Technical Report

September 2025

ELECTRICITY PRICING AND SECTOR REFORM:

Electricity as a Public Service

PRESIDENTIAL CLIMATE COMMISSION
TOWARDS A JUST TRANSITION

ELECTRICITY PRICING AND SECTOR REFORM:

Electricity as a Public Service

Technical Report

September 2025

About this report
This report forms part of a series of six reports prepared by Sustainable Energy Africa (SEA) to support the work of the Presidential Climate Commission (PCC) on its stakeholder engagements on electricity pricing and sector reform.

Funder
This report was produced thanks to generous support from UK PACT (Partnering for Accelerated Climate Transitions).

Author
Hendrik Barnard

Reviewer
Zanie Cilliers

Table of Contents

Document Overview

This paper evaluates the state of electricity cross-subsidies and considers how to mitigate potential threats posed by sector reform to the public service of electricity supply. The document will outline how to accurately determine costs, provide an overview of pricing approaches, and attempt to quantify what is required to adequately meet the energy needs of low-income households. This will include the consideration of new forms of costing and subsidy, as well as new forms of ownership. It will also explore how the current provisions for the poor can be sustained in a competitive electricity market.

The public service in this paper refers to the availability of a basic quantity of electricity, which includes the network and an amount of energy at an affordable price for the poor. The protection of this public service is threatened by the inefficient operation of electricity utilities, continued high Eskom price increases, the emergence of renewable energy and its increased uptake by wealthier consumers, the rising number of low-income consumers, and the declining ability of central government to provide sufficient subsidy funding. Key recommendations include:

- The industry must implement cost-reflective tariffs with basic charges, capacity charges, and, where possible, time-of-use (TOU) energy charges.
- A tariff for low-income households should be applied with no or minimal fixed charges, energy charges that at least cover Eskom purchase costs, and a maximum capacity of 20 Amps.
- The municipal revenue requirement must include either current replacement cost (CRC) depreciation with no surplus, or historic cost depreciation plus a surplus equal to the difference between CRC depreciation and historic depreciation.
- The industry revenue requirement must include adjustments to reflect the true cost and revenues of the utility, including a fair contribution to municipal overhead costs.
- National Treasury's electrification capital grants must cover the full capital cost of electrifying low-income households, including contributions toward the upgrading of bulk infrastructure and the upgrades necessary as a result of increased utilisation of existing infrastructure.
- National Treasury should cover the revenue shortfall of indigent consumers; not only the energy cost relating to Free Basic Electricity (FBE), but also the full fixed costs associated with a 20 Amp supply.
- National Treasury should not increase the amount of FBE, but rather seek more affordable alternatives to support cooking needs, such as gas.
- The industry must urgently address the challenge of non-payment in the electricity supply sector and the resulting failure to pay Eskom.
- Electricity supply operations within municipalities must be normalised to ensure sufficient maintenance and the timely refurbishment of infrastructure assets.
- Strategies must be found to address Eskom's annual price increases, which are undermining the affordability of electricity for poor households and placing pressure on large consumers who provide an essential cross-subsidy base.
- Utilities must enforce the installation of four-quadrant meters for all small-scale embedded generation (SSEG) consumers and charge these customers using TOU tariffs. Export energy should be credited at approximately 80% of the avoided energy cost on a TOU basis. Export limits should be removed, except where practical constraints apply.

Abbreviations and Acronyms

<	less than
≤	less than or equal to
>	greater than
≥	greater than or equal to
A	Ampere
c	Cents
c/kVArh	Cents per reactive kilovolt-ampere hour
c/kWh	Cents per kilowatt-hour
COS	Cost of Supply
CPI	Consumer Price Index
CRC	Current Replacement Cost
DME	Department of Minerals and Energy
FBE	Free Basic Electricity
EPP	Electricity Pricing Policy of South Africa
FBEA	Free Basic Alternative Energy
GWh	Gigawatt-hour
HT	High Tension / Voltage
HV	High Voltage (≥ 40 kV)
IBT	Inclining Block Tariff
IPP	Independent Power Producer
km	Kilometre
kVA	Kilovolt-ampere
kVArh	Reactive kilovolt-ampere hour
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
LED	Light-Emitting Diode
LPG	Liquid Petroleum Gas
LV	Low Voltage (< 1000 V)
MFMA	Municipal Finance Management Act
MSA	Municipal Systems Act
MVA	Megavolt-ampere
MV	Medium Voltage (≥ 1000 V < 40 kV)
N/A	Not Applicable
NERSA	National Electricity Regulator of South Africa
NMD	Notified Maximum Demand
PF	Power Factor
POD	Point of Delivery
POS	Point of Supply
PV	Photovoltaic
R	Rand
RCA	Regulatory Clearing Account
ROA	Return on Assets
R/kVA	Rand per kilovolt-ampere

R/kW	Rand per kilowatt
TOU	Time of Use
SSEG	Small-Scale Embedded Generation
V	Volt
VAT	Value Added Tax
W	Watt

Glossary

Ampere (A)	The unit used to measure electric current, i.e., the rate of flow of electricity through a conductor. Comparable to the volume flow rate of water through a pipe.
Access / capacity charge	A charge levied on a customer to cover the cost of reserved network capacity, typically based on the notified demand or capacity limit.
Availability charge	A charge applied to the owner of a property (erf) that is located near the network but not connected or was previously connected and then disconnected.
Capacity utilisation	The extent to which the installed capacity allocated to a customer is actually used by that customer.
Bulk Purchases	Electricity purchased in large quantities, typically from Eskom by municipalities, for resale to customers.
Bulk customer	A large customer, typically with a connection size exceeding 3 x 150 Amps (100 kVA), or in some cases 3 x 100 Amps.
Charges	Different elements that make up a customer's bill, such as energy charges, capacity charges, or fixed charges.
Clients	External stakeholders such as contractors, consultants, or other entities engaging with the utility.
Connection fee	A once-off upfront payment for a new connection or for additional network capacity.
Consumers	Anyone using electricity, whether illegally connected or receiving unpaid supply a third-party person.
Cross subsidy	When one group of customers pays more than the cost to serve them, thereby subsidising another group whose tariffs are below cost.
Customer	A consumer who is legally connected, contracted with the utility, and pays for services.
Demand charge	A R/kVA or R/kW charge which is time and/or seasonally differentiated and is applied to the chargeable demand registered during the month.
Demand tariffs	Tariffs that include charges based on the maximum demand of a customer each month.
Diversity factor	The ratio of the sum of individual consumers' non-coincident peak demands to the group's total maximum demand. Reflects shared network capacity usage.
Electrical energy	The amount of electricity consumed, usually measured over a billing period (e.g., one month).
Gigawatt (GW)	Equal to one thousand megawatts (MW) or one million kilowatts (kW).
Inter-tariff cross-subsidies	When one tariff category (e.g., commercial) cross-subsidises another (e.g., residential).
Intra-tariff cross-subsidies	When there is cross-subsidisation between different customers within a particular customer category, such as high-usage customers cross-subsidising low-usage customers.
kWh (kilowatt-hour)	A unit of electrical energy. One kWh equals 1000 watt-hours, such as the energy used by a 100-watt globe operating for 10 hours.
Kilovolt-Ampere (kVA)	The product of volts and amperes times 1000, i.e., V x A x 1000. This is a measure of "apparent" electrical power.

Kilowatt (kW)	The product of kVA and a power factor, which is a measure of “true” electrical power. The expression for kW is V x A x power factor x 1000.
Kilowatt-hour (kWh)	The total amount of energy used in one hour by a device that requires one kilowatt of power for continuous operation, i.e., the product of kilowatts and hours.
kVA (kilovolt-Ampere)	The unit of measure for maximum demand. It includes the real and reactive components of power.
kW (kilowatt)	A unit of measure for maximum demand, but only the real component. The maximum demand of ten 100-Watt globes equals to 1 kW.
Load factor (LF)	The amount of electricity consumed by a customer in a billing period relative to the amount of energy that could have been consumed had the appliances been kept on all the time. This indicates how effective the capacity is used.
Load factor (LF) annual	Total kWh/year divided by the highest maximum demand in the year times 12 times the total hours in the year, i.e. (total kWh for year) ÷ (Highest maximum demand in year x 12 x hours in year).
Load factor (LF) average monthly	Total kWh/year divided by the sum of the maximum demands of all months in the year times 12 times the total hours in the year. (Total kWh for year) ÷ (Sum of 12 maximum demands in year hours in year).
Lifeline	A tariff that provides support, subsidy, discount to customers. This is usually not available to all customers and provides more support at low consumption levels and becomes more expensive at high consumption levels.
Maximum demand	The maximum demand that the customer places on the network, normally averaged over a half hour period.
Megawatt (MW)	Equal to one million Watts or 1000 kW.
Network voltage	The voltage at which the network operates. This voltage is usually higher to transfer large amounts of power with minimum technical losses.
Network capacity	The maximum rating of the network equipment that has been installed to supply a customer. This is expressed as kVA or A (Amperes).
Point of delivery	A physical point on the electrical network, where electricity is delivered to a customer, usually the metering point.
Point of supply	It could be a single point of delivery to a customer or a specific group of points of delivery on the system from where electricity is supplied to the customer.
Power factor (PF)	The ratio kW / kVA indicates the ratio of “true” electrical power to “apparent” electrical power, i.e., the ratio of useful work to the total quantity of volts and amperes supplied.
Reactive energy charge	In case of Megaflex, it is levied on every kVArh that is registered in excess of 30% of the kWh supplied during the specified periods of the month.
Supply voltage	The voltage at which customers are supplied. The supply voltage for households is usually 240V.
Single energy rate tariff	This refers to a tariff that only has one charge and that is a simple energy charge e.g., 25 c/kWh.

Seasonal tariffs	Tariffs where the price for electricity consumed varies based on the season. Typically, there is higher demand for electricity in winter, making it more expensive to provide.
Tariff	A tariff is the combination of various charges to constitute a tariff applicable to a specific customer category.
Tariff structure	The type of charges in the tariff, as well as the relative sizes of the different charges.
Tariff restructuring	The process of changing the charges in a tariff, but also the relationship with other tariffs.
Two-part tariff	A tariff that has a single energy rate plus a fixed charge, sometimes called a basic charge. For example, the tariff has a basic charge of R100/month and an energy rate of 105 c/kWh.
TOU (Time of Use) tariffs	Tariffs that charge different energy rates depending on time of day (e.g., peak, standard, off-peak).
Time-of-use (TOU) tariff	A tariff that has different energy rates for different time periods and seasons in order to reflect different cost of supply at different times more accurately.
Voltage discount	A discount applied to customers supplied at higher voltages because it is cheaper to supply, and the customer incurs more costs to transfer the energy for their own applications.
Voltage (V)	Measure of electric pressure that drives electric current through a conductor.
Watt (W)	The unit of electrical power or energy transfer equivalent to one ampere flowing due to an electrical pressure of one volt at unity power factor, i.e., W = V x A.

1 Background

Electricity is best defined as a public service, rather than a pure public good.

A **public good** is a commodity or service that every member of a society can use without reducing its availability to all others. It is also difficult to exclude anyone from a public good. Electricity provision generally does not meet these requirements. The overconsumption of electricity by some can reduce availability to others. In addition, consumers can be excluded through disconnection. Some aspects of the electricity supply industry may be considered as a public good, for example, the transmission network (should not exclude anyone) or the provision of streetlighting (benefits shared by all).

A **public service** refers to essential services provided or regulated by the state to serve public needs — even if they are delivered through private actors. They are often provided universally, with affordability, equity, and reliability as key concerns. In respect of this paper, the public service of electricity refers to the provision of basic electricity to the poor. This statement is loaded:

- How do we define poor?
- What is basic electricity?
- Does it refer to grid-connected electricity or could it be off-grid alternatives?
- Should it refer to energy, rather than electricity, as alternative energy may be cheaper and better for the environment?
- Since subsidy funding is limited, how do you strike a balance between the provision of subsidised electricity and the provision of other subsidised services? Or the provision of a higher volume of subsidised electricity at the expense of the number of customers subsidised?
- Does the public service refer to the network or also the energy?

The issue of basic electricity also needs to be seen in terms of the bigger socio-economic picture in South Africa, which is complex. South Africa's Bill of Rights is the linchpin that enshrines and affirms the rights of all people and the democratic values of human dignity, equality, and freedom in South Africa. Pro-poor policies targeted towards addressing household energy poverty include the following:

i. The Integrated National Electrification Programme, which aims to electrify households with no access to the 'grid', with a goal of reaching universal access to electricity by 2030 (NPC, 2021). This programme provides grants to Eskom and municipalities to cover the incremental capital costs of the electrification of new households. It excludes contributions to the grid backbone (upstream upgrading of higher voltage networks) and cost related to increased loading on existing networks being utilised.

ii. The Free Basic Electricity (FBE) policy specifies an electricity service provision subsidy, capped at 50kWh month, for each qualifying household, to assist indigent households (DME, 2003). This is funded by national government through the Equitable Share Grant allocation to each municipality. This is an unconditional grant, but the objective is to subsidise the energy cost for 50 kWh/month/household. The current grant makes limited provision for fixed customer service and network costs. Each municipality has their own criteria by which a household is classified as indigent. This includes household income, value of the property, etc. The indigent registration process (complexity and lack of household awareness thereof) and criteria exclude many households that are poor but just do not meet the indigent criteria.

iii. The Free Basic Alternative Energy (FBAE) policy aims to assist unelectrified households with subsidised alternative energy such as LPG, bio-ethanol gel-fuel, paraffin and solar home systems (DME, 2007). The provision of these alternative energy systems has been found to be very problematic. It does however provide a realistic option in very low-density areas remote from the grid.

iv. The Inclining Block Tariff (IBT) on domestic customers aimed to mitigate energy poverty through cross-subsidising the price of electricity of the first "block" or volume of units consumed through higher charges on the second/later blocks of units consumed. IBTs were introduced in 2010 (Eskom, 2010) and were guided and strongly encouraged by the National Energy Regulator of South Africa (NERSA). IBT did not cater for any fixed charges and introduced massive subsidies to low consumption customers that were not covered by loss of fixed charges or by higher energy charges from high consumption customers. The extend of this subsidy is not known in the industry. This loss in revenue has been one of the reasons for municipalities defaulting on paying Eskom.

Over and above this:

- Eskom and municipalities are subsidising grid electricity to low usage, poor - but not necessarily indigent - consumers, using tariffs without cost-based fixed charges. *The idea was that the fixed costs of supply would be included in the energy price at a particular consumption level. Unfortunately, the costs increased drastically, the energy prices did not track the cost increases, and the average consumption levels decreased from the original target of 350 kWh/month.*
- Municipal rates and other service charges used to be cross-subsidised by electricity surpluses, but that has almost come to an end due to the bad state of electricity finances. *Most municipalities do not make a profit / surplus on electricity supply any more. This is even before allocating a fair contribution to overhead costs of the municipality. This relates to various factors, such as high losses, many poor consumers being subsidised, bad management, etc.*
- Many consumers, both large (commercial/industrial) and small (domestic), use electricity illegally (usage without payment), from illegal connections to the grid, bypassing / tampering of their meters or just not paying. *Illegal electricity usage is on the rise and has reached very high levels. Eskom and many municipalities are unable to solve this problem. In most cases, illegal use occurs because of bad management and/or political interference.*

The electricity grid is a foundation of human welfare, resilience and service delivery, due to its use in large wealth transfers through subsidised electricity. Declining utility revenue and increasing electricity losses are threatening the delivery of this key service. The imminent restructuring of the industry and the introduction of a wholesale electricity market is further providing new challenges in protecting electricity as a public service.

2 Subsidies

The south African electricity supply industry is characterised by subsidies and cross-subsidies.

Subsidies normally refer to funds obtained from outside of the electricity sector to reduce the charges to consumers. Typical subsidies in the industry are as follows:

- The Equitable Share Grant to local municipalities, which is used to provide an amount of free electricity to indigent consumers.
  - National Treasury allocates the funds to each municipality based on an assessment of the number of indigent consumers in the municipal area, multiplied by the assumed cost of providing 50 kWh/month, based on a R/kWh rate.
  - The problem with this subsidy is that the R/kWh largely only covers the energy cost, with most fixed consumer services and network costs not covered.
  - This means that municipalities need to provide further cross-subsidies to cover the full cost of supplying these consumers.
  - In some municipalities, other funding sources are used to subsidise more than the 50 kWh/month.
- Other grants. National Treasury provides subsidies to cover various municipal operating costs that benefit all consumers. This includes grants to cover training costs, special maintenance projects and many others.
- Integrated National Electrification Programme. The Department of Electricity and Energy provides a large amount of grant funding to subsidise the capital costs of connection, with the objective of providing universal access to electricity. Although the policy states that it covers the bulk infrastructure and household connections cost, in many cases it does not cover the re-enforcement of existing networks that may experience increases in loading from the new connections, which leads to municipalities needing to fund this from own revenues, thus causing cross-subsidies to the electrification of consumers.
- Eskom debt relief. National Treasury's debt relief to Eskom represents a subsidy by taxpayers to electricity consumers. Its intent is to improve Eskom's financial sustainability, reduce fiscal risk relating to credit rating downgrades, and to free up capital for transmission infrastructure investment, amongst others. The debt relief is conditional on structural reform (legal unbundling of Eskom into transmission, generation and distribution units), improvements in operational efficiency, and enhanced transparency and fiscal discipline.
- Municipal debt relief. Many municipalities are in arrears with their Eskom bills. National Treasury introduced a mechanism whereby the arrear amount to Eskom is written off provided various conditions are met, including paying current Eskom bills in full. This represents a subsidy from central government to effectively subsidise consumers who are either undercharged or not paying at all.

Cross subsidies refer to a subsidy from one group of consumers to another, by way of an overcharge applied to one group and an undercharge to another. The following types are most common:

- Inter-tariff cross-subsidies. This refers to subsidies between tariff categories. Most common is cross-subsidisation of domestic consumers by commercial and industrial consumers.

- Intra-tariff cross-subsidies. This refers to subsidies between different consumers within the same tariff.
  - Most common is the cross-subsidisation from high-usage consumers to low-usage consumers, associated with IBT. See illustration Figure 1.
  - Another transparent cross-subsidy is the Eskom cross-subsidy from high voltage consumers (> 132 kV) to those at lower voltages. See Annexure 8.1 Tariff Terminology.
- Inter-regional cross-subsidies. This is where consumers in one region cross-subsidise consumers from another region. The best example in South Africa relates to the Eskom transmission surcharge of 0 to 3%, whereas the actual transmission network cost differences are significantly more. This means that consumers in the regions further away from the centre of generation, defined by Eskom as Johannesburg, are being cross-subsidised by those closer to Johannesburg. See Annexure 8.1 Tariff Terminology.
- Inter-utility cross-subsidies. The best example is where municipalities (and other large Eskom consumers) pay the Eskom electrification and rural network subsidy charge. The cost of the subsidies to these Eskom consumers are charged to all consumers, including municipalities. This is controversial, since it means municipalities cross-subsidise their own electrification and rural consumers, as well as those of Eskom. Even worse, Eskom charges lower tariffs to its electrification consumers in many cases. This means that the energy charge payable by municipalities is inflated by about 14% and all municipal consumers pay this. See Annexure 8.1 Tariff Terminology.

