ANNEXURE A

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Drakenstein Municipality Cost of Supply (COS) Report

10 March 2026

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1. INTRODUCTION

A critical first step in understanding the operational performance of an electricity distributor is to conduct a Cost of Service (COS) study, which is sometimes referred to as a Cost to Serve (CTS) study. The objective of this study is to fairly and equitably allocate all costs associated with servicing customers among different customer classes. To support this objective, the National Energy Regulator of South Africa (NERSA) has developed a COS Framework as depicted in Figure 1 for all licensed electricity distributors ('licensees') in the country. This framework will serve as a guideline for licensees when conducting their own COS studies.

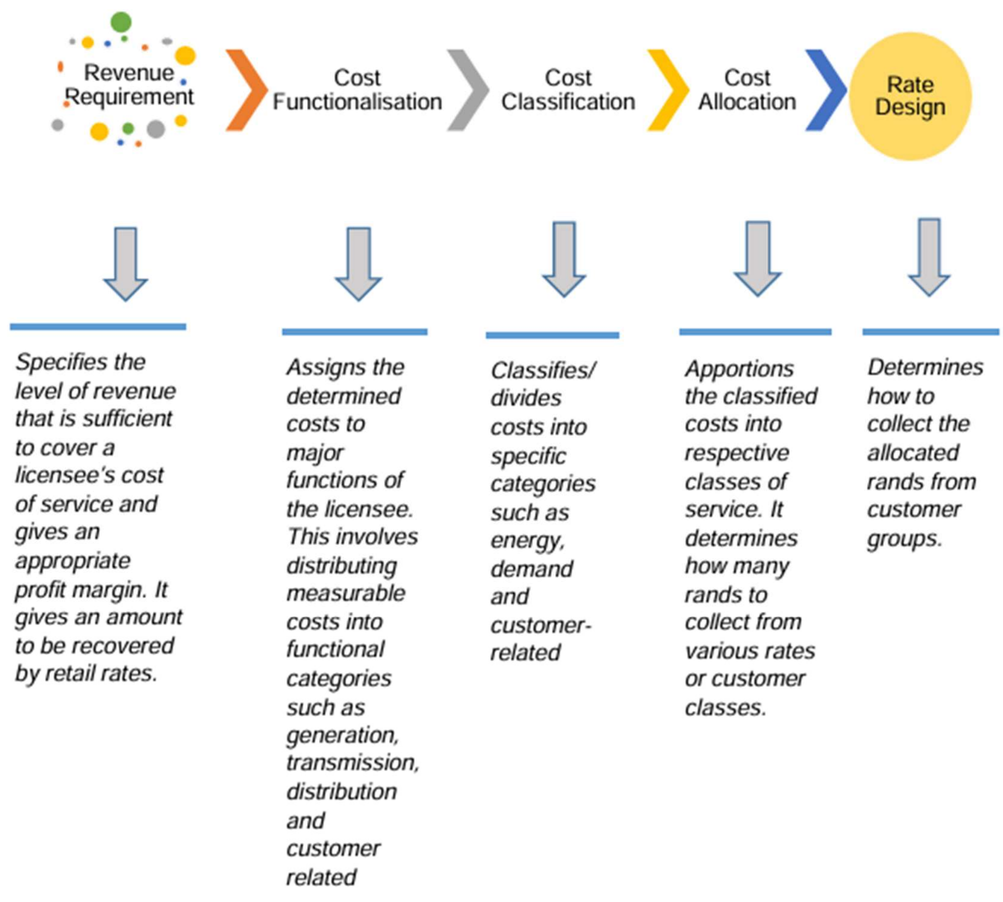

Figure 1: NERSA COS Framework

2. STUDY AREA AND OVERVIEW

Drakenstein Local Municipality (DM) is a Category B municipality in the Western Cape, with a population of 311,793. The municipality's total energy sales were 623,315,782 kWh in the

2024/25 financial year. In 2024/25, the majority of electricity sales (66%) were to industrial and other customers, while 34% were to domestic customers.

