. LEGAL AND REGULATORY FRAMEWORK

### 2.1. Background

2.1.1. The approval of Municipal electricity tariffs constitutes a core regulatory function of the Energy Regulator and must be exercised in accordance with the applicable legislative framework, national policy directives and court orders. The principal legal instruments governing the exercise of this regulatory authority include the National Energy Regulator Act, 2004 (Act No. 40 of 2004) ("NERA"), the Electricity Regulation Act, 2006 (Act No. 4 of 2006) as amended ("ERA"), the Promotion of Administrative Justice Act, 2000 (Act 3 of 2000) ("PAJA"), and the Electricity Pricing Policy for the South African Electricity Supply Industry, 2008 ("EPP").

2.1.2. The approval of municipal electricity tariffs follows the Eskom Multi-year Proce 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 2026/2027 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:

- 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.
- Section 14(1)(d) of the ERA authorises the Energy Regulator to impose licence conditions relating to the setting or approval of prices, charges, rates and tariffs charged by licensees.

2.2.3. Municipalities distributing electricity do so under electricity distribution licences issued by the Energy Regulator and are therefore subject to the tariff approval framework established under the ERA.

## 2.3. Tariff Determination Principles under the ERA

2.3.1. When determining or approving electricity tariffs, the Energy Regulator must apply the principles contained in section 15(1) of the ERA.

2.3.2. Section 15(1) provides that the Energy Regulator:

- must enable an efficient licensee to recover the full cost of the licensed activity;
- must allow for a reasonable return commensurate with the risk of the licensed activity;

- may provide incentives for continued improvement of technical and economic efficiency;
- must avoid undue discrimination between customer categories;
- may permit cross-subsidies of tariffs to certain classes of customers; and
- 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 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 Cost of Supply methodologies have historically not been consistently applied across the electricity distribution industry.

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

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

2.7. **Judicial Oversight of the Tariff Approval Process**

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

2.7.2. In its final judgment delivered on 4 December 2025, the Court held that NERSA's public participation process relating to the 2025/2026 municipal tariff approvals did not comply with the procedural requirements of section 4 of PAJA and was therefore unlawful.

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

2.7.4. NERSA subsequently launched a variation application which sought to vary the timelines which were set by the Court on 4 December 2025, considering the practical difficulties which arose as it relates to the NERSA's compliance with the Court order. The court having heard NERSA's application, granted the variation application in respect of the fixed deadlines for the 2026/27 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 by 6 March 2026;
- municipal tariff applications to be submitted by 31 March 2026;
- public participation processes to be concluded by 21 April 2026
- 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:

- written notice of bulk electricity tariffs be communicated by 31 January each year;
- municipal tariff applications be submitted to NERSA by 20 March each year;
- 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 2026/2027 municipal financial year.

## 3. FINANCIAL AND TECHNICAL PERFORMACE

3.1. In evaluating the financial and technical performance of Ulundi, the assessment relied on the Distribution Forms (D-Forms) for the 2024/25 FY 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. Ulundi's percentage deficit deteriorated from 50.51% in the 2023/24 FY to a deficit of 52.28% in the 2024/25 FY. The decline in financial performance is mainly attributed to a decrease in revenue due to low units sold, increase in Opex with interest on Eskom debt, bulk purchases, salaries and wages as well as NMDD penalty charges being the key drivers of Opex.

3.3. Table 2: Performance Indicators below shows that Ulundi's energy losses increased significantly from 28.72% in 2023/24 FY to 48.29% in 2024/25 FY. The Municipality indicated that this is mainly due to high non-technical losses such as meter tampering and bypassing, illegal connections and theft by informal settlers, faulty or inaccurate meters. The municipality has put in place the following measures to reduce the high energy losses i.e. regular infrastructure inspections, meter auditing and replacement programme, community awareness campaigns and collaborations with law enforcement agencies.

