Eskom retail tariff plan for the restructuring of Eskom tariffs

For implementation 2023/24

Submission to NERSA

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Contents

1. Executive summary 7

2. Steps to determine retail tariffs 12

2.1. The determination of approved revenue by the regulator 12

2.2. The allocation of approved revenue though a cost-of-supply (or cost-to-serve(CTS)) study. 12

2.3. Tariff design 14

3. The relationship between wholesale purchases and retail tariffs 15

4. The relationship between volume risk and tariff structures 17

5. Impact on tariffs because of changing electricity industry 19

5.1. Eskom-proposed changes to the tariffs and their charges 21

5.2. How the standard tariff charges have been calculated 24

5.3. TOU changes 26

5.3.1. TOU proposed period changes 27

5.3.2. TOU proposed peak, standard, and off-peak rate changes: 27

5.4. Introduction of a fixed charge for the provision of generation capacity applicable to loads, the generation capacity charge 28

5.4.1. How the generation capacity charge is derived from costs 29

5.4.2. Allocation of generation capacity costs 30

5.4.3. How the retail generation capacity charge is calculated and charged 30

5.5. Municipal tariff rationalisation 30

5.6. Distribution network-related charges 32

5.6.1. Distribution use-of-system (DUoS) network charges 32

5.6.2. Distribution use-of-system loss factors 34

5.7. Transmission network-related charges 34

5.7.1. Transmission use-of-system (TUoS) charges 34

5.7.2. Transmission network charges for generators 35

5.7.3. Transmission network charges for loads 36

5.7.4. Transmission losses 37

5.7.4.1. Transmission losses payable by loads 38

5.7.4.2. Transmission losses payable by Transmission-connected generators 38

5.8. Ancillary service charges 39

5.9. Residential tariffs 39

5.9.1. Homepower 39

5.9.2. Homeflex - residential TOU and net-billing tariff 41

5.9.3. Homelight 41

5.10. Service charges converted to R/POD and not R/account 43

5.11. Nightsave changes 43
5.12. Subsidies 44
5.12.1. Inter-tariff subsidies....44
5.12.1.1. Homelight inter-tariff subsidies....45
5.12.1.2. Rural inter-tariff subsidies 46
5.12.2. Intra-tariff subsidies....47
5.12.3. Calculation of the ERS charges and the affordability subsidy charge....47
6. Impact of changes per tariff....48
7. Conclusion....51

Annexures

Annexure A – Local-authority tariff impacts....53
Annexure B - Non-local-authority tariff impacts 59
Annexure C – Motivation for the changes to the TOU retail energy charges and rates structure....68
Annexure D – Proposed changes to rate components 77
Annexure E – New residential TOU Homeflex and net-billing offset motivation....92
Annexure F – Proposed retail rates in 2021/22 rand values (excluding VAT) 97
Annexure G – Survey on the customer perceptions and understanding of the Inclining block tariff (IBT) 105
Annexure H – Eskom responses to National Treasury and SALGA inputs 111

Tables

Table 1: Summary of costs, existing revenue and revised revenue. 11
Table 2: Summary of proposed changes to Eskom's retail tariffs 22
Table 3: Tariff design basis....25
Table 4: Wholesale purchase TOU rates excluding losses....28
Table 5: Updated Distribution loss factors 34
Table 6: Proposed Transmission network charges for generators 36
Table 7: Proposed Transmission network charges for loads 37
Table 8: Proposed Transmission loss factors applicable to loads....38
Table 9: Current Transmission loss factors applicable to generators....38
Table 10: Proposed Transmission loss factors applicable to generators....39
Table 11: Proposed ancillary service charges 39
Table 12: Homepower impact (R million)....40
Table 13: Homepower current average month bill versus revised monthly bill 41
Table 14: Homelight current tariffs rates and revenue 42
Table 15: Homelight cost-reflective rates....43
Table 16: Homelight proposed tariff rates 43
Table 17: Inter-tariff subsidies....45
Table 18: ERS charge and affordability charge calculation....48
Table 19: Summary of total impact, per tariff category 50
Table 20: Rand impact per local-authority tariff 53
Table 21: Local authority tariffs Rand and percentage impact per tariff category 54
Table 22: Total impact per voltage for the non-local authority large power tariffs....67

Table 23: Existing and proposed TOU periods 73
Table 24: Current and proposed wholesale purchase structure and rates energy costs and ratios (excluding losses) 74
Table 25: Structure of the service and administration charges 77
Table 26: Structure for the active energy charges 78
Table 27: Structure for the generation capacity charges 81
Table 28: Network charge calculation categories 82
Table 29: Structure of the network charges 85
Table 30: Structure of the ancillary service charges 88
Table 31: Structure of the ERS charge and the affordability subsidy charge 90
Table 32: Structure for the reactive energy charge 91
Table 33: The proposed Homeflex tariff 94
Table 34: Urban LPU tariffs: WEPS, Megaflex, Miniflex, and Nightsave Urban (non-local-authority) 97
Table 35: Rural LPU tariffs: Ruraflex and Nightsave Rural (non-local-authority) 98
Table 36: SPU tariffs: Businessrate, Landrate, Homelight, Homepower and Public Lighting (non-local-authority) 99
Table 37: LPU tariff: Municflex – 12-month view before adjustment for July increase 100
Table 38: SPU tariff: Municrate – 12-month view before adjustment for July increase 100
Table 39: LPU tariff: Municflex – adjusted for a nine-month view (July increase) 101
Table 40: SPU tariffs: Municrate and Public Lighting – adjusted for a nine-month view (July increase) 101
Table 41: Gen-DUoS tariff 102
Table 42: Gen-TUoS tariffs 103
Table 43: Gen-wheeling tariffs 103
Table 44: Gen-offset tariffs 104
Table 45: Gen-purchase tariffs 104

Figures

Figure 1: Steps involved in designing retail tariffs 12
Figure 2: Percentage impact of updating charges with the CTS 14
Figure 3: Tariff change process 15
Figure 4: Average Megaflex price current versus proposed 16
Figure 5: Wholesale and retail tariffs 16
Figure 6: How technology is changing the way the grid works 17
Figure 7: Eskom volume risk exposure 18
Figure 8: Example of cost structure versus tariff structure 19
Figure 9: Proposed changes to the peak, standard and off-peak periods of the TOU tariffs 27
Figure 10: Impact of the municipal tariff rationalisation per local-authority tariff 32
Figure 11: Network charge design and associated risks 33
Figure 12: Transmission cost drivers and customers 35
Figure 13: Transmission zones for generators 36
Figure 14: Transmission zones for loads 37
Figure 15: IBT survey results 42
Figure 16: Homelight 20A and Homelight 60A - cost, current tariff, and revised tariff 42
Figure 17: Current and revised inter-tariff subsidies 45
Figure 18: Impact per charge type 49
Figure 19: Percentage impact per tariff charge type for urban large power tariffs and Municflex 50
Figure 20: Businessrate compared to Municrate at different consumption levels 55

Figure 21: Landrate compared to Municrate at different consumption levels 55
Figure 22: Homepower compared to Municrate at different consumption levels 56
Figure 23: Current Megaflex local-authority tariff and proposed Municflex comparison 57
Figure 24: Current Miniflex local-authority tariff and proposed Municflex comparison 57
Figure 25: Current Nightsave local-authority tariff and proposed Municflex comparison 58
Figure 26: Current Ruraflex local-authority tariff and proposed Municflex comparison 58
Figure 27: Businessrate non-local-authority tariffs impact at different consumption levels 59
Figure 28: Businessrate 1 and 2 non-local-authority tariffs comparison of cost-reflective, current, and proposed tariffs 59
Figure 29: Businessrate 3 and 4 non-local-authority tariffs comparison of cost-reflective, current, and proposed tariffs 60
Figure 30: Landrate and Landlight non-local-authority tariffs impact at different consumption levels 60
Figure 31: Landrate 1 and 2 non-local-authority tariffs comparison of cost-reflective, current, and proposed tariffs 61
Figure 32: Landrate 3 and 4 non-local-authority tariffs comparison of cost-reflective, current, and proposed tariffs 61
Figure 33: Landlight 20A and 60A non-local-authority tariffs comparison of cost-reflective, current, and proposed tariffs 61
Figure 34: Homepower non-local-authority tariffs impact at different consumption levels 62
Figure 35: Homepower 1 and 2 non-local-authority tariffs comparison of cost-reflective, current, and proposed tariff 62
Figure 36: Homepower 3 and 4 non-local-authority tariffs comparison of cost-reflective, current, and proposed tariffs 62
Figure 37: Public Lighting All-Night and 24-Hour non-local-authority tariffs comparison of cost-reflective, current, and proposed tariffs 63
Figure 38: Public Lighting Fixed non-local-authority tariff comparison of cost-reflective, current, and proposed tariffs 63
Figure 39: Current Megaflex non-local-authority tariff compared to the proposed tariff 64
Figure 40: Current Nightsave Urban non-local-authority tariff compared to the proposed tariff 64
Figure 41: Current Miniflex non-local-authority tariff compared to the proposed tariff 65
Figure 42: Current Ruraflex non-local-authority tariff compared to the proposed tariff 65
Figure 43: Current Nightsave Rural non-local-authority tariffs compared to the proposed tariff 66
Figure 44: Current Nightsave Rural and Ruraflex non-local-authority tariffs compared to the proposed tariffs 66
Figure 45: Eskom's System Operator illustrative overview and requirements to optimally manage the power system (not based on actual current system demand values) 70
Figure 46: Scaled winter and summer average week of the national system profile from 2000 to 2021 71
Figure 47: Average summer and winter weekday system profile in 2025 and 2030 72
Figure 48 Comparison between SMC and wholesale purchase structure and rates (without losses, levies, and subsidies) 75
Figure 49 Comparison between wholesale purchase structure and rates (without losses, levies, and subsidies) against OCGT dispatch during 2021 76

Abbreviations

CTS	Cost-to-serve
ERS	Electrification and rural subsidy
HV	High-voltage
IBT	Inclining block tariff

IPP	Independent power producer
LPU	Large power user
LV	Low-voltage
MV	Medium-voltage
MYPD	Multi-year price determination
NCC	Network capacity charge
NDC	Network demand charge
NMD	Notified maximum demand
POD	Point of delivery
PV	Photovoltaic
SPU	Small power user
SSEG	Small-scale embedded generation
TOU	Time-of-use
WEPS	Wholesale Electricity Purchase System

Definitions

Refer to Eskom's Schedule of Standard Prices for the definition of Eskom charges at www.eskom.co.za/tariffs

1. Executive summary

Eskom last revised its tariff structures in 2012 and is proposing structural changes to the Eskom tariffs, based on an updated cost-of-supply (or cost-to-serve (CTS)) study.

There are various reasons Eskom is proposing changes to its tariffs. Firstly, the different tariff rates no longer reflect the different services being provided (that is, they are not aligned with energy, network and retail costs) because of the application of average price increases. Secondly the unbundling of Eskom divisions requiring that the charges are more reflective of the costs per division. Thirdly the energy industry is evolving, and tariff structures also need to evolve to protect all customer interests and to ensure adequate recovery of NERSA approved revenue by Eskom.

The consequences of applying average increases to rates is that there is currently no link between the charges raised and the NERSA approved cost per division, only that the overall sum of all charges recover the approved MYPD revenue decision. Tariffs, therefore, need to be updated to accurately reflect current Eskom divisional cost to avoid volume and trading risk, to reflect cost drivers more accurately, to avoid unintended and unwarranted cross-subsidies, and to ensure that tariff charges cater for the unbundling of Eskom.

Currently Eskom Distribution sets the standard retail tariffs for all customers. The retail tariffs recover the approved MYPD revenue for the whole of Eskom to direct customers and municipal licensees. Eskom Distribution purchases the energy at the wholesale level and the Transmission services through an internal transfer mechanism and this is a pass-through in the standard retail tariffs.

Eskom in 2020, submitted proposed structural changes to NERSA based on the principles in the Electricity Pricing Policy (EPP) and NERSA previous decisions. This submission is an update of the 2020 submission, based on the same motivations used in the 2020 submission, and the latest CTS. It also includes the further unbundling of the energy charges into fixed generation capacity charge and variable time-of-use (TOU) charges to align with the wholesale purchases.

The following are the main objectives of this tariff restructuring submission:

i. To reflect unbundled costs more accurately

Different tariff rates no longer reflect the different services being provided (that is, they are not aligned with divisional energy, network and retail costs) because of the application of average price increases. The consequences of applying average increases to rates is that there is currently no link between the charges raised and the NERSA approved cost per division, only that the overall sum of all charges recovers the approved MYPD revenue decision. Tariffs, therefore, need to be aligned with an updated CTS to accurately reflect current Eskom divisional cost to avoid volume and trading risk, to reflect cost drivers more accurately, and ensure that tariff charges cater for the unbundling of Eskom.

ii. To reflect the changing electricity supply and demand environment

Existing tariff structures are outdated and need to be modernised to reflect the changing electricity environment and crucial decisions in this regard are needed to protect the electricity industry. For example, customers are installing their own generation and using the grid in different ways, and the wheeling of energy is expanding. Fair and equitable revenue recovery from all customers for the services provided can only happen with tariffs and tariff structures that reflect this changing environment.

iii. Alignment between wholesale purchases and retail tariffs

Currently, Eskom Distribution purchases all its energy and Transmission network services from Eskom Transmission through an internal transfer mechanism. These purchase costs form the basis for the retail tariffs. Correct cost recovery reflecting the wholesale purchase costs is vital as there cannot be a disconnect between the wholesale tariff levels and structure and the retail tariff levels and structure, that is, purchasing at one tariff structure and sell at another.

It is necessary that the wholesale purchase structure and rates is correctly reflected in retail tariffs and this submission includes the changes and motivation for this. In the future this may be done as a separate process to the retail tariffs, meaning future separate revenue decisions and separate price increases on new NERSA methodologies.

iv. Mitigate volume and revenue risk

When tariff charges recover fixed costs through volumetric charges, any reduction in sales results in a reduction of revenue, but not necessarily an equal reduction in costs. To ensure adequate recovery of costs, there needs to be an evolution in the thinking of how fixed costs can be recovered in tariffs.

It is important to realise the value of a grid connection and to pay a fair unsubsidised contribution for the use of the grid (network capacity) and the system (generation capacity). The grid and system provide backup, stability, and frequency control, can be used as a battery, provides standby capacity when needed, and provides the ability to receive compensation for energy exported.

In addition to recovering fixed network costs, generator costs should be recovered through a combination of fixed capacity charges (R/kVA) and energy charges (c/kWh). This will reduce the financial risk associated with recovering fixed costs through volumetric charges given the growth in variable energy resources, which also require back up capacity.

The following major structural changes[1] to the retail tariffs are proposed:

1. **Designing all charges using the updated NERSA approved forecast volumes, divisional cost splits, and cost allocation methods:**

   a) **Energy c/kWh rates to reflect internal wholesale energy purchase structure, changes to the TOU ratios (peak, standard, and off-peak) and TOU periods (swopping the peak period and introducing a standard period on Sundays) to be aligned with the wholesale rates**

   About 80% of Eskom sales are on TOU tariffs. These tariffs have peak (most expensive), standard (medium) and off-peak (cheapest) hours and charges, as well as having a winter/summer differential. Customers have requested both Eskom and NERSA to review the TOU tariffs, expressing concerns that the high winter TOU energy rates prohibit the optimisation of their production and impede their economic efficiency, which has a negative impact on their financial sustainability, their competitiveness in the global economy, and their ability to grow. Furthermore, both the Eskom Shareholder and NERSA have asked Eskom to modify the TOU pricing.

   The current TOU charges were last changed in 2005 and no longer reflect the present system and customer requirements. As a result, the current price signals and TOU hours are not optimal for managing the system and therefore changes to the wholesale purchase price structure are being proposed to assist the System Operator to optimise how the Eskom's system is managed, scheduled and dispatched.

[1] The type of price components put together in a tariff package is the tariff structure. The ideal tariff structure would therefore follow the cost structure. A cost-reflective tariff structure has all cost components reflected separately and charged according to the appropriate cost driver per appropriate rate unit.

b) Splitting the energy charges, based on the internal wholesale purchase energy price into variable TOU c/kWh charges and a fixed generation capacity charge –.

Given the fixed and variable costs of generators, the view is that generators' costs should be recovered through a combination of capacity charges (R/kVA) and energy charges (c/kWh). This will reduce the financial risk associated with volumetric recovery rates given the growth in variable energy resources, which also require back up capacity. The introduction of a fixed generation capacity charge (GCC) will result in a reduction of the variable c/kWh charge. The GCC is based on allocated costs for large power user (LPU) tariffs and phased in 50/50 (fixed/variable) for small power user (SPU) tariffs to minimise the impact on these customers. The plan is to gradually increase the SPU tariffs’ GCC to be 100% aligned with the wholesale purchase cost.

c) Network charges to reflect Transmission and Distribution network costs

Transmission and Distribution network charges no longer reflect the network costs because of the application of average price increases. The consequences of applying average increases to rates is that there is currently no link between the charges raised and the NERSA approved cost per division, only that the overall sum of all charges recover the approved MYPD revenue decision. Tariffs, therefore, need to be updated to accurately reflect current Eskom divisional cost to avoid volume and trading risk, reflect cost drivers more accurately, and ensure tariff charges cater for the unbundling of Eskom.

d) Retail charges to reflect the Distribution retail costs.

Like point c. above, retail charges no longer reflect the retail costs because of the application of average price increases and need to be updated with an updated CTS to reflect the costs accurately.

2. Increasing the Distribution fixed-charge network charges component, with a commensurate reduction of the variable charge for all tariffs with network charges

The Distribution business network costs are fixed to deliver the capacity needed. If network charges are not cost-reflective and recovered through variable/volumetric charges such as c/kWh, the Distribution business is at risk of not recovering costs with reduced volumetric sales.

There needs to be a fair recovery of costs by all users of the grid so that tariffs more accurately reflect the value of the service being provided and that unintended subsidies are not created.

3. Rationalising the local-authority tariffs into only three tariff categories: a (LPU) version called Municflex, a (SPU) version called Municrate, and a Public Lighting tariff for non-metered lighting supplies

The proposal is to combine Eskom’s existing suite of multiple tariffs applicable to local authorities into only three tariff categories. This will reduce complexity and simplify the sales and revenue forecasting process in both Eskom and municipalities.

4. Increasing the lower-voltage charges for urban LPU tariffs, thereby reducing the contribution to the low-voltage (LV) subsidies

The low voltage subsidy is an intra-tariff subsidy. Intra-tariff subsidies are when one charge is subsidised by another charge within a tariff category; for example, Megaflex higher-voltage network charges subsidise the lower-voltage network charges. The proposals in this retail plan have reduced some intra-tariff subsidies to rebalance some of the subsidies within a tariff category.

5. Basing service charges on the number of points of delivery (PODs) and not per account

Currently, the administration charge is per point of delivery, and the service charge is per account. Eskom proposes changing the methodology so that both the administration charges and the service charges will be raised per point of delivery and differentiated on size. The rationale is that a customer could have many PODs under one account and pay the same service charge as a customer with one account and one POD. This is not equitable or fair, as more retail resources are used where there are multiple PODs to one account.

6. **Removing IBT for Homepower and Homelight tariffs**

IBT as a tariff structure is no longer appropriate because of customer perceptions and provides uneconomic incentives for customers that install embedded generation. Eskom proposes removing the IBT structure and replacing it with a single energy rate charge. For Homepower, the GCC and more cost-reflective network and retail charges are introduced.

7. **Introducing a residential TOU tariff plus a new net billing offset rate for customers with small-scale embedded generation (SSEG)**

Eskom proposes the introduction of a residential time-of-use tariff, called Homeflex, for its urban residential customers. This tariff is more cost-reflective in structure, aligned with the changes made to Homepower, but with TOU energy charges. This tariff also includes TOU offset rates for compensation for energy exported onto the grid.

8. **Amending the Transmission loss factors for generators so that the loss factors in specific zones are no longer negative.**

Eskom is proposing to amend the current loss factors applicable to Transmission connected generators. Currently in certain Transmission zones the loss factors are negative, effectively meaning that Eskom could pay a generator for being located this specific zone. This principle at the time assumed a generator whose injections increase transmission losses faces a positive loss factor, which results in a charge, while a generator whose injections reduce transmission losses faces a negative loss factor, which results in a rebate. It is, however, not possible to pass-through negative charges, and for this reason Eskom is proposing that the loss factors for the Cape and Karoo zones are set to 1 (that is, will no longer go negative).

9. **Overall revenue impact**

When updating tariffs using a CTS study and implementing structural changes, it impossible to have zero impact on all customers. So, while the total tariff revenue because of the structural changes stays the same, that is, comes back to the MYPD approved revenue requirement, individual customers may pay more or less, depending on the change and their consumption profile. The overall impact per tariff category is shown in the next table. To be noted is the structural changes are a rebalancing exercise, that some tariffs see increases and other reductions, but the overall revenue is the same.

Table 1: Summary of costs, existing revenue and revised revenue.

	CTS allocated allowed costs	Current tariff revenue Rm.	Diff current tariff revenue	Restuctured tariff revenue Rm	Difference new tariff revenue and cost Rm.	Revised subsidy c/kWh	% change in revenue due to restructuring	Difference in revenue Rm. due to restructuring
Total all tariffs	R 247 082	R 247 831	R 749	R 247 829	R 747	0.41	0.00%	-R 2
Local-authority tariffs	R 101 669	R 108 850	R 7 181	R 107 948	R 6 279	7.23	-0.83%	-R 902
Municflex	R 101 140	R 108 370	R 7 230	R 107 419	R 6 279	7.25	-0.88%	-R 951
Municrate	R 263	R 276	R 13	R 263	R 0	(0.01)	-4.66%	-R 13
Public Lighting munic	R 266	R 204	-R 62	R 266	R 0	0.02	30.28%	R 62
Urban tariffs non-local-authority	R 92 682	R 98 815	R 6 133	R 99 650	R 6 969	9.15	0.85%	R 836
Megaflex	R 76 692	R 82 673	R 5 982	R 82 951	R 6 259	9.41	0.34%	R 277
Nightsave Large	R 2 316	R 2 376	R 60	R 2 392	R 76	5.27	0.67%	R 16
Nightsave Small	R 1 094	R 1 112	R 18	R 1 141	R 46	7.06	2.57%	R 29
Miniflex	R 6 183	R 5 725	-R 459	R 6 395	R 212	5.68	11.71%	R 670
Transflex 1	R 4 036	R 3 782	-R 253	R 4 287	R 251	10.03	13.34%	R 505
Transflex 2	R 441	R 630	R 189	R 472	R 31	9.88	-25.08%	-R 158
Businessrate	R 1 919	R 2 516	R 597	R 2 013	R 94	8.98	-19.99%	-R 503
Rural tariffs non-local-authority	R 27 854	R 23 994	-R 3 859	R 23 994	-R 3 859	(35.49)	0.00%	R 0
Ruraflex	R 10 488	R 8 397	-R 2 092	R 8 939	-R 1 549	(30.21)	6.46%	R 542
Nightsave rural	R 3 167	R 3 234	R 67	R 2 692	-R 475	(30.63)	-16.76%	-R 542
Landrate &Landlight	R 14 198	R 12 364	-R 1 835	R 12 364	-R 1 835	(43.74)	0.00%	R 0
Residential tariffs non-local-authority	R 24 833	R 16 138	-R 8 695	R 16 007	-R 8 826	(89.02)	-0.81%	-R 131
Homepower	R 2 913	R 3 043	R 130	R 2 912	-R 1	(0.05)	-4.29%	-R 131
Homelight 20A	R 13 002	R 7 603	-R 5 399	R 7 603	-R 5 399	(100.24)	0.00%	R 0
Homelight 60A	R 8 918	R 5 492	-R 3 426	R 5 492	-R 3 426	(105.48)	0.00%	R 0
Public lighting non-local-authority	R 45	R 34	-R 11	R 45	R 0	0.29	33.19%	R 11
Public Lighting All Night	R 43	R 32	-R 11	R 43	R 0	(0.01)	35.02%	R 11
Public Lighting 24 Hours	R 1.22	R 1.48	R 0.26	R 1.22	R 0.00	(0.01)	-17.73%	R 0
Public Lighting Urban Fixed	R 0.19	R 0.08	-R 0.11	R 0.27	R 0.09	185.23	245.59%	R 0
Generator TUoS and DUoS revenue	R 0.00	R 0.00	R 0.00	R 184.00	R 0.00	0.00	0.00%	R 184

Existing tariff structures are outdated and need to be modernised to reflect the changing electricity environment and crucial decisions in this regard need to be made to protect the electricity industry. For example, it is no longer appropriate to recover fixed costs only through variable kWh-based charges.

For municipalities buying from Eskom, the number of Eskom tariffs offered has to be reduced to simplify and assist in better determination of municipal purchase cost. This also allows for the separation of these municipal tariffs (local-authority tariffs) from non-municipal (non-local-authority) tariffs and better allocation of subsidies. This separation reduces the contribution of the local-authority tariffs to subsidies.

Residential tariffs need an overhaul as well. The inclining block tariff (IBT) as a tariff structure is no longer appropriate, is disliked by customers, and is complex to understand and explain. For this reason, Eskom proposes removing the IBT structure by reintroducing fixed and more cost-reflective network and retail charges for Homepower and introducing a TOU residential tariff with an offset rate for net billing.

The next phase in the journey of tariff design will consider the updating tariffs further based on the revised DMRE EPP and may include:

- alignment with the updated EPP;
- further alignment of the retail charges with the wholesale purchase tariff
- annual updating of different rates because of Eskom unbundled and separate divisional increases – no longer a single average increase applied to all rates;
- further rationalisation of tariffs;
- further rebalancing between fixed and variable network charges;
- further development regarding generator use-of-system charges and net-billing rates;
- moving to make TOU mandatory for all new three-phase SPU connections, and

- introduction of flexible short-term tariff options to address customer needs and Eskom operational requirements.

2. Steps to determine retail tariffs

There are three distinct steps in the recovery of revenue through tariffs. The following diagram summarises these steps

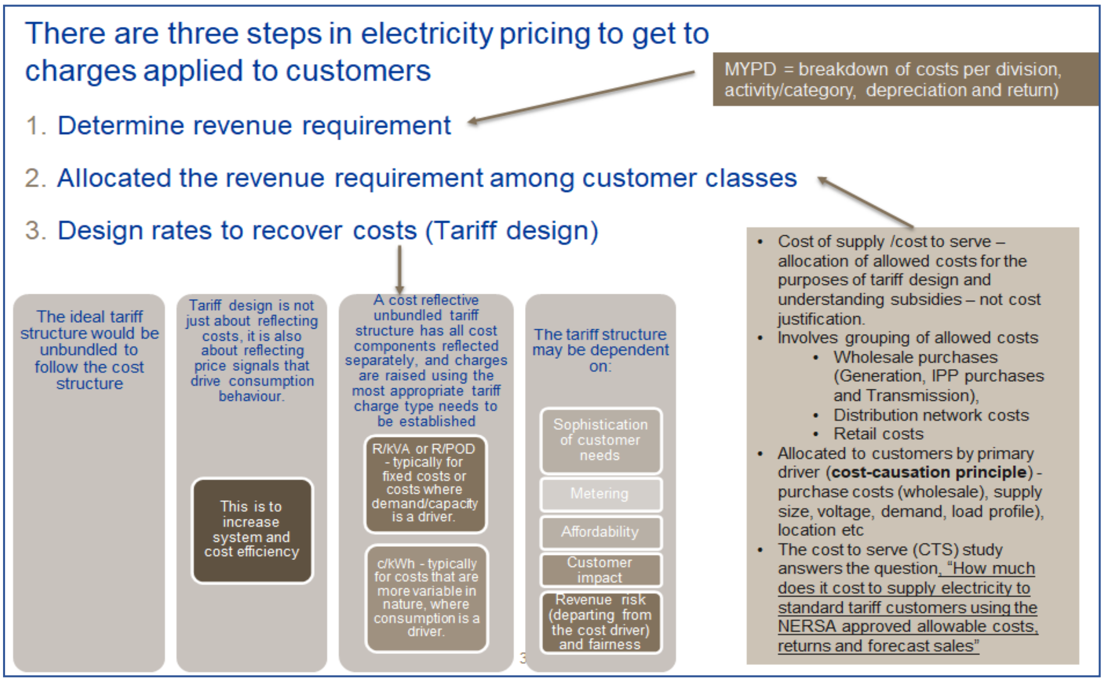

Figure 1: Steps involved in designing retail tariffs

2.1. The determination of approved revenue by the regulator

For Eskom this is done through a NERSA approved methodology called the multi-year price determination (MYPD), which simply is a justification and approval of cost plus return.

2.2. The allocation of approved revenue though a cost-of-supply (or cost-to-serve (CTS)) study.

This exercise takes the already approved revenue and allocates the cost to different customer categories based on volume, demand, load profile, load factor and supply size. The CTS study is a cost allocation exercise for tariff design purposes and understanding subsidies and is not a cost justification exercise. Cost justification (e.g., coal costs) is done through the MYPD revenue requirement process. The CTS study assumes the approved revenue requirement as the basis. Eskom will also publish the CTS study as supporting documentation for this retail tariff plan.

The CTS study is an embedded[2] cost-of-supply study allocating the Eskom allowable revenues from an MYPD decision related to Eskom's standard tariffs by customer categories that are segmented by the supply voltage and location density (which includes using customer load profiles in the study). Once the costs are allocated, then tariffs are designed based on cost. This is explained further in detail in the CTS study report.

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[2] An embedded cost-to-serve study is a cost allocation method based on historical costs, as opposed to a marginal cost-to-serve study, which uses the incremental cost to serve a customer in order to allocate costs.

The CTS study cost allocation is guided by a cost causation principle[3]. That is, it tracks how each customer category contributes to the costs to supply electricity based on its consumption and demand. The cost drivers used in the cost allocation are the volumes used in the NERSA MYPD decision for the costing year, that is, the sales in kilowatt-hours, the demand (utilised capacity, maximum demand, and chargeable demand), and the number of customer PODs.

The following has affected the levels of the cost allocation per cost driver, therefore flowing into the tariff design:

- The MYPD revenue decision per Eskom division
- Changes to the wholesale TOU periods and rates
- Updated Distribution and Transmission loss factors based on forecast volumes and a revised Distribution loss factors study affecting energy costs and network costs
- Updated customer numbers affecting costs per POD
- Changes in chargeable demands and utilised capacities affecting network costs per kVA
- Updated Transmission network charges

The following table summarises the CTS inputs and outputs

Functionalised costs	Costs driver(s)	Allocation method(s)	Unit cost drivers
Energy Purchases	Wholesale energy purchases (TOU) and generation capacity	ToU and seasonally differentiated energy purchase rates and annual maximum demand purchased	c/kWh and R/kVA
Transmission purchases	Installed capacity and location /zonal differentiation	Utilised capacity demand at purchase level per Transmission zone	R/kVA
Distribution	Capacity (transformation and lines)	Maximum demands adjusted for diversity in the cost allocation diagram (CAD)	R/kVA
Retail costs	Number of PoDs	Suppy size weighting / ratio to serve various customer types)	R/POD/day

The CTS applies the following:

- Pass-through of wholesale purchase costs, comprising the NERSA approved Eskom energy related costs (Eskom Generation and IPP purchases), Transmission network costs and ancillary service costs. These are pass through costs into the retail tariffs after which tariff design takes place to calculate tariff charges, and are further explained in paragraph 3:
- Recovery of Distribution network costs, using NERSA approved costs for Distribution network business and allocated in the CTS to customers and customer categories based on voltage, load factor, geographic location, and demand.
- Distribution Retail costs, using NERSA approved costs for Distribution retail business and allocated to customers and customer categories based on supply size.

The following figure demonstrates shows how updating the charges with the CTS has affected each charge type for the large power tariffs.

[3] Those who do not receive any benefit from a service should not be allocated the cost, or customers that receive the benefit should be allocated the cost. This is cost causation.

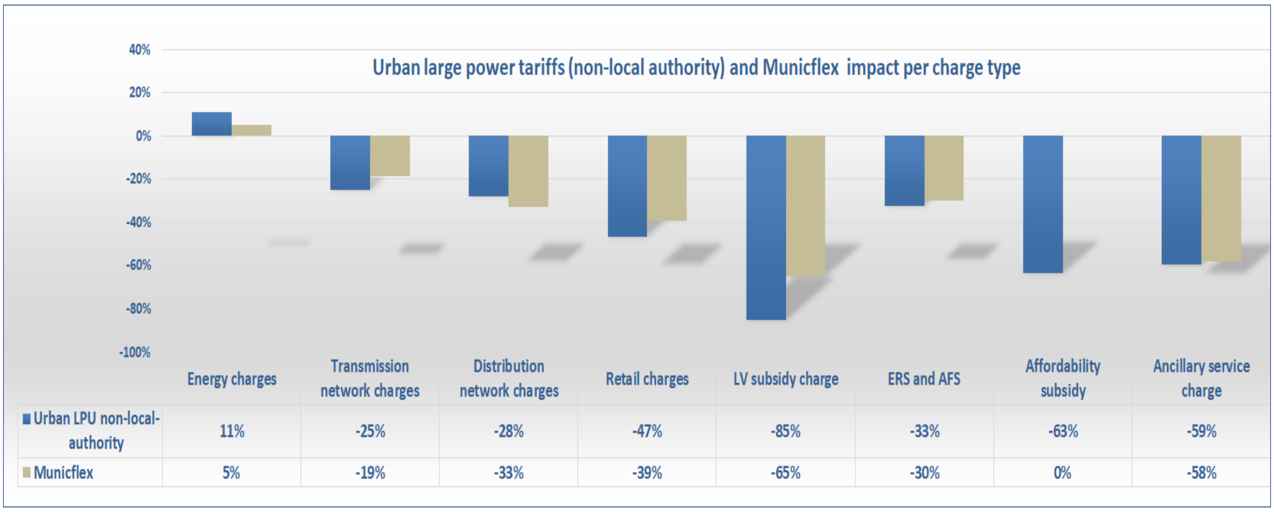


Figure 2: Percentage impact of updating charges with the CTS

- The energy cost has increased at a higher rate than the average price increase applied to energy charges over the years.
- Energy costs and therefore energy charges have increased to align with the above and all other charges reduced.

The approach used in the CTS study complies with the applicable government policies, guidelines and rules as contained in the EPP, the Codes (Distribution and South African Grid Code) and the MYPD methodology (October 2016).

2.3. Tariff design

This is the last step and is informed by the results from the CTS study but can also include specific objectives/pricing signals; to incentivise more optimal use of the system, which is not necessarily cost based, subsidies and minimising customer impacts. This submission deals with structural changes in retail tariffs, that is, the tariffs charged to the end-use customer. The following premises this submission:

- That the current regulatory environment is still in place regarding NERSA regulatory rules for revenue requirement and the application of price increases.
- That Eskom Distribution will be the party that recovers the Eskom revenue applicable to standard tariffs, and any changes due to Eskom unbundling will be dealt with through internal transfer mechanisms, until the above is amended.

Therefore, changes to Eskom's tariffs, follow an MYPD decision, a CTS, and tariff design taking into account national and business imperatives. This process is described in the next figure.

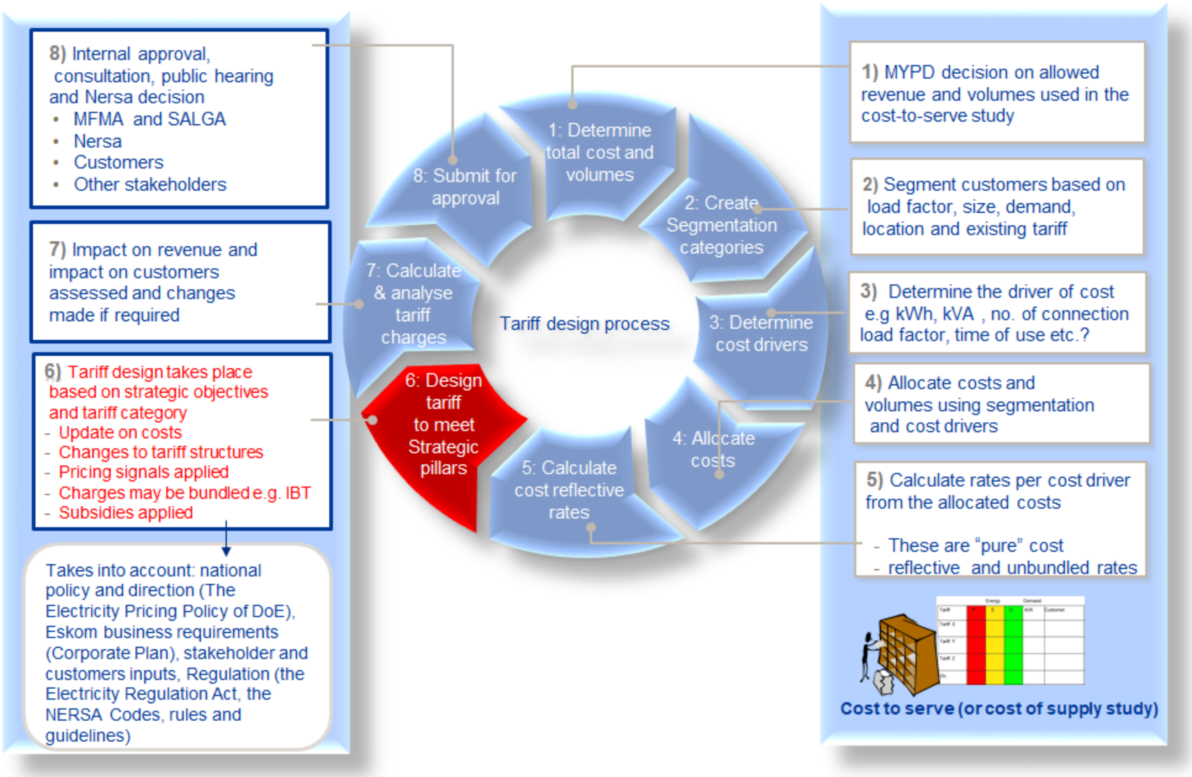


Figure 3: Tariff change process

3. The relationship between wholesale purchases and retail tariffs

Eskom Transmission purchases energy from Eskom Generation and IPPs. A wholesale purchase structure and rates are derived from these costs based on the system profile and capacity at the Transmission level, and not individual customer profiles. This wholesale purchase is a cost to Eskom Distribution and a pass-through in the retail tariffs at the wholesale purchase rates and structure.