Main reasons for many of these cross-subsidies relate to:

- Tariffs simply not reflecting the true cost.
- Deliberate cross-subsidisation of a particular group of consumers.
- The absence of, or too low, basic and capacity charges.
- The application of IBT where the first energy block prices are simply too low and do not even cover the Eskom purchase costs, let alone contributing to the network and customer services costs.

The below example illustrates this dynamic:

- The electricity supply to a 20 Amp one-phase domestic consumer.
- The basic costs, which include customer service costs, including meter, meter reading, meter audit, meter repairs, vending costs, revenue collection, service connection, circuit breakers, distribution box, fault repairs and callouts, and other customer services. This is equal to R150/month.
- Network costs, which include the Eskom transmission network charge, Eskom distribution access charge and Eskom distribution maximum demand charge, and municipal own network costs from the Eskom substation down to the LV network. This includes network capital (depreciation and interest) plus operations, maintenance and repairs. This cost is in R/Amp. In this case, R10/Amp/month at 20 Amp = R200/month.
- Energy costs. This includes the Eskom TOU energy charges plus levies, independent power producer (IPP) and small-scale embedded generation (SSEG) exports, and the losses on the

network down to the consumer. Using a representative load profile for a domestic consumer, the average energy cost is about R2/kWh.

- It thus costs R350/month before one kWh is sold.
- The tariff is a typical municipal IBT:
    - First block of 50 kWh/month at R1.80/kWh.
    - Second block up to 350 kWh/month at R2.00/kWh.
    - Third block up to 700 kWh/month at R3.50/kWh.
    - Final energy beyond 700 kWh/month at R5.00/kWh.

The rates, costs and revenue at various levels of consumption are shown in Table 1.

Table 1. Costs to service domestic customers at various consumption levels

IBT tariffs and costs (2023/24)				**IBT cost vs revenue (2023/24)**		
Service	**Unit**	**Value**		**kWh/month**	**Cost/month**	**Revenue/month**
Energy tariff	R/kWh (0-50kWh)	1.80		0	350	0
	R/kWh (51-350kWh)	2.00		100	550	190
	R/kWh (351-700kWh)	3.50		200	750	390
	R/kWh (701+kWh)	5.00		300	950	590
Energy cost	R/kWh	2.00		400	1,150	865
Capacity cost	R/Amp/month	10		500	1,350	1,215
	Amps	20		600	1,550	1,565
	R/month	200		700	1,750	1,915
Basic cost	R/month	150		800	1,950	2,415

The dynamic of the costs vs. revenue is shown in Figure 1.

Assuming equitable share only covers the energy cost of FBE (R2/kWh) for 2 million indigent consumers using 50kWh/month, this equates to the provision of R2.4 billion via the equitable share grant. Revenue from the 5 million non-indigent low-income customers for the first 50kWh used, assuming a tariff of R1.80/kWh, is R90/month/customer; whereas costs are R100/month/customer, resulting in a subsidy of R0.6 billion/year.

The costs to supply the remaining kWh for a low-income consumer using 350kWh per month (i.e., the remaining 300kWh after the first 50kWh), is R950/month/customer (R350 fixed costs and R600 energy costs). The revenue on the other hand is R600/month/customer. This means a subsidy of R360/month/customer, or R30 billion/year – far higher than what is covered by the equitable share grant.

When developing the basis for a new industry, cognisance needs to be taken of these subsidies and mechanisms to address them.

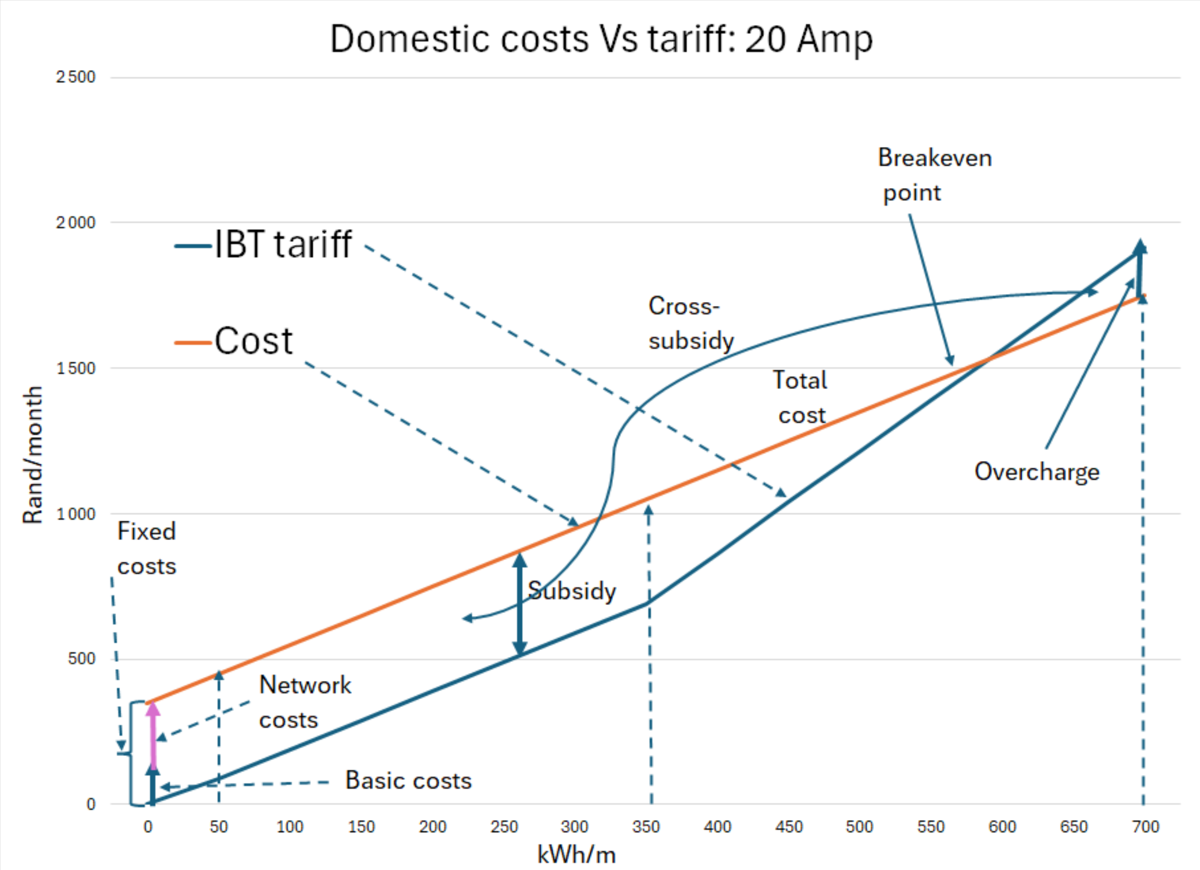


Figure 1. Cost vs revenue from domestic customer at varying consumption levels

Some statistics from 10 cost of supply studies are shown in Table 2. The 20 Amp category are those that use less than 350 kWh/month.

Table 2. Cost of supply summary statistics

Municipality	Total Customers	Number of Indigents	Average kWh/month	20 Amp Customers	Ave kWh/month (20 Amp customers)
Municipality A	14,850	1,267	157	368	91
Municipality B	6,900	1,250	120	1,920	164
Municipality C	33,000	6,224	250	7,300	300
Municipality D	7,300	1,740	180	1,800	240
Municipality E	2,100,000	39,500	160	140,000	113
Municipality F	3,500,000	61,000	200	97,000	250
Municipality G	16,400	3,025	107	7,300	119
Municipality H	11,000	3,406	267	3,315	204
Municipality I	33,000	10,701	260	11,121	303
Municipality J	21,000	1,444	64	19,455	35

The Municipality J data should be treated with caution, as reported losses exceed 50%. Notably, many consumers who are not registered as indigent appear to use less electricity per month than those who are officially classified as indigent. This suggests that a significant number of poor households are not being captured by the current indigent registration criteria.

One of the major challenges facing the electricity supply industry is widespread non-payment, reflected in high non-technical losses as well as growing bad debt. While this could be interpreted as a form of cross-subsidy, it may also be viewed from a different perspective:

- When certain consumers fail to pay their bills and the amounts are written off as bad debt and included in the revenue requirement, it results in a cross-subsidy from paying to non-paying consumers.
- If consumers tamper with their meters or connect illegally, thus ending up not paying, the losses will increase. This reduces revenue.
  - If the municipality raises this revenue from other customers, it effectively means that paying consumers in the municipality cross-subsidise those who do not pay.
  - If this results in the municipality not paying Eskom, as is currently the case in many municipalities, it may end up as Eskom bad debt or could be written off by national government.

Key questions regarding subsidies for domestic consumers include:

- Which consumers, group of consumers or area of consumers should be subsidised or cross-subsidised by other consumers within the sector?
- What criteria should be used to identify eligible consumers, and how will the selection process work?
- Which portion of electricity costs should be subsidised, to what extent, or how many kWh should be subsidised?

Which consumers should be subsidised or cross-subsidised?

- National Treasury's guideline is that poor consumers should be subsidised by the Equitable Share Grant, which it allocates based on the number of poor people within each municipality, informed by specific household income cut-off points within Statistics South Africa data. Each municipality develops its own criteria that qualify customers as indigent and therefore eligible for subsidisation.
- The Electricity Pricing Policy (EPP) states that consumers with a capacity limited to 20 Amps can be cross-subsidised.

What tariff charge should be subsidised and to what extent?

- The National Treasury guideline is that 50 kWh/month should be subsidised; providing funds to cover this in respect of a pre-determined R/kWh cost. Inadequate provision is made for the subsidisation of fixed costs.
- The EPP indicates that the tariff should break even with cost at 350 kWh/month, which effectively means that the subsidy is highest at low levels of consumption and reduces as consumption increases.

When subsidies are provided to consumers who already have access to grid electricity, it effectively means that resources are being diverted from extending access to unserved households. This raises the question of how subsidies should be structured. The EPP provides the following guidance on cross-subsidisation:

Policy Position: 48

a) Qualifying customers shall be subsidised through the application of a lifeline tariff:

- a single energy rate tariff
- no fixed charge
- limited in capacity to 20 Amps
- nominal connection fees

Policy Position: 49

a) The level of the lifeline tariff should be set to break even with the cost-reflective tariff of the licensee for a 20 Amp supply at a recommended consumption level of 350 kWh per month.

Policy Position: 50

a) The shortfall in revenue between the lifeline tariff and the cost of supply, after deducting the electrification capital grant, will be addressed within the distributor. The impact of such cross-subsidy must be pooled over all customers in the licensee, not only on domestic customers, and should be shown transparently as a c/kWh levy on consumption.

The EPP clearly outlines how cross-subsidies should be applied. While it specifies that any shortfall should be recovered through a c/kWh surcharge, in practice, a percentage-based surcharge has often been used instead. This approach has been adopted for the following reasons:

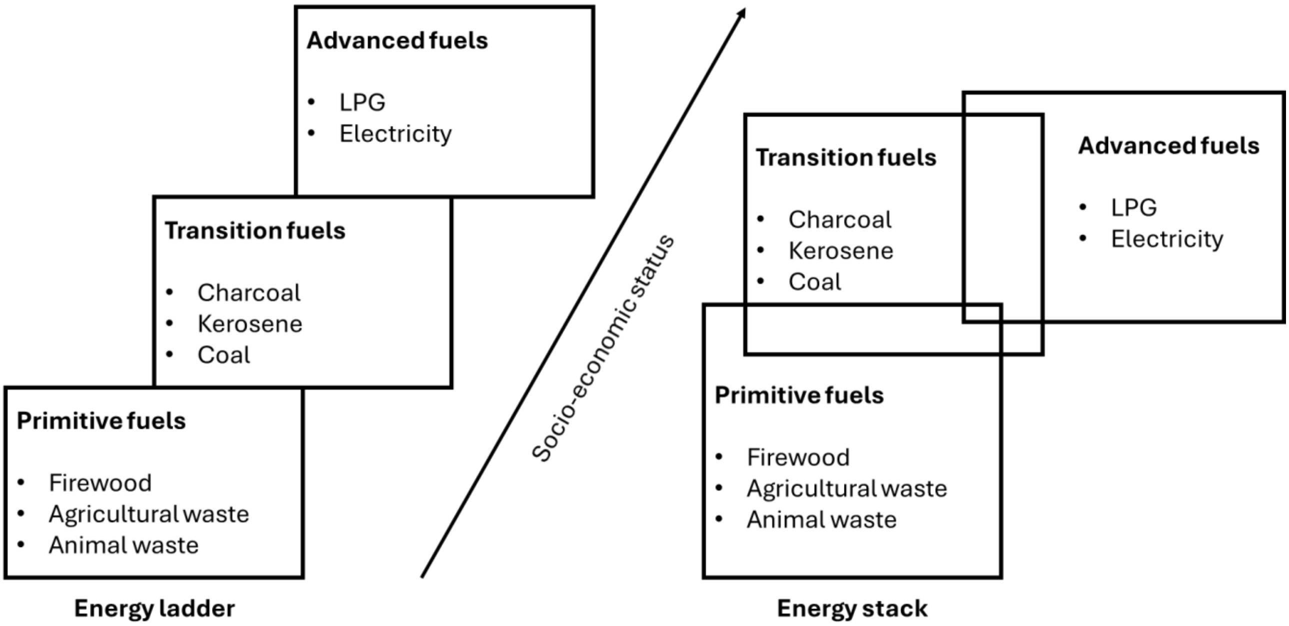
- Many consumers, especially the SSEG consumers, are using very little kWh and often do not pay their fair share for the network, unless they are on a tariff with fixed network charges.
- It would increase the burden on high-usage consumers too much.
- Distributors do not own the electricity and would therefore best recover cross-subsidy revenue from “wires” (fixed capacity) charges.

3 Basic Services

A key question is what constitutes "basic services" in the context of electricity and energy. This is a complex issue that falls outside the scope of this paper. However, a few excerpts from *Rethinking South Africa's Household Energy Poverty through the Lens of Off-Grid Energy Transition* (Masuku, 2024) are included here for reference.

In South Africa, energy poverty is defined as an expenditure-based measure, where households spending more than 10% of their income on energy are deemed energy-poor (Masuku, 2024). This clearly refers to energy and not electricity. There is a common perception that all household energy needs must be met using electricity. However, this is not the case, as illustrated in Figure 2, which shows that household energy needs can be met through a variety of energy sources. This is particularly relevant during periods of socio-economic transition, such as those experienced by many low-income households.

Figure 2.The energy transition and stacking ladder



Source: Van der Kroon, 2016, based on Schlag and Zuzarte, 2008.

The provision of affordable household energy should not be viewed as the sole responsibility of the electricity sector; other energy sources also play a vital role. Even in highly developed countries like Japan, there is widespread use of alternatives such as gas and kerosene (also known as paraffin). This section begins with an analysis of household energy use by application. Table 3 presents various household energy applications, ordered from top to bottom based on their suitability for electricity supply and their potential to improve living standards for low-income households.

Table 3. Ranking of energy applications best-suited for delivery via electricity

Application	No.	Watts	Amps	Total Watts	Total Amps	All Amps	Daily Hours	kWh/ month	Duty cycle (%)	Cum. kWh/m
Lights LED	4	10	0.04	40	0.17	0.17	6.00	7	100%	7
TV, DSTV	1	100	0.43	100	0.43	0.61	5.00	15	100%	23
Radio/Hi Fi	1	20	0.09	20	0.09	0.70	6.00	4	100%	26
Computer	1	40	0.17	40	0.17	0.87	6.00	1	20%	28
Phone chargers	3	10	0.04	30	0.13	1.00	7.00	1	10%	28
Fridge / Freezer	1	100	0.43	100	0.43	1.43	24.00	22	30%	50
Toaster	1	700	3.04	700	3.04	4.48	0.20	4	100%	55
Kettle	1	2,000	8.70	2,000	8.70	13.17	0.25	15	100%	70
Microwave	1	1,800	7.83	1,800	7.83	21.00	0.33	18	100%	88
Hot plates	2	1,000	4.35	2,000	8.70	29.70	1.00	37	60%	125
Iron	1	1,200	5.22	1,200	5.22	34.91	1.00	18	50%	143
Hair dryer	1	800	3.48	800	3.48	38.39	0.25	3	50%	146
Heater	1	2,000	8.70	2,000	8.70	47.09	4.00	43	70%	189
Big stove plates	1	1,700	7.39	3,400	14.78	61.87	1.00	41	40%	230
Oven	1	2,400	10.43	2,400	10.43	72.30	2.00	59	40%	289
Dishwasher	1	2,000	8.70	2,000	8.70	81.00	2.00	24	20%	313
Washing machine	1	2,000	8.70	2,000	8.70	89.70	7.00	128	30%	441
Tumble dryer	1	2,000	8.70	2,000	8.70	98.39	2.00	122	100%	563
Geyser	1	2,000	8.70	2,000	8.70	107.09	24.00	293	20%	856
Pool pump	1	800	3.48	800	3.48	110.57	6.00	146	100%	1,003
Borehole pump	1	700	3.04	700	3.04	113.61	2.00	43	100%	1,045
Air conditioner	4	2,600	2.61	2,400	10.43	124.04	7.00	256	50%	1,301
Under floor heating	1	2,500	10.87	2,500	10.87	134.91	7.00	267	50%	1,568

What this shows is:

- That a small household can fulfil basic energy needs that are best done with grid electricity, at 50 kWh/month.
- Applications that cannot be supported by 50 kWh/month are typically those that involve electric heating elements, which consume large amounts of electricity, or those considered beyond basic needs, such as washing machines and tumble dryers.
- This raises questions about whether cooking with electricity is preferable to other options in terms of environmental impact, carbon footprint, affordability, safety (e.g., fire risk), and availability.

When formulating answers, the following should be considered:

- Many households still do not have access to electricity.
- Current grid electricity is cheaper in terms of end-user energy cost than many other energy sources. For example, grid power for LED lighting is significantly cheaper than candles or any other form of light.
- All electronic equipment, such as cell phones and radios, can only operate with electricity. Grid electricity energy cost is significantly cheaper than using batteries, or even PV systems with batteries.
- Grid power is much more convenient than other energy sources, especially in an urban environment, where firewood is not freely available.
- Grid power results in improved local household air quality when compared with coal or wood.

- Hughes and Larmour (2021) show that many consumers in poor communities do not use electricity for cooking.

The question of whether grid electricity should be used for cooking, and whether it should therefore be included as part of basic electricity provision, is highly complex. Research by Hughes and Larmour (2021) provides an overview of this issue and highlights its multifaceted nature.