**Table 2: Performance Indicators**

| Indicators | 2023-24 | 2024-25 |
|---|---|---|
| Percentage Deficit/Surplus | -50.51% | -52.28% |
| Percentage Energy Losses | 28.72% | 48.29% |

3.4. Based on the above information provided by the municipality from the D-Forms, Ulundi's performance is not satisfactory as evidenced by an increase in the deficit and energy losses.

| | D-Form Input | Energy Loss@12% | Energy Loss@6% |
|---|---|---|---|
| Average Selling Price | 233,92 | | |
| Sales kWh | 39 109 889,00 | 66 560 089,20 | 71 098 277,10 |
| Purchases kWh | 75 636 465,00 | 75 636 465,00 | 75 636 465,00 |
| Losses kWh | 36 526 576,00 | 9 076 375,80 | 4 538 187,90 |
| Losses percentage | **48,29%** | **12,00%** | **6,00%** |
| Additional Energy (kWh) | | 27 450 200,20 | 31 988 388,10 |
| Additional Revenue (Rands) | | 64 211 374,01 | 74 827 080,94 |
| | D-Form Input | Energy Loss@12% | Energy Loss@6% |
| Total Revenue (Rands) | R 132 353 772,00 | R 196 565 146,01 | R 207 180 852,94 |
| Total Expenses (Rands) | R 201 554 045,00 | R 201 554 045,00 | R 201 554 045,00 |
| Net Profit (Loss) | R -69 200 273,00 | R -4 988 898,99 | R 5 626 807,94 |
| Percentage Surplus/Deficit | **-52,28%** | **-2,54%** | **2,72%** |

3.5. The licensee has the potential to improve the deficit to 2.54% if energy losses are limited to 12% and the surplus could potentially increase to 2.72% if the energy losses are reduced to 6%.

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

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

4.2. Ulundi utilised the COS model developed by Sustainable Energy Africa (SEA) to determine its revenue requirements for the 2026/27 FY and to apportion costs required to service each customer's class in a fair and equitable manner. The municipality applied the cost-plus methodology in conducting its COS study. The COS study was submitted to NERSA for the 2024/25 FY and was based on audited financial statements for the 2024/25 FY. The study follows the NERSA COS framework and utilises the latest available audited data which is based on the 2024/25 FY. The asset value is – R 39 099 238 (2024/25FY D-Form and AFS), Depreciation–R 3 640 000 (2026/27FY Budget), Profit Margin/Surplus – R41 105 393 (2026/27FY Budget). The depreciation and surplus are highlighted in figure 2 and table 4 below.

4.3.