In the CTS, customer profile information is used to allocate wholesale purchase costs to each customer or customer category (forecast or representative) based on the wholesale purchase rates and structure.

Eskom Distribution does not pay any generator direct for energy services and therefore it is not possible, to allocate a specific generator profile to a specific customer category.

However, customers with a peakier profile get allocated more peak costs because of the application of the wholesale purchase costs. The introduction of the generation capacity charge at the wholesale level also provides a signal where low load factor customers also see an increase in their tariff. This is demonstrated (as an average c/kWh) in the following figure for the Megaflex tariff, where the following can be noted:

- As the load factor increases the average price reduces.
- More peak usage, the higher the average price.
- That the proposed changes to the Megaflex tariff, shows a higher average price at low factors or higher peak usage and slightly lower prices at high load factors.

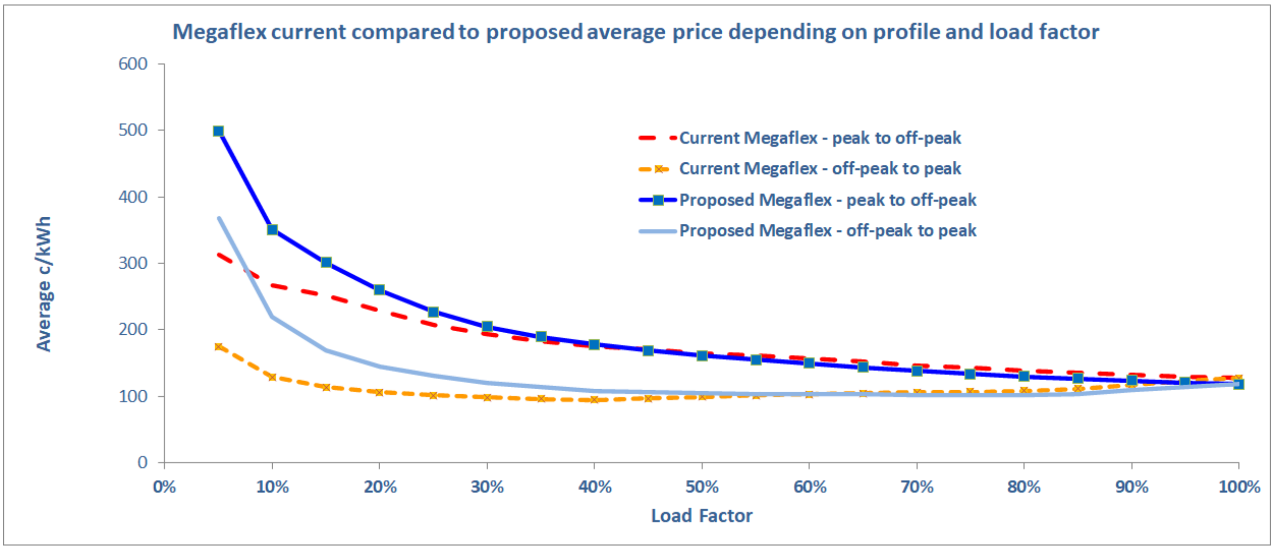


Figure 4: Average Megaflex price current versus proposed

The different trend lines represent the average price (c/kWh) starting with all consumption in peak moving to off-peak or starting all consumption in off-peak moving to peak at different load factors.

Wholesale purchase costs form the basis for the retail tariffs. Correct cost recovery reflecting the wholesale purchase costs is vital as there cannot be a disconnect between the wholesale tariff levels and structure and the retail tariff levels and structure, that is pay at one structure and sell at another. A disconnect between the wholesale purchases and retail tariffs, would result in volume related revenue risk for Eskom.

The following figure demonstrates the relationships between the wholesale purchases and retail tariffs.

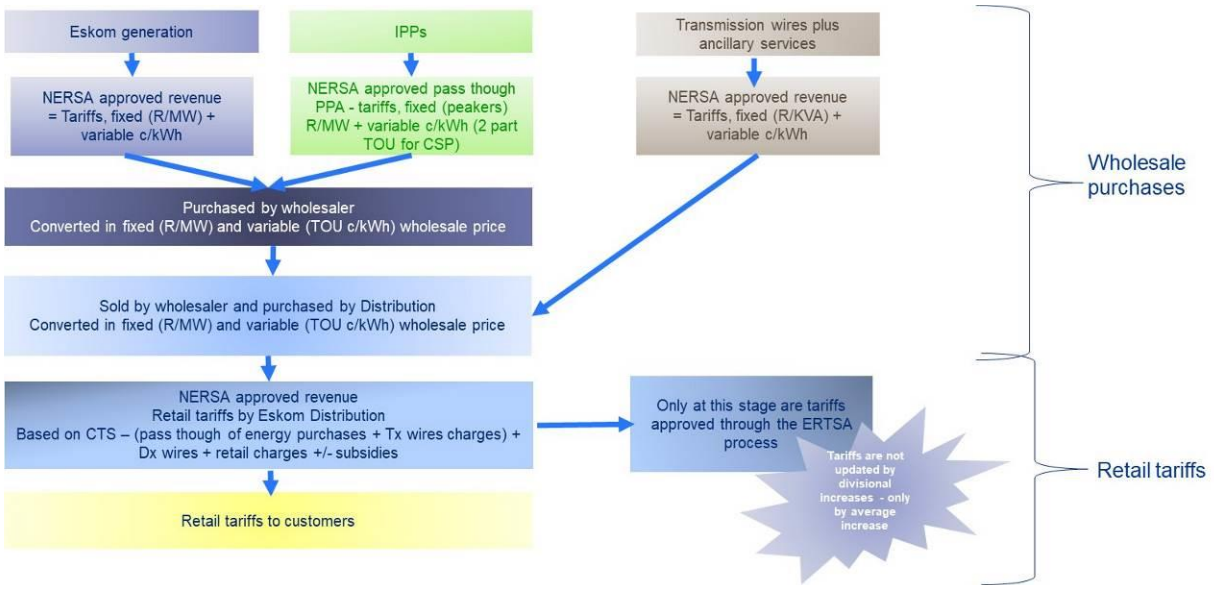


Figure 5: Wholesale and retail tariffs

This submission includes the changes and motivation for the wholesale purchase structure that will need to be reflected in retail tariffs. In the future this may be done as a separate process to the retail tariffs, meaning future separate revenue decisions and separate price increases on new NERSA methodologies including ERTSA.

4. The relationship between volume risk and tariff structures

When tariff charges recover fixed costs through volumetric charges, any reduction in sales results in a reduction of revenue, but not necessarily an equal reduction in costs. To ensure adequate recovery of costs, there needs to be an evolution in the thinking of how fixed costs can be recovered in tariffs.

The following figure demonstrates how the introduction of embedded generation results in the network being used differently to deliver energy – no longer a single direction of energy flow.

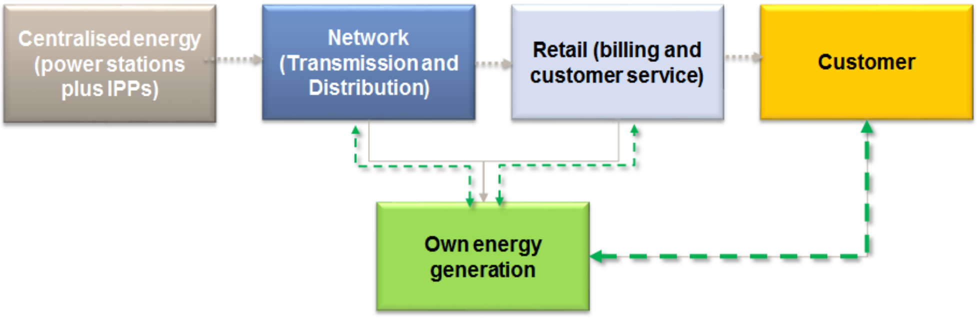


Figure 6: How technology is changing the way the grid works

Because current tariffs recover both network and energy costs through volumetric energy (c/kWh) charges, these tariff structures no longer reflect the changing energy environment; for example, a tariff with only a c/kWh energy charge of R2/kWh makes alternative energy sources look very attractive. However, only R1/kWh of the charge in the example is actually related to energy costs (which also include fixed costs), and the rest of the charge includes fixed capacity-based network costs and retail costs. The economic test should be against the R1/kWh charge and not the R2/kWh charge.

Therefore, the R2/kWh charge should be unbundled into network (fixed daily charge) and energy (volumetric c/kWh). This will not recover extra revenue; it just rebalances the charges.

Unbundling and restructuring will remove artificial subsidies, provide greater transparency of costs, ensure the correct economic signal, and reflect a more accurate payback period by comparing the energy cost of the utility versus the energy cost of the alternative and not including network cost in the analysis.

It is also important to realise the value of a grid connection and to pay a fair unsubsidised contribution for the use of the grid. The grid provides backup, stability, and frequency control, can be used as a battery, and provides the ability to receive compensation for energy exported. If a customer decides to go off-grid (that is, remove the connection), all of this value then has to be provided by the customer.

Tariffs that currently recover fixed costs through a variable charge impose a revenue risk for the utility and increase tariffs for all customers. Correct separation and structuring of network, retail, and energy costs in the tariff charges would provide the correct economic signal and payback period for alternative energy decisions by comparing the energy cost of the utility versus the energy cost of the alternative.

If tariffs are not correctly structured:

- a reduction in sales and volumes results in a reduction of the bill by not only the energy value, but also the network value; and
- this is not equitable or fair to those who, for example, would never be able to afford alternative energy sources.

This loss in revenue must then be recovered elsewhere, as the network costs do not disappear (equipment is not removed), even if there is no consumption. Therefore, if the electricity industry does not start to unbundle and structure the tariffs to respond to changes in technology and the environment, all customers will be affected negatively.

Such changes do not propose increasing tariffs, but instead ensuring the fair recovery of costs by all connected to the grid through tariffs that more accurately reflect the value of being grid-tied. Such changes must not be viewed as "anti-renewable", but rather as an attempt to support the connection of alternative energy resources responsibly and avoid unwarranted and non-economic cross-subsidies.

In summary, network providers should be allowed to make charges more cost-reflective in structure for the following reasons:

- The system and grid provide backup, storage, and the ability to get compensation for energy exported to the customer.
- Not being connected to the grid means that the customer must have an adequate-size generation plant with matching storage capabilities, must have backup for when the storage is depleted if there is no generation, must provide an own fault level, and will have no opportunity to get compensation for time of excess.
- Correct separation and structuring of the network, retail, and energy costs in the tariff charges would provide the correct economic signal and payback period for alternative energy decisions by correctly comparing the energy cost of the utility and the energy cost of the alternative.

Such changes do not propose to increase the tariffs, but rather to ensure the fair recovery of costs by all, so that tariffs more accurately reflect the value of the service being provided. The next figure demonstrates the current ratio of fixed costs to variable costs, the current recovery of these costs through fixed charges and the proposed tariff ratio of fixed to variable charges.

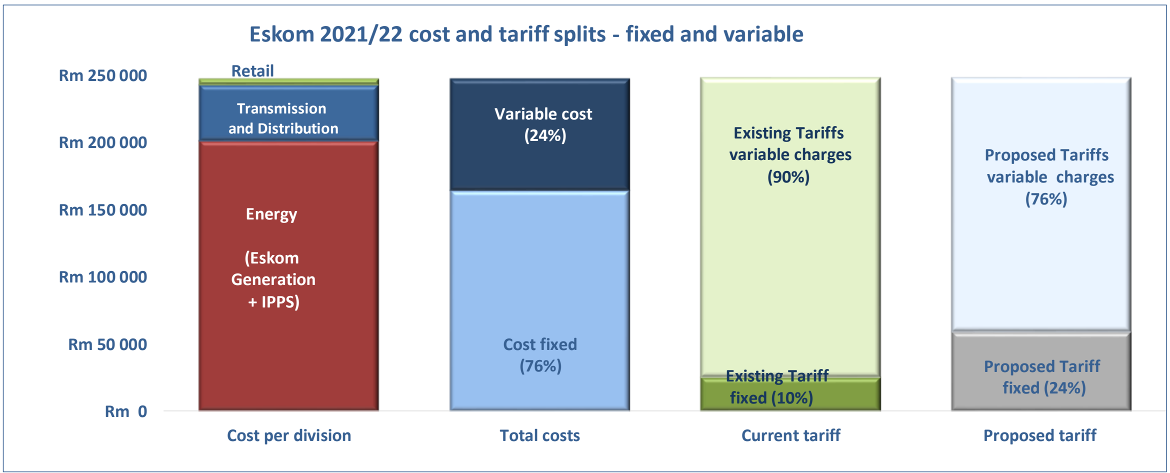
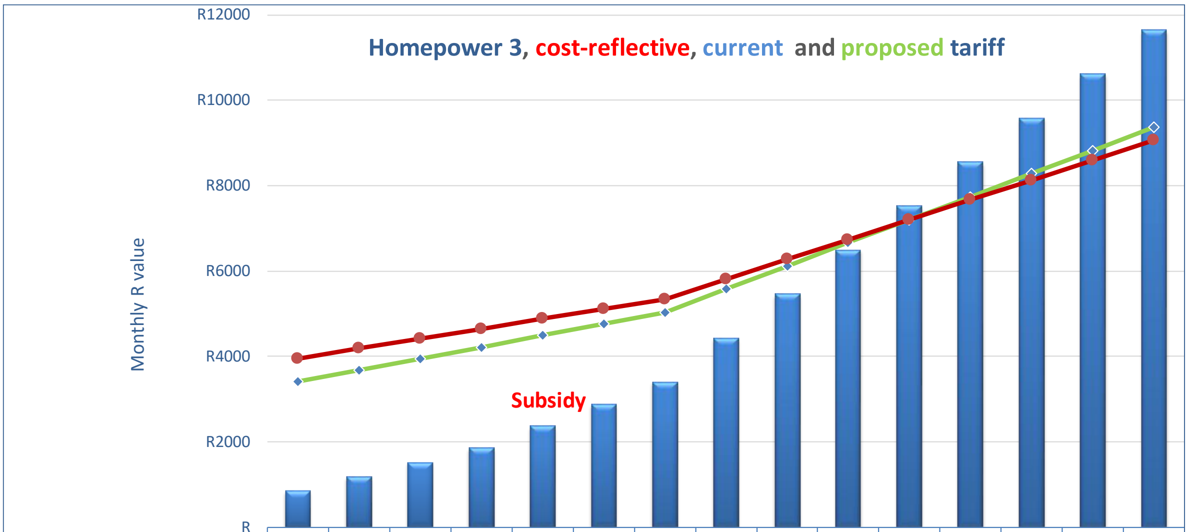


Figure 7: Eskom volume risk exposure

The above figure shows that only 10% of Eskom's revenue is currently recovered through fixed charges, whereas a conservative 76% is fixed costs. The proposed changes, including the introduction of the generation capacity charge, increases the fixed contribution to 24%, still well below the 76% fixed costs.

The next figure compares the cost structure and the tariff structure for the Homepower 3 tariff. In this example, only the network and retail costs are considered fixed. Typically, for more affluent residential households, Homepower 3 is a 100 kVA tariff for residential supplies.



Monthly consumption	0 kWh	200 kWh	400 kWh	600 kWh	800 kWh	1 000 kWh	1 200 kWh	1 600 kWh	2 000 kWh	2 400 kWh	2 800 kWh	3 200 kWh	3 600 kWh	4 000 kWh	4 400 kWh
Homepower 3 current	R844	R1179	R1514	R1849	R2365	R2880	R3396	R4427	R5459	R6490	R7521	R8553	R9584	R10615	R11647
Homepower 3 proposed	R3408	R3679	R3950	R4221	R4493	R4764	R5035	R5577	R6119	R6661	R7203	R7746	R8288	R8830	R9372
Homepower 3 cost-reflective	R3956	R4188	R4420	R4652	R4884	R5116	R5348	R5812	R6276	R6740	R7204	R7668	R8132	R8597	R9061

Figure 8: Example of cost structure versus tariff structure

For customers with decreasing consumption, the current tariff structure for Homepower 3 (below 2 800 kWh) provides a cross-subsidy. This means that, below this level, the cost is higher than the tariff, and this customer is then subsidised by other customers.

5. Impact on tariffs because of changing electricity industry

In 2021 the government made changes to Schedule 2 of the Electricity Regulation Act (ERA) that increased the licensing threshold for generation projects from 1MW to 100MW. This effectively means that generators up to 100MW no longer need a licence but only require registration with NERSA. Eskom commissioned a study to assess among other things how tariffs would need to change to address this changing landscape. This study supported the motivations and the structural changes proposed in this submission.

The study recommended the following regarding tariffs

1. <u>Tariff review by function:</u> Eskom's individual charges (energy, demand, capacity and service) have drifted away from cost reflective levels over time in. One of the main reasons is that NERSA required Eskom to apply the approved increases equally across charges. This approach assumes that the cost increase in generation, transmission and distribution are the same which is of course not the case.

Recommendation
• Engage with NERSA on all levels to emphasise the importance of separately reviewing and approving revenue applications for generations, transmission, and distribution. • Highlight the tariff distortions caused by increasing all charges by the same percentage every year.

2. <u>Calibrate in WEPS (wholesale energy price):</u> Eskom's marginal cost of production has moved upwards, especially during low season periods because of fuel prices increases as well as poor availability of the coal fleet. This necessitated the dispatch of more expensive coal plants as well as frequent operation of the even more expensive diesel plant. Eskom's energy charges (c/kWh) are therefore no longer aligned with the marginal cost of production, and Eskom's energy charges, especially during the low season, are well below the cost of supply while prices during the morning

winter and standard periods are too high. This is sending the wrong economic signals into the market.

> Recommendation
>
> - Eskom to review and recalibrate its TOU definitions and tariff levels including the ratios between low and high seasons as well as between off-peak, standard and peak to align with the marginal cost of production more closely.
> - Marginal cost charges will not only be aligned with a competitive market but will also be consistent with NERSA's tariff recommendations.

3. Generation capacity charge: Generation's fixed costs are currently being recovered via the WEPS energy charges in the peak and standard hours during the high season period. This exposes Generation's revenue to significant volume risk over these few hours in the year.

> Recommendation
>
> - The recovery of Generation's fixed costs needs to be carefully reviewed. By charging customers for the consumption of electricity at the marginal (not average) cost of supply Eskom Generation will recover not only all its variable costs but also a portion of its fixed costs.
> - In addition, it is recommended that Generation more clearly define its Ancillary Services costs and recover it from the TSO as a capacity-based charge.
> - The remaining fixed cost can be recovered either through a percentage uplift on the TOU energy tariff or as a fixed capacity charge. A fixed capacity charge will be more consistent with contracting with dispatchable IPP and international trends.

4. Annual TOU review: Given the strong economic incentive to switch away from Eskom it is anticipated that large penetration of renewable energy will push down on short run marginal costs (SMC) in the future. Modelling shows that if Eskom do not reform its tariff setting approach, SMC may decrease significantly during the day, giveng rise to the "duck-curve" effect in response to the deployment of very large quantities of PV capacities all with a similar production profile at zero marginal cost.

> Recommendation
>
> - To prevent 'over-investment' of especially PV capacity, Eskom needs to send the correct economic signals into the market via its tariffs and in particular the "escapable" energy tariffs.
> - Eskom to annually review and update its TOU definitions and energy charges to align with an evolving SMC profile.
> - If there is significant investment in PV capacity resulting in a decrease of SMC during day-time and if Eskom adjusts its TOU definitions and charges to reflect this change the economic incentive to switch away from Eskom will decrease and fewer customers will want to make the switch.
> - If Eskom does not adjust its TOU definitions and charges frequently there is a real chance that SMC may decrease significantly potentially resulting in stranded thermal generating assets.

5. Migrate to TOU tariffs: Many of Eskom's customers are not on TOU tariffs. It means that other charges such as demand, capacity and subsidies are bundled with energy which inflates energy charges. This practice creates further incentives for customers to deploy onsite generation and "escape" these high energy charges. Although Eskom customers are required to register their SSEG systems and move to the suitable TOU tariffs. In practice, many, if not most, customers do not bother to go through this registration process, which costs them money. As a result, they stay on the wrong tariffs resulting in major sales, revenue and net contribution losses to Eskom.

> Recommendation
>
> - Eskom to develop a tariff migration programme that will move all customers (except low-income customers) to TOU tariffs.
> - While loadshedding is a reality, Eskom may want to wave the cost of registering an SSEG system but of course not the cost of changing and meters or installation of needed infrastructure. The loss in registration fee will be easily recoup if the customer moves over to the correct tariff.
> - Eskom should promote and encourage customers to install and register SSEG.
> - Eskom to more actively monitor customer profiles to identify customers with SSEG system who have not registered.

6. Promote Net-billing: Many customers with on-site solar generation have excess energy during certain times which Eskom currently credits at the full WEPS rate, excluding losses, under the Gen-offset (or net-billing) tariff applicable to Rural and Urban customers provided they have registered their SSEG systems with Eskom.
   a. A net-billing mechanism credits the customer with energy exported. Eskom does not buy the energy; it uses it and then gives it back at the end of the month. Eskom's net-billing tariff also caps the amount of energy credited to that consumed unless banking is approved.
   b. Net-billing will also give Eskom indirect access to onsite storage capacity. Currently customers have installed onsite battery energy storage to mitigate the impact of loadshedding. In future with the anticipated adoption of battery electric vehicles the net-billing mechanism will also provide the correct incentives to use the energy storage potential of these vehicles to support the electricity system. In a way this will act as an important incentive for customers not to defect from the Eskom network because of the economic incentive of using onsite storage to reduce electricity costs.
   c. Embedded generation can, if deployed correctly, reduce losses, and improve voltages.

   Eskom has net-billing tariffs, except for residential. In 2020 Eskom did apply for a residential TOU tariff with net-billing, but no decision was made on this tariff.

> Recommendation
>
> - Eskom to actively promote net-billing to reduce a customer's bill, relief pressure on the national system which is supplied constrained.
> - Eskom to consider increasing the net-billing cap from the amount of energy credited to the customer's total invoice including fixed, capacity and demand charges.
> - Eskom to engage with NERSA at all levels to have the residential TOU tariff with offset approved as soon as possible.
> - In the meantime, Eskom should make this tariff available on a voluntary basis as an incentive for customers to stay connected to the system and to push energy back into the system.

5.1. Eskom-proposed changes to the tariffs and their charges

The proposed changes to the tariffs are based firstly on the CTS results and then include specific objectives, pricing signals, subsidies (payment and receipt), and phasing in of changes to minimise impacts.

A summary of the changes per tariff is shown in the following table (excluding the impact of CTS on the level of the charges).

Table 2: Summary of proposed changes to Eskom's retail tariffs

Tariff	Change	Comments
Non- municipal		

Megaflex, Miniflex, WEPS	• Energy charges –
	  ○ Introduced a fixed generation capacity charge
	  ○ Updated with new TOU ratios and periods
	• Network charges – increasing the network capacity charge (NCC), which is a fixed charge, and commensurate reduction of the network demand charge (NDC), a variable charge
	• Service charge converted from R/account to R/POD
		• Refer to Annexure C – and Annexure D – Proposed changes to rate components

Transflex	• Energy charges –
	  ○ Introduced a fixed generation capacity charge
	  ○ Updated with new TOU ratios and periods
	• Service charge converted from R/account to R/POD
		• Refer to Annexure C – and Annexure D – Proposed changes to rate components

Nightsave Urban Large and Small	• Energy charges –
	  ○ Introduced a fixed generation capacity charge
	  ○ Updated with new TOU ratios and periods
	• Network charges – increasing NCC and commensurate reduction of NDC
	• Service charge converted from R/account to R/POD
		• Refer to Annexure C – and Annexure D – Proposed changes to rate components

Ruraflex and Nightsave Rural	• Increases applied to Ruraflex and reduction of Nightsave Rural
	• Energy charges –
	  ○ Introduced a fixed generation capacity charge
	  ○ Updated with new TOU ratios and periods
	• Network charges – increasing NCC and commensurate reduction of NDC
	• Service charge converted from R/account to R/POD
		• Refer to Annexure C – and Annexure D – Proposed changes to rate components

Businessrate	• Structural change by introducing the electrification and rural subsidy (ERS) charge • Energy charges – Introduced a fixed generation capacity charge (R/POD/day • Network charges – increasing NCC and commensurate reduction of NDC	• Refer to Annexure D – Proposed changes to rate components

Tariff	Change	Comments
Landrate	• Energy charges – Introduced a fixed generation capacity charge (R/POD/day) split 50/50 between fixed (R/POD) and variable charge (c/kWh) to limit customer impact • Network charges – increasing NCC and commensurate reduction of NDC	• Refer to Annexure D – Proposed changes to rate components
Landlight 20 and 60A	• No structural changes	• Refer to Annexure D – Proposed changes to rate components
Homepower	• Structural changes proposed by removing IBT • Introducing a single energy charge (c/kWh), an ancillary service charge (c/kWh), a network demand charge (c/kWh) and a R/day service and administration charge • Network charges with increased NCC • Introduction of R/POD/day GCC at a 50/50 split in a phased approach to limit customer impact of fixed (R/POD/day) and variable (c/kWh) charges to limit impact	• Refer to Annexure D – Proposed changes to rate components
Homelight 20 and 60A	• Structural changes proposed by removing IBT and converting to a single energy charge (c/kWh) (but the option remains to retain IBT structure)	• Refer to Annexure D – Proposed changes to rate components • Refer to paragraph 5.9 concerning IBT
Public Lighting	• No structural changes - Public Lighting tariff for non-metered lighting supplies (no change just updated with the CTS). [Previously approved in Eskom but not approved by NERSA – required it to be based on a cost to serve study. Only have NERSA approval for subsidies for Homelight and rural tariffs].	
Non- municipal		

Municflex	• Local-authority LPU tariffs, Megaflex, Miniflex, Nightsave Urban, Ruraflex, and Nightsave Rural are combined into a new tariff called Municflex (based on Megaflex structure)
	• Energy charges –
	    ○ Introduced a fixed generation capacity charge
	    ○ Updated with new TOU ratios and periods
	• Network charge - increasing NCC and commensurate reduction of NDC
	• Service charge converted from R/account to R/POD
		• Refer to paragraph 5. concerning munic tariff rationalisation and Annexure D – Proposed changes to rate components

Tariff	Change	Comments
Municrate	• Local-authority small power tariffs are combined into a single tariff called Municrate (based on the existing Businessrate structure) • Introduction of the ERS charge to this tariff category • Energy charges - introduction of Generation Capacity Charge (GCC) at 50/50 split between fixed and variable charge to limit customer impact	• Refer to paragraph 5.5 concerning munic tariff rationalisation and Annexure D – Proposed changes to rate components • The introduction of ERS is currently not proposed for this tariff since the majority of the volumes are in the Landrate and Homepower tariffs, which do not contribute to this subsidy. The majority of the urban Munic customers are in the Municflex tariff and will contribute to the ERS subsidy in the Municflex tariff.
	Generator-related tariffs	
Gen-wheeling	• Energy charges – credit rate updated with new TOU ratios and periods	• Refer to Annexure D – Proposed changes to rate components
Gen-offset	• Energy charges – credit rate updated with new TOU ratios and periods	• Refer to Annexure D – Proposed changes to rate components
Gen-DUoS	• No structural change • Updated network charges and loss factors based on HV cost-reflective charge for loads	• Refer to Annexure D – Proposed changes to rate components
Gen-TUoS	• The negative loss factors for Transmission connected generators proposed to change to 1	• Not applicable

5.2. How the standard tariff charges have been calculated

1) Energy costs have been taken as is from the CTS based on the new TOU changes and repacked volumes. See paragraph 5.3.
    a) For the TOU tariffs, the costs have been split into c/kWh peak, standard and off-peak periods and seasonally differentiated, based on the new WEPS purchase costs TOU volumes, structure and periods.
    b) For the Nightsave tariffs, a portion of the energy costs has been converted into a R/kVA energy demand charge.
    c) For non-TOU tariffs, a representative load profile has been used to determine an average annual c/kWh value.
2) Transmission network costs have been taken as is from the CTS study results and either charged as a separate R/kVA charge, combined with Distribution network costs, or bundled together with other charges.
3) Distribution network costs have been taken as is from the CTS study results and then designed as explained in Annexure D – Proposed changes to rate components, paragraph D.4.
4) Retail costs (service and administration) have been used as is from the CTS results, except for tariffs without retail charges (such as Homelight).

5) The sum of all of the above, plus revenue from IPP TUoS and DUoS charges, equals the approved revenue requirement.
6) All rates are in 2021/22 rand values. The price increase process will be used to update the rates to the year of application.

The following table summarise how different costs are recovered in tariff charges.

Table 3: Tariff design basis

Tariff	Energy charges c/kWh	Generation Capacity Charges R/kVA	Transmission network charges	Ancillary service charges	Distribution network charges	Retail charges	Subsidies
Megaflex, Miniflex	TOU wholesale cost per period	Wholesale generation capacity cost R/kVA	Wholesale Transmission network cost R/kVA	Wholesale Transmission ancillary service cost c/kWh	Distribution R/kVA cost, but with intra-tariff network subsidies	Distribution retail cost R/POD/supply size	Pays subsidies
Nightsave Urban	Based on TOU wholesale cost per period, split into R/kVA and c/kWh	Wholesale generation capacity cost R/kVA	Wholesale Transmission network cost R/kVA	Wholesale Transmission ancillary service cost c/kWh	Distribution R/kVA cost, but with intra-tariff network subsidies	Distribution retail cost R/POD/supply size	Pays subsidies
Ruraflex	TOU c/kWh wholesale cost per period	Wholesale generation capacity cost R/kVA	Wholesale Transmission network cost R/kVA	Wholesale Transmission ancillary service cost c/kWh	Distribution R/kVA cost but reduced by inter tariff subsidies	Distribution retail cost R/POD/supply size	Receives subsidies
Nightsave Rural	TOU c/kWh wholesale cost per period	Wholesale generation capacity cost R/kVA	Wholesale Transmission network cost R/KVA	Wholesale Transmission ancillary service cost	Distribution R/kVA cost, but reduced by inter -tariff subsidies	Distribution retail cost R/POD/supply size	Receives subsidies
Businessrate	TOU c/kWh wholesale cost per period based on average profile cost	Wholesale generation capacity cost R/POD/day	Wholesale Transmission network cost R/POD	Wholesale Transmission ancillary service cost c/kWh	Distribution cost split in R/POD/day and c/kWh	Distribution retail cost R/POD/supply size	Pays subsidies
Landrate	TOU c/kWh wholesale cost per period	Wholesale generation capacity cost R/POD/day at a 50/50	Wholesale Transmission network cost R/POD/day	Wholesale Transmission ancillary	Distribution cost, but with inter- and intra-tariff subsidies, aligned to	Distribution retail cost R/POD/supply size	Receives subsidies

Tariff	Energy charges c/kWh	Generation Capacity Charges R/kVA	Transmission network charges	Ancillary service charges	Distribution network charges	Retail charges	Subsidies
	based on average profile cost	split between fixed and variable charge		service cost c/kWh	current inter-tariff subsidies level, split in R/POD/day and c/kWh		
Homepower	TOU c/kWh wholesale cost per period based on average profile cost	Wholesale generation capacity cost R/POD/day at a 50/50 split between fixed and variable charge s	Wholesale Transmission network cost R/POD/day	Wholesale Transmission ancillary service cost c/kWh	Distribution cost split in R/POD/day and c/kWh	Distribution retail cost R/POD/suppl y size	No subsidies
Homelight	Designed based on current tariff revenue - No GCC						Receives subsidies
Public Lighting	TOU c/kWh wholesale cost per period based on average profile cost	Wholesale generation capacity cost c/kWh	Wholesale Transmission network costs c/kWh	Wholesale Transmission ancillary service cost c/kWh	Distribution cost c/kWh	Distribution retail cost c/kWh	No subsidies

5.3. TOU changes

Eskom is proposing changes to the TOU energy charges with respect to the rates in each TOU period and the changes to the peak, standard and off-peak hours to align with the wholesale purchase price and structure. Refer to Annexure E for the full motivation for the proposed TOU changes.

About 80% of Eskom sales are on TOU tariffs. These tariffs have peak (most expensive), standard (medium) and off-peak (cheapest) hours and charges, as well as having a winter/summer differential. The current TOU charges were last changed in 2005 and no longer reflect the present system, costs and customer requirements. As a result, the current price signals and TOU hours are not optimal for managing the system.

Therefore, it is proposed to 1) change the TOU hours and 2) change the TOU prices to:

- meet the System Operator’s requirements to optimise the operation of the power system;
- provide the right economic signals that promote economic efficiency;
- improve financial sustainability by increasing efficiencies in operating costs; and
- incentivise growth and sales for the benefit of the customers and Eskom.

If approved by NERSA, the changes to the TOU tariffs will apply to all customers on TOU tariffs. The changes proposed are:

- updating the energy rates with the CTS, wholesale purchase price and structure, resulting in a reduction in the energy charges because of the introduction of the GCC;
- increasing the evening peak to three hours (from two hours) and reducing the morning peak to two hours (from three hours); see Figure 9: Proposed changes to the peak, standard and off-peak periods;
- introducing a two hour standard period on a Sunday evening. See Figure 9: Proposed changes to the peak, standard and off-peak periods; and
- reducing the current 1:8 ratio of the summer (low-demand season) off-peak rate to the winter (high-demand season) peak rate to a 1:6 ratio and adjusting the rest of the rates commensurately. See Table 4: Wholesale purchase TOU rates excluding losses; and
- The proposed changes are based on analysis of the current and future system profile, correlation against system marginal costs and price signals to optimise the profile. These changes will continue to evolve over time as the industry and market evolve.

5.3.1. TOU proposed period changes

The following figure demonstrates the changes in the peak (1), standard (2), and off-peak (3) periods between the current TOU costs and tariffs and the proposed TOU costs and tariffs.

Existing TOU time periods

	High			Low		
	Weekday	Saturday	Sunday	Weekday	Saturday	Sunday
0	3	3	3	3	3	3
1	3	3	3	3	3	3
2	3	3	3	3	3	3
3	3	3	3	3	3	3
4	3	3	3	3	3	3
5	3	3	3	3	3	3
6	1	3	3	2	3	3
7	1	2	3	1	2	3
8	1	2	3	1	2	3
9	2	2	3	1	2	3
10	2	2	3	2	2	3
11	2	2	3	2	2	3
12	2	3	3	2	3	3
13	2	3	3	2	3	3
14	2	3	3	2	3	3
15	2	3	3	2	3	3
16	2	3	3	2	3	3
17	1	3	3	2	3	3
18	1	2	3	1	2	3
19	2	2	3	1	2	3
20	2	3	3	2	3	3
21	2	3	3	2	3	3
22	3	3	3	3	3	3
23	3	3	3	3	3	3

Proposed new TOU time periods

	High			Low		
	Weekday	Saturday	Sunday	Weekday	Saturday	Sunday
0	3	3	3	3	3	3
1	3	3	3	3	3	3
2	3	3	3	3	3	3
3	3	3	3	3	3	3
4	3	3	3	3	3	3
5	3	3	3	3	3	3
6	1	3	3	2	3	3
7	1	2	3	1	2	3
8	2	2	3	1	2	3
9	2	2	3	2	2	3
10	2	2	3	2	2	3
11	2	2	3	2	2	3
12	2	3	3	2	3	3
13	2	3	3	2	3	3
14	2	3	3	2	3	3
15	2	3	3	2	3	3
16	2	3	3	2	3	3
17	1	2	2	2	3	3
18	1	2	2	1	2	2
19	1	3	3	1	2	2
20	2	3	3	1	3	3
21	2	3	3	2	3	3
22	3	3	3	3	3	3
23	3	3	3	3	3	3

Figure 9: Proposed changes to the peak, standard and off-peak periods of the TOU tariffs

5.3.2. TOU proposed peak, standard, and off-peak rate changes:

Based on requests to reduce winter prices, Eskom reviewed the prices and TOU ratios between the peak, standard, and off-peak periods as well as the high-demand and low-demand seasons. The final changes proposed using the above periods in Figure 9 considered the effect and impact of changing the rates. If the winter price is reduced, it would mean that other prices in all other time periods would have to increase. n to be revenue neutral.