Most homes were electrified, and electricity was the primary fuel used for cooking and, when affordable, for space heating. In cases where households could not afford electricity, alternative fuels were used instead.

Air pollution exposure
The issue of air pollution in low-income areas is extensively covered Wernecke et al., 2024. It is clear that shifting household cooking to electricity or gas will significantly reduce air pollution exposure in urban environments.

Carbon footprint
The carbon footprint of grid electricity used for cooking is higher than almost all other energy forms, considering that cooking usually occurs during the evening peak time, when PV power is largely not available, and electricity is usually supplied by coal, diesel or gas. Less than 25% of the energy in coal ends up in food preparation, due to the inefficiency of converting coal energy into electrical energy, transporting it to the household, and the inefficiency of old appliances and containers (pots and pans).

Cost
The cost of cooking using different energy sources depends on a variety of factors. Many electrified households use electricity for cooking, heating, and lighting when they receive FBE. However, once this subsidy is depleted, these households often switch to alternatives such as wood, coal, or kerosene for cooking and heating. This behaviour suggests that grid electricity is perceived as more expensive than other energy sources for cooking. It may therefore be more cost-effective for government to consider subsidising alternative fuels rather than grid electricity, for certain applications.

The Just Energy Transition Implementation Plan highlights the need for continued investment to address energy poverty and promote social inclusion. It also acknowledges a broad consensus on the long-term goal of increasing the FBE allocation to 350 kWh per household per month but notes that fiscal constraints limit the feasibility of implementing this in the short term.

Emerging evidence suggests that this may not be the most effective approach. Work to date indicates that encouraging a shift to gas for cooking could be a more viable alternative. From an environmental perspective, gas offers a lower carbon footprint compared to grid electricity, which in South Africa is still largely generated from coal.

Cooking with electricity

Given the differing views on this issue, further analysis of the actual cost of cooking with electricity versus gas has been undertaken and is presented in Annexure 8.4 Analysis of Cooking and Space Heating: Gas vs Electricity.

The analysis makes it evident that mechanisms should be developed to encourage the use of gas for cooking, rather than continuing to subsidise electricity for this purpose. These mechanisms could include:

- Establishing reliable gas supplies in low-income areas.
- Making affordable, high-quality gas stoves available.
- Providing education and training on the efficient use of gas for cooking
- Offering targeted subsidies for gas.

Promoting the use of gas for cooking would reduce pressure on the electricity grid, making it easier to ensure that the grid can reliably meet the most basic electricity needs, thereby protecting and sustaining this essential public service.

4 Cost of Supply and Pricing Methodology

This section will cover the theory and practices of the process of ringfencing, costs of supply and pricing. The following section will include practical illustrations of such a study and the typical findings. The undertaking of these studies is guided by the following:

- The draft NRS 058 - Cost of supply methodology for application in the electrical distribution industry. This standard is outdated, complex and Eskom-focused.
- Eskom developed a comprehensive cost of supply model based on NRS 058 and has been using this for their cost of supply studies.
- NERSA developed a Cost of Supply Framework, with a section on ringfencing.

4.1 Ringfencing

Ringfencing refers to the process of determining prudent costs and revenues relating to electricity supply, with a view of determining the level at which the tariffs should be set. This includes calculating a fair contribution to the municipal overhead costs. Temporary operational grants from National Treasury, for example, should not influence the setting of tariff levels to ensure long-term sustainability.

The first step in improving the understanding of current subsidies and cross-subsidies in the electricity supply industry is to examine the full cost of electricity supply, particularly within municipalities.

4.1.1 Eskom

The cost of Eskom distribution is largely ringfenced, since generation, transmission and distribution are ringfenced from one other.

However, there are various functions that may distort the true cost of Eskom Distribution. Once Eskom is fully unbundled and distribution is a separate legal entity, the actual cost of Eskom Distribution will be known. The current costs are likely close to the full cost.

4.1.2 Municipalities

The ringfencing of the electricity supply function within municipalities has been a long-standing issue, particularly during the now-abandoned process of establishing Regional Electricity Distributors (REDs). While this paper does not explore the matter in depth, the following key issues require attention:

Inter-departmental charges
Inter-departmental charges refer to actual, measurable services provided by the electricity department to other municipal departments. Many municipalities are able to account for these services with a reasonable degree of accuracy.

- Electricity services, including:
  - Electricity supply to various municipal departments, such as offices, depots, sewerage works, water supply, etc.
  - Provision of public lighting services, including streetlights and traffic lights.

  - Provision of maintenance of municipal facilities’ electricity installation work.
  - Provision of equipment such as cranes, trucks, generators, etc.
- Water supply to various municipal departments.
- Sewerage supply to various municipal departments.

The purpose of ringfencing is to identify the costs associated with inter-departmental services and to ensure that the corresponding charges accurately reflect these costs.

Overhead/head office costs

Overhead costs refer to central administrative functions that support various municipal line departments, including both trading services – such as electricity and water, which generate significant revenue and are expected to recover their costs through service-related charges – and non-trading services, such as libraries, roads, parks, and community services. National Treasury has emphasised that the full cost of any service must include a fair allocation of overhead costs. However, this remains a significant issue that is often poorly addressed or entirely overlooked. The following points are important to consider in this regard:

- Most metros are in the process of ringfencing overheads. Some of these have been found to be fair and accurate.
- While some municipalities have attempted to allocate overhead costs, these allocations are often found to be inaccurate and inequitable. In some cases, overheads are assigned based on the ability of a line department to pay, meaning the most profitable trading services, such as electricity, bear the largest share of overhead costs. This approach is not cost-reflective.
- A structured system for allocating overhead costs to various line departments has been developed within the industry. This system is based on the following logic:
  - Support departments, such as Human Resources, Finance, Corporate Services, Supply Chain, and IT provide services to line departments and their costs should be proportionally allocated based on service use.
  - Administrative and governance departments, including the Council and the Office of the Municipal Manager, do not provide direct operational services, but their costs are often included in overhead allocations.
  - Certain specialised functions, such as Property Valuations, which support revenue collection (e.g., rates), and in some cases the Council in smaller municipalities (where costs are covered by the Equitable Share Grant), should not have their costs allocated to service departments.
  - In all cases, it is the net cost of each overhead department, calculated as total expenditure minus any own revenue, that is allocated to the line departments.
- The methodology allocates overhead costs based on various allocation factors. For example:
  - HR costs are allocated to line departments using a weighted approach: 50% is based on the number of staff in each department, and the remaining 50% is based on the total labour cost within each department.
  - Some overhead activities, such as those related to the Municipal Manager’s office or legal services, cannot be linked directly to a specific line function. These costs are allocated

proportionally based on the total operating cost of each line department, excluding bulk purchase costs.

Overhead allocation benchmark/limit
A benchmark or guideline needs to be established for overhead cost allocation. In studies conducted using the methodology outlined earlier, overhead costs typically ranged between 10% and 20% of direct costs (excluding overheads). However, in some municipalities, overhead costs were found to exceed 50% of direct costs.

Further analysis is required to determine the typical or reasonable proportion of overhead costs in municipal operations. Based on these findings, a cap or standard should be established to guide the extent of overhead costs allocated specifically to the electricity function.

Challenging issues
Various complex and often politically sensitive issues arise in the management of municipal electricity finances, including:

- Should line departments be charged property rates, as ordinary residents and businesses are? If so, this could reduce the amount of overhead costs that need to be allocated from other departments to line departments.
- Electricity development charges are not ringfenced and are frequently used to fund capital expenditure for unrelated services, rather than being reinvested in the electricity function.
- How should the interest and depreciation be allocated when loans are taken out for a range of activities, including electricity, water and sewerage? In most cases, these amounts are correctly apportioned.
- Use of electricity surpluses to fund other capital projects, such as sewerage infrastructure, undermines the financial sustainability of the electricity service. National Treasury has directed that each trading service should be self-funded. Furthermore, municipalities must become independent from electricity surpluses.

The following is proposed in this respect:

- Electricity should be properly ringfenced within municipal budgets and accounts.
- This means electricity surpluses must be used for electricity capital projects, specifically refurbishment. Further detail on this recommendation is provided in the section addressing the revenue requirement.

4.2 Revenue Requirement

The issue of the revenue requirement has become a central concern in the electricity regulatory landscape, particularly following the recent court cases involving AfriForum and NERSA. The following key developments provide context:

- The Electricity Pricing Policy (EPP) stipulates that electricity utilities must undertake cost of supply studies every 5 years.
- These studies determine the revenue requirement, which refers to the total amount of revenue a utility is allowed to earn to recover its prudent and efficient costs.

- In 2022, businesses in the Nelson Mandela Bay Metro challenged NERSA's use of a benchmarking approach to evaluate tariff increase applications, arguing it did not comply with the EPP's mandate for cost-based tariffs.
- The court ruled in favour of the applicants, confirming that NERSA's method did not meet the EPP's requirements. It ordered NERSA to establish a system that ensures municipal tariffs are based on Cost of Supply (COS) studies from 1 July 2025 onwards.
- In November 2023, NERSA instructed all municipalities to complete their COS studies and submit them by the end of March 2024.
- In February 2024, NERSA released a revenue requirement template, intended to guide municipal applications for annual tariff increases.
- AfriForum subsequently challenged this template in court, arguing it simply applied inflationary increases linked to Eskom tariffs and did not reflect prudent costs as required by the EPP.
- Once again, the court ruled against NERSA, stating that only municipalities that submitted approved COS studies could be granted tariff increases from 1 July 2024, and then only under certain conditions.

These events underscore the critical and controversial nature of the revenue requirement issue. Moving forward, policy formulation must address the following challenges:

- The need for a robust, transparent, and cost-reflective revenue requirement methodology.
- Ensuring compliance with EPP guidelines.
- Improving municipal capacity to complete and update COS studies.
- Clarifying the roles of NERSA, municipalities, and external consultants in the approval process.

The NERSA revenue methodology is illustrated in Table 4.

Table 4. Cost Plus Methodology – the adopted revenue requirement approach

Total Required Purchases (MWh)				
(a) Sales forecast (Expected sales to customers)				**X**
(b) Electricity purchased for own use				**X**
(c) Street lighting				**X**
(d) = (a) + (b) + (c) Total sales forecast				**X**
(e) Allowable loss factor (Represents a percentage energy loss of 10%)				**1.10**
(f) = (d) x (e) Required purchases				**XX**
Sources of Electricity Purchases	**(g)** Volume (MWh)	**(h)** Weight (%)	**(i)= (j) / (g)** Average Purchase Price(c/kWh)	**(j) = (g) x (i)** Total Cost (R)
Purchases from Eskom				**X**
Purchases from IPPs				**X**
Own Generation				**X**
Purchases - Other options				**X**
Total		**100%**		**XX**
Add other costs				
Operating expenditure				**X**
Shared costs				**X**
Depreciation/amortisation of refurbishment and capital costs				**X**
Interest on loans				**X**
(k) Total costs before Repairs and Maintenance (R&M) costs				**XX**
(l) = (k) x 6% Repairs and Maintenance costs at 6% of total costs before R&M				X
(m) = (k) + (l) Total costs before surplus				**XX**
(n) = (m) + 15% Add surplus allowable				15%
(o) = (m) + (n) Total Allowable Revenue				**XXX**
(p) = (o) / (f) Average selling price				
(q) Previous year price				X
(w) = (p) / (q)-1 x100 Average percentage price increase				**X%**

The first consideration in determining the revenue requirement is the percentage surplus, defined as the extent to which revenue exceeds costs. NERSA previously applied a benchmark surplus of 10% to 20%, but this was developed at a time when overhead costs were not allocated to electricity services. Now that overheads are being included, these benchmarks are no longer appropriate. Moreover, the Nelson Mandela Bay court ruling confirmed that NERSA's use of standardised benchmarks is no longer permissible, reinforcing the requirement for cost-reflective tariffs based on COS studies. The Network Sustainability paper within this papers series proposes that:

- The only reason for a surplus is to fund refurbishment of assets at the end of their economic life.
- The provision for refurbishment should thus be set equal to the current replacement cost (CRC) depreciation.
- This can be implemented either with:
  - a surplus plus depreciation, as in the accounts, set equal to the CRC depreciation,
  - or the accounting depreciation set equal to CRC depreciation, with no surplus.

There are several necessary adjustments that must be made to accurately determine the revenue requirement, as the financial statements alone do not reflect the true cost and performance of the electricity service. Currently, none of these adjustments are systematically applied. The key adjustments include:

- **Overhead allocation**: A clear industry benchmark is needed to define a fair percentage of overhead charges allocated from the rest of the municipality.
- **High losses**: NERSA's benchmark for technical and non-technical losses ranges between 8% and 12%. NERSA's current approach deducts the portion of losses exceeding 12% from the total bulk purchase cost in revenue requirement calculations. However, this methodology ignores the fact that network and connection costs are based on supplying all consumers, regardless of losses, which unfairly burdens paying customers. A more accurate approach is to adjust revenue upward by the percentage of losses exceeding the lower threshold of 8%.
- **Interest on deposits**: Interest earned on customer electricity deposits is often excluded from reported revenue. This interest should be added to the current revenue.
- **Internal charges**: Electricity used by other municipal departments is frequently not billed at cost-reflective rates. The difference between actual charges and cost-reflective values should be added to the revenue. This adjustment is especially relevant where no charges are applied at all, which is prevalent in the supply of street and traffic light services.
- **Availability charges**: Many municipalities do not account for availability charges from unconnected, yet serviced, stands. These charges should be assessed and included in revenue.
- **Equitable Share Grant**: In many cases, the portion of the Equitable Share Grant allocated to electricity is not reflected in the electricity department's accounts (trial balance). This is particularly true for FBE payments to Eskom for supplying indigent customers in Eskom-distributed areas. These transfers and payments should be recorded explicitly.
- **FBE exceeding 50 kWh/month**: Some municipalities provide more than the National Treasury guideline of 50 kWh/month of FBE. Any additional amount must be funded from municipal funds, not from the electricity function.
- **Imprudent charges**: Eskom's Excess Access Charges are often considered imprudent, as municipalities are expected to apply and pay for increased capacity in advance, which negates these charges. Delays by Eskom in providing such capacity have resulted in unjustified charges, which have in some cases been reversed. Where Eskom is at fault, these charges should be excluded from the cost base. In addition, interest charged on arrears owed to Eskom should be excluded from the cost base, as these accounts should be fully paid if financial management is sound.
- **Bad debt**: NERSA allows for bad debt provision of up to 5% of revenue. Any amount exceeding this threshold should be removed from the cost base.
- **Depreciation**: Some municipalities apply depreciation on revalued assets, which may not reflect replacement value. The revenue requirement should be structured so that the sum of depreciation and the allowed surplus equals the annual CRC depreciation.
- **Imprudent costs**: This remains a complex issue. In many municipalities, high operating costs, primarily labour-related, have not translated into improved customer service or network

performance. NERSA's technical D-form[1] includes performance indicators that help assess service quality. At present, unless there is clear evidence of imprudent costs, no downward adjustments are made. NERSA's practice of allowing 6% maintenance expenditure, even when municipalities spend less, is not supported. Only actual costs should be used. However, if a municipality presents a credible plan to increase maintenance, such as hiring additional staff or procuring necessary equipment, those future costs may be included in the revenue requirement.

These adjustments provide a more accurate indication of whether a municipality requires an average tariff increase above inflation.

4.3 Cost of Supply and Pricing

The cost of supply methodology, including allocation of costs and pricing, is detailed in the Annexure 8.5 Cost of Supply and Pricing.

[1] A D-Form is a technical data collection form used by NERSA to gather detailed operational, financial, and performance information from licensed electricity distributors, particularly municipalities.

5 Summary Results

The author has conducted numerous Cost of Supply and tariff studies over the past 26 years. While the methodology has evolved slightly over time, the results provide valuable insight into the actual subsidies and cross-subsidies within the electricity sector. The aim is to illustrate the following:

- The difference between the trial balance surplus and the ringfenced, fully adjusted revenue requirement surplus.
- The extent of overhead allocations as a percentage of own costs (i.e., total costs excluding bulk purchases).
- Energy losses.
- How surpluses compare with CRC depreciation.
- The difference between historic cost depreciation and CRC depreciation.
- The average tariff increases required to generate the necessary revenue
- The extent of cross-subsidisation to low-income households, after accounting for the FBE subsidy.

Table 5. Cost of supply summary statistics

Municipality	Year data	Revenue	Initial surplus % of revenue	After corrections	Overhead % of own cost (excl. bulk)	Ringfenced surplus	Losses	Capex
Thaba Chweu	2022/23	R187,102,192	-14.4%	-55.5%	113.2%	-204.1%	39.9%	R8,516,698
Ndlambe	2022/23	R86,267,618	-22.7%	-20.3%	27.0%	-15.8%	13.8%	R1,851,630
Swartland	2022/23	R387,437,332	16.6%	14.4%	53.8%	8.5%	5.3%	R34,086,540
Swellendam	2022/23	R101,793,861	9.8%	6.1%	22.6%	2.4%	9.0%	R242,359
Nelson Mandela	2022/23	R4,702,119,532	-17.4%	-17.4%	16.0%	-7.6%	21.7%	R276,603,817
Ekurhuleni	2022/23	R19,535,429,563	0.1%	4.7%	15.0%	19.6%	17.9%	R663,591,653
Matzikama	2021/22	R138,590,367	-2.4%	-9.3%	41.9%	-15.7%	11.9%	R1,007,600
Witzenberg	2021/22	R336,675,858	11.1%	11.6%	34.8%	7.0%	10.9%	?
Stellenbosch	2021/22	R1,355,657,432	21.1%	19.3%	35.0%	7.8%	5.6%	?
Merafong	2020/21	R302,540,978	-54.2%	-54.2%	50.1%	-67.5%	52.0%	?
Total/Average		R27,133,614,733	-R1	-R1	R4	-R3	R2	R985,900,296

Municipality	Grant	Accounting asset value	Accounting depreciation	Depreciation/ asset value	Depreciation % of revenue	Replacement cost	Replacement cost depreciation	Depreciation / asset value
Thaba Chweu	R8,516,698	R137,441,135	R7,057,523	5.13%	3.8%	R966,085,968	R36,647,410	3.79%
Ndlambe	R1,394,000	R136,459,411	R3,755,448	2.75%	4.4%	R523,963,688	R23,575,427	4.50%
Swartland	R17,600,000	R626,462,382*	R14,340,302	2.29%	3.7%	R743,854,302	R30,725,835	4.13%
Swellendam	R439,236	R54,135,182	R1,391,061	2.57%	1.4%	R552,310,981	R20,739,281	3.76%
Nelson Mandela	R157,146,941	R2,926,226,552	R145,884,465	4.99%	3.1%	R8,177,021,866	R332,147,736	4.06%
Ekurhuleni	R410,551,454	R20,416,008,033	R553,946,571	2.71%	2.8%	R85,351,235,173	R2,054,204,601	2.41%
Matzikama	R1,007,600	R54,896,885	R1,541,522	2.81%	1.1%	R599,162,148	R14,837,477	2.48%
Witzenberg	R9,040,509	R125,981,291	R3,365,565	2.67%	1.0%	R462,790,935	R12,704,556	2.75%
Stellenbosch	R14,467,664	R1,415,78/5,086*	R35,345,335	2.50%	2.6%	R2,796,951,685	R101,651,021	3.63%
Merafong	Not split	R562,854,445	R12,191,556	2.17%	4.0%	R1,397,114,954	R32,278,496	2.31%
Total/Average	R620,164,101	R24,414,002,933	R729,133,710	R0	R0	R98,029,685,713	R2,527,134,984	2.58%

** Assets revalued partially*

Municipality	Depreciation % of revenue	CRC / Historic	Revenue requirement incr. after corrections	Subsidy to the poor % of rest	Avg purchase price	Avg selling price (divide by sales)
Thaba Chweu	19.6%	702.9%	-11.2%	61.6%	R1.097	R2.303
Ndlambe	27.3%	384.0%	8.2%	5.0%	R1.644	R2.201
Swartland	7.9%	118.7%	7.8%	5.7%	R1.621	R2.533
Swellendam	20.4%	1020.2%	15.9%	7.2%	R1.572	R2.702
Nelson Mandela	7.1%	279.4%	11.3%	2.2%	R1.424	R2.074
Ekurhuleni	10.5%	418.1%	-	2.8%	R1.520	R2.680
Matzikama	10.7%	1091.4%	0.0%	14.4%		
Witzenberg	3.8%	367.3%	7.0%	11.3%	R1.373	R2.097
Stellenbosch	7.5%	197.6%	1.2%	17.5%	R1.346	R2.367
Merafong	10.7%	248.2%	?	6.8%	R1.356	R2.420
Total/Average	9.3%	401.5%	5.0%	14.2%	R1.440	R2.380

6 Renewables Impacts

The rapid emergence of renewable energy, particularly embedded solar photovoltaic (PV) systems, presents significant new challenges for maintaining electricity as a public service. The following points aim to provide a broad understanding of the dynamics at play, with a particular focus on PV systems, which have the greatest impact on local energy systems.