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

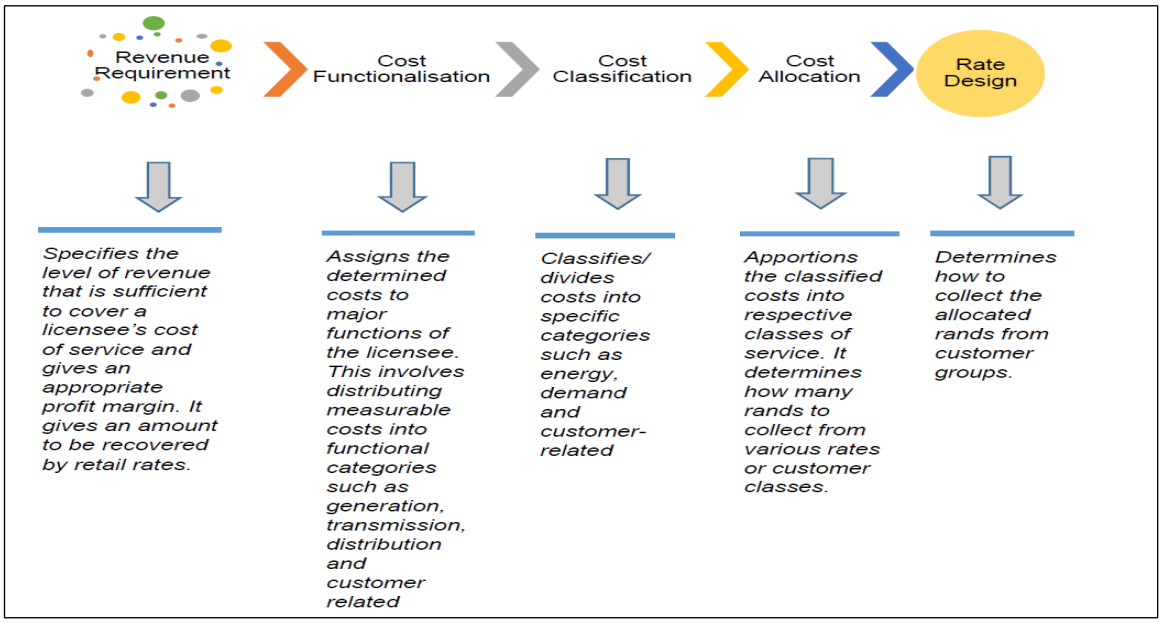



**Figure 1: Fives steps of COS**

4.5. Section 18.7 of the COS Framework requires that tariff adjustments:

4.5.1. Be informed by cost-of-supply outcomes.

4.5.2. Progressively move tariffs towards cost-reflectivity.

4.5.3. Be implemented in a structured and transparent manner, including phased adjustments where required.

4.6. Consideration in the Tariff Application, the licensee has considered and applied these requirements as follows:

4.6.1. The tariff application is based on a COS model incorporating financial, technical, and customer data inputs.

4.6.2. Bulk purchase costs were updated using the approved 9,01% Eskom bulk tariff adjustment.

4.6.3. Controllable electricity Opex costs were adjusted using CPI-linked assumptions.

4.6.4. Adjustments were supported by source documents and reasonability checks (D-Forms, Trial Balance and AFS).

4.7. This ensures that tariff adjustments are grounded in cost-reflective principles.

4.7.1. The licensee has proposed a phased implementation over three (3) financial years to achieve full cost recovery.

4.7.2. This approach aligns with Section 18.7, which allows for gradual tariff realignment to mitigate tariff shocks and maintain affordability for vulnerable customer groups.

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

4.8.1. **Revenue Requirement**

4.8.1.1. The revenue requirement step specifies the level of revenue that is sufficient to cover a licensee's cost of service and appropriate margin. It is an indication of the amount to be recovered from the approved tariffs.

4.8.1.2. The municipality applied a cost-plus methodology in the determination of its revenue requirement, as reflected in table 4 of the RFD, and did not utilise a Rate of Return (ROR) approach. Accordingly, no Regulatory Asset Base (RAB) was determined or applied.

4.8.1.3. Under the cost-plus framework, the allowable revenue comprises:

4.8.1.3.1. Efficient and prudent operating expenditure (Opex) of R 39 612 201 before surplus.

4.8.1.3.2. Depreciation, as a proxy for asset consumption and future asset replacement of R3 640 000.

4.8.1.3.3. A reasonable surplus margin applied to total cost of R41 105 393.

4.8.1.4. To ensure that the applied surplus is not excessive and remains within acceptable regulatory bounds, the following validation procedures were undertaken:

4.8.1.4.1. The applied surplus margin of 17% was benchmarked against the 10–20% range prescribed in the approved NERSA COS framework, as supported by the EPP Policy Position 1, D-Forms, and Trial Balance.

4.8.1.4.2. The margin was further assessed against the municipality's risk profile to ensure alignment with the principle of cost reflectivity and financial sustainability.

4.8.1.5. Risk factors considered include the following:

4.8.1.5.1. Revenue collection risk, with current collection levels at approximately 52%, reflecting exposure to non-payment and indigents.

4.8.1.5.2. Operational risk, including energy losses of approximately 48.29% and ageing network infrastructure; and

4.8.1.5.3. Financial sustainability requirements, including the need to maintain adequate cash flows for ongoing operations and infrastructure investment.

4.8.1.6. Based on the above, the applied surplus margin of 17% is considered conservative, justified, and commensurate with the municipality's risk profile, while remaining within the acceptable parameters of the NERSA COS framework. This approach supports the financial viability of the electricity distribution function without imposing undue burden on consumers.

4.8.1.7. Ulundi submitted a COS detailing revenue requirements of R246.63 million for the 2026/27 FY. This revenue requirement is based mainly on Eskom purchases accounting for 58%, while operational expenditure accounts for 16%.

| Total cost (R) |
|---|

| Revenue Requirement components | Wires | Retail | Total | % of Total |
|---|---|---|---|---|
| **Allowable costs** | 33 104 263 | 213 528 095 | 246 632 358 | 100% |
| Energy purchases from Eskom - net of cost of losses | - | 143 109 094 | 143 109 094 | 58% |
| Energy purchases from Eskom - cost of losses | 9 024 671 | 14 030 839 | 23 055 510 | 9% |
| Other energy purchases | - | - | - | 0% |
| Capital expenditure | - | - | - | 0% |
| Operational expenditure (incl. Depreciation) | 18 624 855 | 20 987 346 | 39 612 201 | 16% |
| Other revenues | 62 640 | 187 200 | 249 840 | 0% |
| Surplus | 5 517 377 | 35 588 016 | 41 105 393 | 17% |

**Figure 2: Revenue Requirement components**

4.8.1.8. The efficiency of costs for the 2024/25 FY have 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 FY, applying stated assumptions to determine the revenue requirement for that period.