Consumer classification	Sales (kWh) Actual 2024/25	% Sales	Number of customers Actual 2024/25
Domestic (pre-paid)	144,946,509	23.25%	24,612
Domestic (conventional)	51,806,413	8.31%	6,217
Agriculture	28,783,330	4.62%	774
TOU - LV	39,286,646	6.30%	388
TOU - MV	179,780,830	28.84%	320
Commercial (pre-paid)	5,450,045	0.87%	783
Commercial (conventional)	33,008,559	5.30%	1,444
Large Bulk	83,561,122	13.41%	334
Small Bulk	17,883,940	2.87%	356
Municipal Domestic	1,753,847	0.28%	392
Municipal Streetlights	5,439,787	0.87%	523
Free Basic Electricity	17,133,940	2.75%	17,505
Municipal TOU - LV	10,650,723	1.71%	65
Municipal Bulk	3,830,092	0.61%	66
Total	623,315,782	100.00%	53,779

Table 1: Municipal energy sales per customer category

3. COS METHODOLOGY

- The Drakenstein Local Municipality's COS study is a sophisticated study that is inclusive of all requirements of NERSA's current COS framework and goes beyond it to accommodate electricity distribution businesses transitioning to a more infrastructure availability-based business.
- The NERSA Cost Plus methodology has been used for both the wires and retail business revenue requirement determinations. The model has functionality to use the allowable return on the regulated asset base or asset values annuitized at selected discount rates to calculate the revenue requirement of the wires business.
- The COS study is a multi-year model spanning across 3 years, namely, the most recent audited financial statement. The years are described as follows:

  Year 0 (FY 24/25) - The data input test year with the recently audited financial statements.

Year 1 (FY 25/26) - The current year in which the study is taking place.

Year 2 (FY 26/27) - The following year for which tariffs are being designed.

- This multi-year approach introduces several complexities and requires forecasting of costs across years, but it does bring a range of benefits to the analysis.

4. OVERVIEW OF COS STUDY KEY RESULTS

4.1 Revenue requirement

The NERSA COS framework requires licensees (municipalities) to recover their total incurred costs to remain viable. This viability is achieved by ensuring that the required total allowable revenue equals the total cost of electricity supply plus an acceptable surplus margin. In the case of DM, the 2024/2025 D-Forms information was used as a basis for a cost plus a surplus margin of 12%. The costs were then forecasted with growth of 2% in electricity sales for the 2025/2026 and 2026/2027 financial years, respectively, and a growth of 1% in the customer base in both 2025/2026 and 2026/2027 financial years. The results of the forecast yielded the revenue requirement for the 2026/2027 financial year as discussed below.

- The revenue requirement in the 2026/2027 financial year is estimated as R2,156,611,761 (excluding the impact of subsidy), increasing from R1,947,554,015 in the 2025/2026 financial year.
- The wires costs (network cost) of R362,620,661 are dominated by network-related costs, namely network repairs and maintenance, depreciation, cost of losses, and other OPEX costs.
- The retail business cost of R1,793,856,152 is dominated by Eskom energy purchases; and overall, a greater proportion of total electricity costs is incurred by the retail part of the business (around 83%), whilst 17% of the cost is related to the wires business.