Facts:

- Small-scale PV systems (without batteries) can now be installed at a levelised cost of less than R1/kWh, even for individual households (based on a 10-year annuity calculation).
- PV systems with battery storage are more expensive, but levelised costs below R3/kWh are achievable.
- The opportunity cost of energy savings for a typical municipality purchasing from Eskom under the Megaflex tariff is approximately R1.60/kWh.
- For domestic consumers on an IBT, savings from self-generation can be substantial, especially in the upper blocks. For example, Ekurhuleni's highest IBT block is priced at R9.87/kWh (excluding VAT).

Implications:

- Based on current average tariff structures, it is financially viable for municipalities or consumers to install PV systems or contract with IPPs to substitute Eskom-supplied power, thereby lowering energy costs.
  - However, it would negatively impact Eskom, as energy sales decrease while peak demand may remain unchanged or even increase, placing upward pressure on Eskom tariffs.
- For households and small businesses, installing PV systems with batteries is especially attractive under an IBT structure with minimal or absent fixed charges.
  - This poses a major financial risk for municipalities, which stand to lose a large share of revenue from electricity sales, while only realising modest savings in bulk power purchases.
  - From a network operations perspective, these dynamics could reduce daytime demand but increase evening peak loads, potentially worsening network stress.
- There are also emerging commercial opportunities for energy traders to contract with IPPs and consumers to wheeling energy through municipal and Eskom distribution networks.
  - While these benefits wheeling customers, municipalities do not inherently benefit unless a well-designed wheeling policy is in place.
  - If wheeling frameworks are cost-reflective, municipalities can avoid financial losses.
  - The implementation of a universal electrification levy on all energy consumed, regardless of source, could help protect municipal revenue streams and ensure continued investment in public infrastructure.

While renewable energy poses challenges for the traditional electricity supply model, it also presents significant opportunities for both the electricity industry and the advancement of the electricity public service. To unlock these benefits and ensure the financial sustainability of the system, a structured and equitable approach to tariff design and embedded generation is essential. The following principles are proposed:

- Retail electricity tariffs should be unbundled to reflect the true cost of service. They must include:
  - Basic charges to cover fixed service-related costs.
  - Capacity charges for small consumers, reflecting Eskom's demand charges and the municipality's own network costs.
  - Demand and capacity charges for bulk consumers, based on contracted maximum demand.
  - TOU energy charges for all bulk and SSEG consumers.
- All SSEG consumers must be equipped with four-quadrant smart meters with remote communication capabilities, enabling accurate measurement of imports, exports, and net usage.
- Any consumer disconnecting from the grid in an electrified area should be subject to a cost-reflective availability charge, to account for continued reliance on grid infrastructure (e.g., for backup or emergency supply).
- Retailers (e.g., Eskom and municipalities) should purchase exported power from SSEG consumers.
  - Export tariffs should be on a TOU Time-of-Use basis and set at a level that provides a meaningful incentive for consumer participation.
  - Currently, consumer accounts are credited based on the export rates up to the value of energy purchased by the consumer. Two common approaches exist:
    - Monthly reconciliation: These disadvantages consumers, because in the first months of the financial year, in winter, consumption is high and generation is low, and vice versa in summer.
    - Annual reconciliation (financial year basis): This is more favourable to a consumer, but is often undermined by insufficient compensation, especially when additional SSEG admin charges and meter costs are imposed by the utility.
  - It is proposed that National Treasury introduce a national provision allowing municipalities to compensate SSEG exports up to a limit aligned with the opportunity cost of bulk electricity purchases.

To illustrate the financial impact of SSEG on retailers, based on current vs. proposed tariffs, a comparison is provided in Table 6 between the Ekurhuleni IBT structure and a proposed cost-reflective tariff model.

Table 6. Impact of SSEG when using IBT vs. cost-reflective tariff

Tariff	Value	Unit
IBT (20 Amps)		
Block 1 (0-50kWh)	2.061	R/kWh
Block 2 (51-600kWh)	2.061	R/kWh
Block 3 (601-700kWh)	3.502	R/kWh
Block 4 (701+kWh)	9.872	R/kWh
Res. 1-ph >20 Amps		
Connection size	30	Amps
Connection charge	13.72	R/Amp/month
Basic charge	134.37	R/month
Energy charge	2.133	R/kWh
PV opportunity cost		
Energy	2.000	R/kWh

kWh/month >	0	100	200	300	400	500	600	700	800	900	1000
IBT (20 Amps)											
Revenue	R0	R206	R412	R618	R824	R1,031	R1,237	R1,587	R2,574	R3,561	R4,548
From 900 kWh/month to	R4,548	R4,342	R4,136	R3,930	R3,724	R3,518	R3,312	R2,961	R1,974	R987	0
Purchase cost savings (R2/kWh)	R2,000	R1,800	R1,600	R1,400	R1,200	R1,000	R800	R600	R400	R200	R0
Net impact	R2,548	R2,542	R2,536	R2,530	R2,524	R2,518	R2,512	R2,361	R1,574	R787	R0
% Of revenue	56.0%	55.9%	55.8%	55.6%	55.5%	55.4%	55.2%	51.9%	34.6%	17.3%	0.0%
Res. 1-ph >20 Amps											
Revenue	R546	R759	R973	R1,186	R1,399	R1,612	R1,826	R2,039	R2,252	R2,466	R2,679
From 900 kWh/month to	R2,133	R1,919	R1,706	R1,493	R1,280	R1,066	R853	R640	R427	R213	R0
Purchase cost savings (R2/kWh)	R2,000	R1,800	R1,600	R1,400	R1,200	R1,000	R800	R600	R400	R200	R0
Net impact	R133	R119	R106	R93	R80	R66	R53	R40	R27	R13	R0
% Of revenue	5.0%	4.5%	4.0%	3.5%	3.0%	2.5%	2.0%	1.5%	1.0%	0.5%	0.0%
Opportunity cost	R0	R200	R400	R600	R800	R1,000	R1,200	R1,400	R1,600	R1,800	R2,000

The results demonstrate significant net revenue losses, calculated as lost revenue minus savings in bulk purchase costs, when existing IBTs are applied, compared to cost-reflective tariffs that include basic charges, capacity charges, and a lower energy rate. This impact is particularly evident in scenarios where customer consumption decreases from 1 000 kWh/month to 200 kWh/month. The effect is illustrated graphically in Figure 3.

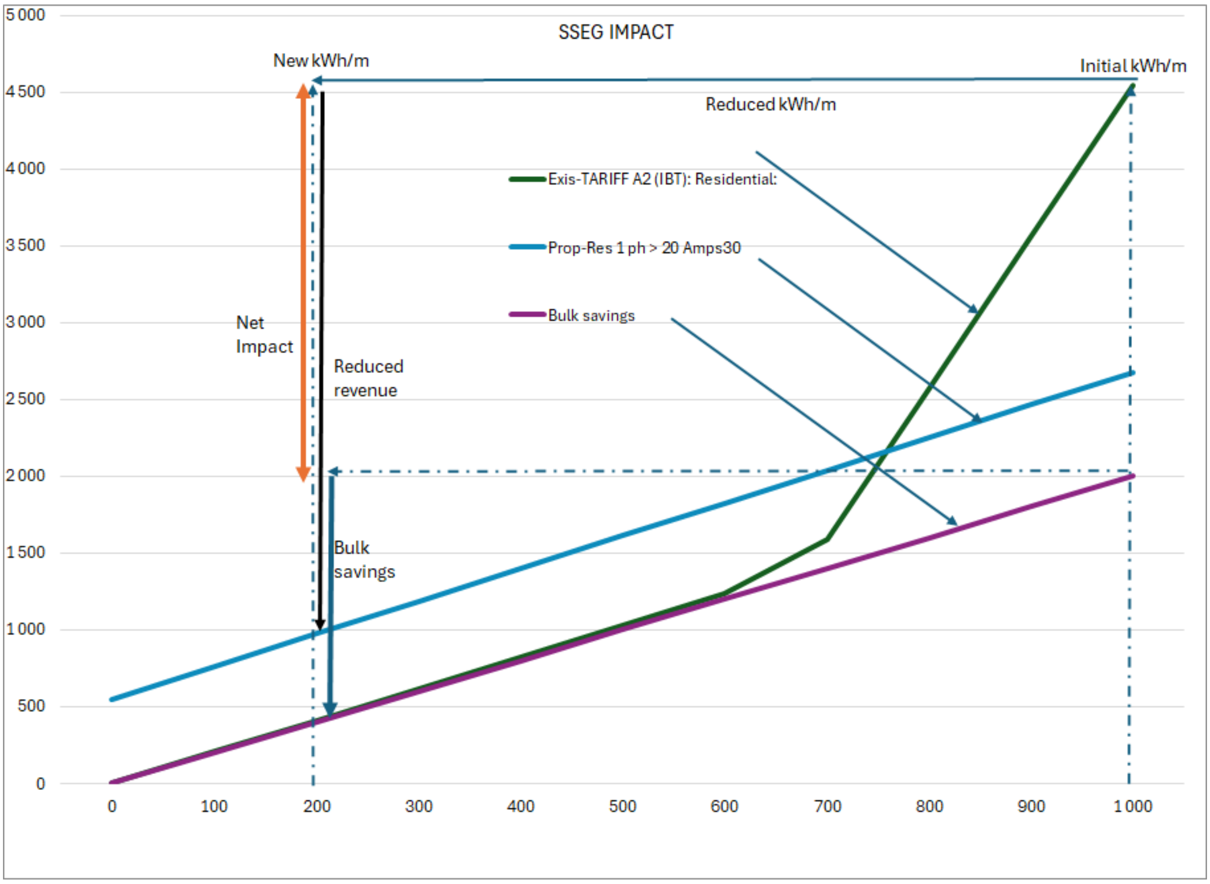


Figure 3. Impact of IBT vs. cost-reflective tariff

The key message is that cost-reflective tariffs can largely protect municipalities from the net revenue losses typically associated with SSEG consumers. While the focus above has been on minimising the financial risks posed by SSEG, it is important to emphasise that SSEG also presents significant opportunities, not only to reduce municipal energy procurement costs, but also to contribute to peak demand reduction and overall system efficiency.

7 Conclusions and Recommendations

This paper has illustrated the structure and effects of existing subsidies and cross-subsidies in South Africa's electricity supply industry. The key question moving forward is how these mechanisms should evolve in the context of a more liberalised, market-based electricity sector. The following proposals are made to support a fair, transparent, and sustainable subsidy framework that aligns with future market conditions:

- **Develop a comprehensive subsidy framework**: The sector has long awaited the development of a national subsidy and cross-subsidy framework. While several policies currently exist, they are fragmented and sometimes overlapping. A single, integrated framework should consolidate all existing subsidy mechanisms, eliminate duplication, and extend to other municipal services such as rates, water, and sewerage.
- **Implement a national tariff structure**: NERSA should develop a standardised national distribution tariff structure and phase it in over the next five years. All consumers should be charged cost-reflective tariffs, aligned with the EPP, including basic and capacity charges. Subsidies should be targeted at low-income consumers, such as those with supply limited to 20 Amps.
- **Recalculate the Eskom transmission cross-subsidy**: The existing geographic cross-subsidy in Eskom Transmission should be retained for now, but recalculated based on evolving load flows, particularly in light of new renewable generation in remote regions.
- **Recalculate the Eskom transmission cross-subsidy**: The existing geographic cross-subsidy in Eskom Transmission should be retained for now, but recalculated based on evolving load flows, particularly in light of new renewable generation in remote regions.
- **Redesign the Eskom Electrification and Rural subsidy:** The current Eskom electrification and rural subsidies should be retained but split between electrification and rural. As new distributors emerge, if at all, a revised electrification and rural levy should be applied to all electricity flows (including wheeled energy) and designed to cover both Eskom and municipal distribution areas.
- **Reform the equitable share policy:** National Treasury should revise the Equitable Share formula to support fixed network and customer service costs only (since this value is more than the 50 FBE units) or in addition to the FBE allocation of 50 kWh. Rather than increasing the FBE allowance to 200 kWh/month, as recently proposed, consideration should be given to subsidising alternative energy sources such as gas or paraffin, which may better meet cooking needs.
- **Standardise Depreciation Practices:** National Treasury should reconsider allowing municipalities to apply depreciation based on revalued assets. This practice creates inconsistencies across municipalities, confusing surplus reporting. Municipalities should instead apply historic cost depreciation and base their surplus on annual CRC depreciation.
- **Separate Cost of Supply and Revenue Requirement processes:** The issues of cost of supply and revenue requirement should be treated separately. A dedicated industry working group, either new or drawn from existing structures, should be tasked with refining the revenue requirement methodology. This may include introducing a Rate Clearing Account (RCA) mechanism, similar to that used for Eskom, adapted for municipal application.

- **Improve regulatory tools**: A new revenue requirement template should be developed to reflect all relevant cost components and applied in the approval of annual tariff increases. Similarly, a standardised Cost of Supply model should support tariff structure planning by municipalities.
- **Prioritise revenue protection and loss reduction**: The issues of non-payment and high losses must be treated as urgent priorities. Innovative solutions, including informal settlement electrification, bulk area disconnections, and improved metering, should be explored and supported.
- **Support off-grid and underserved households**: Mechanisms should be developed to support households without access to the grid. These may include targeted subsidies or tokens for alternative fuels (e.g., paraffin or gas), or basic standalone PV systems for lighting and communication.

It is evident that the interests of low-income households can continue to be protected in a future electricity industry that includes wholesale and retail competition, wheeling, trading, and widespread deployment of SSEG. This can be achieved through the reform and consolidation of existing mechanisms, supported by well-designed policy and implementation strategies.

8 Annexures

The purpose of the annexures is to provide more detailed explanations of various concepts that may not be familiar to the reader.

8.1 Tariff Terminology

This section illustrates many of the charges discussed in the paper, using the Eskom Megaflex tariff applicable to local authorities as an example.

Megaflex – Local Authority

Transmission zone	Voltage	Active energy charge [c/kWh]												Transmission network charges [R/kVA/m]	
		High demand season [Jun - Aug]						Low demand season [Sep - May]							
		Peak		Standard		Off Peak		Peak		Standard		Off Peak			
			VAT incl		VAT incl		VAT incl		VAT incl		VAT incl		VAT incl		VAT incl
≤ 300km	< 500V	634.05	729.16	192.94	221.88	105.28	121.07	207.57	238.71	143.26	164.75	91.31	105.01	R 17.67	R 20.32
	≥ 500V & < 66kV	624.05	717.66	189.08	217.44	102.70	118.11	203.57	234.11	140.10	161.12	88.91	102.25	R 16.12	R 18.54
	≥ 66kV & ≤ 132kV	604.37	695.03	183.08	210.54	99.43	114.34	197.16	226.73	135.73	156.09	86.08	98.99	R 15.68	R 18.03
	> 132kV*	569.57	655.01	172.54	198.42	93.69	107.74	185.80	213.67	127.87	147.05	81.11	93.28	R 19.86	R 22.84
> 300km and ≤ 600km	< 500V	639.22	735.10	193.63	222.67	105.13	120.90	208.52	239.80	143.55	165.08	91.08	104.74	R 17.74	R 20.40
	≥ 500V & < 66kV	630.30	724.85	190.94	219.58	103.68	119.23	205.65	236.50	141.52	162.75	89.77	103.24	R 16.31	R 18.76
	≥ 66kV & ≤ 132kV	610.28	701.82	184.86	212.59	100.39	115.45	199.09	228.95	137.00	157.55	86.90	99.94	R 15.81	R 18.18
	> 132kV*	575.26	661.55	174.31	200.46	94.63	108.82	187.62	215.76	129.18	148.56	81.91	94.20	R 20.05	R 23.06
> 600km and ≤ 900km	< 500V	645.60	742.44	195.58	224.92	106.18	122.11	210.57	242.16	144.97	166.72	91.97	105.77	R 17.98	R 20.68
	≥ 500V & < 66kV	636.65	732.15	192.84	221.77	104.74	120.45	207.72	238.88	142.87	164.30	90.68	104.28	R 16.40	R 18.86
	≥ 66kV & ≤ 132kV	616.50	708.98	186.72	214.73	101.38	116.59	201.04	231.20	138.36	159.11	87.75	100.91	R 15.94	R 18.33
	> 132kV*	581.03	668.18	176.05	202.46	95.58	109.92	189.56	217.99	130.45	150.02	82.75	95.16	R 20.32	R 23.37
> 900km	< 500V	652.06	749.87	197.56	227.19	107.28	123.37	212.74	244.65	146.39	168.35	92.89	106.82	R 18.06	R 20.77
	≥ 500V & < 66kV	643.01	739.46	194.77	223.99	105.79	121.66	209.73	241.19	144.35	166.00	91.54	105.27	R 16.59	R 19.08
	≥ 66kV & ≤ 132kV	622.70	716.11	188.65	216.95	102.44	117.81	203.12	233.59	139.77	160.74	88.67	101.97	R 16.05	R 18.46
	> 132kV*	586.75	674.76	177.82	204.49	96.65	111.15	191.50	220.23	131.81	151.58	83.66	96.21	R 20.45	R 23.52

* 132 kV or Transmission connected

Voltage	Distribution network charges					
	Network capacity charge [R/kVA/m]		Network demand charge [R/kVA/m]		Urban low voltage subsidy charge [R/kVA/m]	
		VAT incl		VAT incl		VAT incl
< 500V	R 35.24	R 40.53	R 66.75	R 76.76	R 0.00	R 0.00
≥ 500V & < 66kV	R 32.29	R 37.13	R 61.22	R 70.40	R 0.00	R 0.00
≥ 66kV & ≤ 132kV	R 11.55	R 13.28	R 21.37	R 24.58	R 28.29	R 32.53
> 132kV*	R 0.00	R 0.00	R 0.00	R 0.00	R 28.29	R 32.53

* 132 kV or Transmission connected

Voltage	Ancillary service charge [c/kWh]	
		VAT incl
< 500V	0.82	0.94
≥ 500V & < 66kV	0.80	0.92
≥ 66kV & ≤ 132kV	0.73	0.84
> 132kV*	0.70	0.81

* 132 kV or Transmission connected

Customer categories	Service charge [R/account/day]		Administration charge [R/POD/day]	
		VAT incl		VAT incl
> 1 MVA	R 402.32	R 462.67	R 181.34	R 208.54
Key customers	R 7 883.85	R 9 066.43	R 251.77	R 289.54

Reactive energy charge [c/kVArh]			
High season		Low season	
	VAT incl		VAT incl
28.30	32.55	0.00	0.00

Electrification and rural network subsidy charge [c/kWh]	
	VAT incl

Note the following Megaflex tariff components, applicable to municipalities (covering approximately 95% of their electricity consumption):

Energy Charges (c/kWh)

- Differentiated by transmission zone, ranging from ≤300km to >900km from Johannesburg.
- Differentiated by supply voltage level: < 500V, ≥ 500V & < 66kV, ≥ 66kV & < 132kV, or ≥132kV.