4.8.1.9. All expenses included in the revenue requirement have been examined to confirm that they pertain exclusively to the licensee's electricity function. Where any amounts were found to be inflated or insufficiently substantiated, adjustments have been effected accordingly, as detailed below.

## Bulk purchases

4.8.2. Ulundi's COS projects a bulk purchase expenditure of R143.11 million which accounts for 58% of total costs when excluding the 9% energy losses allowance. Bulk purchases were verified against Eskom invoices in the 2024/25 FY.

4.8.3. The licensee projected its bulk purchases for the 2026/27 FY using the 2025/26 FY Eskom tariffs as a base and made the following assumptions: sales growth of 3%, and a bulk purchase cost increases of 9.01% for the 2026/27 FY which is in line with the approved Eskom Retail Tariff Structural Adjustments (ERTSA).

## Operational Expenditure

4.8.4. Ulundi's COS projects operational expenditure totalling R39.61 million, representing 16% of overall costs. Table 4 below provides a breakdown of this expenditure.

**Table 3: Operational Expenditure**

| Functions | Total Opex | Wires | Retail |
|---|---|---|---|
| **Depreciation** | 3 640 000 | 3 640 000 | |
| **Network and repairs** | 13 147 372 | 13 147 372 | |
| **Other expenses** | 22 824 828 | 1 837 482 | 20 987 346 |
| **Total** | **39 612 201** | **18 624 855** | **20 987 346** |

4.8.5. Only the portion of shared costs directly attributable to the electricity service was allocated to the revenue requirement. This ensures that electricity consumption is charged solely for costs associated with the provision of electricity services.

4.8.6. Inefficient cost components—such as Notified Maximum Demand (NMD) exceedance penalties and interest incurred on Eskom-related debt—have been excluded from the total, as these items fall within the control of the municipality. The municipality's accounts with Eskom are not up to date, with exceedances recorded under the Notified Maximum Demand (NMD), with outstanding arrears of R1 105 145 for the 2024/25 FY.

4.8.7. All the other licensee expenses have been grouped under "Other expenses". The other operating expenses, including charges from other municipal departments have been checked to ensure that they relate only to the electricity function, furthermore, all these expenses have been projected to grow in line with inflation.

**Surplus**

4.8.8. Ulundi's revenue requirement includes a surplus of R41.11 million, calculated using a surplus factor of 17% applied to operating expenditure, inclusive of bulk purchases, for both the wires and retail components of the electricity business. This figure excludes inefficient or non-allowable costs, including interest on Eskom-related debt (as the municipality is currently in arrears on its bulk electricity account-R12 132 829) and penalties arising from NMD exceedances-R1 105 144. These exclusions were verified against Eskom invoices.

4.8.9. The applied surplus margin of 17% was benchmarked against the established target range of 10–20% on the approved NERSA COS framework, EPP Policy Position 1, D-Form and Trial Balance.

4.8.10. To ensure that the profit margin commensurate with the risk, risk considerations were incorporated qualitatively, including:

4.8.10.1.1. Revenue collection risks (non-payment, indigent levels, bad debts). The municipality has budgeted to write off bad debt of R0 for 2026/27 FY.

4.8.10.1.2. Operational risks remain a concern, particularly in relation to energy losses and ageing infrastructure. For the 2026/27 FY, municipal energy losses are projected at 48.29%.

4.8.10.1.3. Financial sustainability requirements.

4.8.11. In recommending a surplus, NERSA relied on section 15(1)(a) of the Electricity Regulation Act under the tariff principles which specifies that the tariffs set by the Regulator: 'must enable an efficient licensee to recover the full cost of its licensed activities, including a reasonable margin or return'.

4.8.12. In applying the act, NERSA is required to ensure that Ulundi recovers efficient costs and a reasonable return, while preventing excessive compensation. The return proposed by Ulundi is considered reasonable, as it falls within the established target range of 10–20%. Consequently, the requested amount has been recommended as applied for.

4.8.13. The recommended revenue requirement will be applied in the subsequent COS steps, namely Cost Functionalisation, Cost Classification, Cost Allocation, and Rate Setting. These steps have been verified and confirmed to align with the approved revenue requirement. Further details of these steps are provided below.