Too much of a reduction of the winter (high-demand season) rates would increase the summer rates (low-demand season) drastically and reduce the signal for customers to respond to the tariff in winter. The winter TOU period is the time when the avoidance of load shedding is far more critical from a national health, economic, and safety perspective. The changes could not be based only on cost, but on price signals to ensure that demand would be managed in times of constraints and surplus.

The rates are as follows, comparing the WEPS rates before TOU restructuring and then the rates after the TOU restructuring).

Table 4: Wholesale purchase TOU rates excluding losses

	Wholesale energy rates					
Season	High-demand			Low-demand		
Period	Peak	Standard	Off-Peak	Peak	Standard	Off-Peak
1) Existing ratios	8.00	2.31	1.18	2.50	1.67	1.00
2) Existing TOU ratios c/kWh	370.94	112.36	61.03	121.03	83.28	52.84
3) Updated CTS existing TOU ratios c/kWh	432.92	125.00	63.86	135.28	90.38	54.12
4) New ratios	6.00	1.50	1.00	2.49	1.40	1.00
5) Updated new TOU ratios c/kWh	301.98c	75.49c	50.33c	125.32c	70.46c	50.33c
6) Difference between current and new ratios c/kWh	-68.96c	-36.87c	-10.70c	4.29c	-12.82c	-2.51c
7) Difference existing WEPS vs New CTS TOU c/kWh	61.98c	12.64c	2.83c	14.25c	7.10c	1.28c
8) Difference New CTS TOU vs Old CTS TOU	-130.94c	-49.51c	-13.53c	-9.96c	-19.92c	-3.79c

When comparing the proposed wholesale purchase rates and structure to the existing retail rates (excluding losses), the following can be noted:

- The energy charges have generally reduced, because of the introduction of the GCC.
- The winter peak rate ratio has decreased from a 1:8 ratio to a 1:6 ratio (see points 1 and 4 above).
- This ratio change reduced the winter prices and increased the summer peak prices (see points 2 and 5 above).

5.4. Introduction of a fixed charge for the provision of generation capacity applicable to loads, the generation capacity charge

Wholesale electricity pricing structures always need to encourage the efficient use of electricity. Wholesale electricity sales should be based on TOU energy prices to promote the efficient use of electricity as well as standby / generation capacity charges applied as a demand charge. The wholesale tariff structure needs to reflect the true costs in the supply chain and highlight different products and services arising from changes in the industry. Given the fixed and variable costs of generators, the view is that generators' costs should be recovered through a combination of capacity charges (R/kVA) and energy charges (c/kWh). Against this background there is merit in pointing out issues relating to fixed and variable charges, especially at the wholesale level.

A customer's energy demand charge may not be an accurate reflection of costs imposed on generators, considering that the customer's peak demand and the system peak may not occur at the same time. However, given the growth in variable energy resources, the requirement for back-up capacity is not related to the demand peak, as may have been the case historically.

Where a customer's peak demand is not strongly correlated with other customers this reduces the burden on the system from a total capacity point of view but allows that the capacity costs incurred by Eskom in ensuring back-up capacity on the network can be dispersed among all consumers and reduces the absolute capacity required for backup. A stand-by/capacity demand charge could result in high costs for low load factor customers, which might be unpopular, but indicates the true cost of required back-up on all consumers. It will also function as an incentive on low-load-factor customers to either change their demand patterns or to install own battery or other storage or peak-shifting systems, which, if it comes at a lower cost than the system cost of establishing additional peak capacity, will imply overall net gain to the South African economy.

A generation capacity standby charge is applicable to recover capacity costs associated with providing backup power when the customer's generator is out of service. As such, the standby charge functions as an insurance premium, which enables the customer to avoid incurring the cost of own back-up capacity

It should be noted that standby or backup generator capacity is also constantly provided to customers who do not have their own generators. For example, the industry needs to carry sufficient plant and operating reserves to meet the needs of a customer with large switchable block-loads. These customers are currently allowed to switch their loads in or out without notice or incurring standby charges.

However, in a situation such as this there is the certainty that over a period, for example, an annual cycle, such a customer who does not have their own generation capacity would consume sufficient volume of electricity to cover the fixed capacity costs applicable to that customer's load factor and profile (assuming that capacity charges are recovered through volumetric tariffs). This situation, therefore, is different for a customer who has a generator that does not produce electricity constituently and, there is no long-term intention or certainty that such a self-generating customer (or wheeling customer) would consume a sufficient volume of electricity to cover the fixed capacity costs applicable to that customer's load factor and profile.

For this latter type of 'self-generating' customer, it could be compared to an insurance policy with hourly premiums that only requires the normal hourly premium to be paid for the hour during which a claim is registered. Clearly that will be unacceptable – such customer will be required to pay a premium for all hours for which risk coverage is received. In contrast, the 'non-self-generating' customer with a similar frequency of load fluctuation for his switchable block-load will be paying for the coverage by virtue of his high volume of consumption, given that the 'premium' is embedded in the volumetric consumption charge.

It is thus proposed that a generation capacity charge be introduced and applied to all customers at the wholesale level (and consequently carried through to retail customers) to ensure sufficient dispatchable capacity on the South African grid to meet customer demand.

5.4.1. How the generation capacity charge is derived from costs

There are two aspects of generation capacity charges; one being the capacity charge raised by generators to the Eskom Wholesaler and the other is the generation capacity charges raised by the Wholesaler to Eskom Distribution to be recovered through the retail tariffs (and in future by parties that qualify to purchase at the wholesale level).

- Capacity charges are paid by the Eskom Wholesaler to Eskom Generators and IPPs that are dispatchable, in addition to energy charges for all energy supplied by these Eskom Generators and IPPs.
- Eskom Distribution buys energy and capacity from the Wholesaler, and these rates and structures are the wholesale purchase price. The wholesale purchase price is also then split into a retail generation capacity charge and TOU energy charges.

The method used to calculate the capacity charge to loads is not based on the cost reflective capacity charges paid to the dispatchable generators (which is in turn based on the fixed costs of each of the generators) as this would result in very high fixed charges to consumers. The approach adopted is to calculate the generation capacity charge based on the fixed costs associated with the cheapest generators that would provide back-up in a system with high renewable penetration – in this case a combined cycle gas turbine. This capacity charge is, therefore, much lower than that paid to a coal-fired plant (with high fixed costs) and equates to about 20% of total generation costs being recovered through the fixed generation capacity charge.

5.4.2. Allocation of generation capacity costs

In order to fairly assign generator capacity costs across all customers on the Eskom electrical network, a cost allocation exercise must be performed. In general, cost allocation is the process of apportioning functional costs (i.e., network lines and transformers, upgrade and maintenance costs, etc.) to specific customers, or categories of customers, based on their individual demand patterns.

The wholesale generation capacity cost has been allocated in the same manner as all purchase, network and retail costs, using the Eskom CTS. The CTS applies the average and excess cost allocation methodology, which uses customers' forecast demand and load factor as drivers to allocate costs. It is important to note that the generation capacity charge is split out of the current energy charges and takes into account only those costs explicitly associated with generation.

The output of the average and excess process is a diversified peak demand value per customer category, which reflects each customer's peak demand contribution to the total peak demand This is then used to allocate the generation capacity costs as purchased at the wholesale level to each customer category based on the ratio of the peak demand per customer to the total peak demand.

5.4.3. How the retail generation capacity charge is calculated and charged

Once the total generator capacity cost has been allocated among the various Eskom customer categories, a R/kVA value must be assigned to each customer category such that the total fixed generation cost is recovered throughout the financial year via electricity tariffs. This is achieved by dividing the allocated generation capacity costs by the annual utilized capacity (the higher of the notified maximum demand or maximum demand registered during a rolling 12-month period per customer category).

$$Customer\ Unit\ Costs\ (R/kVA) = \frac{Customer\ Allocated\ Costs\ (R)}{Annual\ Utilized\ Capacity\ (kVA)}$$

This value represents the final generation capacity charge which will be assigned to each customer category.

5.5. Municipal tariff rationalisation

In November 2017, Eskom submitted the following to NERSA:

- The combination of Eskom's existing suite of multiple tariffs applicable to local authorities into only three tariff categories:
    - A version based on Megaflex (rates and structure), meaning that the Nightsave Urban Large and Small, Nightsave Rural, Miniflex, and Ruraflex tariff categories would cease to exist
    - A version based on Businessrate (rates and structure), meaning that the Landrate and Homepower tariff categories would cease to exist
    - In the above submission proposed no change in the Public Lighting tariffs.

In February 2019, NERSA provided Eskom with the following decision:

NERSA' DECISION ON ESKOM'S APPLICATION FOR THE RATIONALISATION OF MUNICIPAL TARIFFS FOR THE 2018/19 FINANCIAL YEAR

The National Energy Regulator (NERSA), with reference to your correspondence dated 6 November 2017 made a decision on the Eskom's application for the relationalisation of municipal tariffs on the 28 November 2018 as follows:

1. The Energy Regulator decided **not to approve** the Eskom's application for the rationalisation of municipal tariffs for the implementation in the 2019/20 financial year;
2. Eskom should submit the Cost of Supply study (COS) to support the rationalisation. This also needs to justify any cross-subisidation that must take place.

Therefore, this submission is not based on the initial proposal, but uses new tariff rates based on the CTS, as follows:

- A new tariff LPU based on the Megaflex structure, but rates calculated by combining the costs of Megaflex, Miniflex, Nightsave Urban Large and Small, Ruraflex and Nightsave Rural for local-authority supplies
- A new SPU tariff based on the Business structure, but rates calculated by combining the costs of Landrate, Businessrate and Homepower for local-authority supplies.
- The introduction of a Generation capacity charge in a phased in approach of 50% fixed and 50% variable charges, to align with the Landrate and Homepower tariffs which have significant volumes in the Municrate tariff.
- Public Lighting tariffs based on the cost-reflective CTS results
- The question of inter-tariff cross-subsidisation is dealt with as the above tariffs are now based on cost, except for the existing socio-economic subsidies (Also refer to paragraph 5.12)
- The impact of all the proposed changes in this document is provided in Annexure A and in Annexure D – Proposed changes to rate components
- The municipal tariff rates in this submission are shown in 12-month values (based on the Eskom financial year April to March), and in 9-month values (based on three months April to June current tariffs, nine months at the revised CTS based tariffs.) Refer further to Annexure F – Proposed retail rates in 2021/22 rand values (excluding VAT), Table 37, Table 38, Table 39, and Table 40.

The following benefits will accrue to both Eskom and municipalities by rationalising the local-authority tariffs:

- The new tariff options will reduce complexity:
- There will be one tariff for large power users.
- There will be one tariff for small power users.
- The Public Lighting tariff will remain unchanged.
- Local-authority tariffs will be treated as urban tariffs.
- Two tariffs will simplify the sales and revenue forecasting process in both Eskom and municipalities:
- Two tariff options simplify the process of determining the electricity purchase cost for municipalities.
- Eskom also benefits in terms of its sales and revenue forecasting process, as it has less tariff variation for municipalities.

The following figure demonstrates the impact of updating the tariffs with the CTS, per local-authority tariff.

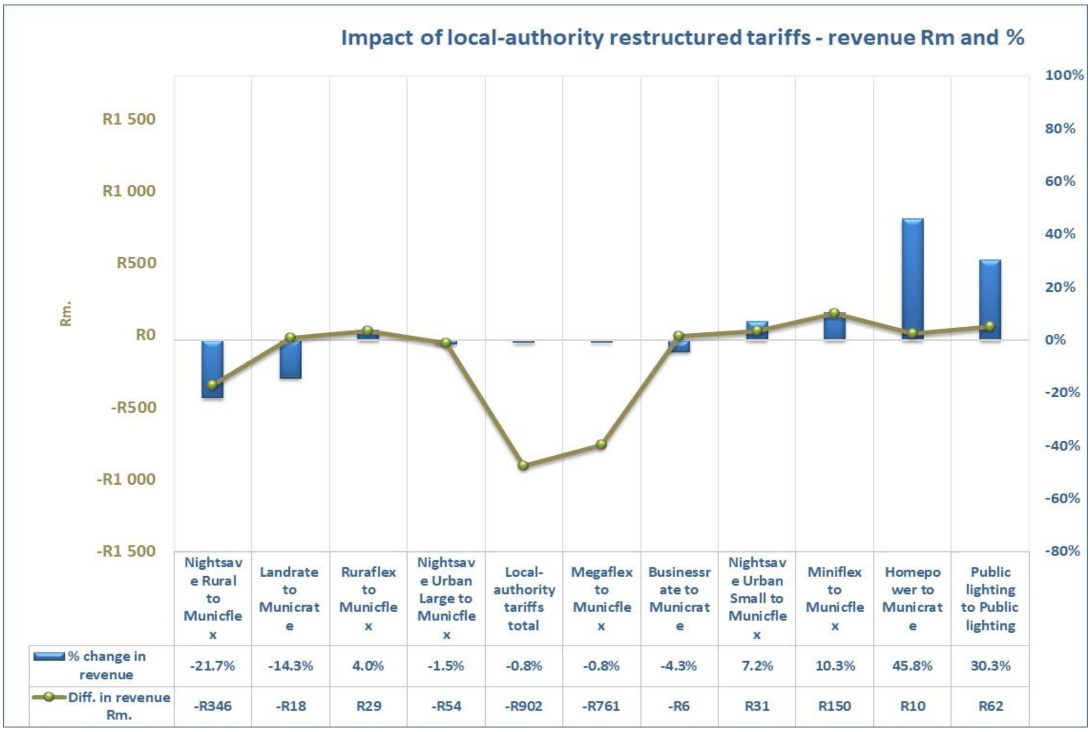


Figure 10: Impact of the municipal tariff rationalisation per local-authority tariff

Refer to Annexure A – Local-authority tariff impacts for more detail on the impact of the tariff changes on the local-authority tariffs.

5.6. Distribution network-related charges

5.6.1. Distribution use-of-system (DUoS) network charges

The Distribution business costs are largely fixed in order to deliver the capacity needed. If network charges are not cost-reflective and are recovered through variable/volumetric charges such as c/kWh, this places the Distribution business at risk of not recovering costs when the volume is reduced. This could be as a result of economic conditions, increased usage of distributed generation, batteries, demand-side management, and the general improvement in smarter and more energy-efficient appliances.

The reliance on the grid is not necessarily reduced, unless the customer goes totally off-grid, but charges for having the grid as a backup (availability at any time) or, in the case of net metering, using the grid as a bank are still required. The introduction of PV, in particular, could result in the customer being a zero net or very low net consumer, and therefore, where network costs are recovered through variable charges, this results in a loss of revenue not commensurate with a reduction in costs. It also results in customers with PV being subsidised by customers without PV. This adds to the potential of a utility death spiral if there is no fair recovery of the grid costs through variable charges. This means a review of tariff structures, in particular for small power users, to ensure adequate recovery of fixed costs.

If network charges are designed to be a fixed charge, this reduces the revenue risk, and the signal to manage consumption and to manage this consumption in peak times. This may result in inefficient use of the network and the Distribution business having to invest uneconomically. For this reason, network charges should recover an appropriate balance between fixed and variable charges and ensure that there is an appropriate signal for peak demand and consumption.

The following figure shows the balance between customer risk and utility risk, depending on the tariff structure choice.

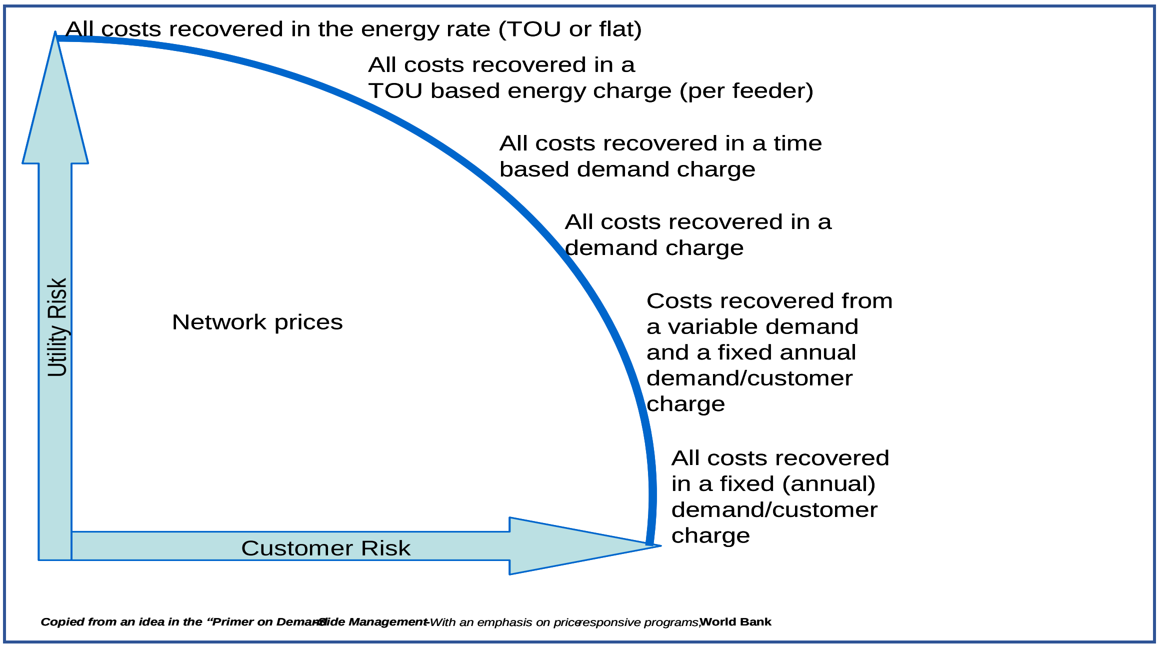


Figure 11: Network charge design and associated risks

This figure shows the options available to be considered when designing a network charge. If all fixed costs are recovered through, for instance, an annual lump sum fixed charge, there is little utility risk, and if all costs are recovered through total variable charges, there is very little customer risk. Fixed charges are, however, not popular with low-consumption customers, as these fix the amount payable each month and also reduce customers' benefit when consumption is reduced. However, this results in an under-recovery of revenue and subsidisation by customers with fixed charges.

Internationally, there is recognition that network tariffs need to be restructured to move away from variable-usage-based charges to tariff structures that better reflect the fixed costs and also the demand a customer imposes on the network.

This is an appropriate mechanism for coping with reduced sales because of rooftop PV to ensure that customers with PV are not overly compensated and do not burden other customers with higher price increases, as the cost of managing the grid must be paid by someone.

For all tariffs that have network charges, these were updated based on the CTS results and then split into a fixed portion (based on the utilised capacity) and a variable portion (based on maximum demand or consumption).

The fixed portion of the network charges (the network capacity charge or NCC) has been increased slightly, and the variable portion (the network demand charge or NDC) has been commensurately reduced. No additional revenue is recovered through the rebalancing; that is, the overall impact of all the changes is revenue-neutral (equals the MYPD allowable revenue).

Also refer to Section 6, which shows the total impact per tariff charge type and Annexure D – Proposed changes to rate components, paragraph D.4.

5.6.2. Distribution use-of-system loss factors

For Distribution-connected loads, the loss factors were updated as contained e in the CTS and the overall losses are 8.5%. These are loss-factors based on voltage and density. The lower the voltage the more assets have to be used and the higher the technical losses. The same is true for areas with low densities such as rural areas where electricity has to be delivered over longer distances between customers. The inverse is true for customer's connected at higher voltage and in more densely populated areas. These loss factors are approved as part of the Schedule of Standard tariffs approved by NERSA.

For Distribution-connected generators, the same Distribution loss factors as for loads, will apply for the network charge rebate for generators. For all SPU tariffs, the loss factors are based on the urban 500V level and Transmission Zone 0.

The updated loss factors used to determine energy charges for loads and network charge rebates for Distribution-connected generators are provided in the following table.

Table 5: Updated Distribution loss factors

Voltage	Urban	Rural
< 500V	1.1512	1.1684
≥ 500V & < 66kV	1.1325	1.1523
≥ 66kV & ≤ 132kV	1.0599	0.0000
> 132kV/Transmission connected	1.0000	0.0000

5.7. Transmission network-related charges

5.7.1. Transmission use-of-system (TUoS) charges

Transmission use of system charges comprise:

- Transmission network charges for loads
- Transmission network charges for generators
- Transmission loss factors for loads
- Transmission loss factors for generators
- Ancillary service charges for loads and generators

Transmission designs its tariff based on the NERSA approved revenue requirement and these tariffs become a pass-through cost to Eskom Distribution as the retailer to all Eskom customers.

Transmission use-of-system charges are based on Transmission's cost-drivers, and allocation of costs using the methodology prescribed in the South African Grid Code. The Figure below illustrates the cost allocation stages followed to determine the Transmission charges and as indicated in the figure, the cost-drivers are based on the number of customers, the network capacity, the customer demand, the ancillary services provided and transmission losses. Accordingly, Transmission's costs are customer-driven, capacity or demand-driven and energy driven.

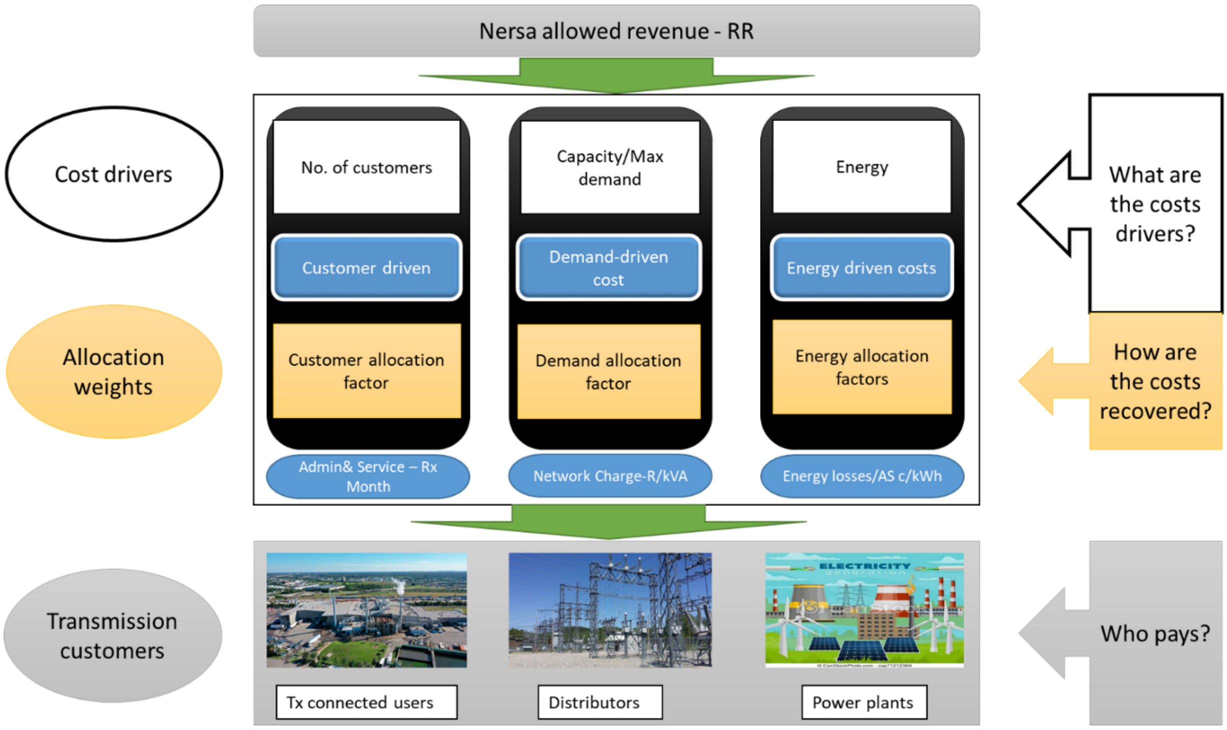


Figure 12: Transmission cost drivers and customers

Transmission recovers 50% of its revenue from generators and 50% from demand (load) customers. Both Transmission-connected generators and loads pay a charge based on the geographical pricing zone in which they are located, and these zones differ for generators and loads. There are six pricing zones for generators, namely, the Cape, Karoo, KwaZulu-Natal, Vaal, Mpumalanga, and Waterberg Zones. The pricing zones for generators are determined through power-flow studies, taking into account the generators' usage of transmission assets, the impact on technical losses, and their geographical location.

The TUoS charges for loads are differentiated into four zones based on the distance of the load, in kilometres, from Johannesburg.

5.7.2. Transmission network charges for generators

The network charges and losses charges for the generators reflect the relative location of each generator and international import point of connection. The figure below depicts the South African map with the location of each zone as it is currently being applied. The network costs for generators are recovered through the following charges:

- A network charge based on the transmission zone is derived using the distribution factor methodology, which calculates the network charges on a nodal basis. Nodes are subsequently allocated into their respective generation zones, and the charges are aggregated per zone. Eskom is in the process of reviewing the zones and their charges, as these were based on the location of generation in 2011. The current system has changed since then requiring a review
- Below are the current zones for generators.

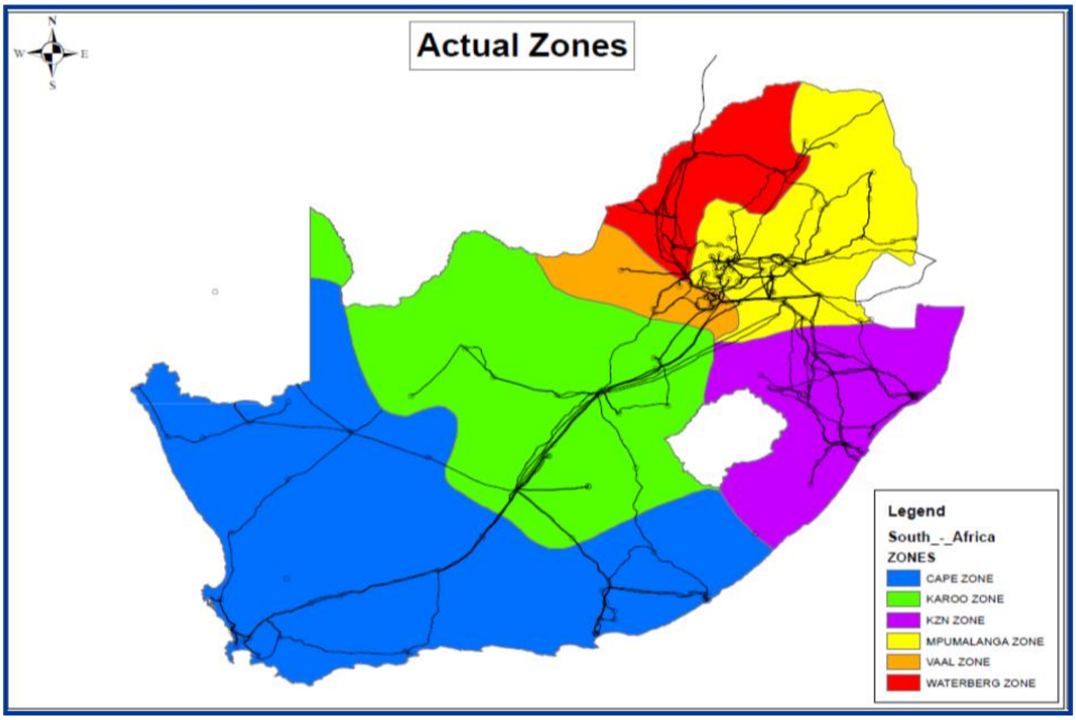


Figure 13: Transmission zones for generators

Below are the proposed use-of-system charges applicable to Transmission connected generators

Table 6: Proposed Transmission network charges for generators

Network charges for Transmission connected generators	R/KW
Cape	R 0.00
Karoo	R 0.00
Kwazulu-Natal	R 3.05
Vaal	R 10.15
Waterberg	R 13.01
Mpumalanga	R 12.07

New studies are underway that would update the current charging structure with the more current data and network changes, and they are planned to be submitted at a later stage, separate from this submission.

5.7.3. Transmission network charges for loads

The TUoS tariffs for loads are based on an historic concentric-pricing approach, based on a cumulative radius from Johannesburg of 300 km. This zoning methodology is arbitrary and based on outcomes of the 1985 De Villiers Commission of Inquiry. Therefore, it does not reflect the actual relative usage of transmission assets by the loads, but is intended to recover 50% of Eskom Transmission’s revenue. The network charge is increased for each zone.

- For direct Transmission-connected customers, the network charges used in the CTS are based on the charges provided by Transmission and are geographically differentiated by the transmission zones.
- For Distribution-connected customers, the Transmission network charges are geographically differentiated by the transmission zones and voltage.
- The direct Transmission network charges are calculated to take into account the diversified demand of all the embedded customers of Distribution, which will be much higher within the Distribution network than the demand at the main transmission substation level.

This adjustment is necessary, as the direct TUoS charges are applied to the undiversified demands of all customers, which would result in an over-recovery of the Transmission-related costs. This gives a lower rate for the TUoS charge for customers connected to the Distribution network than the direct TUoS network charge, as the cost is divided by a greater volume.

The wholesale Transmission network charges for loads connected at the Transmission level are shown in the next table.

Table 7: Proposed Transmission network charges for loads

Transmission connected loads	NCC R/kVA
≤ 300km	R 11.14
> 300km & ≤ 600km	R 11.26
> 600km & ≤ 900km	R 11.37
> 900km	R 11.48

The transmission zones for loads are depicted in the figure below.

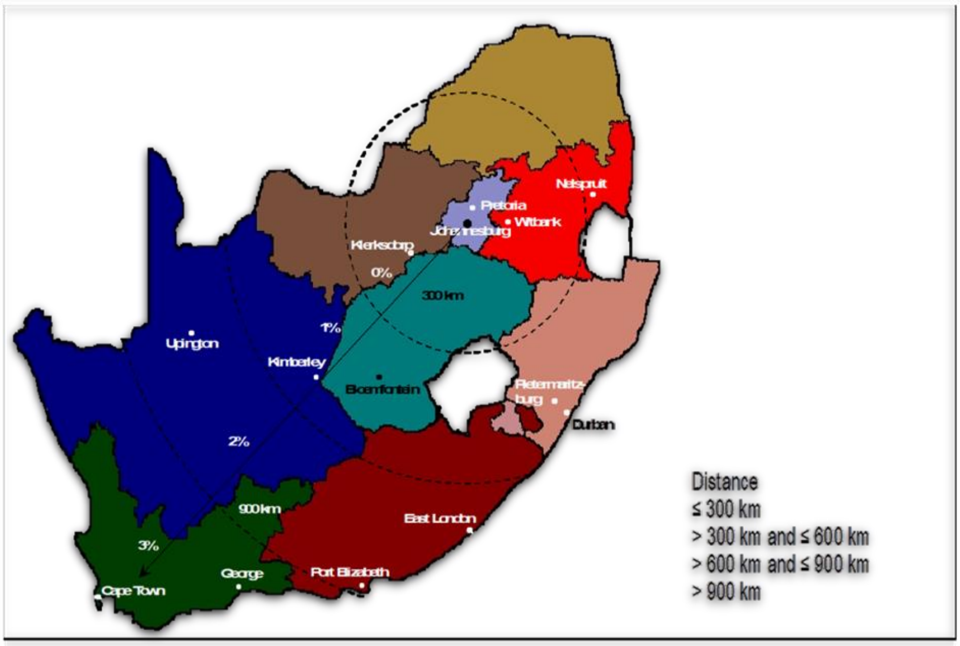


Figure 14: Transmission zones for loads

5.7.4. Transmission losses

Electrical losses occur as a result of transporting electricity from the source (the generator) to the load (the customer). As generators are paid for the energy produced and the customer is charged for the energy received, the difference results in a cost to Distribution and Transmission for the "lost" energy. This is charged for as electrical losses. Average loss factors, not actual losses per customer, are used.

- All customers pay for technical losses through their tariff rates, and the cost of losses is added to the energy rates. Eskom also publishes the loss factors as part of its Schedule of Standard Prices.
- The loss factors are updated based on the CTS, and as a result, there has been a change from the current loss factors.

5.7.4.1. Transmission losses payable by loads

The loss factors for loads are differentiated based on the relative distance of loads from Johannesburg. Loads are charged for transmission losses to recover 50% of the cost of the losses.

For loads connected directly to the transmission system, the loss factors like the TUoS charges are determined by geographical location based on the concentric zones. The further away the customer is from Johannesburg, the greater the technical losses charge.

The cost of electrical losses is recovered as a function of the appropriate loss factors for the relevant zone, the voltage level, and the time-of-use cost of energy. As these are energy-related costs to cover the difference between the amount produced and sold, they need to be recovered from all customers.

The updated Transmission loss factors used to determine energy charges for loads and network charge rebates for Distribution-connected generators are provided in the table below.

Table 8: Proposed Transmission loss factors applicable to loads

Transmission connected loads	Loss factor
≤ 300km	1.0026
> 300km & ≤ 600km	1.0126
> 600km & ≤ 900km	1.0226
> 900km	1.0326

5.7.4.2. Transmission losses payable by Transmission-connected generators

Eskom is proposing to amend the current loss factors applicable to Transmission connected generators. Currently in certain Transmission zones the loss factors are negative, effectively meaning that Eskom could pay a generator for being located in this specific zone. This principle at the time assumed a generator whose injections increase transmission losses faces a positive loss factor, which results in a charge, while a generator whose injections reduce transmission losses faces a negative loss factor, which results in a rebate.

The loss factors are added or rebate the Transmission network charge applicable to generators. Below are the current loss factors per zone.

Table 9: Current Transmission loss factors applicable to generators

Loss factors for Transmission connected generators	Loss factor
Cape	0.971
Karoo	0.995
Kwazulu-Natal	1.004
Vaal	1.020
Waterberg	1.023
Mpumalanga	1.021

It is to be noted that in the Cape and Karoo, the loss factor is less than 1 as per *Table 9*, and the network charges are zero (refer to Table 6). This means per the formula for the raising of the charges (set out below) results in a negative charge.

*Losses charges = energy produced in **peak, standard** and **off-peak** periods x WEPS rates excluding losses in each TOU period x (**Transmission loss factor** (for generators) -1)/**Transmission loss factor** (for generators).*

It is not possible to pass-through negative charges, and for this reason Eskom is proposing that the Loss factors for the Cape and Karoo zone are set to 1 as follows:

Table 10: Proposed Transmission loss factors applicable to generators

Loss factors for Transmission connected generators	
Zone	**Loss factor**
Cape	1.00000
Karoo	1.00000
Kwazulu-Natal	1.01495
Vaal	1.00026
Waterberg	1.01352
Mpumalanga	1.01487

5.8. Ancillary service charges

The ancillary service charge covers the cost of providing ancillary services. These costs include the cost of:

- reserves;
- black-start and islanding;
- constrained generation; and
- reactive power.

The Transmission System Operator purchases these services from generators and some loads. All customers are charged for ancillary services. The ancillary services charge recovers 50% of the cost from generators and the other part from loads. This charge is raised as a c/kWh charge to all users of the networks, generators, and loads, based on voltage only. All tariffs contribute to these costs. The updated ancillary service charges for generators and loads are provided in the next table.

Table 11: Proposed ancillary service charges

Voltage	Ancillary service charge c/kWh
< 500V	0.22c
≥ 500V & < 66kV	0.22c
≥ 66kV & ≤ 132kV	0.21c
> 132kV*	0.19c

5.9. Residential tariffs

Residential tariffs need an overhaul. IBT as a tariff structure is no longer appropriate because of customer perceptions and provides uneconomic incentives for customers installing embedded generation.

Eskom proposes removing the IBT structure, into a single energy rate charge, reintroducing a fixed, more cost-reflective network and retail charges for Homepower, and introducing a TOU residential tariff with an offset rate for net billing.

5.9.1.Homepower

Eskom proposes the amendment of the Homepower structure to align with that of the other SPU tariffs. This will also remove the IBT energy charge structure.

The current Homepower tariff (inclining block rates) structure does not give the right economic signals, for example:

- the use of inclining block tariffs greatly incentivises higher-consumption customers to use alternative energy sources and energy efficiency, resulting in a real revenue loss not commensurate with a real cost reduction;
- the reduction in consumption by these customers because of the switch to alternative energy sources such as PV results in subsidies being unfairly distributed; these customers (mostly affluent, who then reduce consumption) are subsidised by those without PV;
- there are limited signals for the actual demand customers impose on the network; and
- there is a lack of TOU signals for energy consumed (and exported).