Network Charges (R/kVA/month)

- Transmission Network Charge: Based on notified demand, varying by transmission zone and voltage level. This charge embeds transmission-level cross-subsidies.
- Network Capacity Charge: Based on notified demand, reflecting the cost of distribution network availability.
- Network Demand Charge: Based on actual maximum demand incurred each month and differentiated by voltage.

Cross-Subsidy Charges

- Urban Low Voltage Subsidy Charge (R/kVA/month): Applied by voltage level and based on notified demand. Reflects the cross-subsidy from high voltage to low voltage consumers.
- Electrification and Rural Network Subsidy Charge (c/kWh): Recovers the cost of cross-subsidies for Eskom's electrification and rural customers.

Service Charges

- Ancillary Service Charge (c/kWh): Covers grid support services required to maintain stability, reliability, and quality of the electricity grid, such as frequency control, voltage regulation, spinning reserve and black-start capability. Varies by voltage level.
- Service Charge (R/account/day): A fixed charge per account to cover customer service and account management, including billing, metering, customer support, and related administrative functions.
- Administration Charge (R/POD/day): A daily charge per point of delivery (POD) to cover administrative and operational costs associated with managing individual supply points, including metering and data management. A single account may have multiple PODs.

8.2 Analysis of NERSA Cost of Supply Framework

A detailed analysis of the NERSA methodology will not be undertaken; instead, only the key areas of controversy will be highlighted. The NERSA COS guideline outlines three distinct actions, namely:

- Cost functionalisation.
- Cost classification.
- Cost allocation

8.2.1 Cost functionalisation

Table 7 outlines NERSA's stipulations in this regard.

Table 7. Cost functionalisation

Function	Activity/Cost
Generation	All costs associated with the production of electricity, including fuel, operations, and maintenance at generation facilities.
Transmission	Costs related to the transfer of electricity across long distances from generation points to local distribution networks, typically via high-voltage infrastructure.
Distribution	Costs incurred in delivering electricity from the transmission system to end-users through medium- and low-voltage distribution networks.
Customer-Related Cost	Costs linked to the number and type of customers served, including metering, billing, customer service, and account management.
Public lighting	Costs associated with the provision and maintenance of streetlights, high-mast lighting, and traffic signals, typically based on the number of luminaires.

To fully understand the implications, it is necessary to refer to the source documentation, namely the financial statements. In the municipal context, this refers specifically to the trial balance, which provides a breakdown of costs by department and by cost type. The following observations are important in this regard:

- Most trial balances do not disaggregate costs in a way that aligns with regulatory requirements. For example, the energy cost line typically includes only bulk purchases from Eskom, as well as purchases from IPPs and SSEG customers. However, related costs, such as energy management or administration of Eskom supply, are often embedded within other cost categories.
- Public lighting costs, including those for streetlights, high-mast lights, and traffic signals, should be treated separately. These are municipal services provided by the electricity department and are not part of electricity supply to end-users.
- The cost categories in trial balances generally do not reflect these distinctions. Instead, costs are grouped under broad classifications that combine multiple cost drivers. For example:
  - Labour costs may include staff responsible for energy management, demand control, and customer services.
  - Depreciation and interest may cover both network infrastructure and customer service-related assets.
  - Other operating costs are frequently aggregated, masking the underlying drivers and making proper allocation difficult.

A clearer cost classification structure is needed to align financial reporting with regulatory methodologies.

8.2.2 Cost classification

Table 8 presents the relevant NERSA stipulations in this regard.

Table 8. Process of cost classification between fixed and variable cost

Cost Driver	Characteristics
Demand	Triggered by peak demands and fixed in nature
Energy	Vary with volume of energy increased
Customer-Related Cost	Depend on number and type of customer served

The following comments are relevant in this context:

- The cost driver should be linked to demand or capacity, as the capacity requested by consumers has a direct cost implication. This cost is triggered by peak demand and the maximum available capacity and should be considered fixed in terms of demand/capacity, rather than fixed over time.
- The issue of public lighting should also be addressed explicitly. These costs are not part of general electricity supply and should be treated as fixed per luminaire, covering services such as streetlights, high-mast lights, and traffic signals.

The NERSA guideline then aggregates these components in Table 9, which presents a consolidated view of cost categories and their associated cost drivers.

Table 9. Cost functions and classification

Function	Cost classification
Generation	Demand-related Energy-related
Transmission	Demand-related
Distribution	Demand-related Customer-related

8.2.3 Cost allocation

The NERSA guideline refers to cost allocation as shown in Table 10 and Table 11.

Table 10. Voltage level categories

Voltage (urban)	Voltage (rural)
< 500 V	< 500 V
≥ 500 V and < 66 kV	≥ 500 V and < 66 kV
≥ 66 kV and ≤ 132 kV	N/A
> 132	N/A

Table 11. Retail cost categories

Small	< 100 kVA
Medium	>100 kVA and < 500 kVA
Large	>500 kVA and < 1 MVA
Very Large	> 1 MVA
Key Customers	As per qualification criteria

The following important clarification should be noted:

- There is a significant distinction between supply voltage and network voltage. Put differently, a consumer supplied at LV from the LV distribution network is fundamentally different from one supplied at LV directly from a medium-to-low voltage (MV/LV) substation. In the latter case, the consumer does not utilise the downstream LV network, and therefore should not bear the associated LV network costs. The same principle applies to consumers supplied at medium voltage (MV). This approach is explicitly required by the EPP to ensure cost-reflective tariffs.

Figure 4 presents a typical reduced network diagram, illustrating how network cost components should be allocated across different consumer categories based on their point of supply within the network.

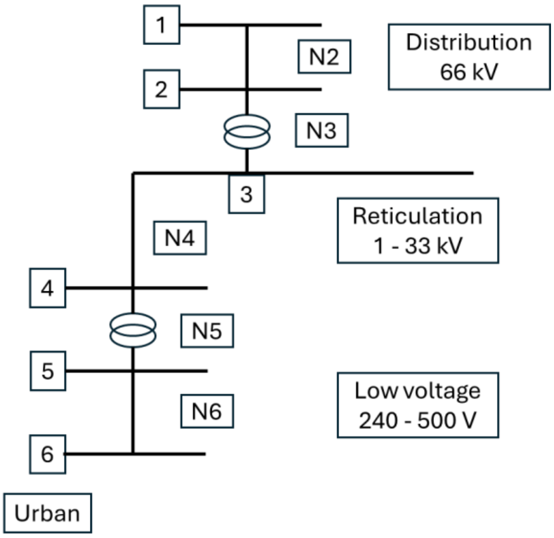


Figure 4. Reduced network diagram

The NERSA guideline outlines a three-phase approach to the cost allocation process, described as follows:

Phase 1: Development of the Cost Allocation Diagram (CAD): The first phase involves preparatory activities aimed at producing the Cost Allocation Diagram (CAD). However, the guideline does not include or illustrate the CAD, which limits its practical application.

Phase 2: Costing Information: This phase focuses on gathering and preparing key financial and technical data through the following activities:

- Determining the revenue requirement per licensee, based on the approved revenue.
- Calculating purchase tariffs by applying energy rates, distribution network charges, and zonal loss factors.
- Updating distribution network loss factors.
- Conducting an electricity sales forecast.
- Defining and validating customer categories.

Phase 3: Cost Allocation: The final phase involves the actual allocation of costs across functional areas, specifically:

- Active energy and technical losses.
- Transmission loss factors.
- Distribution network costs.
- Retail service costs.

While this framework is logically structured and broadly acceptable, it lacks detailed guidance on implementation. The document does not provide clear methodologies, calculation examples, or data structures to support municipalities or licensees in executing the required steps effectively.

8.3 Illustrations

It is often difficult to fully appreciate the implications of the preceding concepts without grounding them in practical examples. This section aims to illustrate the realities by presenting short extracts from one representative COS study completed by the author.

Data Source Selection: The first critical issue is the selection of appropriate data. The NERSA Cost of Supply template recommends using budgeted data; however, based on experience, this approach is problematic. In many municipalities, budgeted figures differ significantly from actuals. Budgets are typically prepared assuming full staff complements, extensive maintenance programmes, and ideal operational conditions. However, in practice, budget allocations are often cut, resulting in much lower actual spending. As a result, using budget data may lead to inflated tariffs that do not reflect the true cost of service.

Proposed Approach: The proposed approach is to base the COS study on actual financial data from the most recently completed financial year, for which verified figures are available. Future tariff adjustments can then be made by applying inflationary adjustments and accounting for any known structural cost changes.

Challenges with Forecast-Based Studies: To perform a forward-looking (forecast-based) COS study accurately, municipalities need to provide detailed forecasts for bulk electricity purchases, sales volumes per tariff category, updated asset registers, and customer profile and consumption data. However, very few municipalities currently have this level of forecasting capacity. As a result, it is both more feasible and more accurate to use audited financial statements and verified technical data from a completed year as the foundation for the study.

8.3.1 Ringfencing

The first aspect to address is the ringfencing of the electricity function from the rest of the municipality's operations.

The initial step in this process is to identify and remove any items in the trial balance that should not be included in the electricity department's revenue requirement. Table 12 presents the trial balance for a representative municipality, serving as the starting point for this analysis.

Table 12. Representative municipality trial balance

	Waste	Waste Water	Water	Electricity							Grand Total
	Total	Total	Total	Bulk Purchase	Administration	Distribution HT	Distribution LT	Substation	Street & Traffic Lights	Total	
Assets	90,938,304	376,017,055	259,632,019	-303,430,733	304,595,179	-1,354,633	-251,034	15,874,366	108,786,143	124,219,288	1,713,170,617
Expenditure	25,254,364	21,859,576	73,587,072	67,178,593	35,612,563	206,763	-	809,513	2,048,003	105,855,435	581,006,685
Bulk Purchases	-		28,900	67,178,593	17,184,497					84,363,090	84,391,990
Contracted Services	7,082,995	2,761,400	9,271,119		14,256,576	183,763		91,820	2,048,003	16,580,162	72,787,324
Depreciation & Amortisation	187,518	5,771,465	14,912,662		3,092,028			663,420		3,755,448	48,964,370
Employee Related Cost	12,285,054	8,819,498	10,666,338		988,087					988,087	184,821,561
Interest, Dividends & Rent	7,595,018		369,809								7,967,220
Inventory Consumed	2,469,602	1,908,610	32,529,410		80,422	23,000	-	54,273		157,695	52,250,991
Irrevocable Debts Written Off	-	-	-		-					-	190,889
Operating Leases	-		284,352								1,953,179
Operational Cost	-4,365,823	2,598,602	5,524,481		10,954				-	10,954	39,283,688
Remuneration of Councillors	-										7,671,207
Surplus / Deficit	-	-	-	-	-	-	-	-	-	-	76,195,607
Transfers & Subsidies	-										4,528,658
Gains & Losses	8,142,123	7,516,336	32,707,353		4,154,802					4,154,802	53,065,373
Disposal of Fixed & Intangible Assets	-	338,126	131,997								1,833,922
Fair Value Adjustment	-										-11,195,458
Impairment Loss	8,142,123	7,178,210	32,575,356		4,154,802					4,154,802	62,425,378
Other Receivables	-										3,745,967
Property, Plant & Equipment	-	45,290	7,021		2,232,428					2,232,428	2,789,447
Trade	8,142,123	7,132,920	32,568,335		1,922,374					1,922,374	55,889,965
Inventory	-										1,531
Reversal of Impairment Loss	-	-	-		-					-	-
Liabilities	-16,811,795	-31,420,108	-28,452,037	4,603,395	-65,415,236	-	-	59,055	-	-60,752,787	-371,038,027
Net Assets	25,662	3,657,071	2,795,111	-	1,552,646	-	-	631,042	-	2,183,689	-1,341,992,603
Accumulated Surplus/Deficit	25,662	3,657,071	2,795,111	-	1,552,646	-	-	631,042	-	2,183,689	-1,341,992,603
Revenue	-28,519,776	-142,600,886	-100,533,844		-84,873,618			-1,394,000		-86,267,618	-634,212,057
Exchange Revenue	-22,219,340	-18,085,565	-66,335,044		-81,735,917					-81,735,917	-207,613,814
Non-exchange Revenue	-6,300,436	-124,515,321	-34,198,800		-3,137,701			-1,394,000		-4,531,701	-426,598,243
Fines, Penalties & Forfeits	-				-7,701					-7,701	-342,734
Interest	-										-3,845,778
Licences or Permits	-										-1,265,973
Property Rates	-										-143,571,830
Property Rates by Usage	-										-1,356
Surcharges & Taxes	-5,680,436										-7,539,659
Transfers & Subsidies	-620,000	-124,515,321	-34,198,800		-3,130,000			-1,394,000		-4,524,000	-270,030,914
Grand Total	**79,028,882**	**235,029,044**	**239,735,673**	**-231,648,746**	**195,626,336**	**-1,147,870**	**-251,034**	**15,979,976**	**110,834,146**	**89,392,809**	**-26**
Total Cost	25,254,364	21,859,576	73,587,072	67,178,593	35,612,563	206,763	-	809,513	2,048,003	105,855,435	581,006,685
Total Revenue	-28,519,776	-142,600,886	-100,533,844	-	-84,873,618	-	-	-1,394,000	-	-86,267,618	-634,212,057
Net	-3,265,411	-120,741,310	-26,946,773	67,178,593	-49,261,055	206,763	-	-584,487	2,048,003	19,587,817	-53,205,373

The trial balance reflects a net loss of 23%. It also shows that an effort has been made to disaggregate electricity-related costs into the following categories:

- Bulk Purchase
- Administration
- Distribution HV
- Distribution LV
- Distribution Substation
- Street Lighting and Signal Systems

This categorisation could potentially support more accurate functional cost allocation. However, it is evident that many cost items, such as depreciation and employee-related expenses, have not been appropriately allocated to their respective functions, limiting the usefulness of the current structure.

At this stage, the only adjustment made is the removal of Transfers and Subsidies related to substations. These represent capital grants and should be offset against capital expenditure, rather than included in the electricity revenue requirement.

The next step involves determining the appropriate overhead contribution from the electricity function. The process of allocating overhead costs across municipal departments is illustrated in Figure 5. It outlines:

- Inter-departmental charges, which are largely accounted for through existing mechanisms.
- The allocation of general overheads to the various line functions.

Line functions refer to direct service delivery, including:

- Trading services, such as electricity and water, which are expected to be fully cost-recovering.
- Non-trading services, such as community facilities, which are typically subsidised through general municipal revenue.

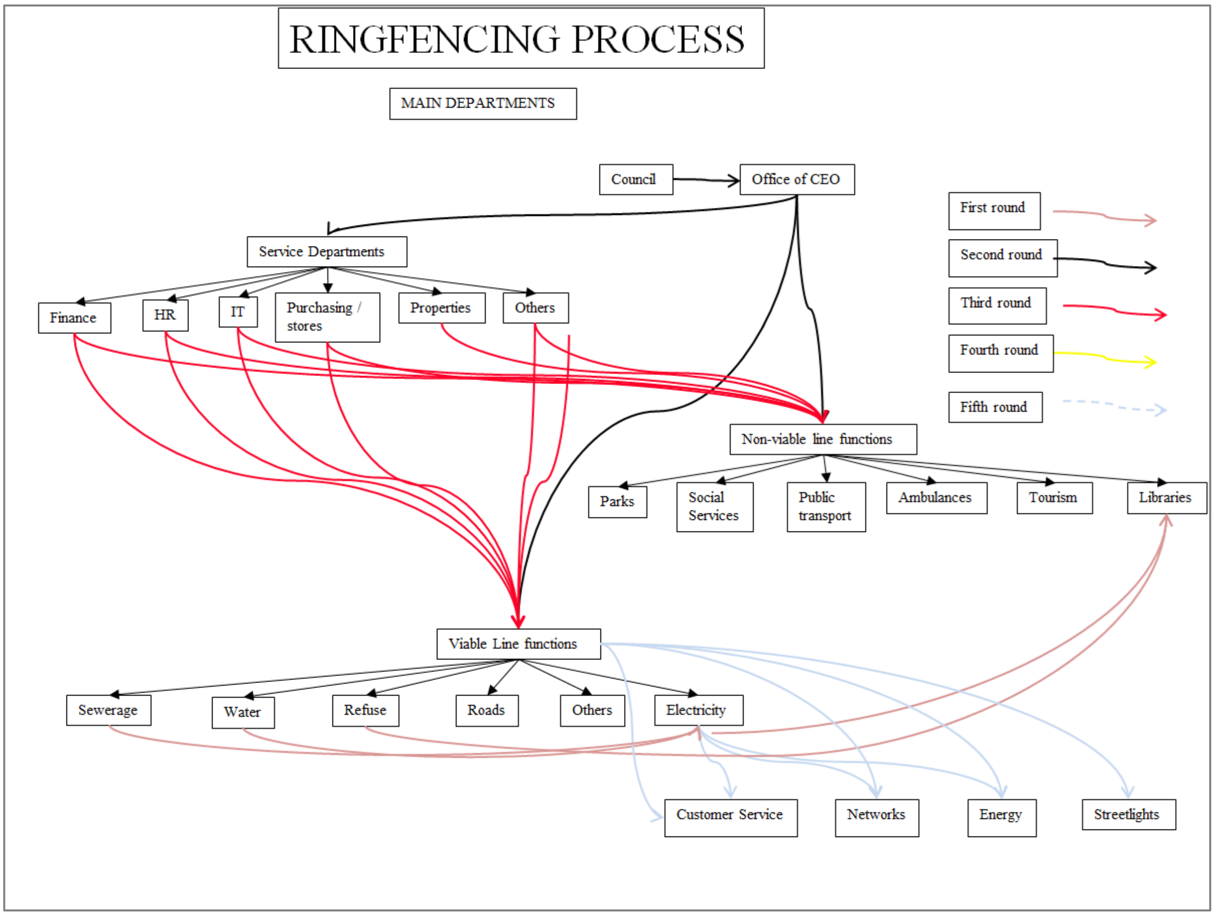


Figure 5. Ringfencing process

The allocation process relies on a range of allocation factors to distribute overhead costs. The calculated values for each factor, based on available data, are presented in Table 13.