## Cost Functionalisation

4.8.14. The licensee has categorised its revenue requirement of R246.63 million into two primary functional components, namely the **wires business (14%)** and the **retail business (86%)**, 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.

| | Total Functionalised Costs (R) | | | |
|---|---|---|---|---|
| Functions | Wires | Retail | Total | % of Total |
| Eskom Energy Purchase - excl. losses | - | 143 109 094 | 143 109 094 | 58% |
| Eskom Energy Purchase - cost of losses | 9 024 671 | 14 030 839 | 23 055 510 | 9% |
| Depreciation | 4 368 000 | - | 4 368 000 | 2% |
| Network repairs & maintenance | 15 701 679 | - | 15 701 679 | 6% |
| OPEX | 4 009 913 | 56 388 162 | 60 398 075 | 24% |

**Figure 3: Costs breakdown by Functions**

4.8.15. 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.

4.8.16. The verification of costs included in the COS model was undertaken using both the NERSA D-Forms and the municipality's Audited AFS for the 2022/23 FY.

## Cost Classification

4.8.17. 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 functionalization upon verification.

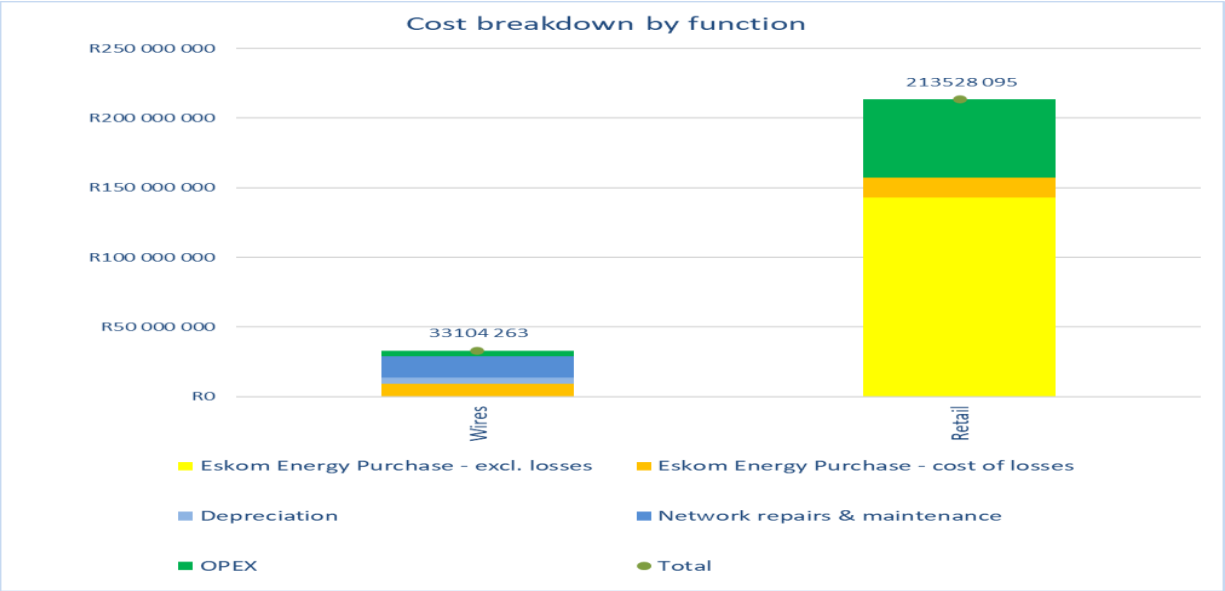



**Figure 4 Costs breakdown by cost structure (Classification)**

4.8.18. 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.

## Cost Allocation

4.8.19. 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 found to be consistent with the stated revenue requirement and aligned with the principles of cost allocation.