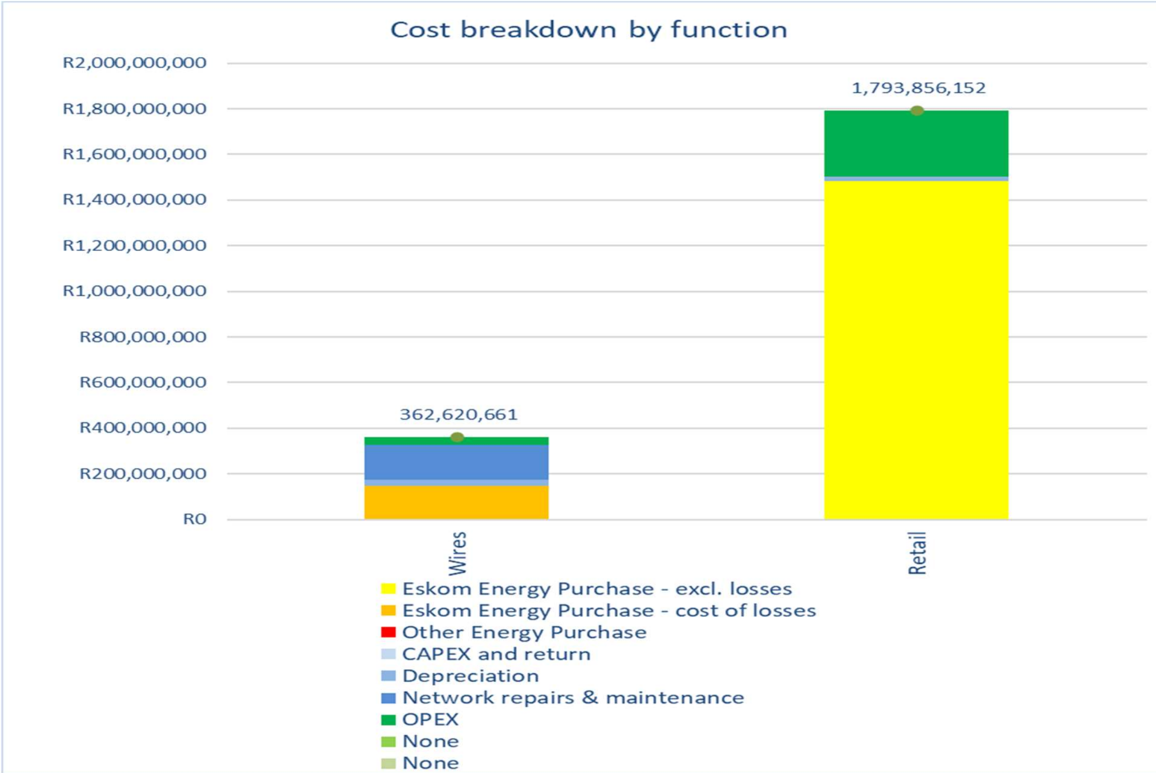

Figure 2: Cost Breakdown by Function

4.2 Cost functionalisation

The cost functionalisation within the COS categorises costs by the municipality's major operating functions. Based on the revenue requirement results discussed above, the cost of Drakenstein Local Municipality can be classified as follows:

	Total Functionalised Costs (R)			
Functions	Wires	Retail	Total	% of Total
Eskom Energy Purchase - excl. losses	-	1,483,358,417	1,483,358,417	69%
Eskom Energy Purchase - cost of losses	148,306,548	-	148,306,548	7%
Other Energy Purchase	-	-	-	0%
CAPEX and return	-	-	-	0%
Depreciation	24,541,135	19,496,826	44,037,962	2%
Network repairs & maintenance	152,948,006	-	152,948,006	7%
OPEX	36,824,972	291,000,909	327,825,882	15%
	362,620,661	1,793,856,152	2,156,476,814	

Table 2: Total cost per function

- The purchases from Eskom projected in terms of the 9.01% increase in tariffs for the 2026/2027 financial year represent the largest cost function at 76%.
- The operation requirements related to the electricity services represent the second-highest functional cost at 15%.
- The network repairs and maintenance are at 7%, and depreciation is at 2%.

4.3 Cost classification

Energy purchases and the cost of losses make up the energy-driven cost, with the highest amount of costs incurred during the Low Season and standard TOU, mostly due to the low season covering a greater proportion of the year and the changes made by Eskom in the TOU times and TOU tariffs in the 2025/2026 financial year. Demand-driven costs include depreciation, network repairs and maintenance, and energy purchase demand-related costs. The period of greatest demand-driven costs is during the Low Season. Finally, customer-driven costs are incurred in offering the electricity distribution service to customers, including salaries.