Table 13. Ringfencing allocation factors

Allocation factors to all line departments	Housing	Other	Community & Social Services	Public Safety	Road Transport	Sport & Recreation	Waste	Waste Water	Water	Energy	Grand Total
Total cost (purchases)	4,178,263	2,785,302	11,648,316	14,989,210	58,359,552	14,672,531	25,254,364	28,992,495	51,569,654	21,492,346	233,942,034
Ratio	1.79%	1.19%	4.98%	6.41%	24.95%	6.27%	10.80%	12.39%	22.04%	9.19%	100.00%
Exchange revenue	-354	-3,685,609	-576,282	-6,864	-49,600	-257,153	-22,219,340	-18,085,565	-66,335,044	-81,735,917	-192,951,728
Ratio	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Trade and other payable transactions	109,036	123,872	2,090,041	-6,191	453,492	-291,605	162,343	-6,192,246	8,347,484	3,976,535	8,772,762
Ratio	1.24%	1.41%	23.82%	0.00%	5.17%	0.00%	1.85%	0.00%	95.15%	45.33%	100.00%
Number of customers / bills / vending							22,884	11,561	21,326	6,841	62,612
Ratio							36.55%	18.46%	34.06%	10.93%	100.00%
Number of meter readings p.a.									21,326	2,361	23,687
Ratio									90.03%	9.97%	100.00%
Employee related cost	2,311,913	2,411,726	7,791,857	11,825,849	35,441,417	9,892,762	12,285,054	8,819,498	10,666,338	988,087	102,434,502
Ratio	2.26%	2.35%	7.61%	11.54%	34.60%	9.66%	11.99%	8.61%	10.41%	0.96%	100.00%
Staff numbers	5	10	14	26	122	51	64	29	34	2	357
Ratio	1.40%	2.80%	3.92%	7.28%	34.17%	14.29%	17.93%	8.12%	9.52%	0.56%	100.00%
Property, plant & equipment	109,010	19,187	112,193,238	6,342,214	307,424,762	15,433,214	9,733,618	163,156,139	229,469,810	97,968,515	941,849,707
Ratio	0.01%	0.00%	11.91%	0.67%	32.64%	1.64%	1.03%	17.32%	24.36%	10.40%	100.00%
Depreciation & amortisation	-	-	147,987	14,127	14,254,378	452,828	187,518	5,771,465	14,912,662	3,755,448	39,496,413
Ratio	0.00%	0.00%	0.37%	0.04%	36.09%	1.15%	0.47%	14.61%	37.76%	9.51%	100.00%
Inventory consumed	19,956	83,288	814,835	864,829	6,089,635	579,690	2,469,602	1,908,610	32,529,410	157,695	45,517,550
Ratio	0.04%	0.18%	1.79%	1.90%	13.38%	1.27%	5.43%	4.19%	71.47%	0.35%	100.00%
Contracted services	1,436,054	239,915	2,110,843	1,627,381	2,392,270	2,995,831	7,082,996	2,761,400	9,271,119	16,580,162	46,497,970
Ratio	3.09%	0.52%	4.54%	3.50%	5.14%	6.44%	15.23%	5.94%	19.94%	35.66%	100.00%

The allocation ratio is calculated by dividing the amount attributed to each line function by the total amount for all line functions. This results in a comprehensive set of allocation factors, although not all of them need to be used. These factors depend on the availability and reliability of the underlying data used in their calculation.

The next step is to determine the most appropriate allocation factor for each Head Office department. The selected factors and the corresponding amounts allocated to each line function are presented in Table 14.

Table 14. Ringfencing head office allocation factors

Allocation to Line Departments			Mayor & Council	Executive & Council	Administrative & Corporate Support	Asset Management	Finance	Fleet Management	Human Resources	Marketing; Customer Relations	Security Services	Supply Chain Management	Valuation Service	Finance & Administration	Internal Audit	Planning & Development	Environ-mental Protection	Health
Executive & Council	R4.5 mill by equitable share	100%	-3,979,006															
Rest of Exec & Council	Total cost (excl. Purchases)	100%		-32,782,570														
Asset Management	Asset values	100%				-1,207,222												
Fleet Management	Total cost (excl. Purchases)	100%						-7,963,602										
Human Resources	HR costs	50%							-10,241,679									
Human Resources	HR numbers	50%							-10,241,679									
Security Services	Total cost (excl. purchases)	100%									-9,523,366							
Supply Chain Management	Inventory consumed	50%										-1,979,229						
Supply Chain Management	Contracted services	50%										-1,979,229						
Valuation Service	Not allocated	0%																
Rest of Finance & Administration	Covered by rev	0%																
Internal Audit	Total cost (excl. purchases)	100%													-8,097,633			
Planning & Development	Asset values	100%														-19,323,829		
Environmental Protection	Total cost (excl. purchases)	100%															-1,774,172	
Health	Total cost (excl. purchases)	100%																-3,912,810
New Cost After Allocation			**8,943,000**	**8,922,006**	**13,234,464**	**90,798**	**33,751,177**	**-**	**308,522**	**432,393**	**-**	**-**	**1,271,995**	**172,203,502**	**-**	**5,173,697**	**1,188,893**	**-1,779,507**
New Revenue			**-4,443,000**	**-4,943,000**	**-**	**-90,798**	**-232,706,823**	**-**	**-308,522**	**-**	**-**	**-**	**-**	**-233,106,143**	**-**	**-5,173,697**	**-1,188,893**	**1,779,507**
New Net Income			**4,500,000**	**3,979,006**	**13,234,464**	**-**	**-198,955,646**	**-**	**-**	**432,393**	**-**	**-**	**1,271,995**	**-60,902,640**	**-**	**-**	**-**	**-**

The following points should be noted in this regard:

- R4.5 million of the Executive and Council expenditure is funded through the Equitable Share, with the remaining amount allocated.
- Valuation Services are not allocated to service departments, as they directly support the property rate’s function and should therefore be fully covered by rates revenue.

Based on these adjustments, the overhead allocation to the electricity department amounts to R9,301,830, which represents 43% of electricity’s own costs (excluding bulk purchases).

8.3.2 Revenue Requirement

Now that the electricity-related overhead costs have been established, the total revenue requirement can be determined. Table 15 presents the calculation of the correct cost base and the corresponding full electricity revenue requirement.

Table 15. Revenue requirement after overheads allocation

Cost adjustments	Actual	Limit	Total	Adjust	Corrected data
Eskom losses exceeding (only Nersa method)	17.9%	8%	R14,833,317,525	-R1,462,683,728	R13,370,633,797
Eskom interest	R5,000,000	0%	R5,000,000	-R5,000,000	R0
Eskom excess access charges	R2,000,000	0%	R2,000,000	-R2,000,000	R0
Bad debt >5% of revenue	7.0%	5%	R170,000,000	-R3,400,000	R166,600,000
Shared cost >30% of own cost	34.0%	30%	R1,487,020,009	-R64,980,818	R1,422,039,192
Cost adjustment excluding Eskom				**-R75,380,818**	**R1,588,639,192**
Revenue adjustments	**Actual trial balance**	**Limit**	**Allowed/correct**	**Adjust**	**Corrected data**
Availability charges	-	N/A	-R11,000,000	-R11,000,000	-R11,000,000
Capital (monetary)	R410,551,454	Zero	R0	-R410,551,454	R0
Interest dividends & rent on land	-R104,262,734	N/A	-R104,262,734	R0	-R104,262,734
Operational (monetary)	-R817,079,203	N/A	-R817,079,203	R0	-R817,079,203
Operational revenue	-R8,473,950	N/A	-R8,473,950	R0	-R8,473,950
Rental from fixed assets	-R6,052,571	N/A	-R6,052,571	R0	-R6,052,571
Sales of goods & rendering of services	-R7,441,639	N/A	-R7,441,639	R0	-R7,441,639
Service charges	-R18,270,852,020	N/A	-R18,270,852,020	R0	-R18,270,852,020
Revenue adjustments	R89,284,008	N/A	R89,284,008	R0	R89,284,008
FBE income foregone	R15,000,000	N/A	R15,000,000	R0	R15,000,000
Equitable share (for own FBE)	-R10,000,000	Equal to FBE	-R15,000,000	-R5,000,000	-R15,000,000
Equitable share (for Eskom)	-R3,000,000	Zero	R0	R3,000,000	R0
Interest on deposits	-	N/A	-R9,000,000	-R9,000,000	-R9,000,000
Additional equitable share to cover operations	-R5,000,000	Zero	R0	R5,000,000	R0
Other income		N/A	R0	R0	R0
CoS streetlight revenue	-	N/A	-R654,020,997	-R654,020,997	-R654,020,997
Traffic light revenue	-	N/A	-R5,000,000	-R5,000,000	-R5,000,000
CoS internal tariffs	-R2,000,000	N/A	-R7,000,000	-R5,000,000	-R7,000,000
Revenue adjusted for high losses			N/A	-R1,801,652,118	-R1,801,652,118
Total revenue	**-R18,719,326,654**			**-R2,893,224,569**	**-R21,612,551,224**

The following adjustments have been made to calculate a more accurate and cost-reflective electricity revenue requirement, as shown in Table 16:

- The municipality provides free basic services to indigent consumers, including 50 kWh/month and the value of the basic charge. The value of this subsidy has been calculated and included below. However, the actual Equitable Share allocation for this purpose amounts to only R3.2 million, resulting in a funding gap.
- Internal electricity charges to other municipal departments are not reflected in the trial balance. The amounts calculated in the Cost of Supply study have therefore been added.
- In line with the EPP, which states that only prudent costs should form the basis for tariff-setting, the following further adjustments were applied:
  - Total losses are capped at 8%, in alignment with NERSA's benchmark range of 8% to 12%. Since technical losses should not exceed 5%, this allows for some level of non-technical losses (approximately 3%). Any losses exceeding 8% have been adjusted out of the bulk purchase costs.
  - Interest on Eskom arrears is excluded, as it is not considered a prudent cost. The municipality should not be in arrears with its Eskom account.
  - No Excess Access charges have been incurred and thus no adjustment is required in this regard.
  - Bad debt levels fall within NERSA's benchmark of 5% of revenue, so no adjustment is needed.
  - Overhead (shared) costs are beyond this author's acceptable threshold of 30% of own costs (i.e., total costs excluding bulk purchases) and was therefore adjusted downwards.

The resulting adjusted revenue requirement is presented in Table 16.

Table 16. Revenue requirement after adjustments for prudency

Corrected Nersa revenue requirement for cost of supply	Nersa method	CRC depreciation, adjusted revenue	Description
Bulk (excluding high losses and excess access)	R13,368,633,797	R14,831,317,525	Bulk (total excluding excess access)
Operating cost	R541,414,177	R541,414,177	Operating cost
Shared cost	R1,487,020,009	R1,422,039,192	Shared cost adjusted to 30% of own cost
Depreciation historic	R553,946,571	R2,054,204,601	CRC depreciation
Interest (excluding Eskom)	R0	R0	Interest excluding Eskom
Repairs and maintenance (actual)	R1,577,541,507	R1,577,541,507	Repairs & maintenance actual
Bad debt written off (this is not a cost)	R166,600,000	R166,600,000	Bad debt written off (<5%)
Sub-total cost	R17,695,156,062	R20,593,117,002	Sub-total cost
Surplus at 10%	R1,769,515,606	R0	
Total allowed revenue	R19,464,671,669	R20,593,117,002	Total allowed revenue
Actual revenue	-R18,719,326,654	-R21,612,551,223	Adjusted revenue
Shortfall	R745,345,014	-R1,019,434,221	Shortfall
Structure increase	4.0%	-4.70%	Structure increase

Key Conclusions

- A 10% surplus, amounting to R1.7 billion when calculated using the NERSA method, is closely aligned with the CRC depreciation figure of R2.05 billion. This suggests that the NERSA surplus benchmark is not necessarily excessive when depreciation is properly accounted for.
- When using the NERSA methodology without adjustments, the results indicate a required tariff increase of 4%. However, when applying the proposed adjusted methodology, the analysis shows that tariffs should decrease. This supports the argument that municipalities may be overcharging consumers in some cases, although this is not universally true.

It is important to note that this analysis determines the overall annual price increase, not the specific tariff structures, which must still be addressed through a separate cost-reflective tariff design process.

8.3.3 Assets

The municipality's asset register was analysed to support the valuation of infrastructure assets. The register provides the original cost and commissioning date for each asset, which were used to escalate the values to 2024 Rand terms. These updated values were then benchmarked against typical CRC values to assess reasonableness. Adjustments were made where necessary to align the asset values with appropriate cost norms.

Subsequently, all assets were grouped according to the Simplified Representative Network model. The resulting valuations are presented in Table 17.

Table 17. Asset register costs

Sum of quantity	Sum of quantity	Service connection	Meter incl. installation	CRC	Life expectancy (years)	CRC depreciation	ROA @ 3.5%	Total capex provision	Current depreciation	Current interest	Total current provision	Capital ratios
Energy					15	-	-	-	-	-	-	0.0%
HV					50	-	-	-	-	-	-	0.0%
HV/MV					50	-	-	-	-	-	-	0.0%
MV	401			205,607,671	45	4,569,059	7,196,268	11,765,328	646,871	-	646,871	17.2%
MV to LV	1,880			196,676,167	40	4,916,904	6,883,666	11,800,570	696,118	-	696,118	18.5%
LV	2,397			42,108,949	35	1,203,113	1,473,813	2,676,926	170,333	-	170,333	4.5%
1-ph kWh pre-paid	14,378	8,000	1,400	135,153,200	10	13,515,320	4,730,362	18,245,682	1,913,452	-	1,913,452	51.0%
3-ph kWh pre-paid	1	10,000	2,500	12,500	10	1,250	438	1,688	177	-	177	0.0%
1-ph kWh	6,115	6,000	1,000	42,805,000	30	1,426,833	1,498,175	2,925,008	202,006	-	202,006	5.4%
3-ph kWh	442	10,000	2,000	5,304,000	30	176,800	185,640	362,440	25,031	-	25,031	0.7%
3-ph TOU	283	20,000	10,000	8,490,000	30	283,000	297,150	580,150	40,066	-	40,066	1.1%
3-ph TOU & CTs	1	12,000	15,000	27,000	30	900	945	1,845	127	-	127	0.0%
TOU RMU & CT/VTs	5	450,000	20,000	2,350,000	30	78,333	82,250	160,583	11,090	-	11,090	0.3%
TOU at HV sub with CB	1	950,000	20,000	970,000	30	32,333	33,950	66,283	4,578	-	4,578	0.1%
Streetlight	778			4,831,184	15	322,079	169,091	491,170	45,599	-	45,599	1.2%
Total	26,682			644,335,671		26,525,925	22,551,748	49,007,674	3,755,448	-	3,755,448	100.0%

Consumer connection costs were calculated using per unit costs and the number of connected consumers, as the asset register does not provide complete information in this area. The CRC depreciation and Return on Assets were then adjusted to reflect the actual interest and depreciation costs per category. The CRC depreciation is used as the basis for determining the required electricity surplus.

8.3.4 Cost Allocation

The process of calculating the cost of supply per tariff category is both comprehensive and complex. For the purposes of this paper, the detailed methodology is not presented. Instead, only the results are shown to highlight key issues related to the provision of electricity as a public service. A summary of the costs per tariff category is provided in Table 18.

Table 18. Costs per tariff category

2023/2024				**Eskom adjust**			0.0%
COSTS PER TARIFF CATEGORY				**Cost increase**			5.0%
				+ Surplus			9.1%
FOR ALL LOAD FACTORS							
			Access	**Demand**	**Peak**	**Standard**	**Off-peak**
High season	Access/Demand	R/kVA/m	47.31	59.24			
	Energy	c/kWh			6.2225	1.8848	1.0237
Low season	Access/Demand	R/kVA/m	47.31	59.24			
	Energy	c/kWh			2.0296	1.3969	0.8858
	Super peak	c/kVArh					
Fixed charges (R/m)		R/m					
Reactive energy - Hi	Total excess for year	c/kVArh	0.2739				
Transmission network		R/m					
National levies		c/kWh	0.1594				
TOTAL COSTS PER SUPPLY POSITION			**Acc %**	**Acc**	**DM**		
Total network charges (including losses)				R/kVA/m	R/kVA/m	c/kWh	R/pod/m
		Total losses		All	All	All	
S0		0.00%				0.00	0.00
S1	Non-tech	0.00%		0.00		0.00	0.00
S2		0.00%		0.00	0.00	0.00	0.00
S3		1.12%		0.00	0.00	0.00	0.00
S4		3.02%		30.08	34.13	0.00	0.00
S5		5.33%		63.36	71.37	0.00	0.00
S6		10.06%		90.47	101.87	0.00	0.00
S7 Lights		10.10%		90.47	101.87	0.00	216.96
Metering	**R/C/m**						
1; 1-ph kWh Pre-paid	37.25						
2; 3-ph kWh Pre-paid	57.82						
3; 1-ph kWh	27.74						
4; 3-ph kWh	46.38						
5; 3-ph TOU	177.46						
6; 3-ph TOU & CTs	258.12						
7; TOU RMU & CT/VTs	538.87						
8; TOU at HV sub with CB	845.19						
9; N/A	0.00						
10; 0	0.00						
Average	36.74						
Billing/cust. service	**R/C/m**						
1; Small <50 kVA	25						
2; Medium <500 kVA	127						
3; Large <2000 kVA	255						
4; Very large >2000kVA	0						
5; N/A							
N/A	27						

The costs per tariff category, together with sales data, are used to calculate the Cost of Supply results for the representative municipality. These results are presented in Table 19.