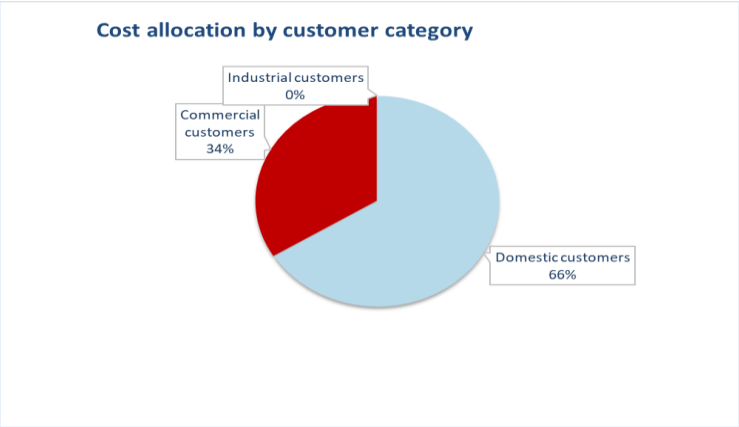


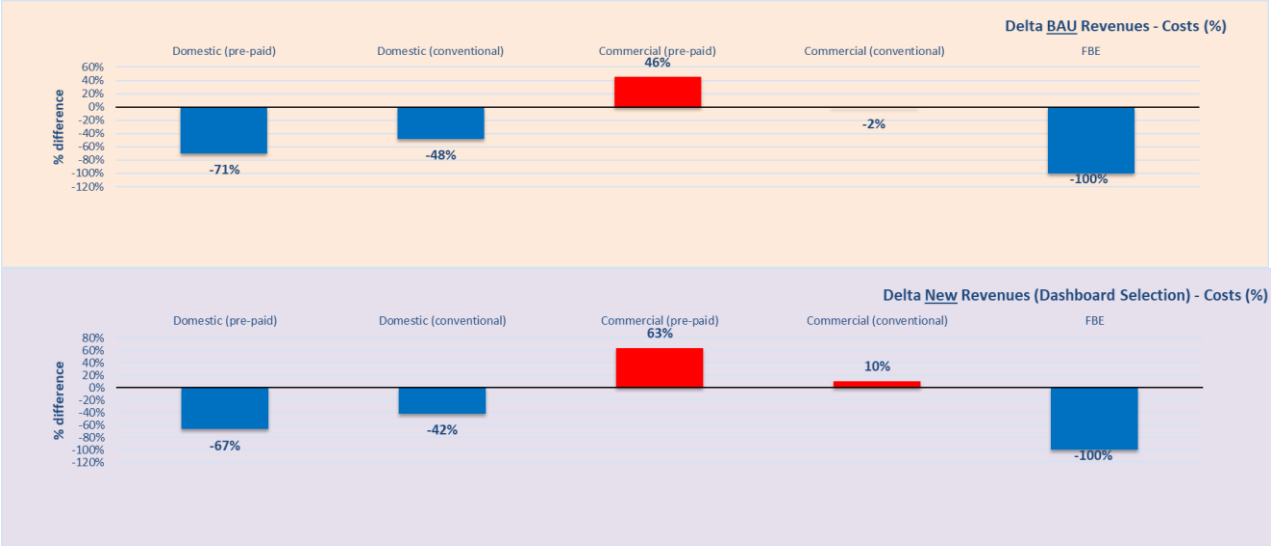

**Figure 5: Costs Allocated**

## Rate Design

4.8.20. Table 4 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 4 below.

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

**Table 4: Revenue Recovery by Customer Category**




4.8.22. The COS study confirms the presence of cross-subsidisation between customer categories. Certain categories are under-recovering (receiving a subsidy), while others are over-recovering (providing the subsidy). Commercial customers are cross-subsidising residential and municipal customer categories, which is consistent with typical municipal tariff structures.

4.8.23. Based on the revenue outputs of the COS main model, a tariff increase of 19% is required by the municipality. However, the municipality has resolved to implement differentiated tariff increases of 16% for commercial, and 14% for domestic customers. This approach seeks to enhance revenue collection while minimising the financial impact on customers, particularly indigent households and low-income households. This approach ensures that cross-subsidies are not removed abruptly, thereby avoiding undue tariff shocks and mitigating adverse impacts on vulnerable consumers. At the same time, it facilitates a managed, transparent, and gradual transition towards tariffs that are cost-reflective, equitable, and aligned with the NERSA principles.

## 5. CONCLUSION ON THE COS

5.1. While the outcome of the COS study may indicate an average tariff adjustment of a certain percentage 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.

5.2. This approach may be informed by a range of considerations, including the need to maintain tariff sustainability to support ongoing demand for electricity services. Excessive tariff increases may adversely affect consumption levels, thereby impacting revenue stability.

5.3. In addition, the licensee may consider 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.

5.4. This approach is intended to safeguard the municipality's revenue base and support its financial sustainability, in line with applicable legislative requirements.

5.5. 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.