The current Homepower IBT tariff structure provides a cross-subsidy at low consumption levels. This means that the cost is higher than the tariff at lower consumption levels and receives a subsidy. Refer to Figure 36 and Figure 36, where this is demonstrated.

Because current tariffs recover both network and energy costs through volumetric energy (c/kWh) charges, they no longer reflect the changing energy environment. For example, a tariff with only a c/kWh energy charge makes alternative energy sources look very attractive, but this does not reflect the proper avoided cost. The economic test should be against the energy-only costs and not a bundled tariff.

The proposed Homepower structure is based on the updated TOU energy costs (using an average load profile for residential customers), with a cost-reflective network, ancillary service, and service/administration costs. The proposed changes will result in increased fixed charges, but the revenue from Homepower will, on average, decrease slightly for Homepower to be equal to cost. Some rebalancing was done between the Homepower supply size categories to reduce the subsidies received and paid between each category. This change does not aim to recover additional revenue, but to properly unbundle costs into tariff charges.

Unbundling and restructuring will remove artificial subsidies, provide greater transparency of costs, ensure the correct economic signal, and reflect a more accurate payback period by comparing the energy cost of the utility versus the energy cost of the alternative and not including network cost bundled with the energy in the analysis.

The challenge with Homepower has been that some of the Homepower tariff sub-category revenues are higher than cost based on current tariffs and, for others, are lower than cost. In addition, converting from a non-cost-reflective IBT structure to a more cost-reflective structure, will mean a correction of the subsidies that low-consumption Homepower customers currently receive. Low-consumption Homepower 4 customers have the choice to convert to Homelight 60A by downgrading from an 80A supply size to a 60A size. For the other tariffs, which are all three-phase supplies, it is not considered appropriate to provide a subsidy at low consumption.

The following table demonstrates the rebalancing done at an overall Homepower tariff category revenue level to recover the costs reflected in the CTS.

Table 12: Homepower impact (R million)

Homepower summary	Current revenue Rm.	Revised revenue Rm.	% impact	Cost Rm.
Homepower 1	R 1 397	R 1 258	-10%	R 1 203
Homepower 2	R 286	R 301	5%	R 299
Homepower 3	R 134	R 130	-3%	R 128
Homepower 4	R 1 224	R 1 222	0%	R 1 281
Homepower Bulk	R 2	R 2	3%	R 3
Total	R 3 043	R 2 912	-4%	R 2 913

The following table shows the percentage impact for the average Homepower customer.

Table 13: Homepower current average month bill versus revised monthly bill

Homepower	Current average monthly bill	Proposed average monthly bill	Difference R	Difference %	Average monthly consumption
Homepower 1	R 2 857	R 2 571	-R 286	-10%	1 204
Homepower 2	R 2 892	R 3 041	R 149	5%	1 131
Homepower 3	R 7 948	R 7 704	-R 244	-3%	3 169
Homepower 4	R 1 347	R 1 345	-R 2	0%	578
Homepower Bulk	R 7 262	R 7 487	R 225	3%	2 444
Total Average	R 2 010	R 1 924	-R 86	-4%	

5.9.2. Homeflex - residential TOU and net-billing tariff

Eskom proposes the introduction of a residential time-of-use tariff, called Homeflex, for its urban residential customers. The Homeflex tariff is a dynamic tariff and a market tool that is able to support a more optimal operation of the power system while providing a benefit to customers. This tariff also provides a net-billing rate that provides compensation for energy exported.

This tariff is more cost-reflective in structure and adaptable to evolving customer needs, changes in technology, and the changing energy environment.

The design of the Homeflex tariff is based on the proposed new TOU structure energy charges, the GCC, network, ancillary service, service/administration charges for the residential customer category, and a net-billing rate. It has the same GCC, network, retail, and ancillary service charges as Homepower, but the energy charges are TOU rates. Refer further to Annexure E for more detail. **Error! Reference source not found.**This tariff will be mandatory for customers with SSEG with the approved post-paid smart metering device, and voluntary for all other residential customers who do not have SSEG.

5.9.3. Homelight

For the Homelight tariff, the aim is to move away from the IBT structure into a single energy rate structure based on the average Homelight current revenue/total sales. IBT is an unpopular structure, is difficult for customers to understand, and causes perverse behaviour when purchasing at the high block rates.

For large low-income/multiple-family dwellings, the assumption that low consumption equals poor may not necessarily be true. Multiple dwellings may also be supplied from a single electricity supply point. An IBT structure has a significant impact on these customers. In addition, there are more affluent customers, for example, with holiday homes that unfairly benefit from the inclining block rate.

Eskom conducted a survey on the inclining block tariff in January 2022 to assess customer understanding and opinions of the current inclining block rate tariff, and to substantiate the perceptions listed above.

Feedback from the online survey indicated that 59% of the participants have a 75% - 100% understanding of how the tariff works, while 11% of the participants found it difficult to understand and find it hard to explain the tariff to customers. Of the participants, 54% indicated that they have a negative opinion about the tariff, because of the tariff being perceived as punitive, unfair, stating challenges around affordability and the high cost of living. Only 17% indicated that they support the tariff and that it promotes an energy efficient culture. A total of 67% of the participants also shared that they do not believe that you need to pay more per unit if you use more electricity.

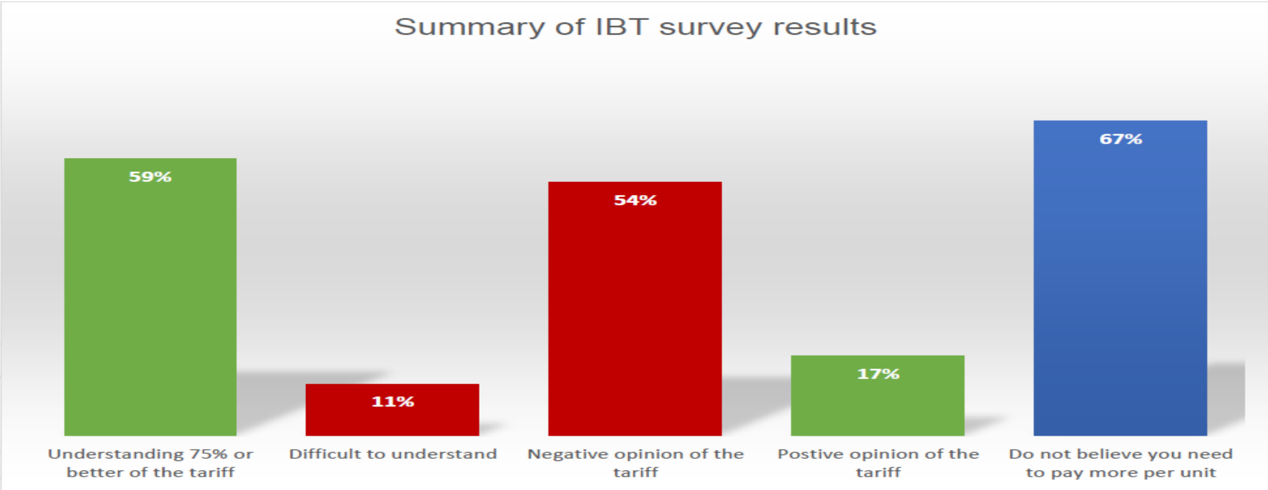


Figure 15: IBT survey results

The details of the survey results are provided in Annexure G

By moving away from an IBT structure, there will be an impact in that lower-consumption customers will pay slightly more and higher-consumption customers less, as demonstrated in the following figures.

	0 kWh/m	200 kWh/m	350 kWh/m	600 kWh/m	700 kWh/m	800 kWh/m	1 000 kWh/m	1 200 kWh/m
Current tariff	R	R280	R490	R887	R1045	R1204	R1521	R1838
Cost reflective	R114	R488	R769	R1236	R1423	R1610	R1985	R2359
Proposed tariff	R	R282	R494	R847	R988	R1129	R1412	R1694

	0 kWh/m	200 kWh/m	350 kWh/m	600 kWh/m	700 kWh/m	800 kWh/m	1 000 kWh/m	1 200 kWh/m
Current tariff	R	R317	R555	R951	R1220	R1489	R2028	R2567
Cost reflective	R244	R677	R1002	R1544	R1760	R1977	R2410	R2844
Proposed tariff	R	R338	R592	R1015	R1184	R1353	R1691	R2029

Figure 16: Homelight 20A and Homelight 60A - cost, current tariff, and revised tariff

The following tables compare the current tariff with costs. It can be noted that the Homelight 20A low energy block does not fully recover energy costs and does not recover network, retail, or ancillary service costs.

Table 14: Homelight current tariffs rates and revenue

	Current Tariff book rates and revenues (2021/22)						
	Tariff book energy charge c/kWh Block 1	Tariff book energy charge c/kWh Block 2	Tariff book ancillary service charge c/kWh	Tariff book NDC c/kWh	Tariff book NCC R/POD/day	Tariff book service and admin R/POD/day	Current tariff revenues
Homelight 20A	139.99c	158.62c	0.00c	0.00c	R 0.00	R 0.00	**R 7 603 038 967**
Homelight 60A	158.44c	269.31c	0.00c	0.00c	R 0.00	R 0.00	**R 5 491 995 965**
							R 13 095 034 932

Table 15: Homelight cost-reflective rates

	Cost reflective						Current revenue versus cost				
	Cost reflective energy charge c/kWh	Cost reflective generation capacity charge R/POD/day	Cost reflective ancillary charge c/kWh	Cost reflective network demand charge	Cost reflective network capacity charges R/POD/day	Cost reflective service & admin charge R/POD/day	Service and admin charge c/kWh	Cost reflective R/y	Difference between cost and current revenue	% subsidy received	Total costs c/kWh
Homelight 20A	112.40c	R 0.90	0.22c	74.48c	R 2.16	R 0.68	*23.28c*	**R 13 002 376 471**	**R 5 399 337 504**	**71%**	241.40c
Homelight 60A	110.51c	R 2.16	0.22c	105.94c	R 5.18	R 0.68	*13.81c*	**R 8 917 601 367**	**R 3 425 605 402**	**62%**	274.58c
	111.69c	**R 1.23**	**0.22c**	**86.31c**	**R 2.96**	**R 0.68**	***19.72c***	**R 21 919 977 838**	**R 8 824 942 906**	**67%**	**253.88c**

Table 16: Homelight proposed tariff rates

Proposed tariff rates			
	Block 1 energy charge	Block 2 energy charge	Single energy charge
Homelight 20A	NA	NA	141.15c
Homelight 60A	NA	NA	169.10c

Note that the average rate for Homelight 20A now at least almost recovers energy costs (which the current first block did not). The principle for all tariffs, even those subsidised, should be that energy costs should be recovered.

This structural change is revenue-neutral to the existing Homelight tariff, that is, recovers the same revenue as the current tariffs, and no change has been made to the overall subsidy received. This structural change is not linked to any of the other tariff changes c in this document, as it is not based on cost.

5.10. Service charges converted to R/POD and not R/account

Currently, the administration charge is per point of delivery, and the service charge is per account. Eskom proposes changing the methodology so that both the administration charges and the service charges will be raised per point of delivery and differentiated on size. No change is proposed to the current size categories.

The rationale is that a customer could have many PODs under one account and pay the same service charge as a customer with one account and one POD. This is not equitable or fair, as more retail resources are used where there are multiple PODs to one account. This service charge will not be raised for each transaction separately where the reconciliation of energy is done for wheeling, offset, and banking and where Eskom is the purchaser of energy for generators embedded in a municipality.

This change will mean that the service charges will decrease in value, but customers who have consolidated many points of delivery into one account may see an overall increase in rates. Customers with few PODs per account will see a reduction. This change, however, cannot be viewed in isolation from the other tariff changes, as the total impact of all changes will have to be considered.

5.11. Nightsave changes

Nightsave Urban is currently split into a Nightsave Urban Small category (1 MVA and below) and a Nightsave Urban Large category (> 1 MVA). It has been decided to combine these tariffs into one category again, based on the total cost for the Nightsave Urban tariff as a whole.

This decision was made as a step toward reducing the number of tariffs and the administrative challenges where customers around the 1 MVA supply size can have an actual bigger or smaller maximum demand. This would require actual tariff conversions between the two Nightsave Urban tariffs. On average, the existing Nightsave Urban Large and Small tariffs will increase on the proposed Nightsave Urban tariff. This change, however, cannot be viewed in isolation from the other tariff changes, as the total impact of all changes will have to be considered.

5.12. Subsidies

The following applies to subsidies in electricity tariffs (where the tariff is not cost-reflective):

- Subsidies may be within a tariff and based on the tariff structure, this is called intra-tariff subsidies. For example, where fixed costs are recovered through variable charges, this means that the subsidies are hidden and that higher-consumption customers pay the subsidies. IBT is a perfect example, but this is true for all current tariffs.
- It is also possible for some charges within a tariff category to be higher than cost and for others within the same category to be lower (as is done with the lower-voltage network charges of the urban LPU tariffs).
- furthermore subsidies may be as a result of pooling of costs (as is done with the Transmission network charges).
    - The above can only be corrected through structural changes, where some charges must increase, and others decrease. This can only be done once a tariff has been redesigned (usually based on a CTS study) and NERSA has approved such changes
- Subsidies may be applied for affordability and/or socio-economic reasons covering either or all, for usage, network, and connection cost. Where the tariff category as a whole may receive a subsidy, and other tariffs pay this subsidy, this is called an inter-tariff subsidy.
    - These subsidies being paid are typically more transparent, but for the receiving tariffs, they tend to be hidden.
    - The tariffs receiving subsidies are the rural tariffs (Landrate, Ruraflex, and Nightsave Rural) and the Homelight tariffs.
    - The overall level of subsidies for the subsidised rural and Homelight tariffs remains the same in this plan, but some changes have been made structurally within tariff categories.
- The subsidy charges (the electrification and rural subsidy (ERS) and affordability subsidy) in this plan have decreased because of the updating of the rates by the CTS study.
- There is no national directive, rule, or guideline on electricity subsidies, except for the policy positions in the EPP (EPP policy positions on subsidies) and the NERSA 2005 subsidy framework (the status of the latter is not known).
- Most subsidies are from legacy historical decisions, such as the then government's decision in the 1980s to cross-subsidise rural electrification.

Section 16 of the ERA states that NERSA may permit certain levels of cross-subsidies. NERSA has, at its discretion, determined subsidies over the years such as the lower tariff increases to the Homelight tariffs, which placed an additional burden on Eskom's urban non-local-authority LPU tariffs. Eskom has no mandate to make changes to socio-economic subsidies and has, therefore, kept these subsidy levels the same.

5.12.1. Inter-tariff subsidies

The inter-tariff subsidies are those paid by other tariffs to the Homelight 20A, Homelight 60A, Landrate, Ruraflex, and Nightsave Rural tariffs. The inter-tariff subsidies are currently recovered through the ERS charge from all the urban LPU tariffs and the affordability subsidy from only the non-local-authority urban LPU tariffs. These are socio-economic subsidies.

The following table provides an overview of current subsidies versus revised subsidies. Some rebalancing has been done between Nightsave Rural and Ruraflex, as Nightsave Rural has been paying subsidies, and Ruraflex's subsidies have been reduced to align these tariffs better.

Table 17: Inter-tariff subsidies

Subsidies received 2020/21	Cost Rm	Current Tariff Rm	Current subsidy received Rm	Current subsidy c/kWh	Revised Tariff Rm	Revised subsidy received Rm	Revised subsidy received c/kWh
Landrate	R 14 198	R 12 364	-R 1 835	(43.74)	R 12 364	-R 1 835	(43.74)
Ruraflex	R 10 488	R 8 397	-R 2 092	(40.78)	R 8 939	-R 1 549	(30.21)
Nightsave Rural	R 3 167	R 3 234	R 67	4.31	R 2 692	-R 475	(30.63)
Homelight 20A	R 13 002	R 7 603	-R 5 399.3	(100.24)	R 7 603	-R 5 399.3	(100.24)
Homelight 60A	R 8 918	R 5 492	-R 3 425.6	(105.48)	R 5 492	-R 3 425.6	(105.48)
Total	R 49 774	R 37 090	-R 12 684	(61.01)	R 37 090	-R 12 684	(61.01)

The following figure represents the current and revised subsidies after updating the tariffs according to the principles contained in this plan.

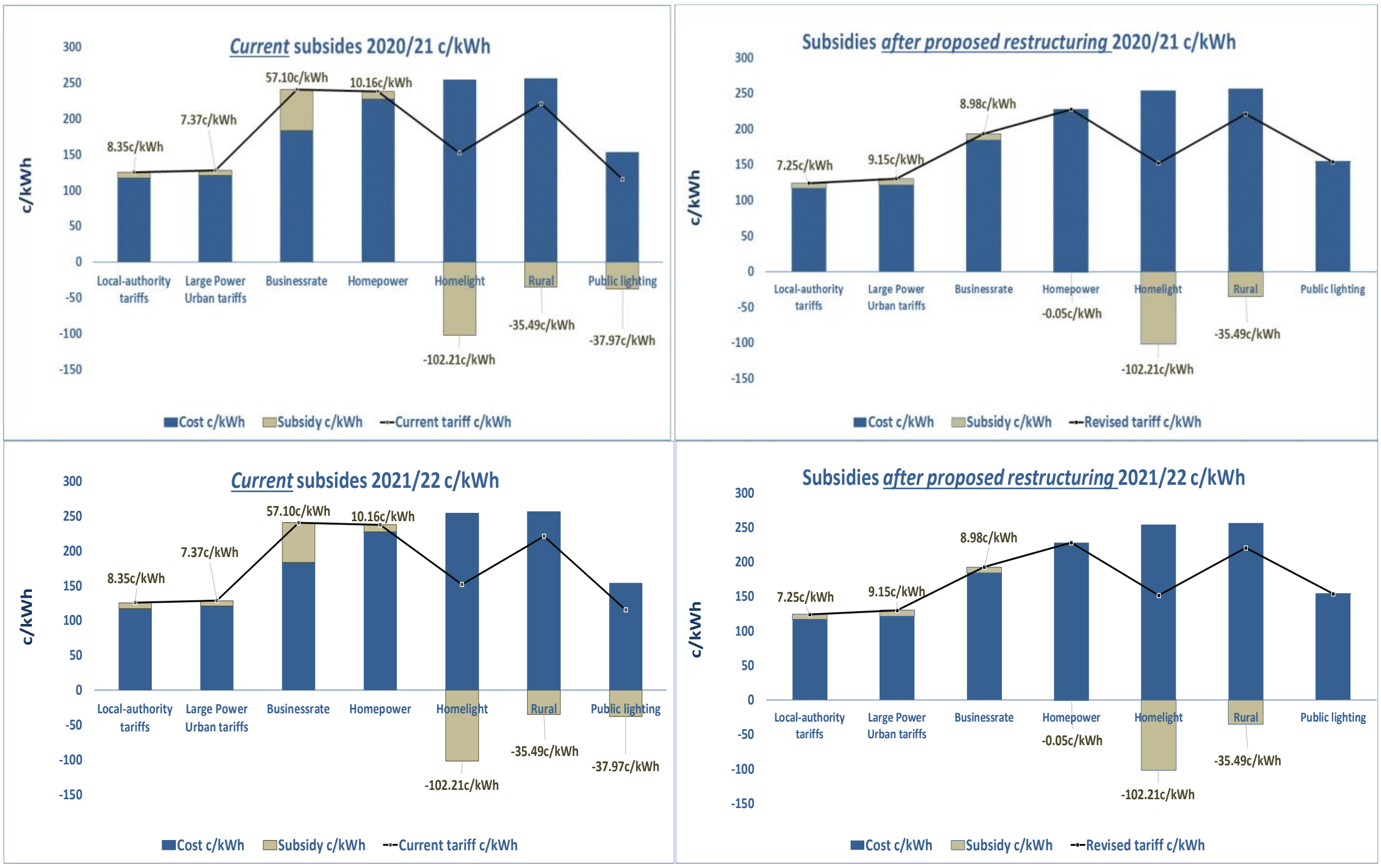


Figure 17: Current and revised inter-tariff subsidies

5.12.1.1. Homelight inter-tariff subsidies

Homelight was introduced as a single energy rate tariff in the late 1980s and was designed by Eskom to provide subsidies for low-consumption customers below 350 kWh, initially for 60A only. At that stage, Eskom also funded the capital cost. The capital cost was subsequently funded by the government through the national electrification programme. The tariff was later split into 20A and 60A versions, with the 20A version being the most subsidised.

In 2010, NERSA redesigned the tariff to be an inclining block rate tariff. NERSA also determined a lower price increase for Homelight 20A than the average. This resulted in a new subsidy (the affordability subsidy charge) payable by non-local-authority urban LPU tariffs.

At this stage the Homelight tariff, on average, only contributes towards energy cost. The tariff does not recover service and administration, maintenance, operating and refurbishment costs. Even though the initial capital is funded by the government, the ongoing costs are, therefore, not fully recovered by the tariff. Current subsidies are R8.8 billion recovered through the ERS charge and the affordability subsidy charge.

This socio-economic subsidy is provided to vulnerable customers within all municipal boundaries where Eskom is the supplier.

5.12.1.2. Rural inter-tariff subsidies

After representations by the South African Agricultural Union to both the government and Eskom in the early 1980s, Tariff D (now called Landrate) was introduced by Eskom in January 1982 for application in rural areas to assist in the costs of connection. This led to the government determining 2 km of network plus the transformer costs to be "free" for the cost of connection (referred to as the capital allowance). Part of this capital allowance cost was included in the tariff and part through subsidies.

After an investigation into the profitability of Tariff D done during 1988, it was seen that the then Tariff D did not cover the cost-of-supply and that the subsidies were increasing. The 2km was then reduced to 200 m. Where applicable the excess of this line allowance, was raised as a connection charge.

In 1994, Eskom introduced a rural LPU version, then Landrate 4 in 1997, and Landlight in 2009.

In 2002, Eskom requested approval from the then NER to reduce all outstanding monthly connection charges of customers by R900,00 per month and include this amount in the standard tariffs. The network charges were commensurately increased.

The network charge is payable to recover the total network costs of the network not funded through connection charges. The network charge contributes to the capital allowance and the costs of maintaining, operating, and refurbishing the network, and this is payable while there is still a connection. However, because the rural tariffs receive a subsidy, the tariff charges currently recover only a small portion of the total costs of the rural networks.

This under-recovery is subsidised by the LPU urban tariffs in the order of R3.8 billion. This is a historical subsidy recovered through the ERS charge.

Even if the connection charge were to fully recover all the connection costs, **which it does not**, the current network charges would not be sufficient to cover maintenance and refurbishment costs. To date, Eskom has continued to provide a capital allowance towards the cost of connection. This also means that new customers are subsidised by existing customers in order to facilitate connection. This is standard practice for all Eskom tariffs.

The that customers have already paid for their network costs through connection charges and, therefore, should not be paying network charges is not justifiable. Connection charges only recover a small portion of the initial capital and, as stated above, do not include maintenance, operating, and refurbishment of these assets. Rural customers have higher costs than those in urban areas because of the lower density (mostly one transformer per customer), longer distances between customers, and relatively low consumption for the assets invested. This makes the cost per customer, per kWh, per kVA much higher than that in urban areas, where assets are shared to a much greater extent.

Nightsave Rural currently pays subsidies, while Ruraflex receives the largest allocation of subsidies in the rural tariffs. For this reason, some rebalancing has been done to reduce the subsidies to Ruraflex and give Nightsave a subsidy allocation. This rebalancing has been done equitably, that is, increasing Ruraflex and reducing Nightsave by an equal amount.

5.12.2. Intra-tariff subsidies

Intra-tariff subsidies are when one charge is subsidised by another charge within a tariff category; for example, Megaflex higher-voltage network charges subsidise the lower-voltage network charges.

Intra-tariff subsidies are also as a result of pooling done in the CTS exercise, as it is not possible to calculate a tariff for each and every customer. Therefore, costs are pooled, for example:

- network costs are allocated based on a generic network model, not per individual customer; and
- residential energy tariffs are based on statistically measured representative load profiles, not on actual TOU usage (as this is not measured).

The proposals in this retail plan have reduced some of the intra-tariff subsidies in order to rebalance some of the subsidies within a tariff category, for example:

- increasing some Landrate tariffs and reducing others within the Landrate tariff category; and
- reducing the LV subsidy paid by the HV and Transmission-connected urban LPU tariffs by increasing the LV and MV network charges.

5.12.3. Calculation of the ERS charges and the affordability subsidy charge

The calculations of the ERS charge and the affordability charge are shown next.

- The ERS calculation is as follows:

∑ Total cost[1] - ∑ Total revised revenue[1] = Total subsidy
The greater of Total subsidy or ∑ Total network cost [1] = ERS allocation
ERS allocation / ∑ Total GWh[2] x 100 = ERS c/kWh
ERS is then scaled to ensure no additional revenue recovery (revenue-neutral to MYPD decision).

[1]= Total for Landrate, Ruraflex, Nightsave Rural, Homelight 20A and Homelight 60A

[2]= Total for local-authority and non-local-authority tariffs, Megaflex, Miniflex, Nightsave Urban, Transflex 1 and 2, Businessrate and Municflex

- The affordability subsidy charge is the difference between the network cost and the total subsidy for the current Homelight 20A tariff, calculated as follows:

∑ Total subsidy [3] - ∑ Total network cost [3] = Affordability subsidy allocation
Affordability subsidy allocation / ∑ Total GWh[4] x 100 = ERS c/kWh

[3]= Total for Homelight 20A

[4]= Total for non-local-authority tariffs, Megaflex, Miniflex, Nightsave Urban, Transflex 1 and 2 and Businessrate.

To ensure parity with comparable tariffs with the same supply sizes (Miniflex and Nightsave Urban) as Businessrate that currently contribute to the above subsidies, Businessrate now also has an ERS and affordably charges applied to the tariff. As the proposed Businessrate is significantly reduced because of the tariff being updated with the CTS values, this change does not result in an increase in the current tariff.

The table below shows the value of the subsidy charges. To ensure revenue-neutrality so that the overall revenue is equal to the approved MYPD costs, the ERS is adjusted.

Table 18: ERS charge and affordability charge calculation

Tariff	Costs Rm.	New tariff Rm.	Subsidy Rm.	ERS (network cost) Rm.	allocation Rm.	ERS charge c/kWh	ERS charge scaled c/kWh	AFS charge c/kWh	
Landrate	Rm 14 198	Rm 12 364	-Rm 1 835	-Rm 1 835	Rm 0	1.13	1.16		
Ruraflex	Rm 10 488	Rm 8 939	-Rm 1 549	-Rm 1 549	Rm 0	0.95	0.98		
Nightsave Rural	Rm 3 167	Rm 2 692	-Rm 475	-Rm 475	Rm 0	0.29	0.30		
Homelight 20A	Rm 13 002	Rm 7 603	-Rm 5 399	-Rm 4 012	-Rm 1 387	2.46	2.54	1.82	
Homelight 60A	Rm 8 918	Rm 5 492	-Rm 3 426	-Rm 3 426	Rm 0	2.10	2.17		
Total	Rm 49 774	Rm 37 090	-Rm 12 684	-Rm 11 297	-Rm 1 387	**6.94**	**7.16**	**1.82**	3.22%

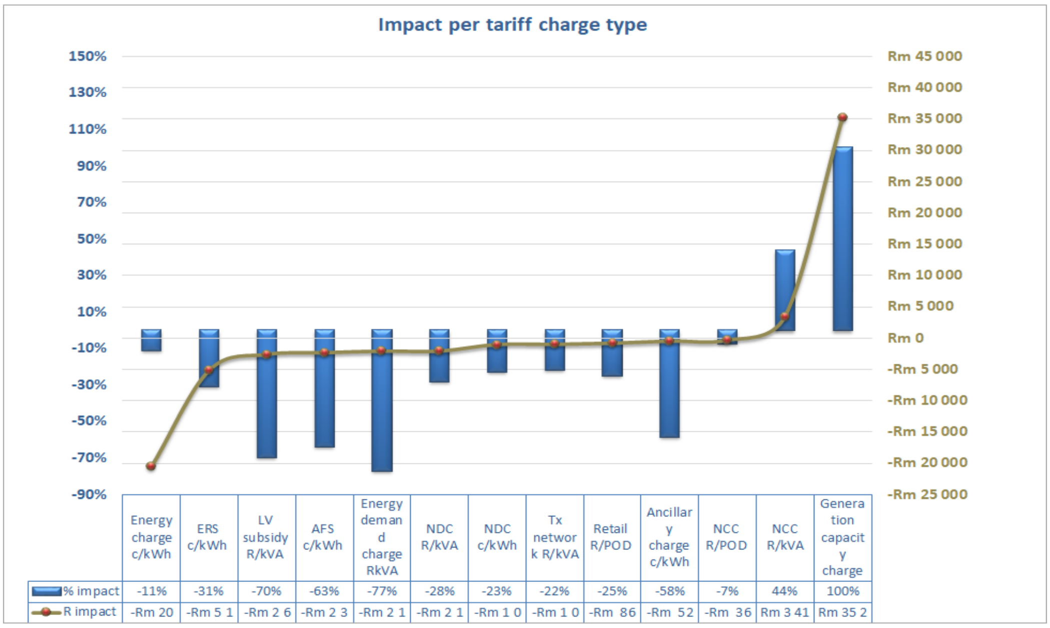
6. Impact of changes per tariff

The impacts of the tariff restructuring are largely caused by the following:

- Updating rates with the CTS, in particular the increase in total energy costs by 7% relative to other charges. This is an important change to note, as this corrects the misalignment caused by applying average increases to all tariffs instead of increases per Eskom division. It also highlights that the current energy charges are lower than they ought to be.
- The inclusion of a fixed generation capacity charge for energy (GCC) results in a reduction in the variable c/kWh energy charge. The c/kWh energy charge has reduced by 11% as a result of the introduction of the GCC.
- The changes to the TOU periods and rates. This impact per customer will largely depend on load profile through the year and response to the TOU changes.
  i. Reduced winter rates result in high consumers paying less in winter (and vice versa).
  ii. High summer peak users will pay more.
  iii. It is not possible to determine the impact of the TOU response, as this response is not known at the time of doing the tariff design. It is expected that there will be a response based on research results and history, but this may only happen over time and not immediately. This response (whether positive or negative for Eskom), like all volume responses, will be treated in terms of NERSA RCA rules.
- Increasing the fixed-charge components will result in lower average network prices for higher load factor customers (and vice versa).
- A reduction in the retail costs will result in lower service and administration charges. Charging the service charge per POD and not per account may negatively affect customers with many PODs linked to one account.
- Splitting of the LV subsidy charge between non-local-authority LPU tariffs and local-authority LPU tariffs, where previously this was calculated in one pool for both, has resulted in the contribution to the low- and medium-voltage subsidy for the non-local-authority LPU tariffs being increased, as there is more volume in this category. This is illustrated by the increase in the revised subsidy for Megaflex, which in actual effect would have seen a reduction of sorts because of a reduction in its contribution to the low voltage subsidy. Local-authority LPU tariffs now only contribute to low- and medium-voltage subsidies in the local-authority tariff pool.
- The ERS charge and affordability subsidy charge have also decreased; mainly because of the rates being updated based on the CTS. Currently, these subsidy charges are overstated.

- As per NERSA's requirement, the local-authority tariffs have been based on the CTS and combined for both rural and urban per LPU tariff category and per SPU tariff category. This has resulted in an average decrease for these tariffs, except for the Public Lighting tariffs.
- Public Lighting tariffs see a significant increase, resulting from updating the tariffs with the CTS study. This tariff has been under-recovering significantly against costs and is not one of those identified as receiving subsidies. This tariff currently barely recovers energy costs.
- Nightsave Urban Large and Nightsave Urban Small have been aligned to make the energy demand charges the same. Both tariffs see an increase because of updating with the CTS, with Nightsave Small having a larger negative impact.
- Businessrate sees a big reduction because of updating with the CTS. This tariff category now also contributes to the ERS charge and affordability subsidy charge in order to align with the other commercial LPU tariffs paying this contribution.
- For the Homelight tariffs, removing IBT has a small negative impact on very-low-consumption customers and a positive impact on higher-consumption customers.
- For Landrate, some rebalancing has been done between tariff categories, firstly, based on cost and, secondly, on applying subsidies. There is a slight increase of 2% and 3% on Landrate 2 and 3 respectively, based on the design and this is done to reduce the significant subsidies in these categories. Landrate 1 and 4 see a reduction. The level of subsidies, however, remains the same overall.
- For Ruraflex and Nightsave Rural, the network charges have been aligned (made the same). This, together with the cost-reflective increase in energy charges, has resulted in Nightsave Rural seeing a reduction and Ruraflex an increase. The level of subsidies, however, remains the same overall.
- For Homepower, per supply size category, the impact is due to updating rates with the CTS study. Homepower, on average, sees a reduction due to using costs as the basis, with no overall subsidy. Removing IBT and introducing a more cost-reflective fixed R/day charge result in lower-consumption customers paying more (and vice versa).

The table below provides a summary of the impact per tariff.



	Energy charge c/kWh	ERS c/kWh	LV subsidy R/kVA	AFS c/kWh	Energy demand charge RkVA	NDC R/kVA	NDC c/kWh	Tx network R/kVA	Retail R/POD	Ancillary charge c/kWh	NCC R/POD	NCC R/kVA	Generation capacity charge
% impact	-11%	-31%	-70%	-63%	-77%	-28%	-23%	-22%	-25%	-58%	-7%	44%	100%
R impact	-Rm 20	-Rm 5 1	-Rm 2 6	-Rm 2 3	-Rm 2 1	-Rm 2 1	-Rm 1 0	-Rm 1 0	-Rm 86	-Rm 52	-Rm 36	Rm 3 41	Rm 35 2

Figure 18: Impact per charge type

To be noted in the figure above is that current energy charge revenue, when aligned with the total updated energy-related costs, has increased significantly, and the majority of the rest of the charges have decreased. The following table shows these impacts in rand.

Table 19: Summary of total impact, per tariff category

Impact of changes to rates	Urban LPU non munic	Rural LPU non munic	Urban SPU non munic	Urban SPU rural	Public lighting non munic	Homelight	Munic LPU	Munic SPU	Munic Public lighting	Total
Network charge current	R 12 907.4	R 12 907.4	R 3 386.3	R 958.8	R 4 556.6	R 0.0	R 9 285.2	R 84.6	R 0.0	R 44 086.3
Network charges adjusted	R 11 701.5	R 11 701.5	R 3 454.3	R 1 336.0	R 4 517.6	R 0.0	R 8 367.6	R 90.0	R 0.0	R 41 168.3
% difference	-9%	-9%	2%	39%	-1%	0%	-10%	6%	0%	-7%
Energy charges current	R 70 141.2	R 7 671.4	R 4 329.5	R 6 134.4	R 33.6	R 13 095.0	R 86 989.4	R 157.0	R 204.0	R 188 755.6
Energy charges adjusted	R 78 598.1	R 7 753.1	R 3 111.8	R 6 660.7	R 44.7	R 13 095.0	R 91 647.4	R 152.4	R 265.8	R 201 329.0
% difference	12%	1%	-28%	9%	33%	0%	5%	-3%	30%	7%
Retail charges current	R 689.0	R 573.0	R 270.7	R 1 672.8	R 0.1	R 0.0	R 275.7	R 34.7	R 0.3	R 3 516.4
Retail charges adjusted	R 466.3	R 423.5	R 383.8	R 1 185.4	R 0.3	R 0.0	R 168.1	R 21.1	R 0.4	R 2 648.8
% difference	-32%	-26%	42%	-29%	246%	0%	-39%	-39%	12%	-25%
ERS and AS charges current	R 11 711.1	R 0.0	R 0.0	R 0.0	R 0.0	R 0.0	R 8 857.6	R 0.0	R 0.0	R 20 568.6
ERS and AF charges adjusted	R 6 745.7	R 0.0	R 94.0	R 0.0	R 0.0	R 0.0	R 6 200.5	R 0.0	R 0.0	R 13 040.1
% difference	-42%	0%	0%	0%	0%	0%	-30%	0%	0%	-37%
LV subsidy current	R 849.7	R 0.0	R 0.0	R 0.0	R 0.0	R 0.0	R 2 962.0	R 0.0	R 0.0	R 3 811.7
LV subsidy adjusted	R 125.4	R 0.0	R 0.0	R 0.0	R 0.0	R 0.0	R 1 035.6	R 0.0	R 0.0	R 1 161.0
% difference	-85%	0%	0%	0%	0%	0%	-65%	0%	0%	-70%
Total current	R 96 298.4	R 11 630.8	R 5 559.1	R 12 363.7	R 33.7	R 13 095.0	R 108 369.8	R 276.4	R 204.3	R 247 831
Total adjusted	R 97 636.9	R 11 630.9	R 4 925.5	R 12 363.6	R 45.0	R 13 095.0	R 107 419.1	R 263.5	R 266.1	R 247 646
Difference	R 1 338.6	R 0.1	-R 633.5	-R 0.1	R 11.3	R 0.0	-R 950.7	-R 12.9	R 61.8	-R 185.4

The following figure shows these impacts per tariff charge type in percentage for the urban large power tariffs and Municflex.