In terms of DM, the detailed cost classification is as follows:

Wires (Network Cost)

Wires	Wires	Wires	Wires	Wires	Wires	Wires	Wires	Wires
Energy	Energy	Energy	Energy	Energy	Energy	Demand	Demand	Customer
High season	High season	High season	Low season	Low season	Low season	High season	Low season	All
Offpeak	Standard	Peak	Offpeak	Standard	Peak	All	All	All
-	-	-	-	-	-	-	-	-
10,375,236	15,056,376	22,713,177	30,411,174	36,326,365	25,381,014	2,035,563	6,005,448	2,195
-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	6,520,302	18,020,833	-
-	-	-	-	-	-	40,636,557	112,311,448	-
-	-	-	-	-	-	-	-	36,824,972
10,375,236	15,056,376	22,713,177	30,411,174	36,326,365	25,381,014	49,192,423	136,337,730	36,827,167

Table 3: Wires (Network Cost) Cost Classification

Retail

Retail	Retail	Retail	Retail	Retail	Retail	Retail	Retail	Retail
Energy	Energy	Energy	Energy	Energy	Energy	Demand	Demand	Customer
High season	High season	High season	Low season	Low season	Low season	High season	Low season	All
Offpeak	Standard	Peak	Offpeak	Standard	Peak	All	All	All
103,772,853	150,593,495	227,176,637	304,171,812	363,335,405	253,860,270	20,359,649	60,066,346	21,950
-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	5,180,087	14,316,740	-
-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	291,000,909
103,772,853	150,593,495	227,176,637	304,171,812	363,335,405	253,860,270	25,539,736	74,383,086	291,022,860

Table 4: Retail Cost Classification

4.4 Cost allocation

The domestic customer categories (Domestic pre-paid, conventional and FBE) carry the largest portion of the cost at 42.6% of the total cost, followed by industrial customer categories (TOU MV, TOU LV, Large Bulk and Small Bulk) at 42.5%. The commercial customer category represents 6.8% of the cost, while the agricultural consumer category and municipal consumer category represents 4.6% and 3.5% of the cost, respectively. The differences in results across customer categories are driven by differences in connection-point voltage, load factors, coincidence factors, and average specific consumption.

Business area:	**Wires**	**Retail**	**Total**
Customer Categories			
Domestic (pre-paid)	106,309,361	524,135,007	630,444,368
Domestic (conventional)	36,757,571	177,541,948	214,299,519
Agriculture	16,851,018	82,045,481	98,896,500
TOU-LV	22,290,240	106,374,929	128,665,168
TOU-MV	82,765,911	414,393,666	497,159,577
Commercial (pre-paid)	4,003,077	21,954,854	25,957,931
Commercial (conventional)	20,218,018	101,149,022	121,367,040
Large Bulk	38,895,444	195,976,744	234,872,188
Small Bulk	9,009,751	47,358,586	56,368,337
Municipal Domestic	1,204,607	5,696,133	6,900,740
Municipal Street Lights	3,565,761	16,322,790	19,888,551
FBE	12,573,233	62,009,012	74,582,246
Municipal TOU-LV	5,940,778	28,031,159	33,971,937
Municipal Bulk	2,235,891	10,866,821	13,102,712
	362,620,661	1,793,856,152	2,156,476,814

Table 4: Cost allocation by customer category

4.5 COS results

The COS results reveal that under the current rate regime, DM will recover R1,947,554,015 in the 2025/2026 financial year. If the municipality does not increase electricity tariffs for the 2026/2027 financial year, it is projected to recover only R1,985,443,011 of the cost of servicing consumers, which is projected at R2,156,476,814 for the 2026/2027 financial year. This is illustrated in Figure 3 below.