5.6. The COS study results indicate a required increase of 23.30% to reach the overall cost-reflectivity, as illustrated in Figure 7 below. The licensee has proposed an average increase of 15.23% to ensure customer protection and municipal sustainability. Based on the available information, the municipality is expected to remain financially sustainable under the recommended tariff increase of 14% and 16%, respectively.

5.7. The outcome of the COS study indicates that the municipality requires a tariff increase of 23.30% to achieve efficient cost reflectivity as shown in figure 7 below.

*Results BEFORE phasing*

| | BAU | CTS (net of subsidies) | New rates (Dashboard selection) |
|---|---|---|---|
| Total revenue forecast (with new rates) | 151 844 246 | 187 232 358 | 170 065 556 |
| | | Delta = | - 17 166 802 |
| Average increase in rates | 12,0% | | |
| Average increase in rates to reach overall cost-reflectivity | 23,3% | | |
| Share of total cost recovered with the new rates | 90,8% | | |
| Share of total costs recovered (existing rates) | 81,1% | | |

**Figure 6: Rate of Design**

5.8. The licensee has applied for a 14.00% and 16.00% tariff increase respectively, which is below the increase required for full cost reflectivity. NERSA made an

Page 21 withheld by Unmapped Dataworks.

This page is part of the decision's record of public participation, objections or comments, which names members of the public. We do not republish it.

The whole decision is on NERSA's website: https://www.nersa.org.za/file/9402/UlundiRFD2026-27.pdf