Table 19. Cost of supply results

Tariff name	Cost	Tariff revenue	Overcharge (Rands)	Overcharge (+% of tariff)
Domestic Indigent PP	7,408,612	3,262,842	-4,145,770	-127.1%
Domestic Indigent Conv	118,685	29,104	-89,581	-307.8%
Domestic 20A PP	8,431,104	5,095,997	-3,335,107	-65.4%
Domestic 20A Conv	8,215,442	10,282,310	2,066,868	20.1%
Domestic >20A PP	13,260,634	13,381,353	120,719	0.9%
Domestic >20A Conv	17,841,423	18,368,715	527,292	2.9%
Commercial PP	5,965,299	7,609,400	1,644,101	21.6%
Commercial Conv	13,884,260	15,668,376	1,784,116	11.4%
Bulk TOU LV	17,175,525	14,298,519	-2,877,006	-20.1%
Bulk TOU MV	10,639,795	8,784,860	-1,854,935	-21.1%
Streetlighting	8,913,564	-	-8,913,564	
Availability	4,863,235	4,666,652	-196,583	-4.2%
Municipal	5,282,581	-	-5,282,581	
Total	122,000,160	101,448,129	-20,552,031	-20.3%

The costs per tariff category are then adjusted to align with the actual revenue, which is calculated by multiplying the applicable tariff by actual consumption, along with relevant adjustments. The final results of this reconciliation are shown in Table 20.

Table 20. Target revenue

	2023/24
Previously calculated revenue	101,448,129
Plus income foregone 2022/2023	6,307,379
Plus internal sales	5,319,439
Plus additional streetlighting revenue	8,925,213
Total	122,000,160

Table 21 presents the costs under the current tariff structure, highlighting which specific charges contribute most significantly to revenue imbalances or distortions.

Table 21. Costs per current tariff charge

	Tariffs (2023/24)							Simplified Costs (2023/24)		
Tariff charges	Basic	MD (all hours)	All energy	Block 1 kWh	Block 2 kWh	Block 3 kWh	Block 4 kWh	Basic	Demand	kWh all
Tariff name	R/POS/m	R/kVA/m	R/kWh	50	350	600	>600	R/month	R/kVA	R/kWh
Domestic Indigent PP					2.00	2.82	3.30			3.24
Domestic Indigent Conv					2.00	2.82	3.30			5.82
Domestic 20A PP				1.56	2.00	2.82	3.30			3.20
Domestic 20A Conv	346.91			1.56	2.00	2.82	3.30	231.00		3.16
Domestic >20A PP	346.91			1.56	2.00	2.82	3.30	577.00		2.98
Domestic >20A Conv	346.91			1.56	2.00	2.82	3.30	726.00		2.94
Commercial PP	622.08		2.76					689.00		1.87
Commercial Conv	622.08		2.76					1,363.00		1.87
Bulk TOU LV	1,413.86	207.82	2.16					838.00	494.27	1.77
Bulk TOU MV	1,277.04	169.54	1.82					788.00	335.04	1.74
Streetlight								266.00		1.89
Availability	346.91							362.00		
Municipal								4,624.00		2.02

The results reveal the following key issues:

- Energy charges for consumers without fixed charges, particularly those on the first IBT tiers, are significantly too low.
- For other consumer categories, energy rates are too high, while fixed charges remain too low, leading to tariff imbalances and misaligned cost recovery.

Table 22 presents an analysis of the marginal bulk supply costs for domestic consumers, based on their load profile data and modelled against the Eskom Megaflex tariff. The findings further confirm that current energy charges are set below the actual cost of supply.

Table 22. Marginal bulk supply costs for domestic consumers

Demand charges (R/kVA/m)	2023/24
Transmission network charges	14.72
Distribution charges	
Network capacity charge	28.65
Network demand charge	54.31

Energy charges (c/kWh)	Time	Energy	Ancillary services	Electrification & rural network subsidy	Total
High demand season (Jun - Aug)	Peak	570.45	0.71	13.90	585.06
	Standard	172.79	0.71	13.90	187.4
	Off-peak	93.85	0.71	13.90	108.46
Low demand season (Sep - May)	Peak	186.06	0.71	13.90	200.67
	Standard	128.06	0.71	13.90	142.67
	Off-peak	81.21	0.71	13.90	95.82

Domestic characteristics									
Season	High			Low			Monthly load factor	Annual load factor	Losses
Time	Peak	Standard	Off-peak	Peak	Standard	Off-peak			
Month	kWh (for)	kWh (for)	kWh (for)	kWh (for)	kWh (for)	kWh (for)			
Load profile	5%	15%	18%	9%	23%	30%	11.0%	7.0%	10.06%

Effective cost	Transmissions network charges	Distribution network charges		Energy high season			Energy low season			Reactive energy	Energy sub-total	Total
		Network capacity charge	Network demand charge	Peak	Standard	Off-peak	Peak	Standard	Off-peak			
Charge unit	R/kVA/m	R/kVA/m	R/kVA/m	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh
Eskom charges	14.72	28.65	54.31	585.06	187.40	108.46	200.67	142.67	95.82	19.51		
Cost	33.114	38.652	73.271	34.250	30.040	22.080	18.970	36.810	31.210	-	173.350	318.390

8.3.5 Subsidies

The study clearly demonstrates that low-usage consumers are being undercharged. This raises a critical policy question: Should these consumers be required to pay cost-reflective tariffs, or should subsidies continue to be applied to support affordability? To explore this further, Table 23 presents a more detailed analysis of the subsidised consumer segments, highlighting the extent and distribution of current subsidies.

Table 23. Subsidy analysis

Tariffs to be subsidised	Customers	Total cost	Current revenue	Shortfall	Equitable share	Subsidy	Subsidy (%)
Domestic indigent prepaid	1,150	7,408,612	3,262,842	4,145,770	3,137,701	1,008,069	14%
Domestic indigent conventional	95	118,685	29,104	89,581		89,581	75%
Domestic 20A prepaid	1,172	8,431,104	5,095,997	3,335,107		3,335,107	40%
Total		15,958,401	8,387,943	7,570,458	3,137,701	4,432,757	28%
Total revenue excl. subsidy customers		93,060,186					
Total subsidy as share of base revenue						4.76%	

The following key points should be noted:

- Indigent consumers would face significantly higher charges if required to pay fully cost-reflective tariffs.
- All consumers using less than 350 kWh/month are generally considered low-income and should be viewed as eligible for some form of subsidy.

Figure 6 illustrates the relationship between cost and revenue across different domestic tariff structures. The following observations can be made:

- The existing domestic tariff with a basic charge closely aligns with the cost of supply for a 20 Amp connection up to approximately 350 kWh/month and begins to break even at higher consumption levels for higher-capacity connections.
- In contrast, the existing domestic tariff without fixed charges only reaches cost recovery for 20 Amp consumers at around 650 kWh/month, indicating significant under-recovery at lower usage levels.

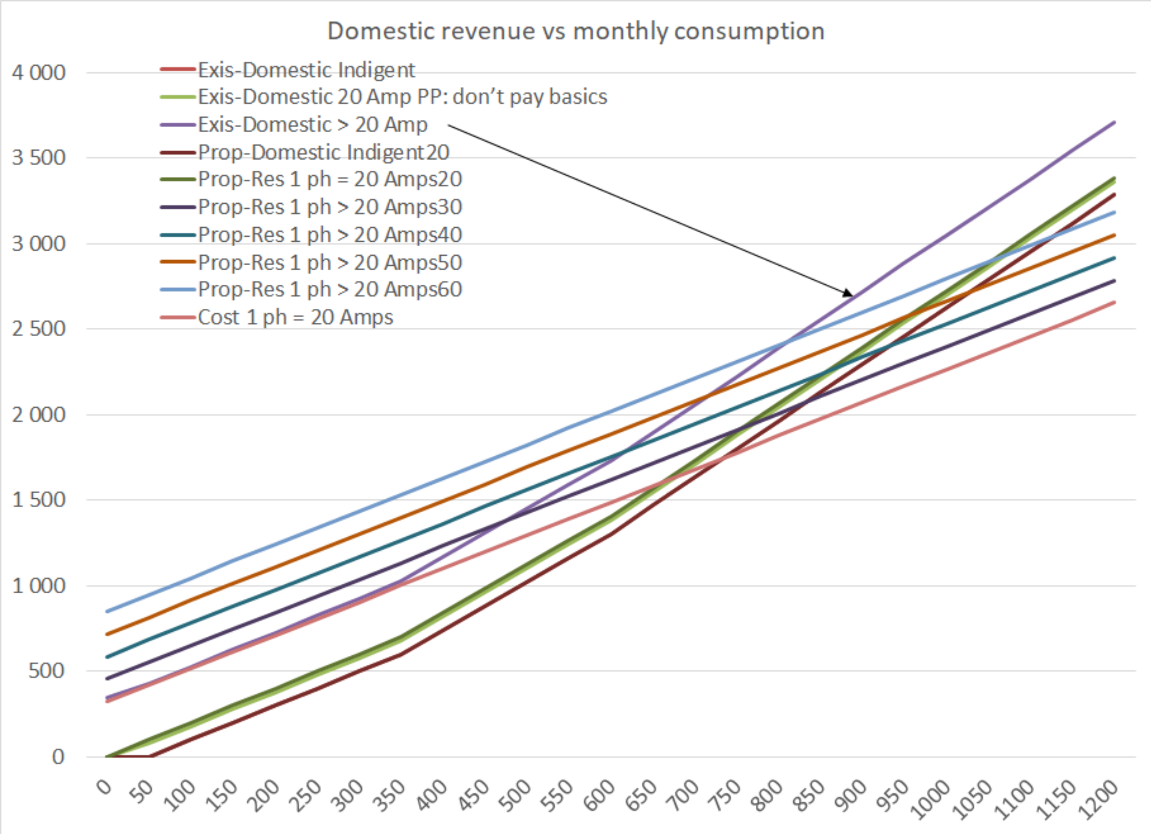


Figure 6. Revenue from domestic consumers at various monthly consumption levels

Figure 7 presents the cost of supply and proposed tariff for a 20 Amp connection. It highlights the presence of a cross-subsidy at low consumption levels, where consumers pay less than the cost of supply, and an overcharge at higher consumption levels, where tariffs exceed the actual cost.

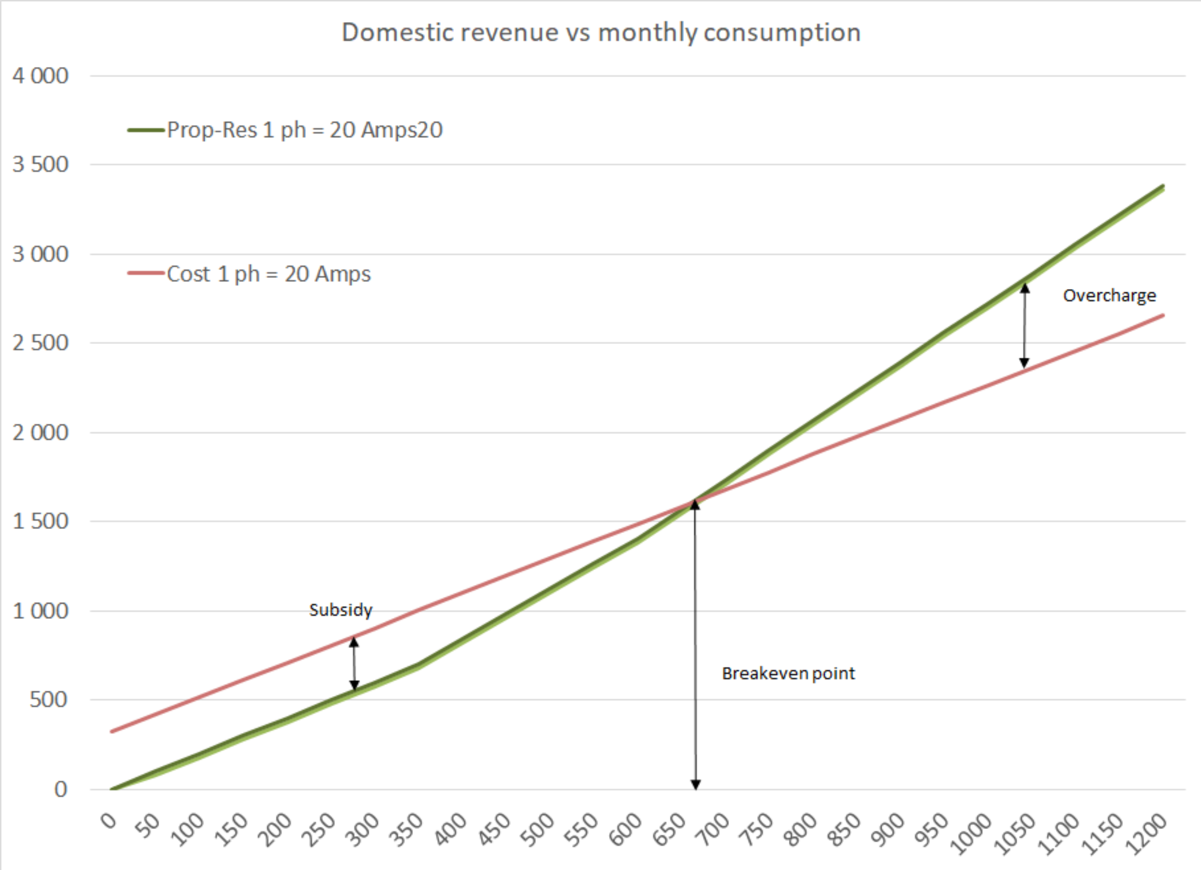


Figure 7. Revenue from 20A domestic consumers at various monthly consumption levels

This provides a clear illustration of why significant cross-subsidies exist for consumers without fixed charges and with low levels of consumption. The break-even point, where the revenue matches the cost of supply, occurs at a much higher consumption level than the proposed 350 kWh/month threshold.

Figure 8 shows the frequency distribution of non-indigent consumers, revealing that fewer than 100 consumers use more than 650 kWh/month, the level required to reach cost recovery under the current tariff structure without fixed charges.

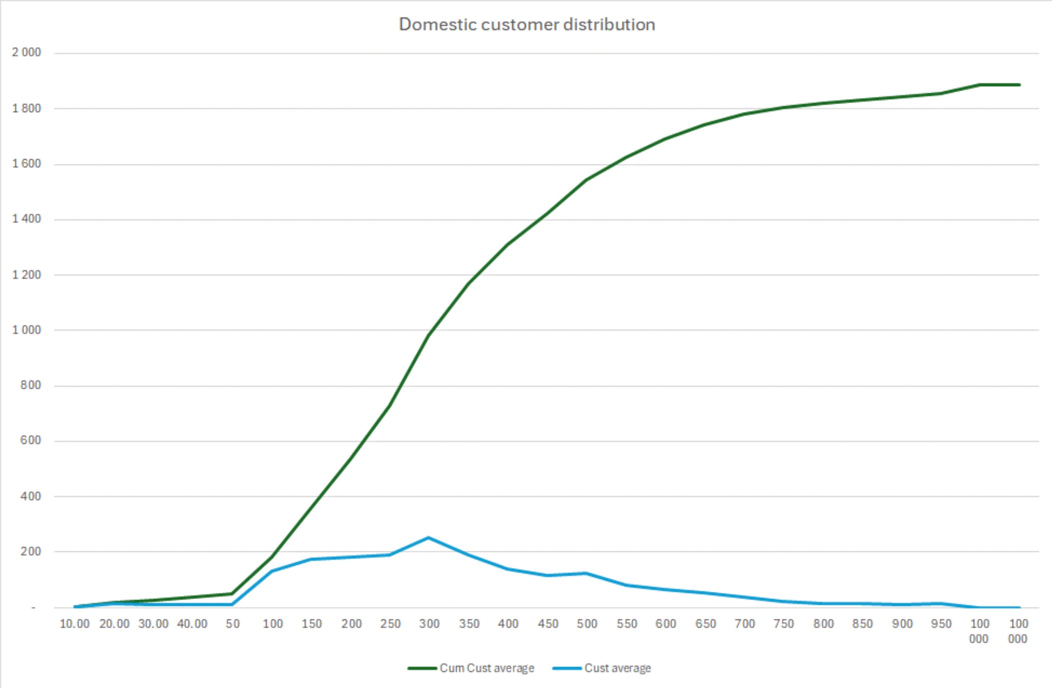


Figure 8. Domestic customer distribution

8.4 Analysis of Cooking and Space Heating: Gas vs Electricity

This section examines a critical aspect of energy as a public service: the relative cost of providing essential energy services, such as cooking, using either electricity or gas.

To support this analysis, simulated cooking load profiles for both high-demand (winter) and low-demand (summer) periods under the Eskom Megaflex tariff are presented in Figure 9 and Figure 10, respectively.