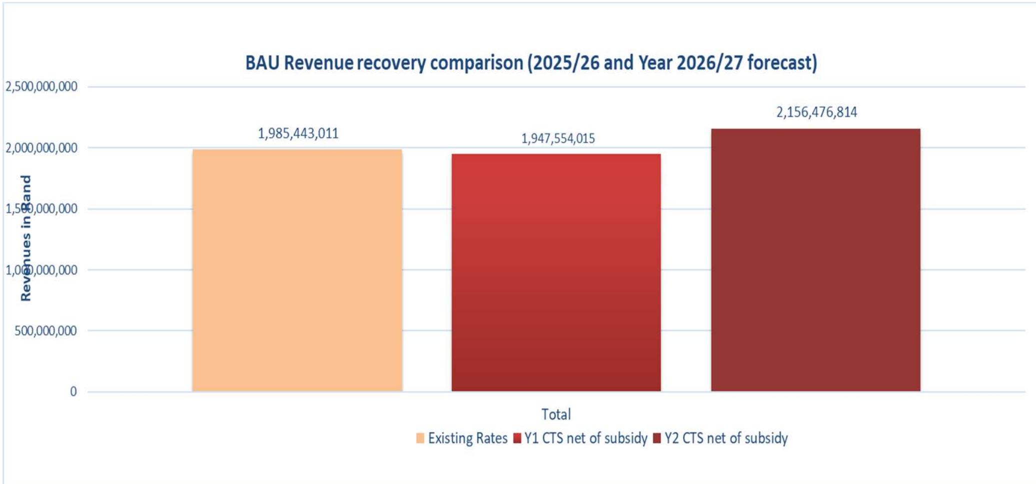

Figure 3: Revenue recovery comparison.

This means the municipality would recover only 92.1% of the total cost if no increases are applied. The cost recovery pertaining to each consumer category is illustrated in Figure 4 below.

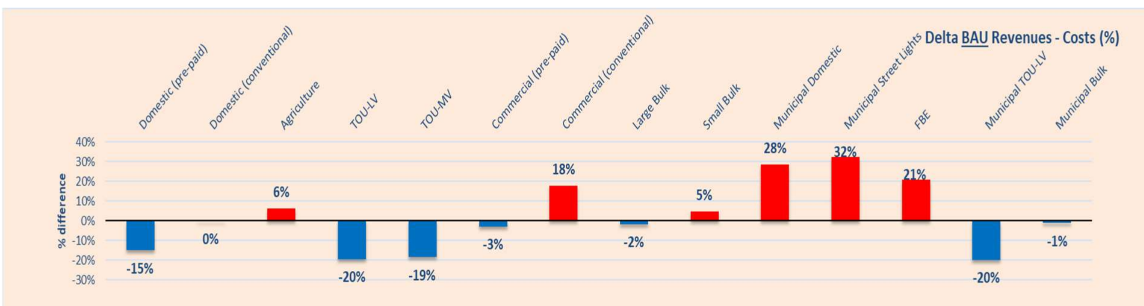

Figure 4: Percentage Over/Under recovery of customers.

The key insight is that prepaid customers are currently receiving electricity services at a price below cost (i.e., being cross-subsidized) while business-scale customers are paying above cost for electricity. Interestingly, all the time-of-use tariffs are under the cost. The business-as-usual (BAU) rates, as shown in the figure below, indicate that existing tariff structures are not cost-reflective. As the uptake of distributed generation increases in electricity distribution networks, a more cost-reflective approach to setting tariffs is proposed.