| **1. Domestic Tariffs** | | | | | | |
|---|---|---|---|---|---|---|
| **1.1 Domestic Prepaid Low Season** | ***2025/26 Approved*** | **% Increase** | ***2026/27 Proposed*** | **2026/27 Recommended** | **Recommended % Increase** | **Analysis and Key Findings** |
| Block 1 (0 - 600kWh) | *260,89* | 14,00% | 297,41 | 297,41 | 14,00% | Tariffs recommended for approval as applied. |
| Block 2 (> 600 kWh) | *371,8* | 14,00% | 423,85 | 423,85 | 14,00% | |
| **1.2 Domestic Prepaid High Season** | **2025/26 Proposed** | **% Increase** | ***2026/27 Approved*** | **2026/27 Recommended** | **Recommended % Increase** | **Analysis and Key Findings** |
| Block 1 (0 - 600kWh) | 334,68 | 14,00% | 381,54 | 381,54 | 14,00% | Tariffs recommended for approval as applied. |
| Block 2 (> 600 kWh) | *356,9* | 14,00% | 406,87 | 406,87 | 14,00% | |
| **1.3 Domestic Conventional Low Season** | ***2025/26 Proposed*** | **% Increase** | ***2026/27 Approved*** | **2026/27 Recommended** | **Recommended % Increase** | **Analysis and Key Findings** |
| Block 1 (0 - 50kWh) | *200,49* | 14% | 228,56 | *228,56* | 14,00% | Tariffs recommended for approval as applied. |
| Block 2 (51 - 350 kWh) | *254,73* | 14% | 290,39 | 290,39 | 14,00% | |
| Block 3 (351 -600kWh) | *343,16* | 14% | 391,20 | 391,20 | 14,00% | |
| Block 4 (>600 kWh) | *410,00* | 14% | 467,40 | 467,40 | 14,00% | |
| Basic Charge (R/month) | *556,39* | 14% | 634,28 | 634,28 | 14,00% | |
| **1.4 Domestic Conventional High Season** | ***2025/26 Proposed*** | **% Increase** | ***2026/27 Approved*** | **2026/27 Recommended** | **Recommended % Increase** | **Analysis and Key Findings** |
| Block 1 (0 - 50kWh) | *201,76* | 14% | 230,00 | 230,00 | 14,00% | Tariffs recommended for approval as applied. |
| Block 2 (51 - 350 kWh) | *259,1* | 14% | 296,15 | 296,15 | 14,30% | |
| Block 3 (351 -600kWh) | *350,78* | 14% | 399,89 | 399,89 | 14,00% | |
| Block 4 (>600 kWh) | *413,83* | 14% | 471,77 | 471,77 | 14,00% | |
| Basic Charge (R/month) | *561,64* | 14% | 640,27 | 640,27 | 14,00% | |
| **5. Commercial Tariffs** | | | | | | |
| **5.1 Commercial ≤40KVA** | ***2025/26 Proposed*** | **% Increase** | ***2026/27 Approved*** | **2026/27 Recommended** | **Recommended % Increase** | **Analysis and Key Findings** |
| Basic Charge (R/month) Low Season | *2 211,39* | 16% | 2 565,21 | 2 565,21 | 16,00% | Tariffs recommended for approval as applied. |
| Energy Charge c/kWh Low Season | *321,26* | 16% | 372,66 | 372,66 | 16,00% | |
| Energy Charge c/kWh High Season | *328,63* | 16% | 381,21 | 381,21 | 16,00% | |
| **5.2 Commercial ≥40KVA** | ***2025/26 Proposed*** | **% Increase** | ***2026/27 Approved*** | **2026/27 Recommended** | **Recommended % Increase** | **Analysis and Key Findings** |
| Basic Charge (R/month) | *2838,24* | 16% | 3 292,36 | 3292,36 | 16,00% | Tariffs recommended for approval as applied. |
| Energy Charge c/kWh Low Season | *152,86* | 16% | 177,32 | 177,32 | 16,00% | |
| Energy Charge c/kWh High Season | *187,84* | 16% | 217,89 | 217,89 | 16,00% | |
| Demand Charge R/kVALow Season | *527,12* | 16% | 611,46 | 611,46 | 16,00% | |
| Demand Charge R/kVA High Season | *535,83* | 16% | 621,56 | 621,56 | 16,00% | |
| **7. Prepayment** | ***2025/26 Proposed*** | **% Increase** | ***2026/27 Approved*** | **2026/27 Recommended** | **Recommended % Increase** | **Analysis and Key Findings** |
| Energy Charge c/kWh Low Season | *432,64* | 16% | 501,86 | *501,86* | 16,00% | Tariffs recommended for approval as applied. |
| Energy Charge c/kWh High Season | *447,00* | 16% | 518,51 | *518,51* | 16,00% | |
| **8. Bulk Purchases** | | | | | | |
| **8.1 Bulk≤500 KVA** | ***2025/26 Proposed*** | **% Increase** | ***2026/27 Approved*** | **2026/27 Recommended** | **Recommended % Increase** | **Analysis and Key Findings** |
| Basic Charge (R/month) | *N/A* | 16% | 14 244,33 | *14 244,33* | 16,00% | Tariffs recommended for approval as applied. |
| Energy Charge c/kWh Low Season | *N/A* | 16% | 623,77 | *623,77* | 16,00% | |
| Energy Charge c/kWh High Season | *N/A* | 16% | 692,45 | *692,45* | 16,00% | |
| Demand Charge kVA Low Season | *N/A* | 16% | 700,00 | 700,00 | 16,00% | |
| Demand Charge kVA High Season | *N/A* | 16% | 754,15 | 754,15 | 16,00% | |
| **8.2 Bulk≤500 KVA** | ***2025/26 Proposed*** | **% Increase** | ***2026/27 Approved*** | **2026/27 Recommended** | **Recommended % Increase** | **Analysis and Key Findings** |
| Basic Charge (R/month) | *N/A* | 16% | 19 745,40 | 19 745,40 | 16,00% | Tariffs recommended for approval as applied. |
| Energy Charge c/kWh Low Season | *N/A* | 16% | 694,87 | 694,87 | *16,00%* | |
| Energy Charge c/kWh High Season | *N/A* | 16% | 699,39 | 699,39 | *16,00%* | |
| Demand Charge kVA Low Season | *N/A* | 16% | 791,77 | 791,77 | 16,00% | |
| Demand Charge kVA High Season | *N/A* | 16% | 837,52 | 837,52 | 16,00% | |
| **9. Non-Standard Tariffs** | | | | | | |
| **9.1 Streetlights** | ***2025/26 Proposed*** | **% Increase** | ***2026/27 Approved*** | **2026/27 Recommended** | **Recommended % Increase** | **Analysis and Key Findings** |
| Energy Charge c/kWh | *403,92* | 16% | 468,54 | 468,54 | 16,00% | Tariffs recommended for approval as applied. |
| **10. Municipal departmental** | ***2025/26 Proposed*** | **% Increase** | ***2026/27 Approved*** | **2026/27 Recommended** | **Recommended % Increase** | **Analysis and Key Findings** |
| Energy Charge c/kWh | *360,41* | 16% | 418,08 | 418,08 | 16,00% | Tariffs recommended for approval as applied. |

## 9. CONFIDENTIALITY

None.

## 10. CONCLUSION

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

***End.***