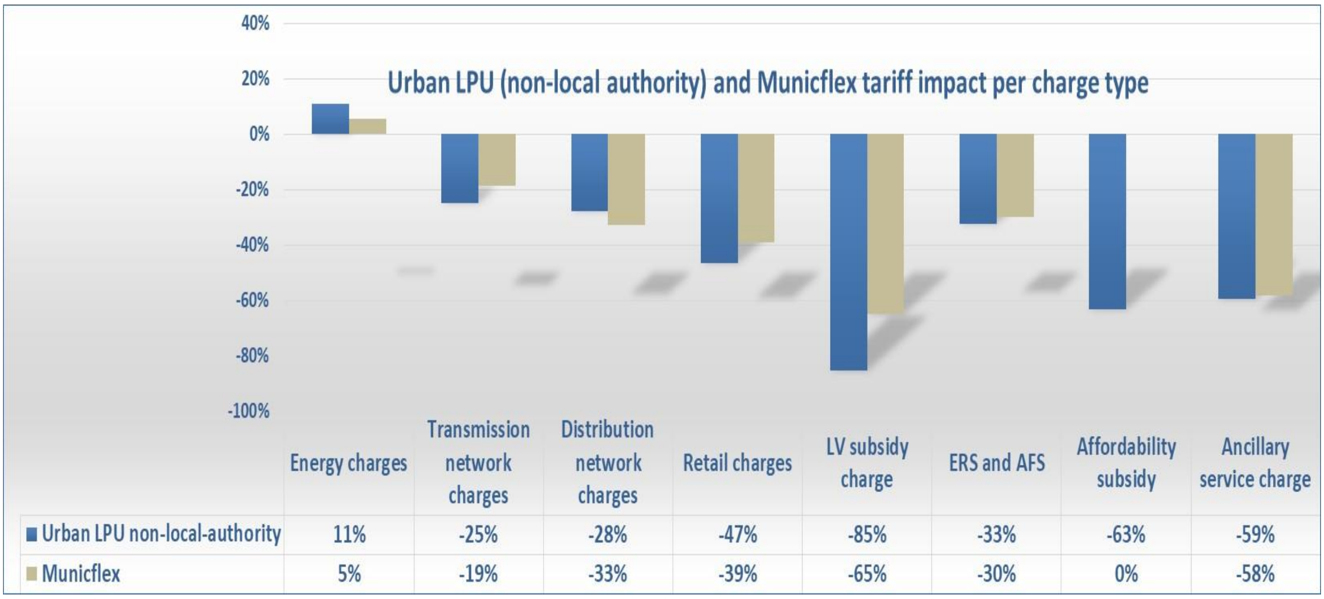


Figure 19: Percentage impact per tariff charge type for urban large power tariffs and Municflex

7. Conclusion

As per NERSA's request for tariffs to be motivated based on the cost of supply, Eskom updated its cost-of-supply (CTS) study, and from this study, based all the tariff changes in this document on the CTS plus specific objectives/signals to incentivise more optimal use of the system, which is not necessarily cost based, but forward-looking.

Eskom's tariff restructuring plan is based on the unbundled NERSA approved divisional costs. The motivation for such efficient costs is dealt with in a MYPD revenue application. As this is a justification of costs, it is not an issue for tariff restructuring as tariffs are based on already approved costs. However, Eskom supports that tariffs should be unbundled as far as possible to represent costs per division and to reflect the different services being provided. This is made possible through the cost-to-serve approach where costs are allocated based on the different services being provided, the cost drivers, customer segmentation, assets used, demand, voltage, losses and the different load profile for each customer, or customer categories where actual load profiles are not known and load profile.

The changing environment, decreasing sales, and increasing use of photovoltaic (PV) technology mean that the existing tariff structures are outdated and need to be modernised to reflect current realities. It is no longer appropriate to recover fixed costs through kWh charges, and crucial decisions in this regard need to be made to protect the electricity industry. Given the fixed and variable costs of generators, Eskom proposes that generators costs should be recovered through a combination of capacity charges (R/kVA) and energy charges (c/kWh). This will reduce the financial risk associated with volumetric recovery rates given the growth in variable energy resources, which also require back up capacity. The introduction of a fixed generation capacity charge (GCC) will result in a reduction of the variable c/kWh charge.

Use of system costs are currently recovered equally through a fixed and variable charge. This however poses a volume risk because of the increase in distributed generation (DG). The grid provides backup and storage for DG. Correct separation and structure of network charges is imperative to ensure that there is a fair recovery of costs by all users of the grid so that tariffs more accurately reflect the value of the service being provided and that unintended subsidies are not created. To make network charges more reflective of the cost drivers, there will be a gradual increase in the fixed network charge. For this submission, the fixed network charge increased to 60% and the variable network charge reduced to 40%.

For municipal customers, the number of Eskom tariffs offered has to be reduced to simplify and assist in better determination of municipal purchase costs. This also allows for the separation of municipal tariffs from non-local-authority tariffs and better allocation of subsidies. This separation reduces the municipal contribution to subsidies.

Residential tariffs need an overhaul as well. The inclining block tariff (IBT) as a tariff structure is no longer appropriate, is disliked by customers, and is complex to understand and explain. For this reason, Eskom proposes removing the IBT structure by reintroducing a single energy rate charge, fixed and more cost-reflective network and retail charges for Homepower, and introducing a time-of-use (TOU) residential tariff with an offset rate for net billing.

The unbundling of Eskom will require tariffs to reflect current divisional cost accurately to avoid volume and trading risk and to reflect cost drivers more accurately.

When updating tariffs using a CTS study and implementing structural changes, it is not possible for this to have a zero impact on all customers. So, while the sum of the structural changes is revenue-neutral, that is, the sum of all changes comes back to the revenue requirement, individual customers may pay more or less, depending on the change and their consumption profile.

The next phase in the journey of tariff design may include:

- further aligning the retail charges with the wholesale purchase tariff
- annual updating of different rates due to Eskom unbundled and separate divisional increases – no longer a single average increase applied to all rates;
- further rationalisation of tariffs;
- further rebalancing between fixed and variable network charges;
- further development regarding generator use-of-system charges and offset rates;
- moving to making TOU mandatory for all new three-phase SPU connections, and
- introduction of flexible short-term tariff options to address customer needs and Eskom operational requirements.

All rates in this document will be updated based on the price increase process for the year of application.

Annexure A – Local-authority tariff impacts

The proposed changes to the local-authority tariffs are as follows:

- A new tariff LPU based on the Megaflex structure, but rates are calculated by combining the costs of Megaflex, Miniflex, Nightsave Urban Large and Small, Ruraflex, and Nightsave Rural for local-authority supplies.
- A new SPU tariff based on the Business structure, but rates are calculated by combining the costs of Landrate, Businessrate, and Homepower for local-authority tariffs.
- Public Lighting tariffs are based on the cost-reflective CTS results.
- The impact of all the proposed changes in this document is provided in this Annexure A.
- The municipal tariff rates in this submission are shown in 12-month values (based on the Eskom financial year of April to March for comparison against the non-local-authority 12-month rates) and in nine-month values (based on three-month April to June current tariffs, nine months at the revised CTS-based tariffs adjusted for the later price increase). Refer, furthermore, to Annexure F – Proposed retail rates in 2021/22 rand values (excluding VAT),Table 37, Table 38, Table 39 and Table 40.
- If approved by NERSA, the existing local-authority LPU tariffs Megaflex, Miniflex, Nightsave Urban Large and Small, Ruraflex, and Nightsave Rural will cease to exist and be replaced by Municflex.
- If approved by NERSA, the existing local-authority SPU tariffs Landrate, Businessrate, and Homepower will cease to exist and be replaced by Municrate.

The following table provides the costs, current revenue, and revised revenue per current local-authority tariff.

Table 20: Rand impact per local-authority tariff

Municipal tariffs	CTS allocated allowed costs Rm.	Current tariff revenue Rm.	Diff current tariff revenue and cost	Restuctured tariff revenue Rm	Difference new tariff revenue and cost Rm.	Revised subsidy c/kWh	% change in revenue due to restructuring	Difference in revenue Rm. due to restructuring
Local-authority tariffs total	R 101 669	R 108 850	R 7 181	R 107 948	R 6 279	7.23	-1%	-R 902
Megaflex to Municflex	R 93 504	R 100 523	R 7 019	R 99 762	R 6 258	7.69	-0.76%	-R 761
Miniflex to Municflex	R 1 526	R 1 448	-R 78	R 1 598	R 72	6.75	10.34%	R 150
Nightsave Urban Large to Municflex	R 3 469	R 3 649	R 179	R 3 595	R 126	4.84	-1.47%	-R 54
Nightsave Urban Small to Municflex	R 422	R 426	R 5	R 457	R 35	12.37	7.17%	R 31
Ruraflex to Municflex	R 862	R 732	-R 130	R 762	-R 100	(21.85)	4.01%	R 29
Nightsave Rural to Municflex	R 1 357	R 1 591	R 235	R 1 245	-R 111	(13.14)	-21.75%	-R 346
Businessrate to Municrate	R 104	R 132	R 28	R 126	R 22	45.42	-4.30%	-R 6
Landrate to Municrate	R 134	R 122	-R 12	R 105	-R 29	(70.65)	-14.30%	-R 18
Homepower to Municrate	R 26	R 22	-R 3	R 33	R 7	72.29	45.82%	R 10
Public lighting to Public lighting	R 266	R 204	-R 62	R 266	R 0.04	0.02	30.28%	R 62

The following is to be noted regarding the above impacts:

- There is a total revenue decrease based on Municflex due to local-authority LPU tariffs no longer contributing to non-local-authority low-voltage subsidies and updating of rates based on the CTS.
- The current rural tariffs, Ruraflex, Nightsave Rural, and Landrate, have the biggest decrease when based on Municflex, and this is mainly due to these tariffs being pooled with the urban tariffs. This will assist the smaller municipalities on these rural tariffs.
- Four tariffs see increases:
  - Public Lighting tariffs have the biggest percentage increase due to these tariffs currently being subsidised and updating them with the CTS.
  - Miniflex is increased by R150 million mainly due to converting the current c/kWh NDC into the Municflex R/kVA NDC, but for individual customers, this will also depend on their TOU profile.

- Homepower is increased by R10 million, and this is mainly because of removal of the non-cost reflective IBT structure.
- Nightsave Urban Small is increased by R31 million, and this can mainly be attributed to the updating the rates with the CTS and the increasing fixed network charges.

The following table provides the breakdown per tariff charge type of the impact of the restructuring on the local-authority tariffs.

Table 21: Local authority tariffs Rand and percentage impact per tariff category

Rm. impact of changes to rates	Municflex	Municrate	authority Public lighting	Total local authority tariffs
Network charge current	R 9 285	R 85	R 0	R 9 369.8
Network charges proposed	R 8 368	R 90	R 0	R 8 457.6
% difference	-10%	6%	0%	-10%
Energy charges current	R 86 989	R 157	R 204	R 87 350.4
Energy charges proposed	R 91 647	R 152	R 266	R 92 065.5
% difference	5%	-3%	30%	5%
Retail charges current	R 276	R 35	R 0.3233	R 310.8
Retail charges proposed	R 168	R 21	R 0.3613	R 189.6
% difference	-39%	-39%	12%	-39%
ERS and AS charges current	R 8 858	R 0	R 0	R 8 857.6
ERS and AF charges proposed	R 6 200	R 0	R 0	R 6 200.5
% difference	-30%	0%	0%	-30%
LV subsidy current	R 2 962	R 0	R 0	R 2 962.0
LV subsidy proposed	R 1 036	R 0	R 0	R 1 035.6
% difference	-65%	0%	0%	-65%
Total current	R 108 370	R 276	R 204	R 108 850.5
Total proposed	R 107 419	R 263	R 266	R 107 948.7
R Difference	-R 951	-R 13	R 62	-R 901.8
% Difference	-1%	-5%	30%	-1%

It can be noted in the above table, that in most cases the energy charges have increased, and all other charges have reduced. The following figures provide the potential impacts per tariff category at different consumption levels.

A.1 Businessrate compared to Municrate

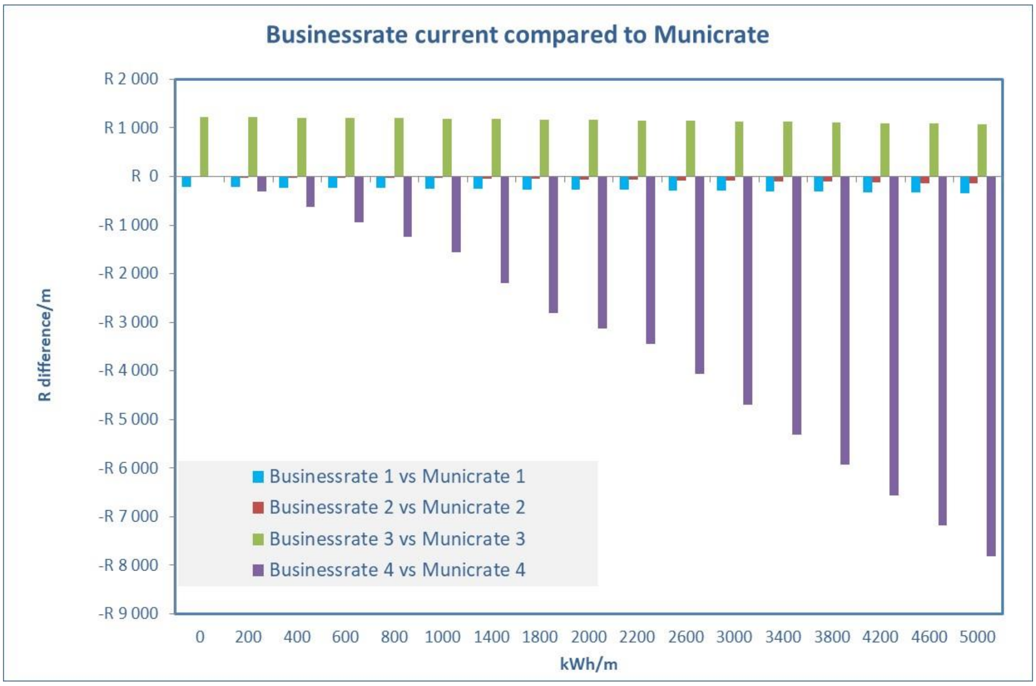


Figure 20: Businessrate compared to Municrate at different consumption levels

A.2 Landrate compared to Municrate

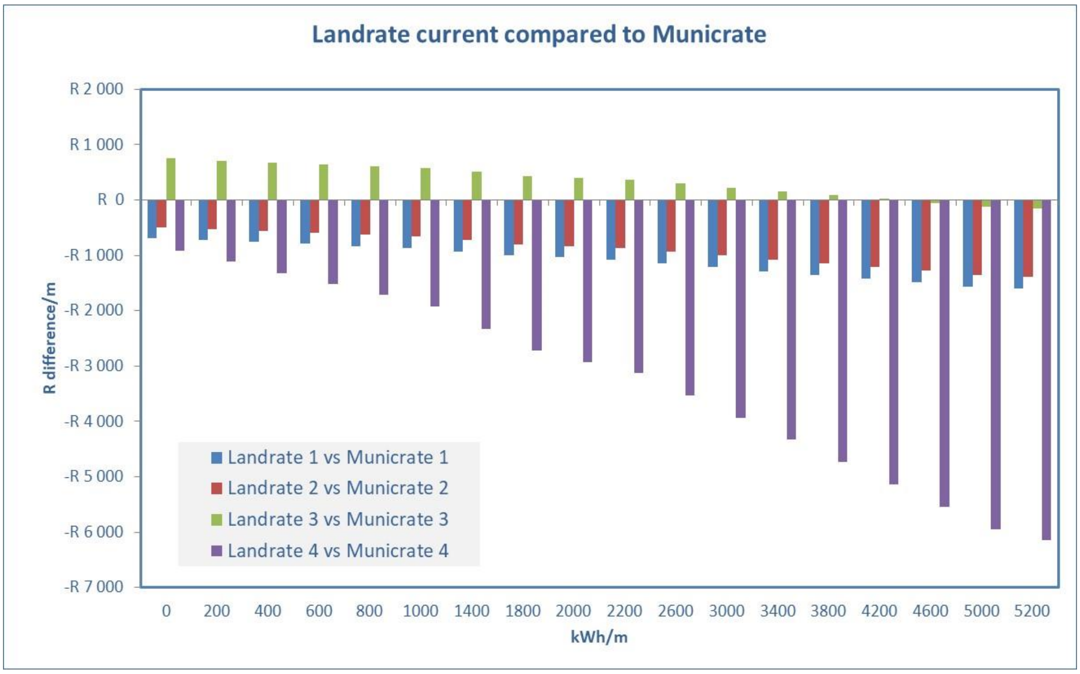


Figure 21: Landrate compared to Municrate at different consumption levels

A.3 Homepower compared to Municrate

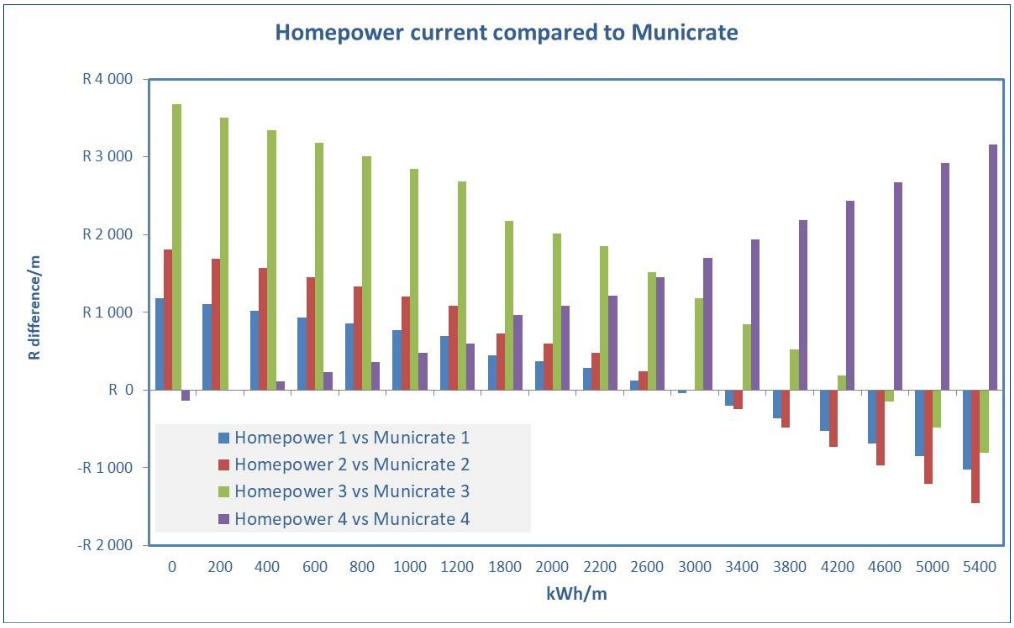


Figure 22: Homepower compared to Municrate at different consumption levels

A negative impact is observed on Homepower 1 and 4 sub-tariffs, based on the average consumption of these tariffs. The introduction of fixed charges means that at lower consumption, there will be a negative impact. A comparison was done to see if this impact would be reduced if Homepower tariff was excluded from the Municrate and retained as a standalone residential local-authority tariff, based on the proposed Homepower structure.

The results of this comparison demonstrated that there would still be a negative impact, although slightly reduced and because of the updating of the Homepower tariff with the CTS and making the tariff to be more cost reflective by removing the IBT structure. It is therefore proposed that the Municrate tariff structure remain as initially proposed based on a combination of the three small municipal power tariffs, which are Businessrate, Landrate and Homepower because removing Homepower from Municrate will defeat the intended objective of rationalising and simplifying the municipal tariffs.

The following figures provides a comparison between the current and proposed local-authority LPU tariffs at different load factors. For the TOU tariffs, the maximum amount payable will begin with all consumption being in the peak times and then as the load factor increases, the consumption moves into the standard period and then into the off-peak consumption. The minimum amount payable is the opposite, that is, starting at the off-peak consumption. The amount payable, therefore, can be at any point between the maximum and minimum of the profile.

A.4 Megaflex local-authority compared to Municflex

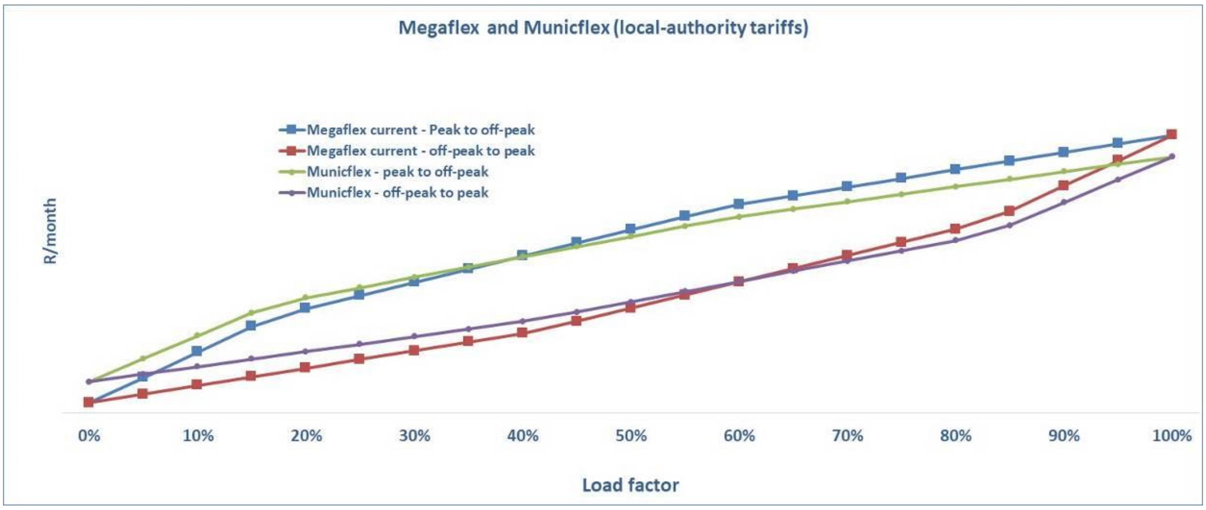


Figure 23: Current Megaflex local-authority tariff and proposed Municflex comparison

A.5 Miniflex local-authority compared to Municflex

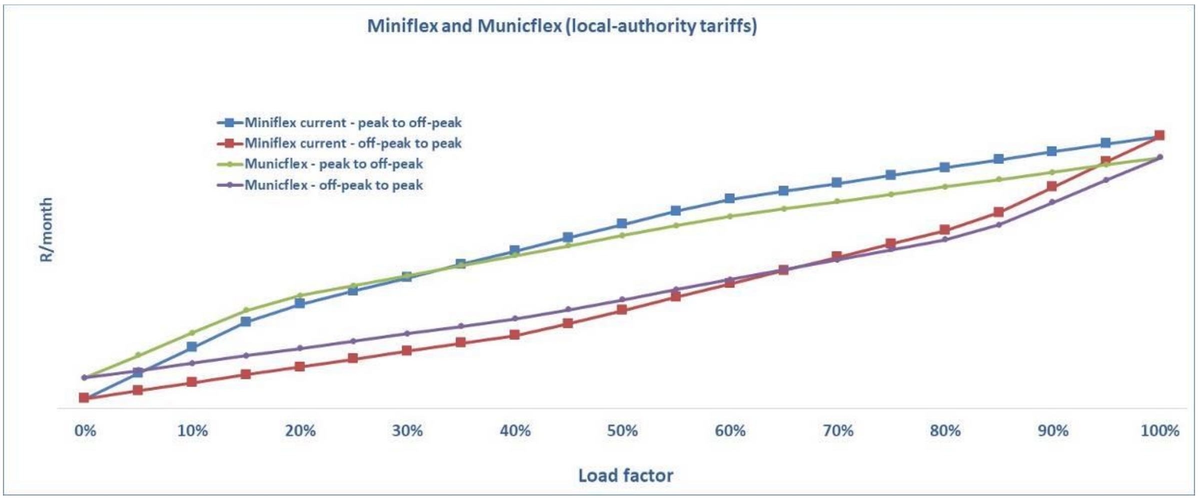


Figure 24: Current Miniflex local-authority tariff and proposed Municflex comparison

A.6 Nightsave local-authority compared to Municflex

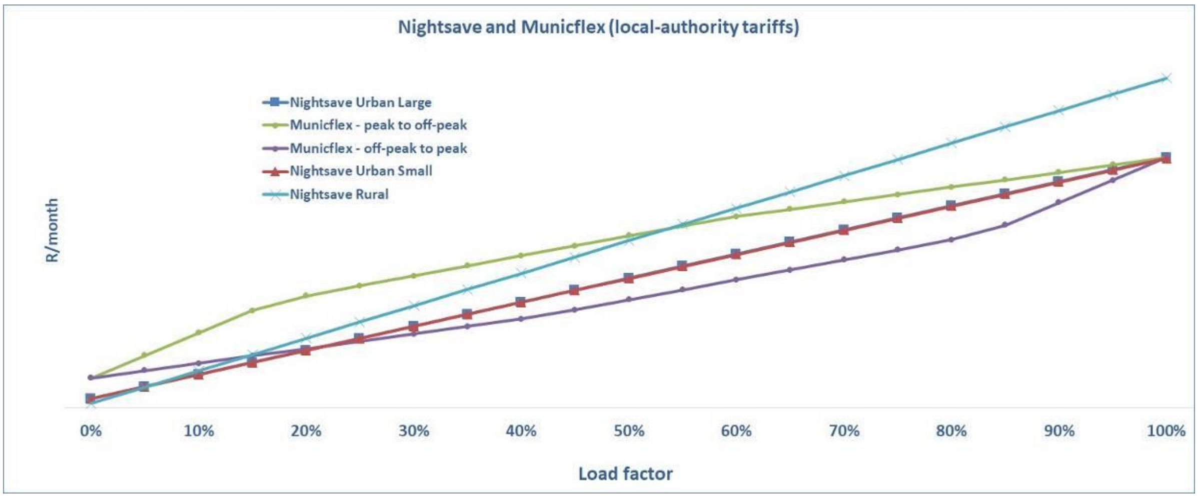


Figure 25: Current Nightsave local-authority tariff and proposed Municflex comparison

A.7 Ruraflex local-authority compared to Municflex

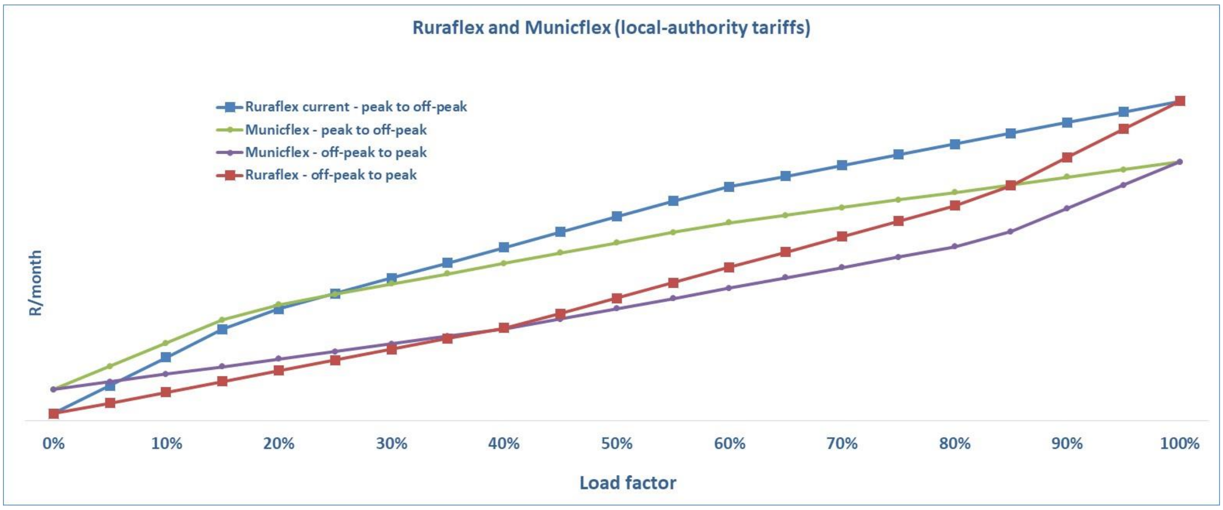


Figure 26: Current Ruraflex local-authority tariff and proposed Municflex comparison

A.8 Comparison tools

Comparison tools will be provided to assess the impact of the proposed changes.

Annexure B - Non-local-authority tariff impacts

The next set of figures provides a comparison between the current and proposed non-local-authority SPU tariffs at different consumption levels and also compares these against cost.

B.1 Businessrate non-local-authority

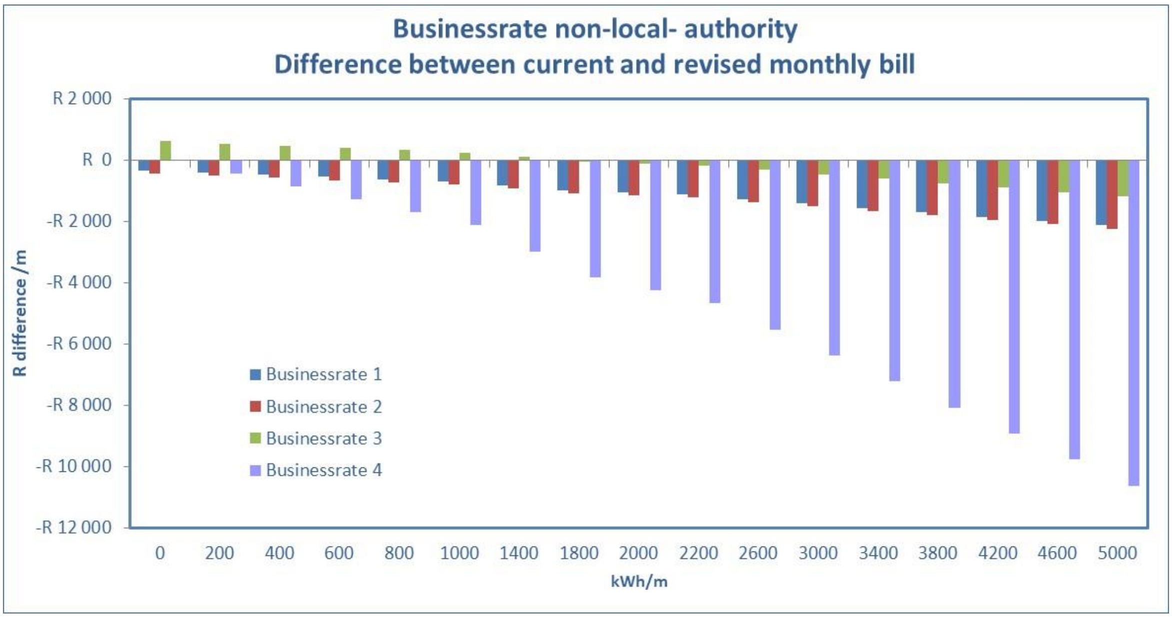
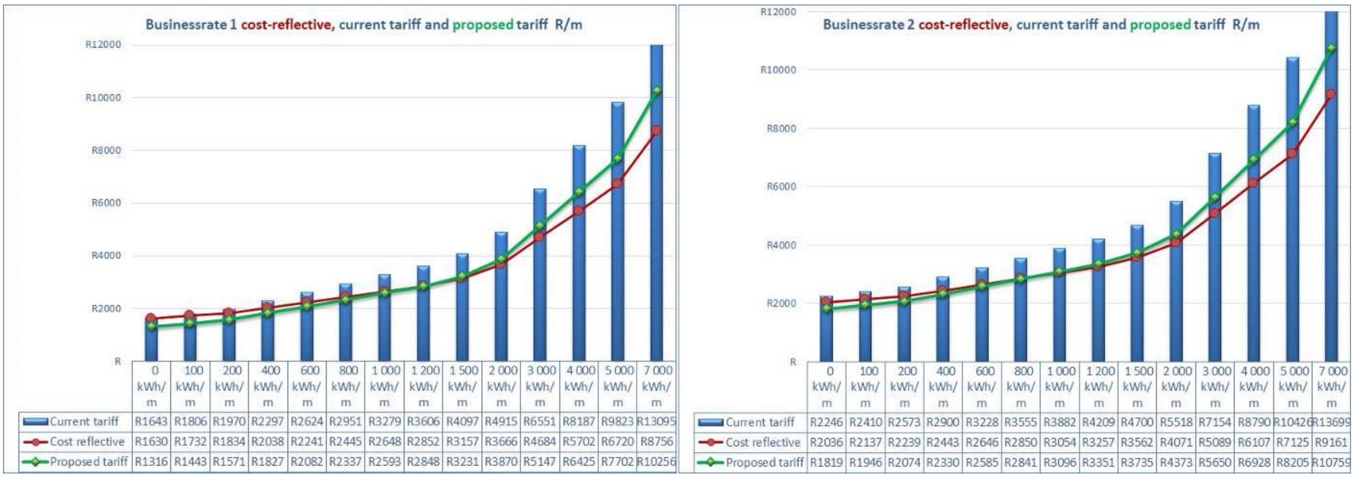


Figure 27: Businessrate non-local-authority tariffs impact at different consumption levels



	0 kWh/m	100 kWh/m	200 kWh/m	400 kWh/m	600 kWh/m	800 kWh/m	1 000 kWh/m	1 200 kWh/m	1 500 kWh/m	2 000 kWh/m	3 000 kWh/m	4 000 kWh/m	5 000 kWh/m	7 000 kWh/m
Current tariff	R1643	R1806	R1970	R2297	R2624	R2951	R3279	R3606	R4097	R4915	R6551	R8187	R9823	R13095
Cost reflective	R1630	R1732	R1834	R2038	R2241	R2445	R2648	R2852	R3157	R3666	R4684	R5702	R6720	R8756
Proposed tariff	R1316	R1443	R1571	R1827	R2082	R2337	R2593	R2848	R3231	R3870	R5147	R6425	R7702	R10256

	0 kWh/m	100 kWh/m	200 kWh/m	400 kWh/m	600 kWh/m	800 kWh/m	1 000 kWh/m	1 200 kWh/m	1 500 kWh/m	2 000 kWh/m	3 000 kWh/m	4 000 kWh/m	5 000 kWh/m	7 000 kWh/m
Current tariff	R2246	R2410	R2573	R2900	R3228	R3555	R3882	R4209	R4700	R5518	R7154	R8790	R10426	R13699
Cost reflective	R2036	R2137	R2239	R2443	R2646	R2850	R3054	R3257	R3562	R4071	R5089	R6107	R7125	R9161
Proposed tariff	R1819	R1946	R2074	R2330	R2585	R2841	R3096	R3351	R3735	R4373	R5650	R6928	R8205	R10759

Figure 28: Businessrate 1 and 2 non-local-authority tariffs comparison of cost-reflective, current, and proposed tariffs

	0 kWh/m	100 kWh/m	200 kWh/m	400 kWh/m	600 kWh/m	800 kWh/m	1 000 kWh/m	1 200 kWh/m	1 500 kWh/m	2 000 kWh/m	3 000 kWh/m	4 000 kWh/m	5 000 kWh/m	7 000 kWh/m
Current tariff	R3326	R3490	R3654	R3981	R4308	R4635	R4962	R5290	R5781	R6599	R8235	R9871	R11507	R14779
Cost reflective	R5113	R5215	R5317	R5520	R5724	R5928	R6131	R6335	R6640	R7149	R8167	R9185	R10203	R12238
Proposed tariff	R3950	R4078	R4205	R4461	R4716	R4972	R5227	R5482	R5866	R6504	R7781	R9059	R10336	R12890

	0 kWh/m	100 kWh/m	200 kWh/m	400 kWh/m	600 kWh/m	800 kWh/m	1 000 kWh/m	1 200 kWh/m	1 500 kWh/m	2 000 kWh/m	3 000 kWh/m
Current tariff	R	R405	R811	R1621	R2432	R3242	R4053	R4863	R6079	R8105	R12158
Cost reflective	R994	R1096	R1198	R1401	R1605	R1808	R2012	R2215	R2521	R3030	R4048
Proposed tariff	R	R193	R386	R771	R1157	R1543	R1928	R2314	R2892	R3857	R5785

Figure 29: Businessrate 3 and 4 non-local-authority tariffs comparison of cost-reflective, current, and proposed tariffs