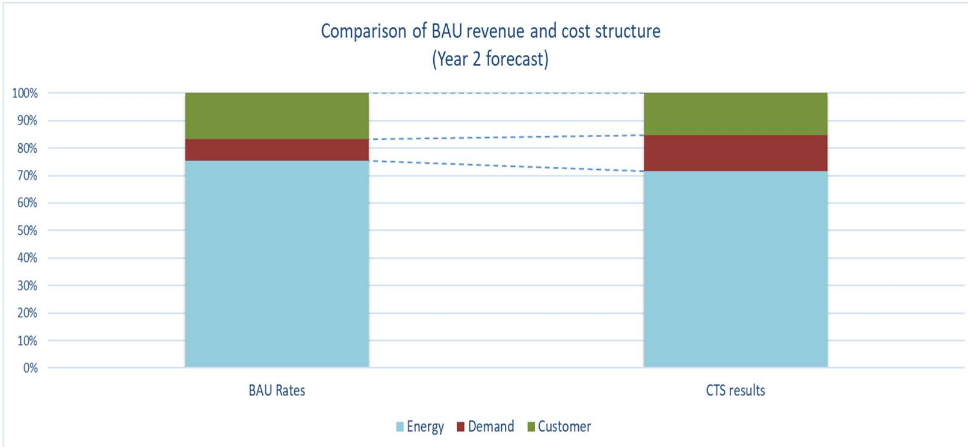

Figure 5: Comparison of revenue and cost structure.

Cost reflective charges are shown in the table below. These are the results of the COS study and indicate what the municipality should be charging customers to recover 100% of their revenue. However, due South Africa's socio-economic conditions and the municipality's revenue recovery strategy, the municipality may deviate from these cost reflective tariffs in the tariff design stage of the COS study. Rate design is discussed in the next section and may deviate from these results based on the municipality's maximum tolerable tariff increase, subsidy policy, price signals, and tariff design choices.

Business area:	**Total**	**Total**	**Total**
Cost class:	**Energy**	**Demand**	**Customer**
Season:	All	All	All
TOU:	All	All	All
Unit:	*c/kWh*	*R/kVA/month*	*R/POD/month*
Customer Categories			
Domestic (pre-paid)	248	202	590
Domestic (conventional)	248	202	688
Agriculture	248	205	1,179
TOU-LV	248	205	1,867
TOU-MV	226	188	1,867
Commercial (pre-paid)	248	205	983
Commercial (conventional)	248	205	1,179
Large Bulk	226	188	1,769
Small Bulk	226	188	1,769
Municipal Domestic	248	202	295
Municipal Street Lights	248	201	491
FBE	248	202	98
Municipal TOU-LV	248	205	1,867

Table 5: Cost reflective results by business area, class, season, TOU

5. RATE DESIGN

Municipal tariff setting is guided by Municipal Tariff Policy, which is developed with reference to various pieces of legislation, but in particular Sections 4 and 74 of the Municipal Systems Act (32 of 2000) and the National Electricity Pricing Policy (2008), which also outlines the General Tariff Principles as set out in S16 of the Electricity Regulation Act of 2006. The regulatory framework on tariffs seeks to balance the often competing or contradictory tariff principles of revenue sufficiency, economic efficiency, equity, fairness, and simplicity.

The COS is an important, but not deterministic, input to tariff design. It enables a municipality (and the Regulator) to assess:

a. Revenue sufficiency of proposed tariffs and the financial sustainability of the utility.
b. That tariffs reflect the costs associated with rendering the services and those customers are treated equitably and pay in general proportion to use of services.
c. The reasonableness of the low-income tariff determination in line with guiding policy, including access to a free basic service plus lifeline tariff based on operation and maintenance only.
d. Whether environmental objectives are being encouraged; and
e. The transparency of subsidies and surcharges.
f. The changes made by Eskom to their tariff structure.

The municipality is proposing to increase its tariffs on average by 6.3% to achieve cost-reflectivity in a phased approach, while the COS study proposes an 8.6% for complete cost reflectivity. The average increase of 6.3 % entails the following:

(a) A proposed increase of 5% to the tariffs of all consumer categories except time of use consumers.

(b) A proposed increase of 10% for time of use consumers to phase in cost reflectivity for this consumer category over a period of three financial years.

(c) A proposed increase of 2% in fixed basic charges for all consumer categories.

(d) A proposed increase of 2% in the notified demand charges for time of use consumers.