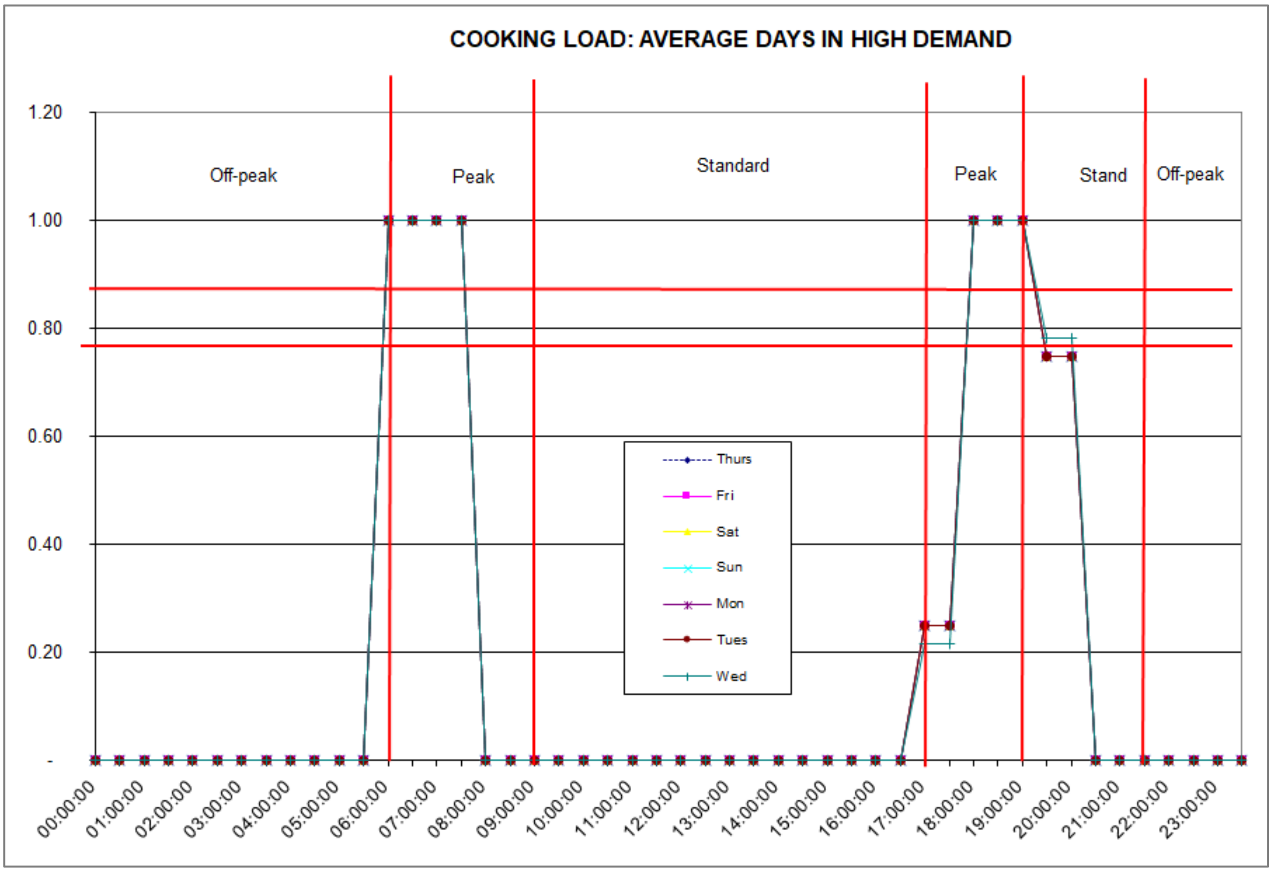


Figure 9. Simulated cooking load in high demand season

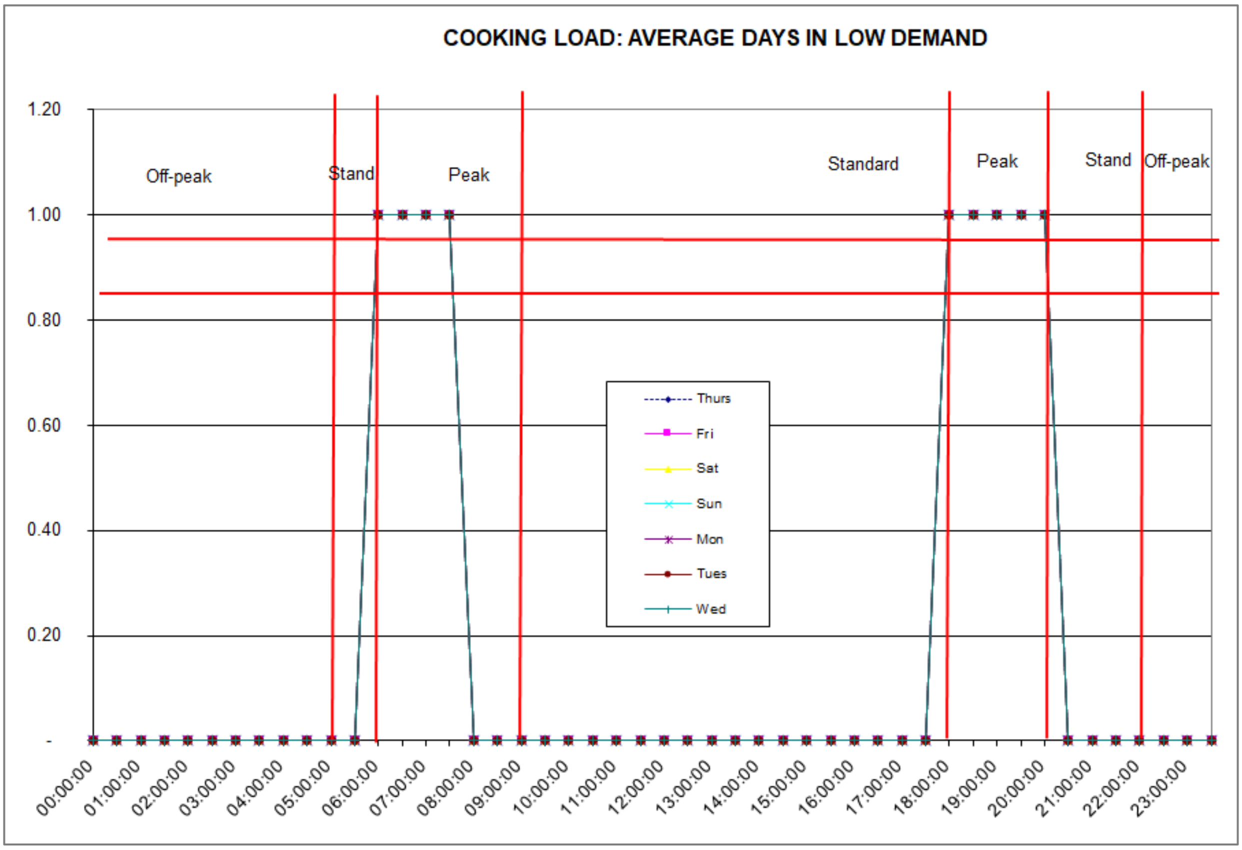


Figure 10. Simulated cooking load in low demand season

A space heating profile was also simulated, assuming four hours of use per day during the high-demand (winter) period only. The corresponding TOU billing quantities were then calculated and applied to the Eskom Megaflex tariff at 11 kV in Johannesburg. The results are presented in Table 24.

The analysis demonstrates that cooking and space heating loads are problematic for electricity supply, for several reasons:

- A large share of consumption for both cooking and space heating occurs during peak demand periods, placing additional strain on the grid.
- Space heating demand is concentrated in the high-demand (winter) period, further intensifying load pressures during the highest-demand period of the year.
- The annual load factors for these applications are extremely low, 19% for cooking and just 4% for space heating, indicating that the network must be available year-round for utilisation during only a small portion of the time.

Financially:

- The Eskom purchase cost for electricity during peak periods exceeds the average selling price of at least the first two IBT block prices.
- As a result, utilities incur financial losses when selling electricity for cooking and space heating.

Environmentally, the carbon footprint of supplying electricity for these applications is higher than average, especially during peak periods, due to:

- Limited availability of solar PV in the evenings and winter months.
- Reliance on older, less efficient coal-fired power stations.
- Use of gas turbines.
- Operation of pumped storage systems, which add at least 20% more emissions compared to the average, due to energy conversion efficiencies of only 70–80%.

To compound the issue, the conversion efficiency of electricity to useful cooking energy is often low, especially when compared to more direct energy sources like gas.

Table 24. Analysing impact of space heating load on cost

Demand charges (R/kVA/m)	2023/24
Transmission network charges	14.72
Network capacity charge	28.65
Network demand charge	54.31

Energy charges (c/kWh)	Time	Energy	Ancillary services	Electrification & rural network subsidy	Total
High demand season (Jun - Aug)	Peak	570.45	0.71	13.90	585.06
	Standard	172.79	0.71	13.90	187.4
	Off-peak	93.85	0.71	13.90	108.46
Low demand season (Sep - May)	Peak	186.06	0.71	13.90	200.67
	Standard	128.06	0.71	13.90	142.67
	Off-peak	81.21	0.71	13.90	95.82

Domestic characteristics										
Season	High			Low			Monthly load factor	Annual load factor	Reactive energy	Losses
Time	Peak	Standard	Off-peak	Peak	Standard	Off-peak				
Month	kWh (for)	kWh (for)	kWh (for)	kWh (for)	kWh (for)	kWh (for)			% of kWh	
Res	4%	12%	10%	13%	31%	31%	47.7%	42.4%	5.57%	10.00%
Cooking	16%	4%	5%	34%	25%	15%	18.9%	18.8%	0.00%	10.00%
Space heating	29%	49%	22%	0%	0%	0%	16.8%	4.2%	0.00%	10.00%

Effective cost	Transmissions network charges	Distribution network charges		Energy high season			Energy low season			Reactive energy	Energy sub-total	Total
		Network capacity charge	Network demand charge	Peak	Standard	Off-peak	Peak	Standard	Off-peak			
Charge unit	R/kVA/m	R/kVA/m	R/kVA/m	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh
Eskom charges	14.72	28.65	54.31	585.06	187.40	108.46	200.67	142.67	95.82	19.51		
Res	5.235	10.188	17.157	26.710	24.020	11.850	28.050	48.000	32.640	-	171.270	203.850
Cooking	11.830	23.025	43.291	99.910	8.850	6.430	75.800	39.270	16.270	-	246.520	324.670
Space heating	52.800	102.766	48.702	187.120	100.270	26.580	-	-	-	-	313.980	518.250

8.5 Cost of Supply and Pricing

This section outlines the process for calculating cost-reflective charges, beginning with the allocation of costs and followed by the pricing methodology used to set appropriate tariff levels.

8.5.1 Cost Allocation

Once the revenue requirement has been formalised, the approved costs can be allocated across customer and cost categories. The key objective of this analysis is to determine the cost breakdown for the functions of generation, transmission, distribution, customer service, and public lighting, as shown in Table 25.

Table 25. Cost functionalisation

Function	Activity/Cost
Generation	All costs associated with the production of electricity, including fuel, operations, and maintenance at generation facilities.
Transmission	Costs related to the transfer of electricity across long distances from generation points to local distribution networks, typically via high-voltage infrastructure.
Distribution	Costs incurred in delivering electricity from the transmission system to end-users through medium- and low-voltage distribution networks.
Customer-Related Cost	Costs linked to the number and type of customers served, including metering, billing, customer service, and account management.
Public lighting	Costs associated with the provision and maintenance of streetlights, high-mast lighting, and traffic signals, typically based on the number of luminaires.

These costs must be allocated to appropriate cost drivers, namely:

- Per kWh (energy consumption).
- Per kVA (demand and capacity).
- Per customer category.
- Per public lighting luminaire.

This allocation methodology is illustrated in Table 26. Network costs are generally allocated on a R/kVA basis, reflecting demand and capacity requirements. Only in the case of rural supply, where demand-based metering may not be feasible, can network costs be allocated per customer.

Table 26. Cost allocation by cost driver

COST ALLOCATIONS				
		c/kWH P/S/O	R/kVA P/S/O	R/cust
Purchases		yes	yes	no
Network costs				
	Capital	no	yes	yes
	Support	no	yes	yes
Customer services		no	no	yes

The distribution network costs must then be determined for each network level, as illustrated in Figure 11 and

Table 27.

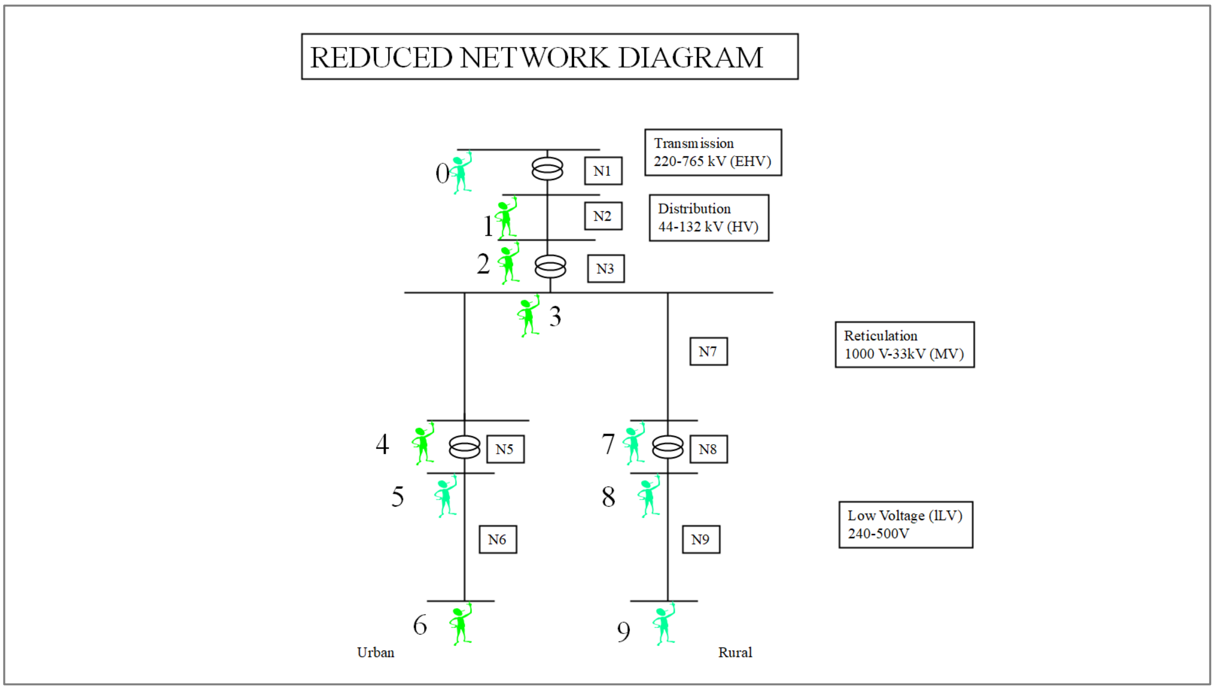


Figure 11. Allocating distribution costs to the network

Table 27. Allocating distribution costs to the network

Network Construction			
Primary description	**Secondary description**	**Network code**	**Voltage**
Transmission	N/A	N0	275, 400, 765 kV
Transmission to distribution transform	N/A	N1	>132 to 132 - 33 kV
Distribution	LG distribution	N2	132, 88, 66, 44, 33 kV
Distribution/reticulation transform	Distribution substations	N3	132 to 22, 11, 6.6 kV
Reticulation	Reticulation urban	N4	22, 11, 6.6 kV (incl. 22 to 11, 6.6 kV)
Reticulation/LV transform	Reticulation substations urban	N5	22, 11, 6.6 kV to 400 V
LV	LV urban	N6	400, 230 V

Once the costs have been determined per tariff category, they can be compared to the actual revenue generated under each tariff, thereby assessing the degree of cost reflectiveness. This is a highly complex process, and the pace of completing comprehensive cost of supply (COS) studies across the sector has been slow:

- In the past 20 years, only about 30 comprehensive COS studies have been completed and submitted to NERSA.
- In the early years, NERSA did not provide thorough evaluations of the studies, but approved some that were successfully implemented.
- In recent years, NERSA has improved its evaluation processes, but approval timelines remain lengthy, often taking months or even years.
- Some completed studies were of poor quality, and therefore were not accepted by municipalities or implemented.
- There is a shortage of capacity in the sector to conduct high-quality COS studies, which remains a significant challenge.

Despite these challenges, the completion of detailed COS and tariff studies is essential for accurately determining the true cost of supply, as well as the extent of subsidies and cross-subsidies in the electricity distribution sector.

Further analysis of the issues with the NERSA methodology is provided in Annexure 8.2 Analysis of NERSA Cost of Supply Framework, while Annexure 8.3 Illustrations includes illustrations from a typical cost of supply study.

8.5.2 Pricing

The NERSA COS guideline addresses the topic of rate setting, outlining a set of principles and objectives that should guide the process. These are summarised in Table 28.

Table 28. Cost of supply objectives

Stakeholder	Tariff objective	Description
Licensee	Cost-reflective	Tariffs should recover all prudently incurred costs and allow a reasonable return.
	Encourage efficient use	Tariffs should provide appropriate price signals to promote efficient energy use.
	Low implementation cost	The administrative burden and cost of implementation should be minimised.
Customer	Affordability	Tariffs should remain affordable, especially for low-income customers.
	Predictable and stable	Tariffs should be stable over time, enabling customers to forecast future costs.
	Transparent	Tariffs should be easy to understand and apply, with no hidden charges.

However, the guideline does not provide detailed guidance on how these principles and objectives should be practically implemented or addressed in tariff design.

9 References

Bekker & Gaunt, 2008	Bekker, B. and Gaunt, C.T., 2008. *Uncertainties within South Africa's goal of universal access to electricity by 2012*. Journal of Energy in Southern Africa, 19(2), pp.4–13.
DME, 2003	Department of Minerals and Energy (DME), 2003. *Electricity Basic Services Support Tariff (Free Basic Electricity) Policy for the Republic of South Africa*. Government Gazette, 457(25088), General Notice No. 1693 of 2003, 4 July 2003. Pretoria: Government Printer.
DME, 2007	Department of Minerals and Energy (DME), 2007. *Free Basic Alternative Energy Policy (Households Energy Support Programme)*. Pretoria: Department of Minerals and Energy.
DMRE, 2008	Department of Minerals and Energy, 2008. *Electricity Pricing Policy of the South African Electricity Supply Industry*. Government Gazette, 517(31741), Government Notice No. 1398 of 2008, 19 December 2008. Pretoria: Government Printer.
Eskom, 2010	Eskom, 2010. *Eskom Tariffs and Charges 2010/11: Charges for Non-Local Authorities and Local Authorities*. April 2010. Johannesburg: Eskom Holdings SOC Ltd.
Hughes & Larmour, 2021	Hughes, A. and Larmour, R., 2021. *Residential electricity consumption in South Africa*. Research Project Report. Cape Town: University of Cape Town, Energy Research Centre.
Masuku, 2024	Masuku, B., 2024. *Rethinking South Africa's household energy poverty through the lens of off-grid energy transition*. Development Southern Africa, 41(3), pp.467–484.
NERSA, 2018	National Energy Regulator of South Africa (NERSA), 2018. *Cost of Supply Framework for Licensed Electricity Distributors*. Pretoria: NERSA.
NPC, 2021	National Planning Commission (NPC) (2012), National Development Plan 2030: Our future – make it work. Pretoria: The Presidency.
PCC, 2023	Presidential Climate Commission (PCC), 2023. *Just Energy Transition (JET) Implementation Plan 2023–2027*. Pretoria: Presidential Climate Commission.
SABS, n.d.	South African Bureau of Standards (SABS), n.d. *Cost of Supply Methodology for Application in the Electrical Distribution Industry*. Pretoria: SABS.
Stats SA, 2023	Stats SA (Statistics South Africa), 2023. *Non-financial census of municipalities for the year ended 30 June 2022*. Pretoria: Statistics South Africa.
Van der Kroon, 2016	Van der Kroon, B., 2016. *Climbing the African energy ladder: internal and external factors influencing household demand for improved cookstoves and modern fuels in sub-Saharan Africa*. PhD thesis. Vrije Universiteit Amsterdam.
Wernecke et al., 2024	Wernecke, B., Langerman, K.E., Howard, A. and Wright, C., 2024. *Fuel switching and energy stacking in low-income households in South Africa: A review with recommendations for household air pollution exposure research*. Energy Research & Social Science.

PRESIDENTIAL
CLIMATE COMMISSION
TOWARDS A JUST TRANSITION

UK PACT

SEA