B.2 Landrate and Landlight non-local-authority

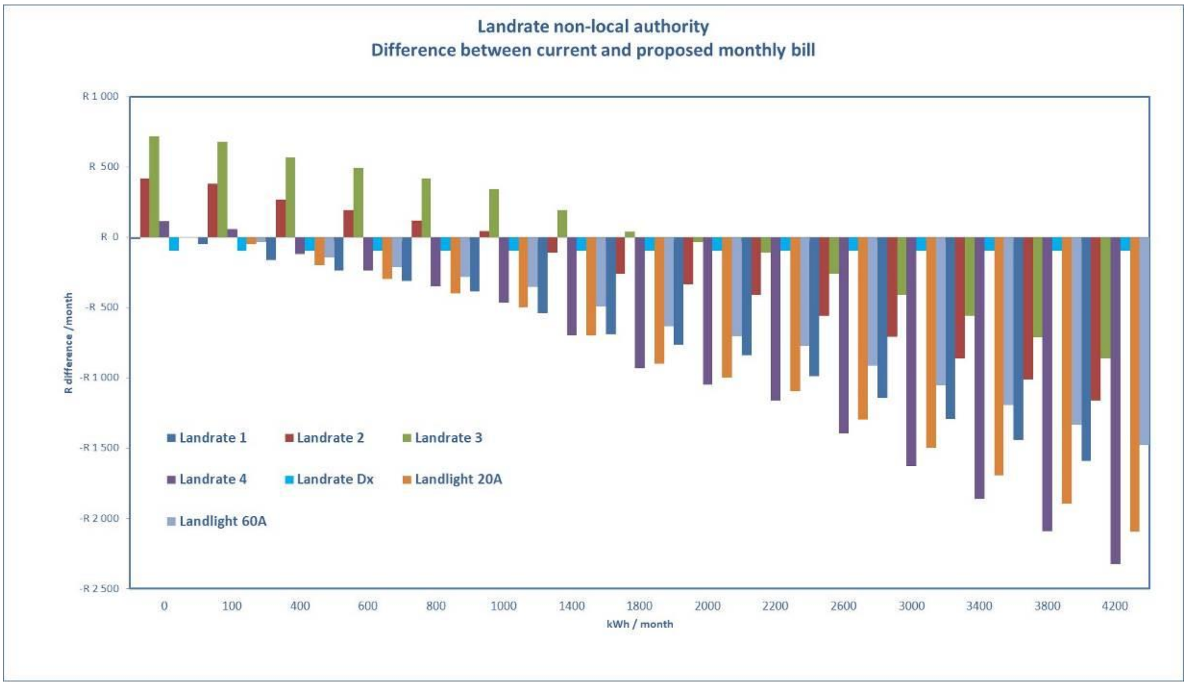
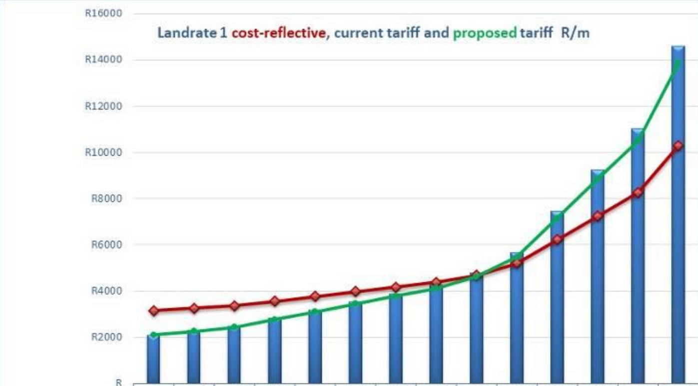
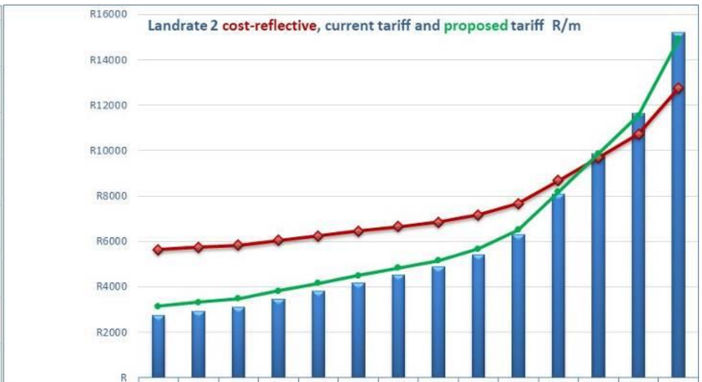


Figure 30: Landrate and Landlight non-local-authority tariffs impact at different consumption levels

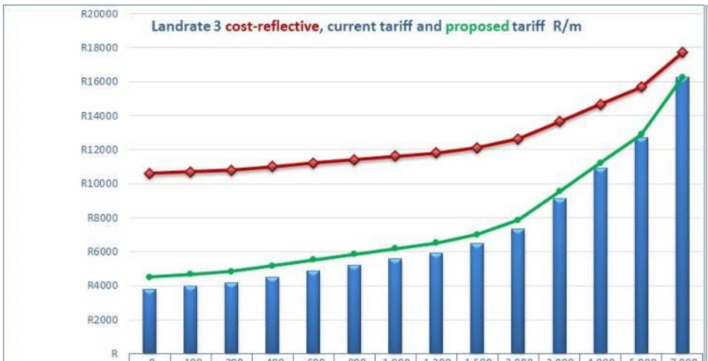


	0 kWh/m	100 kWh/m	200 kWh/m	400 kWh/m	600 kWh/m	800 kWh/m	1 000 kWh/m	1 200 kWh/m	1 500 kWh/m	2 000 kWh/m	3 000 kWh/m	4 000 kWh/m	5 000 kWh/m	7 000 kWh/m
Current tariff	R2115	R2293	R2471	R2828	R3184	R3541	R3897	R4254	R4789	R5680	R7463	R9245	R11028	R14593
Cost reflective	R3154	R3256	R3358	R3562	R3766	R3970	R4175	R4379	R4685	R5196	R6217	R7238	R8259	R10301
Proposed tariff	R2103	R2271	R2439	R2775	R3110	R3446	R3782	R4118	R4622	R5461	R7141	R8820	R10499	R13858

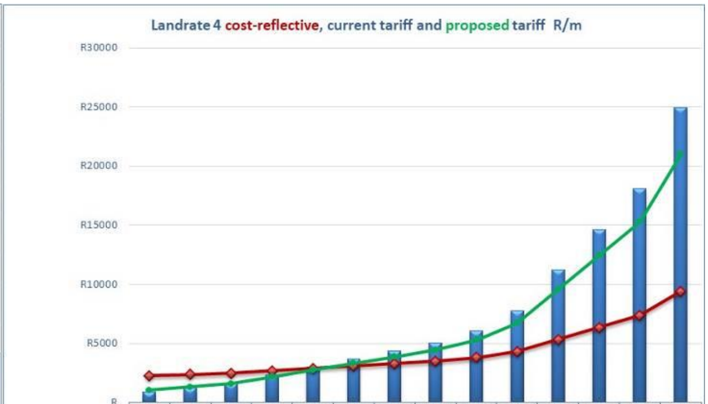


	0 kWh/m	100 kWh/m	200 kWh/m	400 kWh/m	600 kWh/m	800 kWh/m	1 000 kWh/m	1 200 kWh/m	1 500 kWh/m	2 000 kWh/m	3 000 kWh/m	4 000 kWh/m	5 000 kWh/m	7 000 kWh/m
Current tariff	R2735	R2913	R3092	R3448	R3805	R4161	R4518	R4874	R5409	R6300	R8083	R9866	R11649	R15214
Cost reflective	R5638	R5740	R5842	R6045	R6249	R6452	R6656	R6859	R7164	R7673	R8690	R9708	R10725	R12760
Proposed tariff	R3153	R3321	R3489	R3825	R4161	R4497	R4833	R5169	R5672	R6512	R8191	R9870	R11550	R14908

Figure 31: Landrate 1 and 2 non-local-authority tariffs comparison of cost-reflective, current, and proposed tariffs

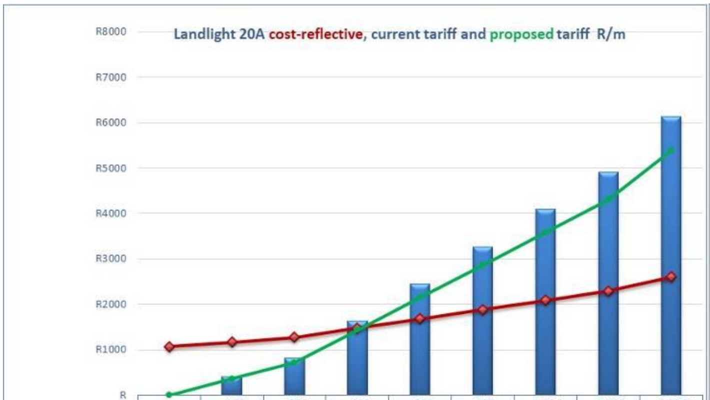


	0 kWh/m	100 kWh/m	200 kWh/m	400 kWh/m	600 kWh/m	800 kWh/m	1 000 kWh/m	1 200 kWh/m	1 500 kWh/m	2 000 kWh/m	3 000 kWh/m	4 000 kWh/m	5 000 kWh/m	7 000 kWh/m
Current tariff	R3798	R3976	R4155	R4511	R4868	R5224	R5581	R5937	R6472	R7364	R9146	R10929	R12712	R16277
Cost reflective	R10608	R10710	R10812	R11015	R11219	R11422	R11626	R11829	R12134	R12643	R13660	R14678	R15695	R17730
Proposed tariff	R4516	R4684	R4852	R5188	R5524	R5860	R6196	R6531	R7035	R7875	R9554	R11233	R12912	R16271

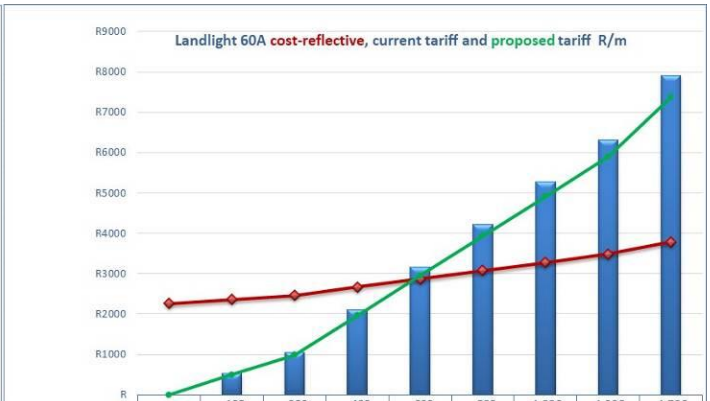


	0 kWh/m	100 kWh/m	200 kWh/m	400 kWh/m	600 kWh/m	800 kWh/m	1 000 kWh/m	1 200 kWh/m	1 500 kWh/m	2 000 kWh/m	3 000 kWh/m	4 000 kWh/m	5 000 kWh/m	7 000 kWh/m
Current tariff	R920	R1263	R1606	R2293	R2979	R3665	R4352	R5038	R6068	R7784	R11216	R14648	R18080	R24944
Cost reflective	R2259	R2361	R2463	R2668	R2872	R3077	R3281	R3486	R3792	R4303	R5325	R6347	R7369	R9414
Proposed tariff	R1034	R1319	R1604	R2174	R2745	R3315	R3886	R4456	R5311	R6737	R9589	R12441	R15292	R20996

Figure 32: Landrate 3 and 4 non-local-authority tariffs comparison of cost-reflective, current, and proposed tariffs



	0 kWh/m	100 kWh/m	200 kWh/m	400 kWh/m	600 kWh/m	800 kWh/m	1 000 kWh/m	1 200 kWh/m	1 500 kWh/m
Current tariff	R	R409	R818	R1635	R2453	R3271	R4089	R4906	R6133
Cost reflective	R1066	R1169	R1271	R1476	R1681	R1885	R2090	R2295	R2602
Proposed tariff	R	R359	R718	R1436	R2154	R2872	R3590	R4308	R5385



	0 kWh/m	100 kWh/m	200 kWh/m	400 kWh/m	600 kWh/m	800 kWh/m	1 000 kWh/m	1 200 kWh/m	1 500 kWh/m
Current tariff	R	R527	R1054	R2108	R3162	R4217	R5271	R6325	R7906
Cost reflective	R2259	R2361	R2463	R2668	R2872	R3077	R3281	R3486	R3792
Proposed tariff	R	R492	R984	R1968	R2952	R3935	R4919	R5903	R7379

Figure 33: Landlight 20A and 60A non-local-authority tariffs comparison of cost-reflective, current, and proposed tariffs

B.3 Homepower non-local-authority

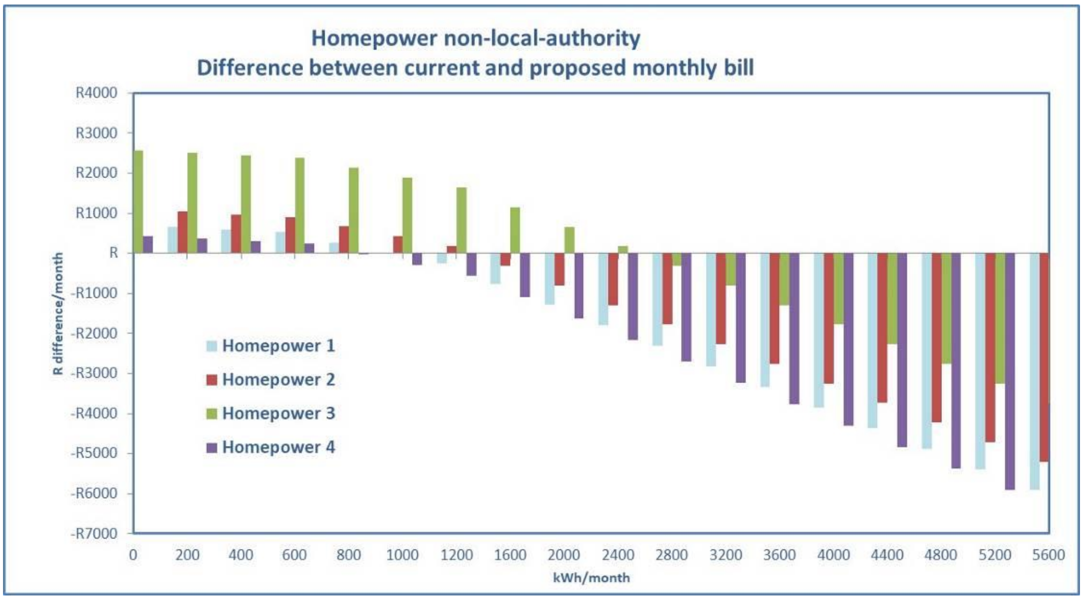
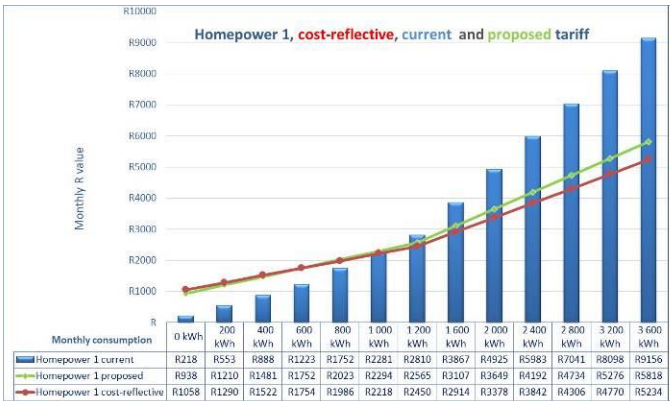


Figure 34: Homepower non-local-authority tariffs impact at different consumption levels



Monthly consumption	0 kWh	200 kWh	400 kWh	600 kWh	800 kWh	1 000 kWh	1 200 kWh	1 600 kWh	2 000 kWh	2 400 kWh	2 800 kWh	3 200 kWh	3 600 kWh
Homepower 1 current	R218	R553	R888	R1223	R1752	R2281	R2810	R3867	R4925	R5983	R7041	R8098	R9156
Homepower 1 proposed	R938	R1210	R1481	R1752	R2023	R2294	R2565	R3107	R3649	R4192	R4734	R5276	R5818
Homepower 1 cost-reflective	R1058	R1290	R1522	R1754	R1986	R2218	R2450	R2914	R3378	R3842	R4306	R4770	R5234

Monthly consumption	0 kWh	200 kWh	400 kWh	600 kWh	800 kWh	1 000 kWh	1 200 kWh	1 600 kWh	2 000 kWh	2 400 kWh	2 800 kWh	3 200 kWh	3 600 kWh
Homepower 4 current	R133	R468	R803	R1138	R1677	R2215	R2754	R3831	R4908	R5986	R7063	R8140	R9217
Homepower 4 cost-reflective	R740	R972	R1204	R1437	R1669	R1901	R2133	R2597	R3061	R3525	R3989	R4453	R4917
Homepower 4 proposed	R562	R833	R1104	R1375	R1646	R1917	R2188	R2730	R3273	R3815	R4357	R4899	R5441

Figure 35: Homepower 1 and 2 non-local-authority tariffs comparison of cost-reflective, current, and proposed tariff

Monthly consumption	0 kWh	200 kWh	400 kWh	600 kWh	800 kWh	1 000 kWh	1 200 kWh	1 600 kWh	2 000 kWh	2 400 kWh	2 800 kWh	3 200 kWh	3 600 kWh
Homepower 2 current	R409	R744	R1079	R1414	R1929	R2445	R2961	R3992	R5023	R6055	R7086	R8117	R9149
Homepower 2 proposed	R1508	R1779	R2050	R2321	R2592	R2863	R3134	R3677	R4219	R4761	R5303	R5845	R6388
Homepower 2 cost reflective	R1706	R1938	R2170	R2402	R2634	R2867	R3099	R3563	R4027	R4491	R4955	R5419	R5883

Monthly consumption	0 kWh	200 kWh	400 kWh	600 kWh	800 kWh	1 000 kWh	1 200 kWh	1 600 kWh	2 000 kWh	2 400 kWh	2 800 kWh	3 200 kWh	3 600 kWh	4 000 kWh	4 400 kWh
Homepower 3 current	R844	R1179	R1514	R1849	R2365	R2880	R3396	R4427	R5459	R6490	R7521	R8553	R9584	R10615	R11647
Homepower 3 proposed	R3408	R3679	R3950	R4221	R4493	R4764	R5035	R5577	R6119	R6661	R7203	R7746	R8288	R8830	R9372
Homepower 3 cost-reflective	R3956	R4188	R4420	R4652	R4884	R5116	R5348	R5812	R6276	R6740	R7204	R7668	R8132	R8597	R9061

Figure 36: Homepower 3 and 4 non-local-authority tariffs comparison of cost-reflective, current, and proposed tariffs

B.4 Public Lighting non-local-authority

Figure 37: Public Lighting All-Night and 24-Hour non-local-authority tariffs comparison of cost-reflective, current, and proposed tariffs

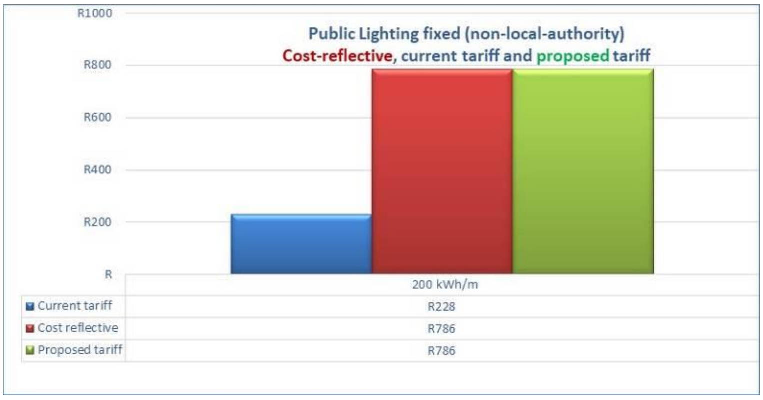


Figure 38: Public Lighting Fixed non-local-authority tariff comparison of cost-reflective, current, and proposed tariffs

The next set of figures provides a comparison between the current and proposed non-local-authority LPU tariffs at different load factors. For the TOU tariffs, the maximum amount payable will begin with all consumption being in the peak times and then as the load factor increases, the consumption moves into the standard period and then into the off-peak consumption. The minimum amount payable is the opposite, that is, starting at the off-peak consumption. The amount payable therefore can be at any point between the maximum and minimum.

B.5 Megaflex non-local-authority

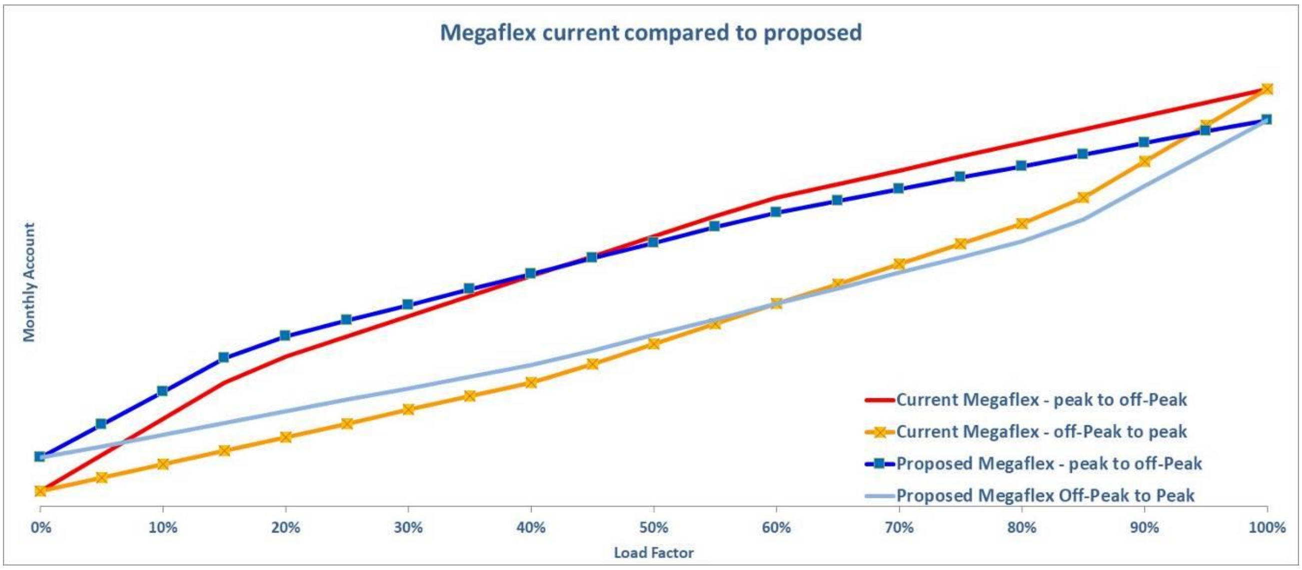


Figure 39: Current Megaflex non-local-authority tariff compared to the proposed tariff

B.6 Nightsave Urban non-local-authority

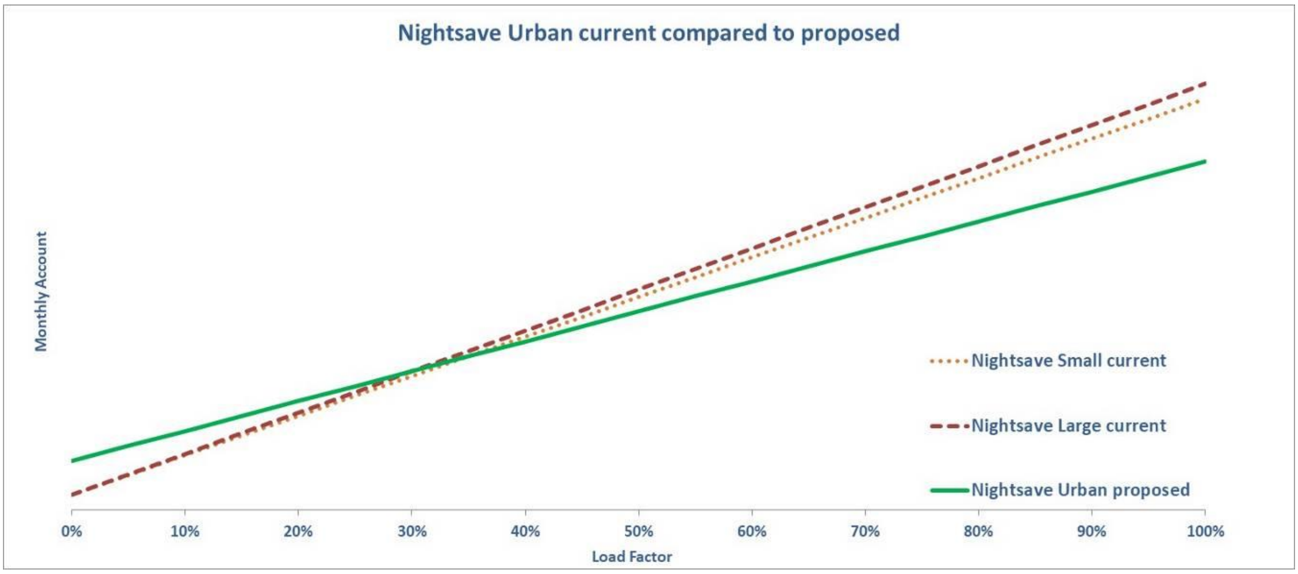


Figure 40: Current Nightsave Urban non-local-authority tariff compared to the proposed tariff

B.7 Miniflex non-local-authority

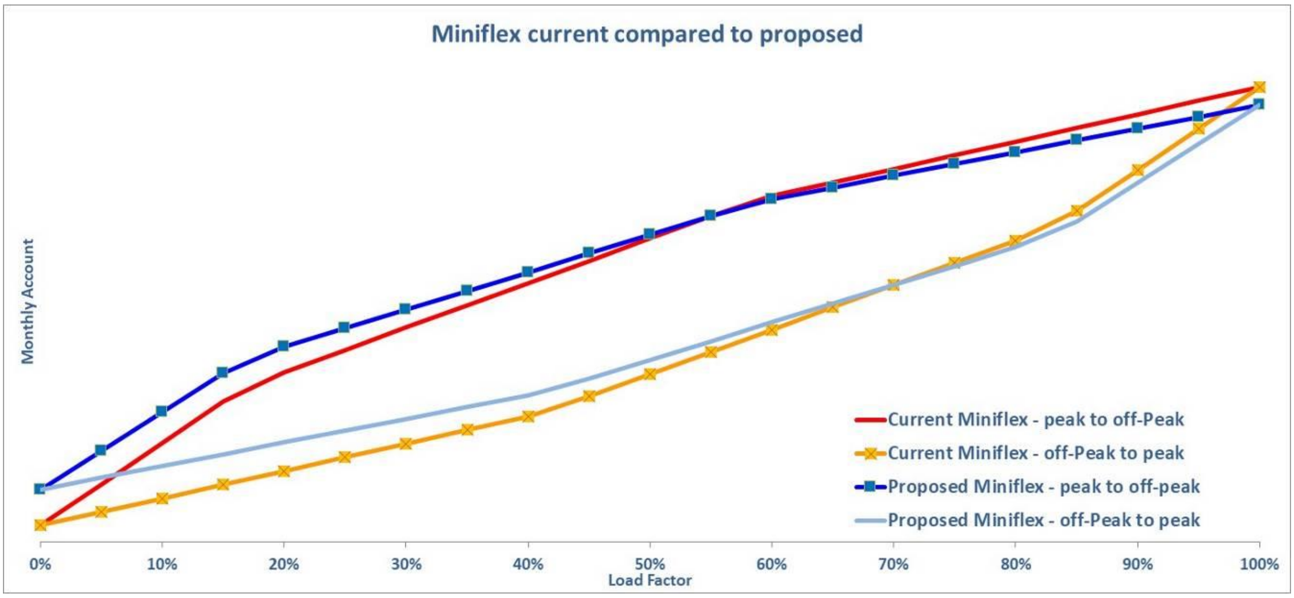


Figure 41: Current Miniflex non-local-authority tariff compared to the proposed tariff

B.8 Ruraflex non-local-authority

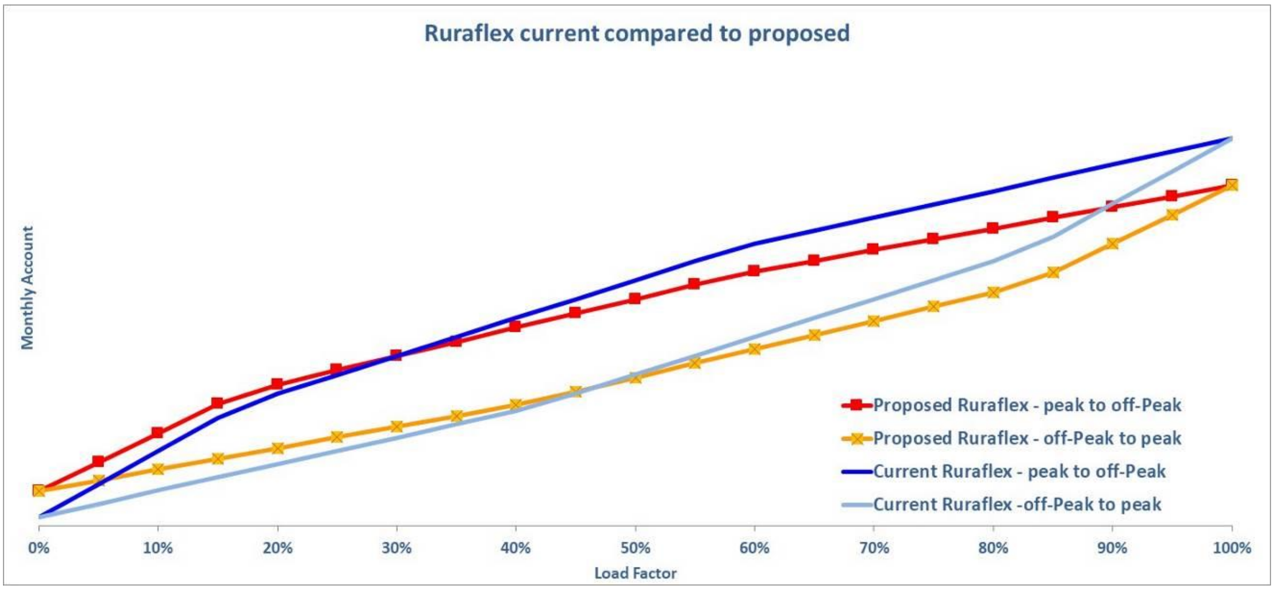


Figure 42: Current Ruraflex non-local-authority tariff compared to the proposed tariff

B.9 Nightsave Rural non-local-authority

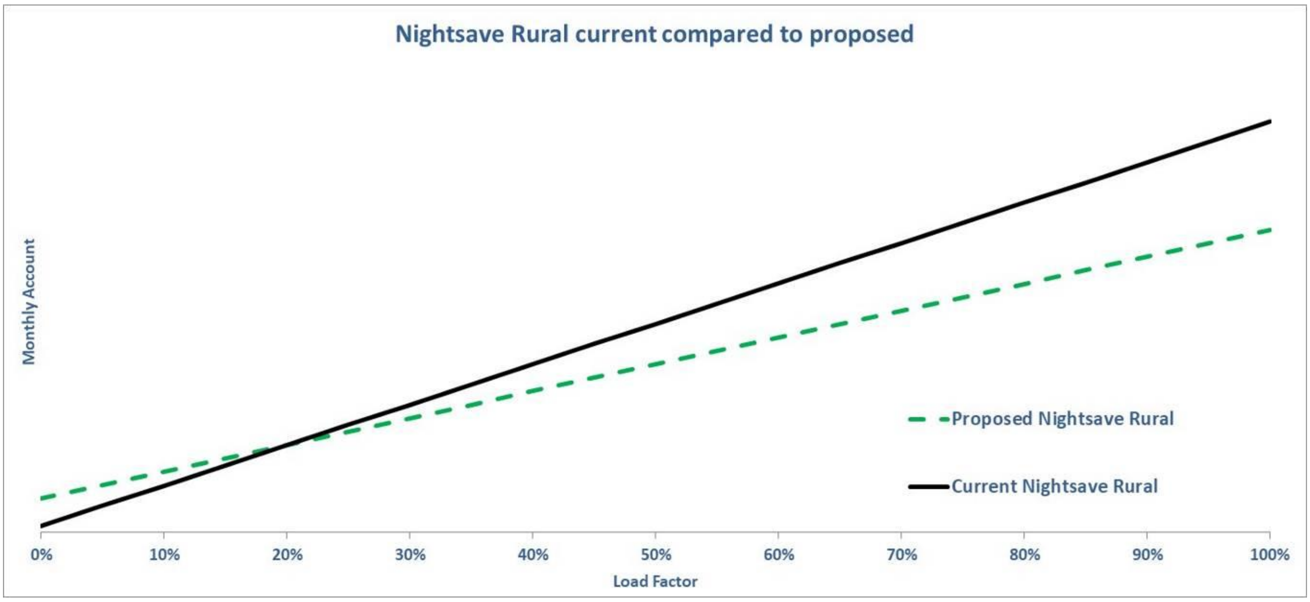


Figure 43: Current Nightsave Rural non-local-authority tariffs compared to the proposed tariff

B.10 Nightsave Rural and Ruraflex non-local-authority

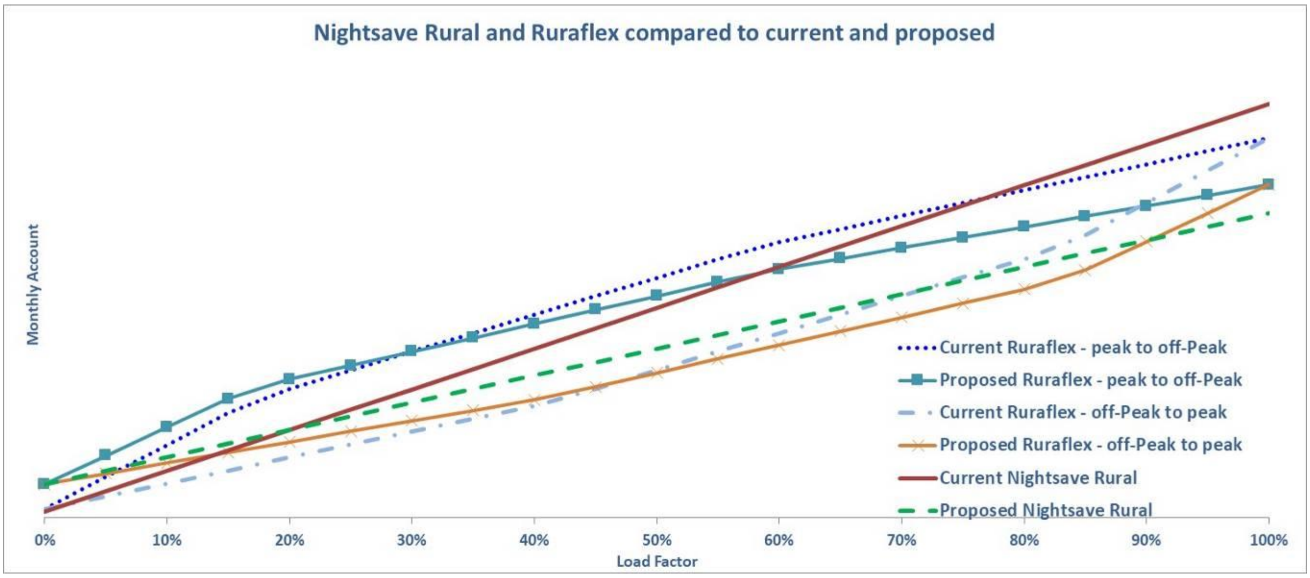


Figure 44: Current Nightsave Rural and Ruraflex non-local-authority tariffs compared to the proposed tariffs

B.11 Total impacts for large power non-local authority tariffs per voltage

The following table provides the impact per voltage for the large power non-local authority tariffs

Table 22: Total impact per voltage for the non-local authority large power tariffs

LPU tariffs impact per voltage (%)	Megaflex	Miniflex	Nightsave Large	Nightsave Small	Transflex 1	Transflex 2	Ruraflex	Nightsave Rural
<500V	8%	4%	-7%	-3%			5%	-18%
≥500V & <66kV	1%	15%	4%	15%	8%	-20%	8%	-15%
≥66kV & <132kV	27%	25%	-5%	-5%	14%	-32%		
>132kV	-17%				35%			
Total	**0%**	**12%**	**1%**	**3%**	**13%**	**-25%**	**6%**	**-17%**

LPU tariffs impact per voltage (Rm.)	Megaflex	Miniflex	Nightsave Large	Nightsave Small	Transflex 1	Transflex 2	Ruraflex	Nightsave Rural
<500V	R 1	R 77	-R 40	-R 24			R 277	-R 304
≥500V & <66kV	R 837	R 546	R 65	R 53	R 53	-R 78	R 265	-R 239
≥66kV & <132kV	R 1 492	R 42	-R 9	-R 1	R 432	-R 80	R 0	R 0
>132kV	-R 2 052	R 5	R 0	R 0	R 19	R 0	R 0	R 0
Total	**R 277**	**R 670**	**R 16**	**R 29**	**R 505**	**-R 158**	**R 542**	**-R 542**

B.12 Comparison tools

Comparison tools will be provided to assess the impact of the proposed changes

Annexure C – Motivation for the changes to the TOU retail energy charges and rates structure

C.1 Background

The wholesale energy purchase structure is the basis for all Eskom retail TOU tariffs. The current retail tariffs TOU structure (periods and rates) in the retail tariffs does not reflect the wholesale purchase structure and rates and not aligned to Eskom present system requirements. Eskom proposes changes to the TOU rates and periods to align with the changes to the wholesale purchase structure for the following reasons:

1. To meet the System Operator’s requirements to optimise the operation of the power system.
2. To provide the right economic signals that promotes economic efficiency.
3. To incentivise growth and sales for the benefit of both the customers and Eskom.
4. To improve financial sustainability by increasing efficiencies in operating costs.