(e) A proposed increase of 2% in the demand charges for time of use consumers and large and small bulk consumers.

The above proposal will increase the cost recovery in some categories more than others to manage the cross-subsidies in the system. After the proposed changes are implemented, the under and over recovery per tariff category presents as follows:

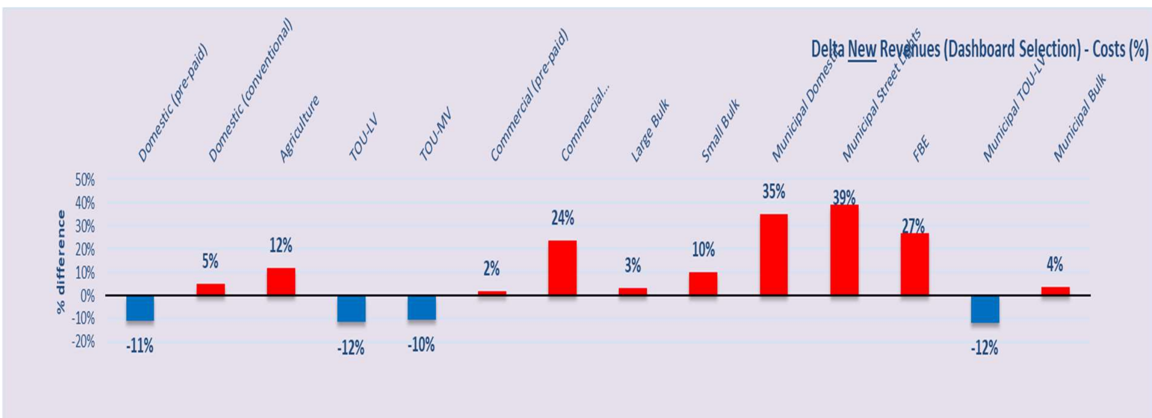

Figure 6 : Over and under recovery after tariff increases.

- The key takeaway from the proposed tariffs is that the time-of-use tariffs after the increase of 10% are moving towards cost-reflectivity and will, in the next three financial years, be able to subsidise the smaller customers.
- The municipality is not proposing any major structural changes to its tariff schedule but is introducing a new optional domestic time-of-use tariff for cogeneration consumers that will put consumers in a better position to manage their electricity consumption and feed-in patterns. The new tariff is included in the electricity tariff listing attached as Annexure to this report.

6. KEY ASSUMPTIONS

The key assumptions made in the development of this COS study are essential to guide the reader to the basis of the COS and how the projections were derived. These assumptions are as follows:

- The energy consumption will increase year on year by 2.0% and 2.0% for the outer years.
- The customer growth will increase by 1% year on year.
- The D-Form expenses will increase year on year by 10% for 2026/2027 financial year and 6% for the outer years.
- The total maximum demand of the municipality is 180.00 MVA per month.
- The Eskom bulk purchase energy price was assumed to increase by 9.01% in the 2026/2027 financial year. It must be noted that at the compilation of the report, there was still uncertainty regarding any further reconstruction to the Eskom tariffs as was the case in the 2025/2026 financial year.

7. DATA DESCRIPTION AND IMPROVEMENTS

The municipality considers its electricity sales data (in kWh) and associated customer information to be relatively accurate, with a confidence rating of good. To enhance the efficiency of reporting and forecasting, the municipality has compiled its COS analysis based on the fourteen customer categories that are inherently managed within its existing structure. This internal alignment ensures consistency and supports more effective analysis.

Future D-form submissions will be aligned with these fourteen categories, as the unbundling of customer groups increases the availability of rich, disaggregated data to support better operational and financial decision-making.

Looking ahead, the planned migration to smart metering technology is expected to significantly improve the accuracy and timeliness of data collection and reporting. This will enable real-time monitoring and reduce reliance on estimated or manually reported figures, enhancing the municipality's ability to plan, budget, and manage its electricity distribution system more effectively.

Bradley Brown
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