The changes to the wholesale purchase structure and rates were used in the CTS to develop the retail tariffs, using the revised wholesale purchase structure and rates proposed TOU hours and, the tariff ratios to be applied to Eskom’s standard tariffs.

Customers have formally requested both Eskom and NERSA to review the TOU tariffs, expressing concerns that the high winter TOU energy rates prohibit the optimisation of their production and impede their economic efficiency, which has a negative impact on their financial sustainability, their competitiveness in the global economy, and their ability to grow. Both the Eskom shareholder and NERSA have, furthermore, requested that Eskom revise the TOU tariffs.

C.2 Drivers, motivation and strategic objectives for the proposed changes to the TOU tariff structure

The current retail tariffs TOU energy charges structure no longer reflects the present system requirements and costs incurred at the wholesale level during the time-of-use hours. Changes are required to this structure to assist the System Operator to optimise how the Eskom's system is managed, scheduled and dispatched.

The changes to the retail tariffs TOU energy charges correlation against system marginal costs, with the wholesale purchase structure and rates and price signals will optimise the management of the power system, enable an increase in sales, incentivise growth, reduce Eskom’s revenue risks (moving some of the winter revenue risk to summer) and reduce trading risk caused by a misalignment between wholesale and retail tariffs. The changes to the structure will also drive cost-efficiencies to support Eskom’s long-term price path.

After these proposed changes have been implemented, it is expected that the wholesale structure and rates will be reviewed further in the future to accommodate changes in the energy mix, future changes in the Generation capacity availability, future System Operator requirements, and customer needs to achieve Eskom’s long-term price path.

C.3 System Operator's requirements

The System Operator's requirements to manage the power system optimally are as follows:

a) The ideal system load profile is flat, as expensive generators have to be used to supply electricity during peak times. The current power system has two peaks, that is, the morning peak and the evening peak. The evening peak occurs when the demand for electricity is the highest in the day, and expensive peaking generators may have to be uneconomically used for very few hours in a day to provide electricity to the country. The winter evening peak hours are when the system demand is highest in the year.

The System Operator has also recognised the impact of PV on the system and how dispatchable plant (mainly coal plant) will have to be used to manage the impact that renewables will have on system operations. For example, customers using SSEG systems such as PV will reduce the energy in the system during the day, but will not change the current morning and evening peak period system demand.

TOU pricing signals, therefore, will continue to be needed to manage the high system demand in the morning and evening peak periods as well as to manage the variation of system demand levels between the high- and low-demand months (summer and winter months).

b) The System Operator has to plan for sufficient generation to be available to meet the highest demand in the day. When compared to the minimum load on the power system a significantly additional higher amount of MWs is required to meet the evening peak demand. This significant difference in the minimum and maximum system demand is not an efficient technical and economical use of generation capacity.

TOU pricing signals are, therefore, needed to optimise the system load profile, that is, to reduce demand when the system is constrained during peak hours and incentivise electricity usage when there is operational surplus during certain hours of the days.

c) The System Operator requires the evening ramp-up rate currently being experienced in the system to be managed, as the current generators can only ramp up to meet the steep increase in the evening peak at a technically limited rate. If the ramp-up rate to the evening peak is not addressed, the system will not be able to meet the demand at these times, and this will affect security of supply.

This system requirement means that the evening peak hours need to be increased in order to reduce the ramp-up rate in the evenings. The proposed TOU hour changes include an increase in the evening peak for both summer and winter; currently, there are two evening peak hours, and it is proposed that there be three evening peak hours.

Customers using PV systems during the day results in drop in the demand for electricity during the day – with the highest drop in system demand in the middle of the day. This midday demand drop (called the "duck curve") affects the power system negatively, as it means that the generators have to ramp up at an even faster rate than before to meet the evening peak demand. This is a higher pickup at a steeper ramp rate because of PV energy production dropping off, while demand increases.

d) The System Operator has requested that the Sunday evening peak demand currently being experienced at a national system level be managed so that uneconomical use of expensive peaking generators for a very few hours can be avoided. Avoiding the use of expensive peaking generators will reduce Eskom costs.

e) In the proposed TOU hour changes, two standard hours are being introduced during the times that the system has a Sunday evening peak. In the current WEPS and retail TOU tariffs, all hours on a Sunday are off-peak hours, with the low off-peak price, and there is currently no price signal to manage the Sunday evening peak demand.

An illustrative example of the System Operator requirements to demonstrate the optimal management of the power system is shown in the figure below (not based on actual current system demand values).

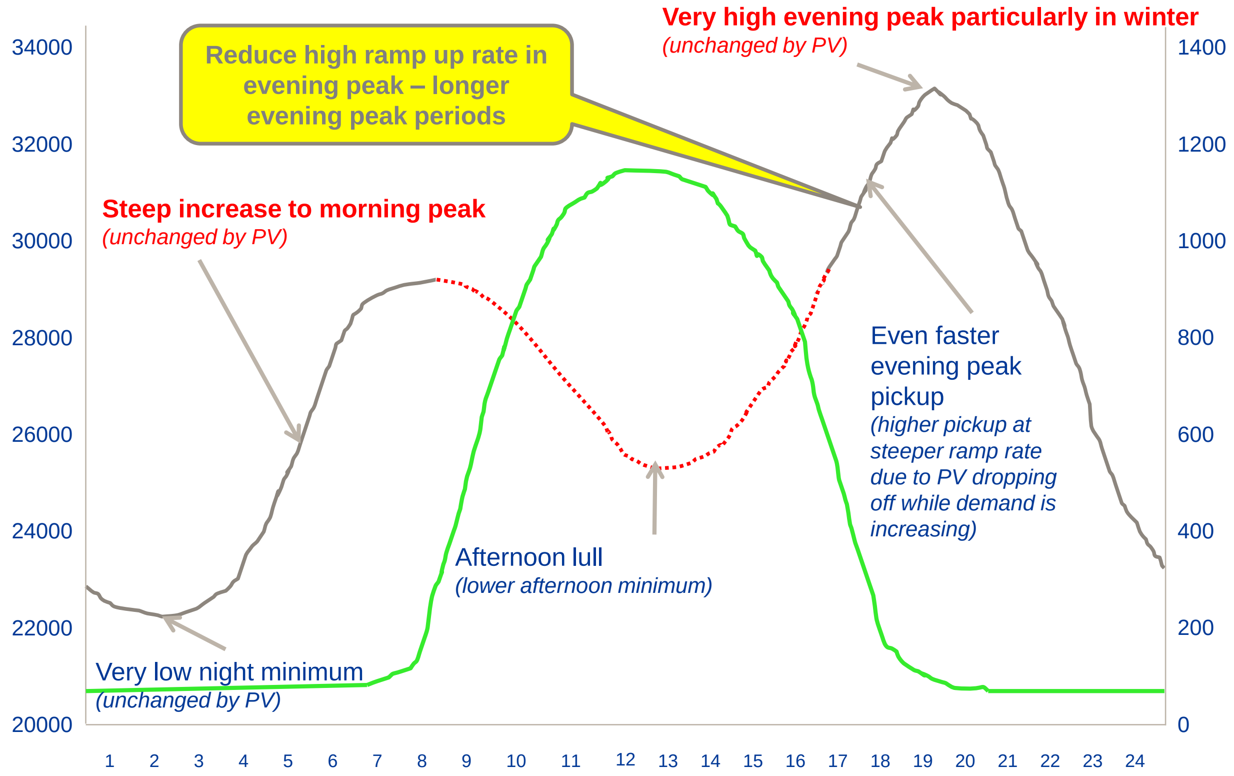


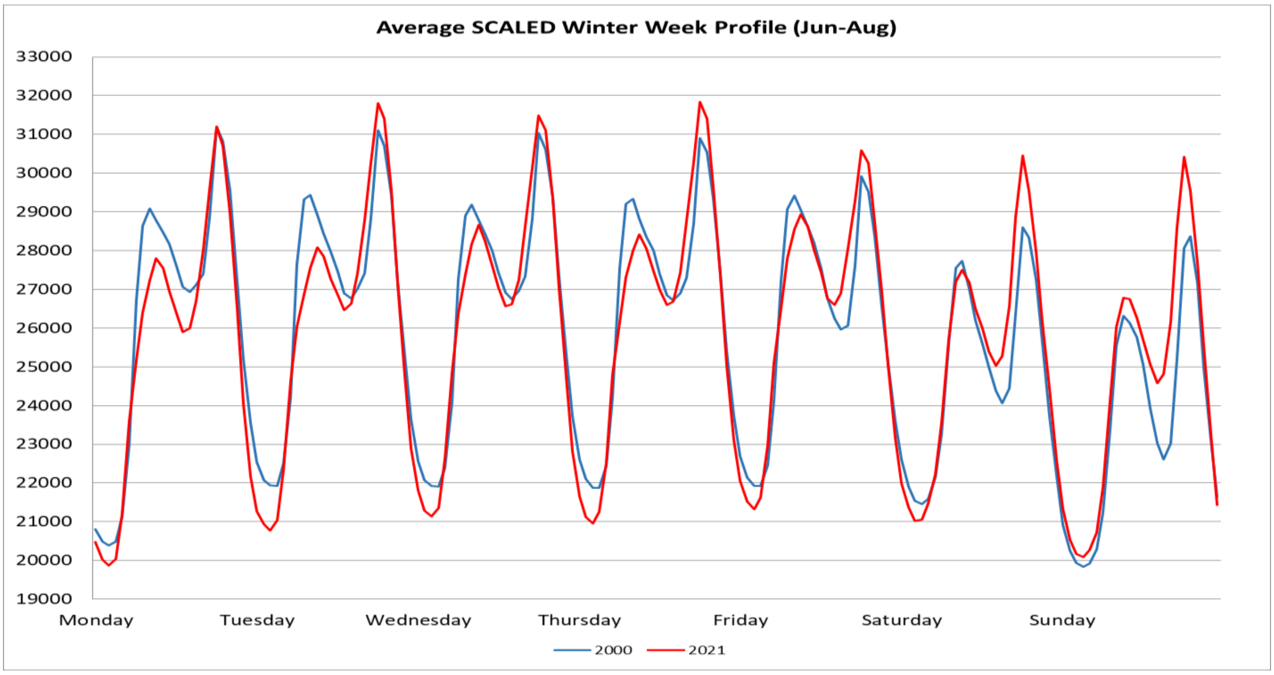
Figure 45: Eskom's System Operator illustrative overview and requirements to optimally manage the power system (not based on actual current system demand values)

C.4 Changes to the system profile over the last 24 years

Customers who have responded to the current TOU pricing signals have assisted Eskom in managing the peak periods. This response has contributed to the flattening of Eskom's load profile and the management of demand, particularly in the winter TOU periods (June to August). The changes in the Eskom system load profile over a period of 20 years (normalised) from 2000 to 2021 are shown the next figure.

Analysis of the scaled winter and summer average week of the national system profile from 2000 to 2021 shows the following changes in the system profile:

1. A reduction in the morning peak over the years
2. A significant increase in the evening peak over the years
3. An increase in the Sunday evening demand



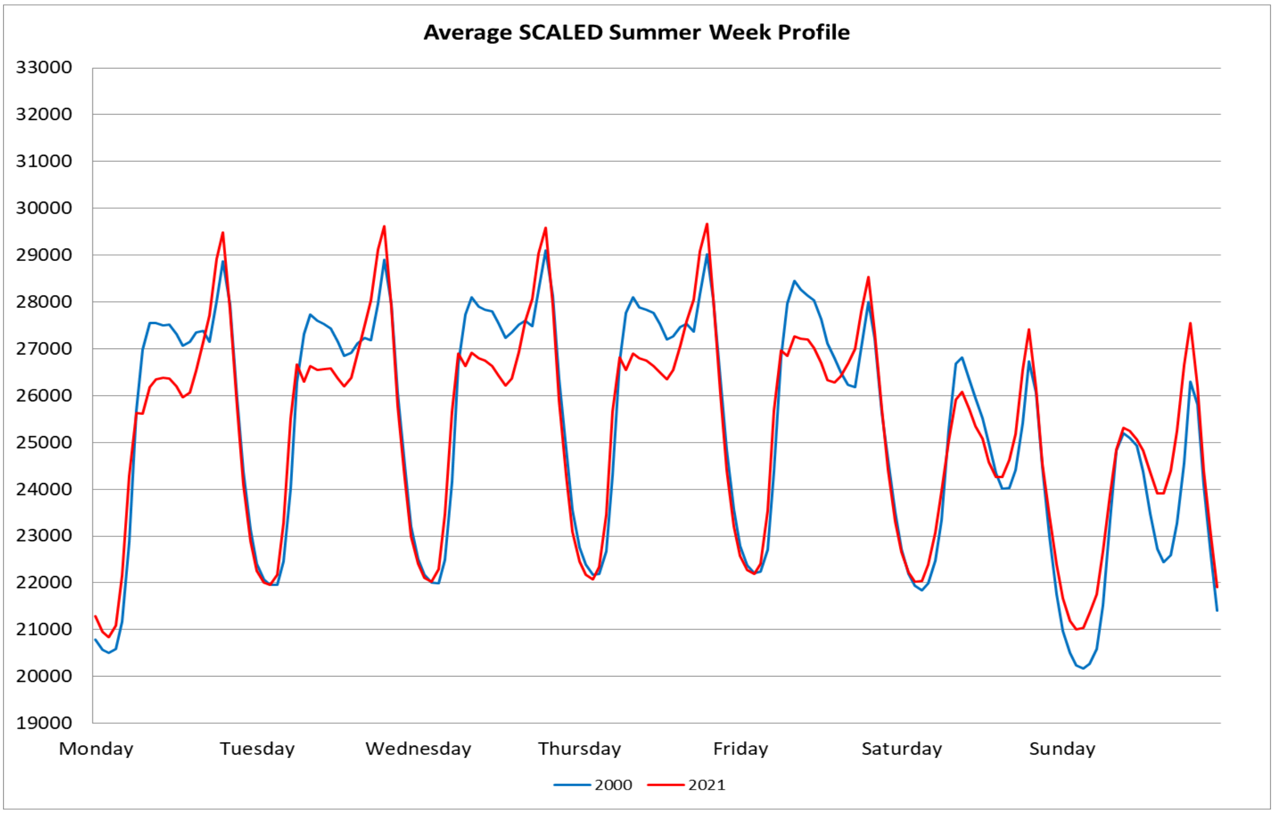


Figure 46: Scaled winter and summer average week of the national system profile from 2000 to 2021

From the changes to the system profile over the last 20 years, it is evident that customers have responded to the time-of-use price signals, especially in the morning periods.

C.5 The future system load profile

The system requirements in the future also need to be accommodated in the changes to be made to the TOU tariffs. The impact of renewables, wheeling, and decreasing sales must be taken into consideration to improve the future system load factor and manage the operational constraint/surplus during certain hours of the day. The changes to the TOU tariffs are, therefore, needed to drive cost-efficiencies to support Eskom's long-term price path.

Analysis has been done on the average summer and winter weekday system profile for 2025 and 2030 based on the IRP draft 2016 base case plus some additional renewables (as approved by Eskom's Integrated Strategic Energy Planning).

The average summer and winter weekday system profile in 2025 and 2030 is shown in the figure below.

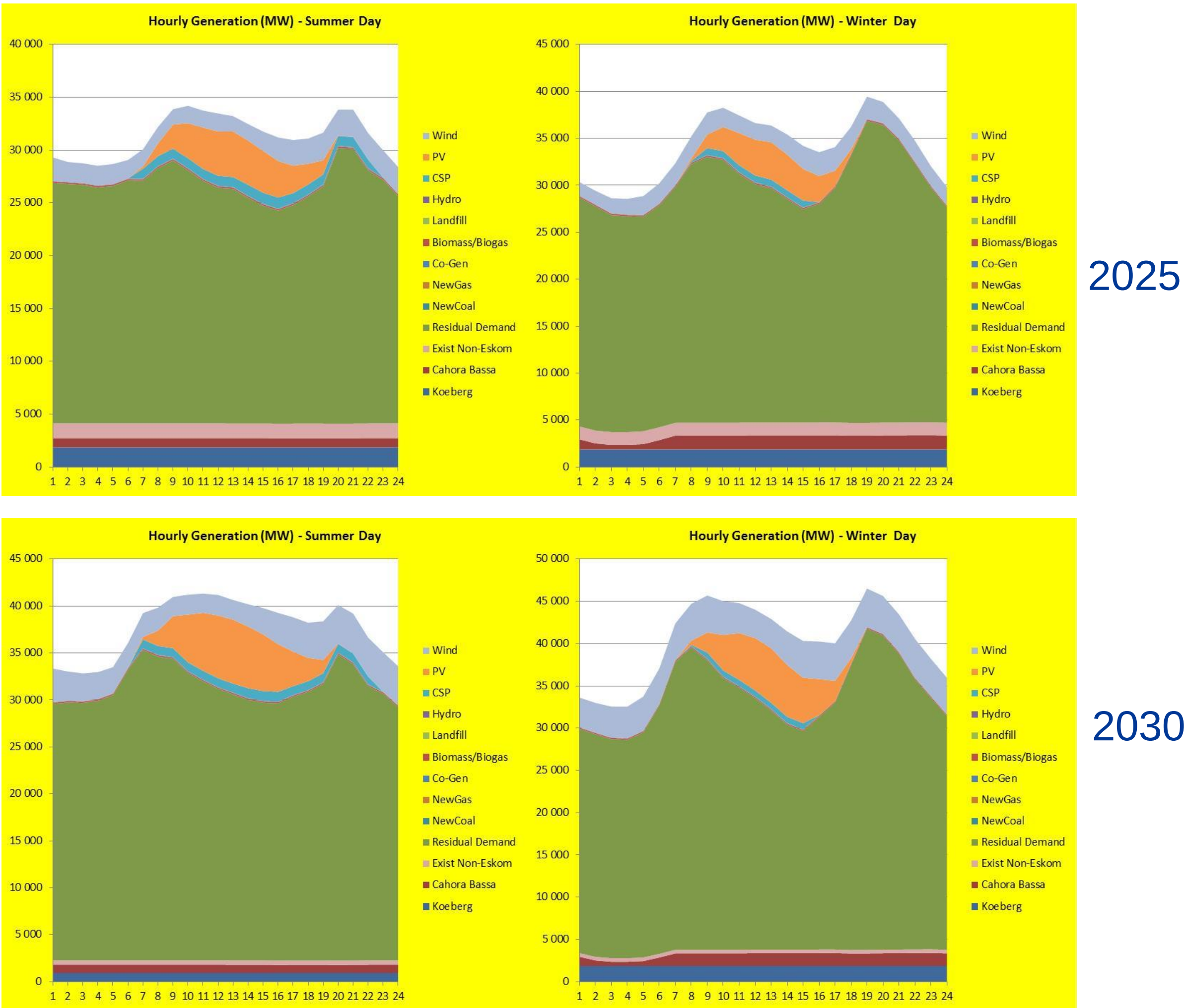


Figure 47: Average summer and winter weekday system profile in 2025 and 2030

It is evident from the future system outlook that TOU tariffs are still required in the future to optimise residual demand.

1. Although there is renewable energy in the national load profile shown in 2025 and 2030, this is not "dispatchable". Eskom has to provide the "balance of energy" or "residual demand" – shown in the green area and below in the load profile.
2. There are still morning and evening peaks in the system. Morning and evening peaks become "peakier" over time and still need to be managed by price signals.

3. A difference remains in the demand level in winter and summer, which still requires different price signals for winter and summer.
4. The drop in midday demand is evident and is more pronounced over time.

The proposed changes to the retail TOU tariffs are required not only to manage the current system constraints, but also to mitigate future system challenges.

C.6 The features of the proposed changes to the wholesale purchase structure and rates and retail TOU tariffs

The proposed changes to the wholesale purchase structure and rates and retail TOU tariffs include:

a) changes to the time-of-use hours and time periods of the day; and
b) changes to the tariff peak, standard, and off-peak ratios and rates.

The proposed TOU hours and time periods have been done in consultation with, and have been signed off by, the System Operator to ensure that the System Operator's requirements to optimise the management of the system are met. The existing and proposed time periods of the wholesale purchase structure and rates and retail tariffs are shown in the following table.

Table 23: Existing and proposed TOU periods

Existing TOU time periods

	High			Low		
	Weekday	Saturday	Sunday	Weekday	Saturday	Sunday
0	3	3	3	3	3	3
1	3	3	3	3	3	3
2	3	3	3	3	3	3
3	3	3	3	3	3	3
4	3	3	3	3	3	3
5	3	3	3	3	3	3
6	1	3	3	2	3	3
7	1	2	3	1	2	3
8	1	2	3	1	2	3
9	2	2	3	1	2	3
10	2	2	3	2	2	3
11	2	2	3	2	2	3
12	2	3	3	2	3	3
13	2	3	3	2	3	3
14	2	3	3	2	3	3
15	2	3	3	2	3	3
16	2	3	3	2	3	3
17	1	3	3	2	3	3
18	1	2	3	1	2	3
19	2	2	3	1	2	3
20	2	3	3	2	3	3
21	2	3	3	2	3	3
22	3	3	3	3	3	3
23	3	3	3	3	3	3

Proposed new TOU time periods

	High			Low		
	Weekday	Saturday	Sunday	Weekday	Saturday	Sunday
0	3	3	3	3	3	3
1	3	3	3	3	3	3
2	3	3	3	3	3	3
3	3	3	3	3	3	3
4	3	3	3	3	3	3
5	3	3	3	3	3	3
6	1	3	3	2	3	3
7	1	2	3	1	2	3
8	2	2	3	1	2	3
9	2	2	3	2	2	3
10	2	2	3	2	2	3
11	2	2	3	2	2	3
12	2	3	3	2	3	3
13	2	3	3	2	3	3
14	2	3	3	2	3	3
15	2	3	3	2	3	3
16	2	3	3	2	3	3
17	1	2	2	2	3	3
18	1	2	2	1	2	2
19	1	3	3	1	2	2
20	2	3	3	1	3	3
21	2	3	3	2	3	3
22	3	3	3	3	3	3
23	3	3	3	3	3	3

Peak = 1
Standard = 2
Off-peak = 3

The proposed changes to the wholesale purchase structure and rates and retail tariff TOU time periods are as follows:

1. Morning peaks are reduced by one hour for both summer and winter (that is, a two-hour morning peak period instead of the previous three-hour morning peak period). The morning peaks are not the highest system demand and can be managed.
2. Evening peaks are increased by one hour for both summer and winter (that is, a three-hour evening peak period instead of the previous two-hour evening peak period to reduce the evening ramp-up rate).
3. Sundays have two standard hours to assist the system with high demand on Sunday evenings.
4. Standard hours for Saturday and Sunday have been moved forward to start at 17:00 for winter only. Standard hours for Saturday and Sunday start at 18:00 for summer.

Several scenarios and their impacts have been analysed, and there have been extensive consultation workshops internally in Eskom and externally with customers on the proposed changes and the impact of the proposed changes. The System Operator, Eskom divisions, the Energy Intensive Users Group (EIUG), and the Association of Municipal Electricity Utilities (AMEU) are some of the key stakeholders consulted.

The proposed changes to the wholesale purchase structure and rates peak, standard, and off-peak ratios and rates, including the changes to the hours, are shown in the table below.

Table 24: Current and proposed wholesale purchase structure and rates energy costs and ratios (excluding losses)

	Wholesale energy rates					
Season	High-demand			Low-demand		
Period	Peak	Standard	Off-Peak	Peak	Standard	Off-Peak
1) Existing ratios	8.00	2.31	1.18	2.50	1.67	1.00
2) Existing TOU ratios c/kWh	370.94	112.36	61.03	121.03	83.28	52.84
3) Updated CTS existing TOU ratios c/kWh	432.92	125.00	63.86	135.28	90.38	54.12
4) New ratios	6.00	1.50	1.00	2.49	1.40	1.00
5) Updated new TOU ratios c/kWh	301.98c	75.49c	50.33c	125.32c	70.46c	50.33c
6) Difference between current and new ratios c/kWh	-68.96c	-36.87c	-10.70c	4.29c	-12.82c	-2.51c
7) Difference existing WEPS vs New CTS TOU c/kWh	61.98c	12.64c	2.83c	14.25c	7.10c	1.28c
8) Difference New CTS TOU vs Old CTS TOU	-130.94c	-49.51c	-13.53c	-9.96c	-19.92c	-3.79c

	Peak	Standard	Off peak
New TOU annual average	170.16c	71.74c	50.33c

When comparing the proposed wholesale purchase structure and rates to the existing retail rates (excluding losses), the following can be noted:

- The winter peak rate ratio has been decreased from a 1:8 ratio to a 1:6 ratio (see points 1 and 4 above).
- The energy charges have reduced except for the summer peak, because of the introduction of the GCC.
- This ratio changes before updating the energy costs with the CTS, has reduced the winter prices and increased the summer peak prices (see points 2 and 5 above).

C.7 The correlation and support of the proposed changes to the wholesale purchase structure and rates and retail TOU tariffs with short-run marginal costs

A study was commissioned to examine the impact of the 100MW exemption on Eskom. Included in this study was an analysis of the impact on Eskom revenue and proposed changes to tariffs to mitigate revenue loss not associated with a reduction in costs.

The study showed that there is misalignment between the current retail TOU and the short-run marginal costs (SMC). The study “points to the urgent need to review Eskom’s TOU definition and charges.”

The findings from this study are included below comparing the SMC and the current retail TOU rates (excluding losses). The results are shown in the figure below:

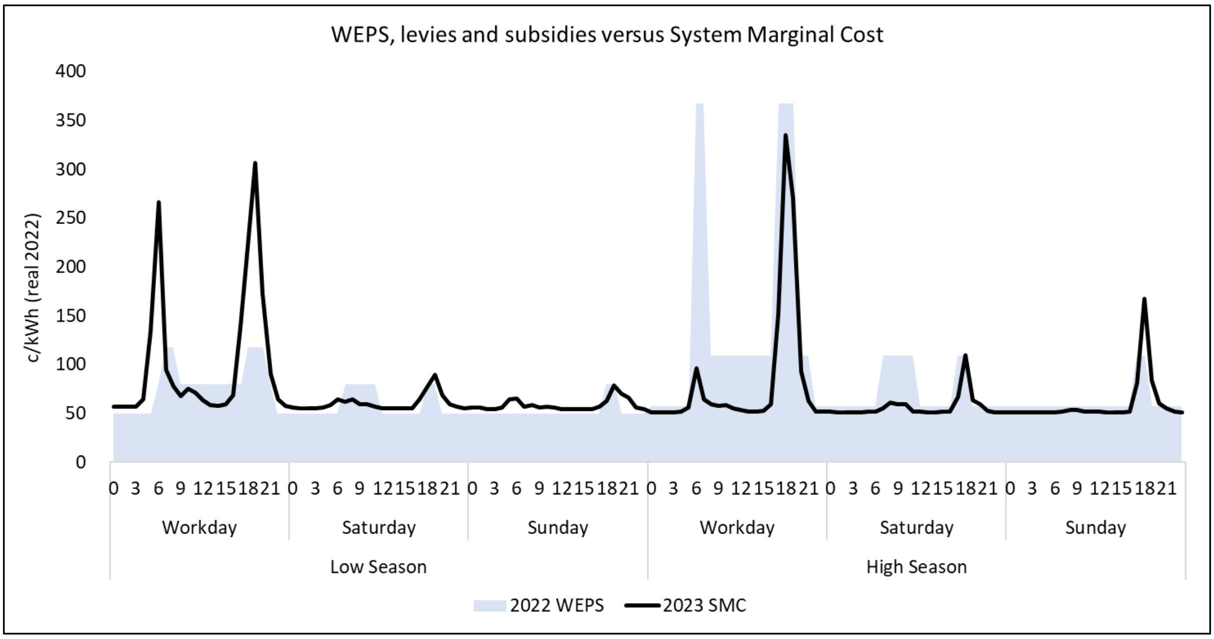


Figure 48 Comparison between SMC and wholesale purchase structure and rates (without losses, levies, and subsidies)

The following is observed from the study:

1. There is a reasonable correlation between the tariff TOU profile (periods and rates) and the SMC profile, but there are clearly also some exceptions.
2. The TOU charges are higher than the SMCs in the peak and standard periods during the winter months, except for Sunday evenings. This reflects the fact that Eskom recovers not only its variable cost but also a large portion of the fixed generation cost via the TOU rates during these times. In fact, it could be argued that Eskom's TOU rates in the morning peak and in the standard periods in the high season are too high.
    a. The proposed changes to the TOU rates are supported by the above statement in that the TOU rates in the morning peak and standard periods in the high demand season are reduced.
3. However, what is of concern is that Eskom appears to sell off-peak electricity in the low season period below the marginal cost of supply. It means that incremental electricity sold during these periods not only fail to recover the marginal cost of production, but these sales do not contribute to the recovery of Eskom's capital costs.
    a. The rates in the off-peak periods are reduced and therefore not aligned to the marginal costs. In the next revision of the TOU charges the off-peak rates will be assessed.

The above are important observations because it shows that the more Eskom sells in during the low season, the more it loses. This is obviously a point that deserves further attention and is one of the issues addressed in the recommendation around tariff structure and level adjustments.

Another important point to highlight is the recovery of Generation's fixed costs hinges on high-price energy sales for a few peak and standard hour sales during the high season. This exposes Generation's revenue requirement to significant volume risk. This issue is addressed in this submission under the generation capacity charges.

It is also noted that, assuming that Eskom does not update its TOU definitions and tariff levels at annual intervals to track the evolution of SMC, Eskom will face an increasing net contribution loss due to divergence between SMC and WEPS charges.

A comparison in the report was done against Eskom's OCGT usage during 2021 against the TOU tariff profile to determine whether the high prices produced by the model are supported by actual dispatch. The comparison is shown in the following figure.

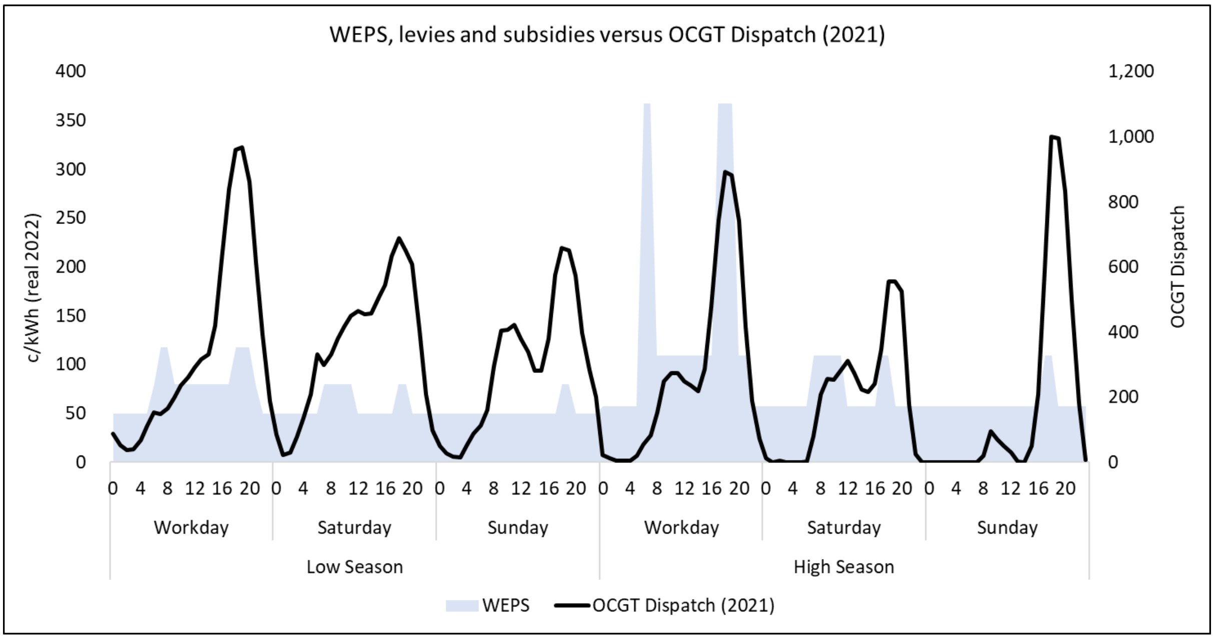


Figure 49 Comparison between wholesale purchase structure and rates (without losses, levies, and subsidies) against OCGT dispatch during 2021

The above figure shows:

1. Evening peaks in all the days and seasons stand out as a period of high OCGT dispatch.
2. A surprising result is the high usage of OCGT during Sunday evening peaks in the high season.
3. OCGT plant have also been dispatched in many other hours of the day and not only during the peaks. This confirms that South Africa is experiencing a not only a supply capacity deficit but also an energy supply shortage.

These results confirm the mismatch between TOU rates and the SMC especially during the high-demand season period and points to the urgent need to review Eskom's TOU definition and charges. It also supports the need to have TOU tariffs to ensure that customers who consume in peak periods, including baseload customers need to contribute towards the costs in these periods.

Annexure D – Proposed changes to rate components

The information below sets out the proposed changes to each rate component per tariff.

D.1 Service and administration charges

a) Retail charges recover the cost of administration (meter reading and billing) and customer service (queries, applications, quotations, call centres, etc.). It is proposed that this charge be cost-reflective for all tariffs, except Homelight.

b) The charges per tariff will be based on the updated CTS using the following units:

Table 25: Structure of the service and administration charges

Tariff	Charge unit	Features
Businessrate 1, 2, 3	• R/POD/day	• No change from current tariffs with a combined service and administration charge, not differentiated on size
Businessrate 4	• c/kWh	• No change from current tariffs, with a combined service and administration charge, bundled together with other c/kWh charges
Landrate 1, 2, 3	• R/POD/day	• No change from current tariffs, with a combined service and administration charge, not differentiated on size
Landrate Dx	• R/POD/day	• No change from current tariffs, with a combined service and administration charge, bundled together with other R/POD charges
Landrate 4, Landlight 20A, Landlight 60A	• c/kWh	• No change from current tariffs, with a combined service and administration charge, not differentiated on size and, bundled together with other c/kWh charges
Homepower 1, 2, 3, 4	• R/POD/day	• This is a proposed change from the current tariff, where a combined service and an administration charge is reintroduced
WEPS, Megaflex, Miniflex, Nightsave Urban and Rural, Ruraflex, Megaflex Gen, Ruraflex Gen, Transflex 1 and Transflex 2, Gen DUoS and Gen TUoS,	• R/POD /day	• Structural change with a service charge changing from R/account/day to R/POD/day
Gen Offset, Gen Wheeling, Gen Purchase	• R/POD/day	• No change from current tariffs – an administration charge for each transaction
Public Lighting	• c/kWh	• No change from current tariffs, with a combined service and administration charge bundled together with other c/kWh charges
New tariffs		
Municflex	• R/POD/day	• Same structure as Megaflex, but based on local-authority cost for current Megaflex, Miniflex, Nightsave Urban, Ruraflex and Nightsave Rural

Tariff	Charge unit	Features
		• The above tariffs have been combined into one new tariff called Municflex • Separate service and administration charge per POD.
Municrate	• R/POD/day	• Combined service and administration charge, not differentiated on size • Same structure as Businessrate, but based on the combined costs for Businessrate, Landrate, and Homepower • Landrate Dx has been converted to the Public Lighting Fixed tariff
Homeflex 1, 2, 3, 4	• R/POD/day	• This is a new tariff that has service and administration charges that are exactly the same as for Homepower

D.2 Active energy charges

a) The active energy charges for all tariffs will be based on the new wholesale TOU rates, ratios, periods and updated loss factors.

b) The energy charges may be averaged annually, seasonally, or by TOU, depending on the tariff structure.

c) All tariffs should at least recover energy costs. Subsidies should only be applied to network and retail costs.

d) The active energy charges per tariff will be based on the updated CTS using the following units:

Table 26: Structure for the active energy charges

Tariff	Charge unit	Features
Non-local-authority tariffs		
Businessrate 1, 2, 3	• Single active energy c/kWh charge	• Reflecting variable energy costs only • Single average rate based on representative TOU profile and wholesale costs plus losses
Businessrate 4	• Single active energy c/kWh	• Single average rate based on representative TOU profile, bundled together with all other costs, and converted into a single c/kWh charge
Landrate 1, 2, 3, 4	• Single active energy c/kWh charge	• Reflecting variable wholesale energy costs only (including the 50% of the GCC) • Single average active variable energy charge based on representative TOU profile and wholesale costs (including 50% of the GCC) plus losses • For Landrate 4, combined with the c/kWh service and administration charge • Is subsidised
Landrate Dx	• R/POD/day	• Single average rate calculated based on representative TOU profile, bundled together with other costs, and converted into a R/POD/day charge based on 200 kWh/m

Tariff	Charge unit	Features
Non-local-authority tariffs		
Landlight 20A and 60A,	• Single active energy c/kWh charge	• Single average energy charge based on representative TOU profile, bundled together with all other costs, and converted into a single c/kWh charge • Is subsidised
Homepower 1, 2, 3, 4	• Single active energy c/kWh charge	• This is a proposed change from the current IBT structure where the fixed costs are removed from the active energy charges, and recovered transparently through retail and network charges • Single average active variable energy charge based on representative TOU profile and wholesale costs (including 50% of the GCC) plus losses • Also refer to paragraph 5.9.1 which provides the motivation for the proposed changes
Homelight 20A and 60A	• Single active energy c/kWh charge recovering all cost less subsidies	• This is a proposed change from the current IBT structure • Single average energy charge based on current revenue (not costs) • The option remains to retain IBT structure • Subsidised
WEPS, Megaflex, Miniflex, Ruraflex, Megaflex Gen, Ruraflex Gen, Transflex 1 and Transflex 2,	• Active energy c/kWh charges • TOU, seasonally, voltage (reflecting losses) and transmission zone differentiated.	• Changes to the TOU ratios and periods • Reflecting TOU wholesale structure and variable energy costs plus losses
Nightsave Urban and Rural	• Active energy c/kWh charges and R/kVA energy demand charges • Time, seasonally, voltage (reflecting losses), and transmission zone differentiated.	• Nightsave Urban Large and Small combined • Reflecting TOU wholesale variable energy costs plus losses, separated into seasonal c/kWh energy charges, and R/kVA seasonal demand charges applicable in peak and standard periods
Gen DUoS and Gen TUoS	• The TOU active energy charges are used to calculate the losses charge applied to the DUoS and TUoS network charges	• Loss charges based on revised wholesale purchase costs • Gen TUoS loss factors revised
Gen-offset	• Negative TOU-based c/kWh charges • Time, seasonally, voltage (reflecting losses), and	• Credit for energy exported • These rates are equal to the applicable tariff TOU active energy charges

Tariff	Charge unit	Features
Non-local-authority tariffs		
	transmission zone differentiated	
Applicable to both non-local-authority and local-authority tariffs		
Public Lighting All-Night, Public Lighting 24-Hour	• Single energy c/kWh	• Structurally no change from current tariffs • Single average rate calculated based on representative TOU profile plus losses, bundled together with other costs, and converted into a single c/kWh charge • Public Lighting tariff for non-metered lighting supplies (no change just updated with the CTS).
Public Lighting Fixed charge tariff	• R/POD/day	• Single average rate calculated based on representative TOU profile, bundled together with other costs, and converted into a R/POD/day charge based on 200 kWh/m. • GCC is fully converted to the energy charge • Public Lighting tariff for non-metered lighting supplies (no change just updated with the CTS). [Previously approved in Eskom but not approved by NERSA – required it to be based on a cost to serve study. Only have NERSA approval for subsidies for Homelight and rural tariffs]
Gen-wheeling	• Negative TOU-based c/kWh active energy charges, excluding losses	• Credit for energy exported based on restructured wholesale costs and structure excluding losses • These rates are equal to the WEPS active energy charges less losses
Gen-purchase	• Positive TOU-based c/kWh active energy charges, excluding losses	• Add-back of Eskom purchased energy, but consumed by the customer • The rates are equal to the TOU active energy rates less losses
New tariffs		
Local-authority tariffs		
Municflex	• Active energy c/kWh charges that are TOU, seasonally, voltage (reflecting losses), and transmission zone differentiated	• Changes to the TOU ratios and periods • Reflecting TOU wholesale structure and variable energy costs plus losses • Same structure as Megaflex, but based on the combined local-authority energy cost for the current Megaflex, Miniflex, Nightsave Urban, Ruraflex and Nightsave Rural tariffs
Municrate	• Single energy c/kWh	• Same structure as Businessrate, but based on the combined costs for Businessrate, Landrate, and Homepower

Tariff	Charge unit	Features
Non-local-authority tariffs		
		• Single active average rate calculated based on a combined representative TOU profile energy cost plus losses • Landrate Dx converted to Public Lighting Fixed charge tariff
Residential tariffs		
Homeflex 1, 2, 3, 4	• c/kWh charges that are TOU-based and seasonally differentiated • Offset rate for export of energy	• Reflecting TOU wholesale structure and variable energy costs, plus variable GCC c/kWh rate plus losses- also refer to paragraph 5.9.2 • Offset rate equal to the TOU active energy variable charge excluding the GCC variable charge

D.3 Generation capacity charges

a) The generation capacity charge will be introduced for most tariffs

b) The active energy charges per tariff will be based on the updated CTS using the following units:

Table 27: Structure for the generation capacity charges

Tariff	Charge unit	Features
Non-local-authority tariffs		
Businessrate 1, 2, 3	• R/POD/day charge	• New charge, reflecting fixed energy costs • Charge based on NMD
Businessrate 4	• Single active energy c/kWh	• Single average rate
Landrate 1, 2, 3, 4	• Single active energy c/kWh charge	• New charge, reflecting fixed energy costs • Charge based on NMD
Landrate Dx	• R/POD/day	• Included in the R/POD/day charge
Landlight 20A and 60A,	• Single active energy c/kWh charge	• Included in the single average energy charge
Homepower 1, 2, 3, 4	• R/POD/day charge	• New charge, reflecting fixed energy costs • Charge based on NMD based on representative TOU profile and wholesale costs
Homelight 20A and 60A	• Single active energy c/kWh charge recovering all cost less subsidies	• Included in the single average energy charge • Subsidised
WEPS, Megaflex, Miniflex, Ruraflex, Megaflex Gen, Ruraflex Gen, Transflex 1 and Transflex 2,	• R/kVA	• New charge, reflecting fixed energy costs • Charge based on utilised capacity
Nightsave Urban and Rural,	• R/kVA	• New charge, reflecting fixed energy costs • Charge based on utilised capacity

Tariff	Charge unit	Features
Non-local-authority tariffs		
Gen DUoS and Gen TUoS,	• N/a	• N/a
Gen-offset	• N/a	• N/a
Applicable to both non-local-authority and local-authority tariffs		
Public Lighting All-Night, Public Lighting 24-Hour	• Single energy c/kWh	• Included in the single average energy charge
Public Lighting Fixed charge tariff	• R/POD/day	• Included in the fixed charge
Gen-wheeling	• N/a	• N/a
Gen-purchase	• N/a	• N/a
New tariffs		
Local-authority tariffs		
Municflex	• R/kVA	• New charge, reflecting fixed energy costs • Charge based on utilised capacity
Municrate	• R/POD/day charge	• New charge, reflecting fixed energy costs • Charge based on NMD
Residential tariffs		
Homeflex 1, 2, 3, 4	• R/POD/day charge	• New charge, reflecting fixed energy costs • Charge based on NMD

D.4 Network charges

a) The network charges are differentiated according to Distribution's current voltage and geographic categories. The geographic aspect (locational signal) is provided in the network charges through a rural and an urban differentiation.

b) The calculations of the network charges have been split into the following categories:

Table 28: Network charge calculation categories

Category	Tariffs applicable
Non-local-authority urban LPU tariffs	Combining current tariffs; Megaflex, Miniflex, Nightsave Urban, and Megaflex Gen costs and revenues
Local-authority tariff Municflex	Combining current local-authority tariffs; Megaflex, Miniflex, Nightsave Urban, Ruraflex, and Nightsave Rural costs and revenues
Non-local-authority rural LPU tariffs	Combining current tariffs; Ruraflex, Ruraflex Gen, and Nightsave Rural costs and revenues
Municrate	Combining current local-authority tariffs; Businessrate, Landrate, and Homepower costs and revenues
Businessrate	Current tariff
Landrate	Current tariff

Category	Tariffs applicable
Homepower	Current tariff
Homelight	No network charge
Public Lighting	No network charge

c) For the urban LPU tariffs, the Distribution network costs have been split into fixed R/kVA unit rates (based on utilised capacity and not dependent on consumption) and variable R/kVA unit rates (dependent on demand in a month), where the fixed-charge component was increased, and the variable-charge component reduced.

- Network charges are differentiated according to Distribution's current voltage and geographic categories. The geographic aspect (locational signal) is provided in the network charges through a rural and an urban differentiation.
- For the urban non-local-authority LPU tariffs (Megaflex, Miniflex, Nightsave Urban, Megaflex Gen), the HV and Transmission-connected network charges are based on cost, plus a transparent subsidy raised to recover shortfall because of the LV and MV connected rates that are lower than cost.
  i. A total of 60% of costs has been allocated as fixed and divided by the total utilised capacity to determine the R/kVA NCC.
  ii. A total of 40% of costs has been allocated as variable and divided by the total maximum demand to determine the R/kVA NDC according to the existing voltage categories.
  iii. For Miniflex, the NDC was then converted to a c/kWh value by dividing the cost by the peak and standard energy sales, and the NCC was added to the Transmission network charge.
  iv. As the two lower-voltage categories are currently subsidised, a subsidy of 10% has been applied to the NCC of the two lower-voltage categories and a 14% subsidy to the NDC of the 500 V category. This has adjusted the cost-reflective NDC and NCC for these two lower-voltage categories.
  v. The shortfall against cost for the two lower-voltage categories has then been converted into the LV subsidy charge.
  vi. It must be noted that, in some cases, the overall contribution to network charges has increased and, in others, decreased. This is a result of (1) adjusting the LV subsidies and (2) updating the charges with new costs and volumes (for example, lower volumes result in increased charges, and vice versa).
  vii. The Miniflex tariff has the greatest negative impact, as most of the points of supply of this tariff are at the two lowest voltages. This tariff currently receives the highest subsidy of the urban LPU tariffs.

d) For the LPU local-authority tariff Municflex:
  i. No change was made to the four voltage categories.
  ii. The network charges are based on local-authority cost for current local-authority Megaflex, Miniflex, Nightsave Urban, Ruraflex, and Nightsave Rural tariffs.
  iii. A total of 60% of costs has been allocated as fixed and divided by the total utilised capacity to determine the network capacity charge according to the existing voltage categories.
  iv. A total of 40% of costs has been allocated as variable and divided by the total maximum demand to determine the network demand charge according to the existing voltage categories.
  v. As the two lower-voltage categories are currently subsidised, a subsidy of 20% has been applied to the NCC and NDC charges of the two lower-voltage categories.
  vi. The shortfall against the cost for the two lower-voltage categories has then been converted into the LV subsidy charge for local-authority tariffs.

e) For the rural LPU non-local-authority tariffs (Ruraflex, Nightsave Rural), the network charge has been calculated as an average for both Ruraflex and Nightsave Rural (the network charge is a combined charge) Distribution and Transmission costs and volumes and then reduced by applying subsidies so that the current level of subsidies is maintained.

i. The network costs for Transmission and a percentage of the Distribution costs have been combined to calculate the NCC.

ii. The network charges for the two tariffs have been aligned, that is, made the same. Nightsave Rural currently has a different network capacity charge from Ruraflex. This has resulted in a slight increase to Nightsave Rural's and a reduction to Ruraflex's overall contribution to network charges mainly due to volume changes.

iii. Between the two tariffs, the total current level of subsidies related to **all charges** has been maintained, as any changes to overall subsidy must be guided by NERSA and government policy. For Gen DUoS Urban, the network charge will only be applicable for the > 66 kV category and is calculated as the total Distribution network costs (urban NCC and NDC)/utilised capacity for the Dx > 66 kV category.

vii. The shortfall against the cost for the two lower voltage categories has been converted into the LV subsidy charge for the local-authority LPU tariffs.

f) For the rural non-local-authority LPU tariffs (Ruraflex, Nightsave Rural), the network charge has been calculated as an average for both Ruraflex and Nightsave Rural (the network charge is a combined charge) Distribution and Transmission costs and volumes and then reduced by applying subsidies so that the current level of subsidies is maintained.

iv. The network costs for Transmission and a percentage of the Distribution costs have been combined to calculate the NCC.

v. The network charges for the two tariffs have been aligned, that is, made the same. Nightsave Rural currently has a different network capacity charge from Ruraflex. This has resulted in a slight increase to Nightsave Rural and a reduction to Ruraflex overall contribution to network charges- mainly due to volume changes.

vi. Between the two tariffs, the total current level of subsidies related to all charges has been maintained, as any changes to overall subsidy must be guided by NERSA and government policy. For Gen DUoS Urban, the network charge will only be applicable for the > 66 kV category and is calculated as the total Distribution network costs (urban NCC and NDC)/utilised capacity for the Dx > 66 kV category.

g) For Landrate, subsidies have been applied to the network charges to ensure the same level of subsidies as current tariffs.

- The network costs for Transmission and Distribution have been combined to calculate the network charge.
- The fixed R/day/POD charge has been increased, with a commensurate reduction of the c/kWh network charge.

h) For Businessrate, the Distribution network costs have been split into a fixed (not dependent on consumption) and variable (dependent on consumption) allocation.

- The network costs for Transmission and Distribution have been combined to calculate the network charge.
- The fixed charges are lower than the current tariff fixed charges rate due to updating with the CTS.
- The weighting of the fixed R/day/POD charge allocation has been increased, with a commensurate reduction of the variable c/kWh network charge allocation.

i) For Homepower, more cost-reflective network charges have been introduced, where network costs have been split into a fixed (not dependent on consumption) and variable (dependent on consumption) allocation.

- The network costs for Transmission and Distribution have been combined to calculate the network charge.
- The fixed R/day/POD charge has been increased, with the introduction of a variable c/kWh network charge.

j) For Homelight, network costs have been ignored, as the current tariff was used as the basis.

k) For Municrate:

- The network costs for Transmission and Distribution have been combined to calculate the network charge.
- The network charges have been based on the cost-reflective combined costs for the local-authority tariffs, Businessrate, Landrate, and Homepower.
- A total of 60% of costs has been allocated and divided by the number of PODs to determine the R/POD NCC charge.
- A total of 40% of costs has been allocated and divided by the total kWh sales to determine the c/kWh NDC charge.

l) Landrate Dx will be converted to the Public Lighting Fixed charge tariff.

The network charge units per tariff are described in the following table:

Table 29: Structure of the network charges

Tariff	Charge unit	Features
Non-local-authority tariffs		
Businessrate 1, 2, 3	• R/POD network capacity charge • c/kWh network demand charge	• Structurally no change from current tariffs • Reflecting Distribution and Transmission network costs combined, split into a fixed R/kVA/POD and a variable (c/kWh) charge • Increasing the fixed-portion charge (the NCC) and commensurate reduction of the variable-portion charge (the NDC)
Businessrate 4	• Network energy charge c/kWh	• Structurally no change from current tariffs • Reflecting Distribution and Transmission network costs combined • The variable-cost component is recovered through the c/kWh network demand charge, and the fixed-cost component is bundled into the c/kWh energy charge.
Landrate 1, 2, 3, 4	• R/POD network capacity charge • c/kWh network demand charge	• Structurally no change from current tariffs • Reflecting Distribution and Transmission network costs combined, less subsidies, and split into a fixed R/kVA/POD and a variable (c/kWh) component

Tariff	Charge unit	Features
		• Increasing the fixed charge (the NCC) and commensurate reduction of the variable charge (the NDC) • Is subsidised
Landrate Dx	• R/POD/day	• Structurally no change from current tariffs • Bundled together with other costs and converted into a R/POD/day charge based on 200 kWh/m • Is subsidised
Landlight 20A and 60A	• c/kWh charge	• Structurally no change from current tariffs • Single c/kWh charge reflecting Distribution and Transmission network costs combined, less subsidies, bundled together with other costs, and converted into a single c/kWh charge • Is subsidised
Homepower 1, 2, 3, 4	• R/POD network capacity charge • c/kWh network demand charge	• This is a proposed change from the current IBT structure where the current fixed costs are removed from the active energy charges and recovered transparently through retail and network charges. • Reflecting Distribution and Transmission network costs combined, split into a R/POD fixed-charge and a c/kWh variable-charge • Increasing the fixed-portion charge component (NCC))
WEPS, Megaflex, Miniflex, Nightsave Urban	• R/kVA network capacity charge • R/kVA network demand charge (Miniflex c/kWh) • R/kVA LV subsidy charge • Voltage differentiated	• Structurally no change from current tariffs • Based only on non-local-authority urban • Separate Transmission and Distribution network charges • Increasing the fixed-charge (NCC) and commensurate reduction of variable-charge (NDC) • LV subsidy charge reflecting only LV subsidy on non-local-authority urban tariffs
Transflex 1 and 2	• R/POD/day	• Structurally no change from current tariffs • Reflecting Distribution and Transmission network costs combined

Tariff	Charge unit	Features
Ruraflex, Nightsave Rural	• R/kVA network capacity charge • c/kWh network demand charge • Voltage differentiated	• Structurally no change from current tariffs • Combined Transmission and Distribution network charges, less subsidies • Calculated network charges on combined Nightsave Rural and Ruraflex costs
Gen-DUoS,	• R/kW network charges • Losses charge • Voltage differentiated	• Structurally no change from current tariffs, but tariff charges updated to be equal to the cost-reflective HV load charge
Gen-TUoS	• R/kW network charges • Losses charge • Voltage differentiated	• No changes in this retail tariff plan to the rates or structure.
Gen Offset	• No network charges	
Applicable to both non-local-authority and local-authority tariffs		
Public Lighting All-Night tariff and Public Lighting 24-Hour tariff	• Single energy c/kWh	• Structurally no change from current tariffs • Network costs bundled into energy charges
Public Lighting Fixed charge tariff	• R/POD/day	• Structurally no change from current tariffs • Network costs bundled in fixed charge
Gen-wheeling	• Standard network charges payable (also refer to applicable tariff) • Voltage differentiated	• Structurally no change from current tariffs • R/kW
Gen-purchase	• No network charges	• N/a
New tariffs		
Local-authority tariffs		
Municflex	• R/kVA network capacity charge, and • R/kVA network demand charge and • R/kVA LV subsidy charge • Voltage differentiated	• Separate Transmission and Distribution network charges • Same structure as Megaflex, but based on local-authority cost for current Megaflex, Miniflex, Nightsave Urban, Ruraflex, and Nightsave Rural tariffs • Increasing the fixed-portion charge component (NCC) and a commensurate reduction of the variable-portion charge component (NDC)

Tariff	Charge unit	Features
		• LV subsidy charge reflecting only LV subsidy on local-authority urban tariffs
Municrate	• R/POD network capacity charge • c/kWh network demand charge	• Reflecting Distribution and Transmission network costs combined, split into a fixed R/kVA/POD and a variable (c/kWh) component • Same structure as Businessrate, but based on the combined costs for Businessrate, Landrate, and Homepower • Landrate Dx will be converted to the Public Lighting Fixed charge tariff.
Residential tariffs		
Homeflex 1, 2, 3, 4	• R/POD network capacity charge • c/kWh network demand charge	• Same network charges as Homepower

D.5 Ancillary service charge

a) The ancillary service charge is based on the CTS and is applicable to the following tariffs:

Table 30: Structure of the ancillary service charges

Tariff	Charge unit	Features
Non-local-authority tariffs		
Businessrate 1, 2, 3	• c/kWh ancillary service charge	• Structurally no change from current tariffs • Reflecting ancillary service costs
Businessrate 4	• c/kWh ancillary service charge	• Structurally no change from current tariffs • Reflecting ancillary service costs bundled into the active energy charge
Landrate 1, 2, 3, 4	• c/kWh ancillary service charge	• Structurally no change from current tariffs • Reflecting ancillary service costs
Landrate Dx	• R/POD/day	• Structurally no change from current tariffs • Bundled together with other costs and converted into a R/POD/day charge based on 200 kWh/m
Landlight 20A and 60A	• c/kWh	• Structurally no change from current tariffs • Bundled together with other costs and converted into a single c/kWh charge

Tariff	Charge unit	Features
Homepower 1, 2, 3, 4	• c/kWh ancillary service charge	• This is a proposed change from the current IBT structure • Reflecting ancillary service costs
WEPS, Megaflex, Miniflex, Nightsave Urban, Transflex 1 and 2	• c/kWh ancillary service charge • Voltage differentiated	• Structurally no change from current tariffs • Reflecting ancillary service costs
Ruraflex and Nightsave Rural	• c/kWh ancillary service charge • Voltage differentiated	• Structurally no change from current tariffs • Reflecting ancillary service costs
Gen-DUoS and Gen-TUoS	• c/kWh ancillary service charge • Voltage differentiated	• Structurally no change from current tariffs • Reflecting ancillary service costs
Gen Offset	• c/kWh ancillary service charge • Voltage differentiated	• Structurally no change from current tariffs • Reflecting ancillary service costs
Applicable to both non-local-authority and local-authority tariffs		
Public Lighting All-Night tariff, Public Lighting 24-Hour tariff	• c/kWh	• Structurally no change from current tariffs • Reflecting ancillary service costs bundled into active energy charges
Public Lighting Fixed charge tariff	• R/POD/day	• Structurally no change from current tariffs • Reflecting ancillary service costs bundled into the fixed charge
Gen-wheeling	• c/kWh ancillary service charge • Voltage differentiated	• Structurally no change from current tariffs • Reflecting ancillary service costs
Gen-purchase	• c/kWh ancillary service charge • Voltage differentiated	• Structurally no change from current tariffs • Reflecting ancillary service costs
New tariffs		
Local-authority tariffs		
Municflex	• c/kWh ancillary service charge • Voltage differentiated	• Structurally no change from current tariffs • Reflecting ancillary service costs combined for all non-local-authority LPU tariffs
Municrate	• c/kWh ancillary service charge	• Reflecting ancillary service costs combined for all non-local-authority LPU tariffs
Residential tariffs		
Homeflex 1, 2, 3, 4	• c/kWh ancillary service charge	• Reflecting ancillary service costs

D.6 ERS and affordability charge

a) The ERS charge is applicable to the following tariffs:

Table 31: Structure of the ERS charge and the affordability subsidy charge

Tariff	Charge unit	Features
Non-local-authority tariffs		
Businessrate 1, 2, 3	• c/kWh ERS charge • c/kWh affordability charge	• Reflecting contribution to subsidies
Businessrate 4	• c/kWh ERS charge • c/kWh affordability charge	• Reflecting contribution to subsidies
Landrate 1, 2, 3, 4	• N/a	• Receives subsidies
Landrate Dx	• N/a	• Receives subsidies
Landlight 20A and 60A	• N/a	• Receives subsidies
Homepower 1, 2, 3, 4	• N/a	• Does not receive or pay subsidies
WEPS, Megaflex, Miniflex, Nightsave Urban, Transflex	• c/kWh ERS charge • c/kWh affordability charge	• Reflecting contribution to subsidies
Ruraflex, Nightsave Rural	• N/a	• Receives subsidies
Gen-DUoS, Gen-TUoS	• N/a	• Generators do not contribute to subsidies
Gen-offset	• N/a	• Subsidies as applicable, paid on consumption
Applicable to both non-local-authority and local-authority tariffs		
Public Lighting All Night tariff and Public Lighting 24-Hour tariff	• N/a	• Does not receive or pay subsidies
Public Lighting Fixed Charge tariff	• N/a	• Does not receive or pay subsidies
Gen-Wheeling	• c/kWh ERS charge	• Reflecting contribution to network subsidies
Gen -Purchase	• c/kWh affordability charge	• Reflecting contribution to affordability-related subsidies
New tariffs		
Local-authority tariffs		
Municflex	• c/kWh ERS charge	• Reflecting contribution to network subsidies
Municrate	• N/a	• N/a
Residential tariffs		
Homeflex 1, 2, 3, 4	• N/a	• Does not receive or pay subsidies

D.7 Reactive energy charge

a) The reactive energy charges value remains unchanged from the current and is applicable to the following tariffs:

Table 32: Structure for the reactive energy charge

Tariff	Charge unit	Features
Non-local-authority tariffs		
Businessrate 1, 2, 3	• N/a	• Does not have a reactive energy charge
Businessrate 4	• N/a	• Does not have a reactive energy charge
Landrate 1, 2, 3, 4	• N/a	• Does not have a reactive energy charge
Landrate Dx	• N/a	• Does not have a reactive energy charge
Landlight 20A and 60A	• N/a	• Does not have a reactive energy charge
Homepower 1, 2, 3, 4	• N/a	• Does not have a reactive energy charge
WEPS, Megaflex, Miniflex, Ruraflex.	• c/kVArh	• Payable as current tariffs on reactive energy in the high-demand season
Transflex 1 and 2	• c/kVArh	• Payable as current tariffs on reactive energy in the high and low-demand season
Nightsave Urban, Nightsave Rural	• N/a	• Does not have a reactive energy charge
Gen-DuoS, Gen-TUoS	• N/a	• Does not have a reactive energy charge
Gen Offset	• N/a	• Does not have a reactive energy charge
Applicable to both non-local-authority and local-authority tariffs		
Public Lighting All-Night tariff, Public Lighting 24-Hour tariff	• N/a	• Does not have a reactive energy charge
Public Lighting Fixed charge tariff	• N/a	• Does not have a reactive energy charge
Gen-wheeling	• N/a	• Does not have a reactive energy charge
Gen-purchase	• N/a	• Does not have a reactive energy charge
New tariffs		
Local-authority tariffs		
Municflex	• c/kVArh	• Payable as current Megaflex on reactive energy in the high-demand season
Municrate	• N/a	• Does not have a reactive energy charge
Residential tariffs		
Homeflex 1, 2, 3, 4	• N/a	• Does not have a reactive energy charge

Annexure E – New residential TOU Homeflex and net-billing offset motivation

E.1 Introduction of a proposed new residential tariff

Eskom proposes introducing a residential time-of-use tariff, called Homeflex, for its urban residential customers that is more cost-reflective in structure and adaptable to evolving customer needs, changes in technology, and the changing energy environment, thereby providing a benefit to both the customers and Eskom.

The Homeflex tariff is a dynamic tariff for the residential urban sector that supports a more optimal operation of the power system.

Eskom identified the need for a residential time-of-use tariff to provide the right economic signals that promote economic efficiency and sustainability for Eskom and the customer long ago.

Therefore, in the past, Eskom ran pilots testing the customers' response to the TOU price signals. These pilots were run when electricity was significantly cheaper, with a statistically proven positive response to the price signals (TOU rates) from pilot customers.

The design of the Homeflex tariff is based on the proposed new TOU wholesale purchase tariff ratios plus cost-reflective network, ancillary service and service/administration charges for the residential customer category. It is then scaled to be revenue-neutral to the existing residential tariff (Homepower) to avoid over- and under-recovery of revenue.

In order to roll out the tariff, the customer would need to pay for the required smart time-of-use meter.

This submission focuses mainly on the tariff, not the metering, load management, or communications requirements.

E.2 Drivers, motivation and strategic objectives for the proposed Homeflex tariff

The need for a residential TOU tariff that also provides offset for exported generation (net billing) can be described as follows:

a. **Correcting the economic signals to the customer**

The current IBT tariff is not cost-reflective. There is a mismatch between cost and tariff:

- as it recovers fixed costs through variable charges; and
- as there is no signal for TOU usage/demand, energy capacity, and network capacity.

The second IBT block rate:

- uneconomically incentivises higher-consumption customers to reduce consumption with a rate that includes more than just avoided energy cost, resulting in a real revenue loss not commensurate with a real cost reduction.

b. Optimising the system

To better manage supply and demand and to increase efficiencies in operating cost, there is a need to expand TOU tariffs to the residential sector.

- South Africa's residential urban customers contribute approximately 23%[4] to the peak demand, but do not pay rates that reflect the peak cost.

[4] IDM Electrical Usage 2013

- Residential TOU provides a market tool to deal with the variability of operational capacity.
- Current IBT has limited signals for the actual demand customers impose on the network.

c. Protecting future revenue

There is a need to position Eskom to have appropriate tariffs for a future energy mix, such as, electric vehicles and battery storage, and to accommodate the impact of PV (fixed charges and to ensure that customers with SSEG are not subsidised by customers without).

- The Department of Mineral Resources and Energy has amended Schedule 2 of the Electricity Regulation Act to facilitate the registration of SSEG. Increased SSEG penetration is, therefore, expected.
- There is a need to get fair compensation for the use of the grid and to incentivise customers to stay connected to the grid.
- The current IBT structure does not provides a TOU signal or a signal for net billing; PV, for example, reduces sales, but not peak consumption and peak demand.
- A study done showed the following:

  1. The biggest losses will occur when Behind-the-Meter embedded PV is deployed on a non-TOU tariff structure such as Homepower.

  2. The potential net contribution impact, considering revenue and cost reductions depending on various scenarios, is approximately R21 billion to R85 billion between 2023 and 2030.

E.3 The features of the proposed Homeflex tariff

The Homeflex tariff consists of unbundled energy and wires charges, namely:

a) a three-part (peak, standard and off-peak) time-differentiated and seasonally differentiated active energy charge, including losses, based on the NMD (size) of the supply;
b) a R/POD/day network capacity charge based on the NMD (size) of the supply;
c) a c/kWh network demand charge based on the active energy measured at the point of delivery (POD);
d) a c/kWh ancillary service charge based on the active energy measured at the POD;
e) a R/day service and administration charge for each POD, which charge shall be payable every month whether any electricity is used or not, based on the applicable daily rate and the number of days in the month;
f) Introducing GCC at a 50/50 split to limit the impact on the customer in a phased approach, and it is envisaged that the current GCC split phasing in be increased in the future; and
g) a c/kWh offset rate for customers exporting energy onto the grid under the net billing scheme.

E.4 The Homeflex tariff design methodology

The methodology used to design the Homeflex tariff is as follows:

Step 1: Calculation of energy rates

The energy rates are TOU and on the 2019/20 CTS.

Step 2: Calculation of network charge

The network charges are equal to the Homepower network charges.

Step 3: Calculation of ancillary service charge

The ancillary service charge is equal to the Homepower ancillary service charge.

Step 4: Offset rate for customers' exporting energy onto the grid under the net billing scheme

The offset rate for customers exporting energy onto the Distribution system at the same point of supply (or metering point) under the net billing scheme will, at this stage, be made equal to the current Homeflex TOU energy rates.

Step 5: Introduction of the Generation Capacity charge

The GCC is introduced at a 50/50 split between fixed (GCC R/POD) and variable (c/kWh added to the energy charges) charges to limit the impact on the customer in a phased approach, and it is envisaged that the current GCC split phasing in be increased in the future.

E.5 The Homeflex tariff

The Homeflex tariff would be suitable for medium- to high-usage residential urban customers who have the ability to shift load from the expensive peak periods to the less expensive off-peak periods.

The Homeflex tariff will be made up of a range of tariffs (aligned with Homepower supply sizes), as follows:

Homeflex 1: dual-phase 32 kVA three-phase supplies (80 A per phase)
three-phase 25 kVA three-phase supplies (40 A per phase)
Homeflex 2: dual-phase 64 kVA three-phase supplies (150 A per phase)
three-phase 50 kVA three-phase supplies (80 A per phase)
Homeflex 3: dual-phase 100 kVA three-phase supplies (225 A per phase)
three-phase 100 kVA three-phase supplies (150 A per phase)
Homeflex 4: 16 kVA single-phase supplies (80 A per phase)

Table 33: The proposed Homeflex tariff

	High			Low							
Homeflex	Peak c/kWh	Standard c/kWh	Off-peak c/kWh	Peak c/kWh	Standard c/kWh	Off-peak c/kWh	Generation capacity charge R/POD/day	Ancillary service charge c/kWh	NDC c/kWh	NCC R/POD/day	Service and admin charge R/POD/day
Homeflex 1	359.06	97.66	68.62	155.17	91.85	68.62	R 3.36	0.22	9.01	R 21.77	R 5.72
Homeflex 2	359.06	97.66	68.62	155.17	91.85	68.62	R 5.84	0.22	9.01	R 38.02	R 5.72
Homeflex 3	359.06	97.66	68.62	155.17	91.85	68.62	R 14.40	0.22	9.01	R 91.93	R 5.72
Homeflex 4	359.06	97.66	68.62	155.17	91.85	68.62	R 2.16	0.22	9.01	R 10.59	R 5.72
	Included in the above energy charges is the GCC c/kWh variable component of				10.53c/kWh						
Offset rate	**348.53**	**87.13**	**58.09**	**144.64**	**81.32**	**58.09**					

E.6 Grid-tied and net-energy billing tariffs

Net billing is a credit mechanism where the customer's generation is synchronised with the grid (grid-tied), and at times, there may be export an of energy. This energy is not purchased by the utility; the energy still belongs to the customer. Depending on the legislation, this customer may or may not be required to apply for a license.

Customers may consider going off-grid when they get their own generation. However, there are benefits to being grid-tied, and these are as follows:

- The grid is a virtual battery; that is, it can temporarily store excess energy and accommodate more storage than a battery.
- The grid has higher efficiency rates than batteries; that is, batteries have higher losses.
- The customer can benefit from a net billing tariff, which is a debit and credit process for energy consumed and produced at the same point of supply and not a netting of import consumption kWh and export production kWh.
- If net billing is combined with storage, the customer can benefit by reducing higher-cost peak power. Storage could include hot water and batteries (including electric cars).

- The grid provides ancillary services that the customer would otherwise have to provide such as supplemental and backup power and a fault level.
- The customer can also provide ancillary services to the grid provider and the System Operator, that is, remote control over the generation and/or storage, for which he/she can be compensated.

With grid-tied and net billing tariffs, it is important that appropriate charges are raised for the use of the network and the services being provided and that these charges are not raised as volumetric c/kWh charges as far as possible. The initial design of Homeflex still has volumetric charges, but this has had to be done to achieve some alignment with Homepower. This is, therefore, only the first step in the design, and Homepower will be redesigned in the future.

If tariffs do not reflect cost causation (the customer who incurs the cost pays for this cost), this means that customers with own generation could end up being subsidised by customers without their own generation by reducing their contribution to covering network and retail costs, while shifting those costs onto utility customers who do not have own generation.

TOU tariffs (or dynamic tariffs) should be mandatory to ensure fair payment and compensation in the various time-of-use periods. Tariffs that reflect costs in different time periods, plus net billing, will encourage storage and the reduction of evening peaks.

E.7 Impact on the residential customer

This tariff will be voluntary for customers without embedded generation and mandatory for those with embedded generation in order to provide the correct signals for consumption, generation, and battery use over the period of a day. For example, usage in peak may only decrease slightly, but there may be much lower consumption during the day. Therefore, it is important not to charge at an average energy rate (as this will, in any case, no longer be valid due to the profile change) and to have a peak energy signal. TOU tariffs will also incentivise charging of batteries in the off-peak periods and using these to reduce peak consumption. Offset (net billing) rates that are on TOU, furthermore, provide the correct signal for when export does occur. That is, lower rates are applied for export in the off-peak or standard periods.

For the average customer, the Homeflex tariff is designed to be revenue-neutral to the existing residential tariff (Homepower) over the financial year if there is no change in the customer's consumption pattern.

It is impossible to design a tariff that has no impact on every customer when comparing it to Homepower; therefore, the average Homepower customer is used to calculate the impact.

For the average-consumption customer who converts from the existing Homepower tariff to the Homeflex tariff, the impact of this tariff conversion may be positive or negative (depending on the load profile). Customers who respond to the TOU signals will experience a positive impact.

E.8 The proposed roll-out of the tariff

a) Homeflex will be mandatory for all customers with grid-tied generation, whether export or not.
b) For all other residential urban customers, converting to the Homeflex tariff will be a choice.
c) The tariff will be implemented with the approved technology, that is, a post-paid smart metering device. The Homeflex tariff cannot be offered to customers who are on a prepaid smart meter because of current technological constraints.

E.9 Homeflex financial impact

All of the above changes have been calculated to be equal to the revised Homepower tariff revenue. Positive customer response to the TOU rates may result in revenue loss, which should be offset against avoided costs.

There is a potential to increase sales when customers invest in other electrical appliances to get more electricity value from their savings together with the flexibility to manage their consumption and electricity charges better.

The customer will pay for the conversion cost (the meter) to the Homeflex tariff, unless a smart meter has already been installed.

Annexure F – Proposed retail rates in 2021/22 rand values (excluding VAT)

Table 34: Urban LPU tariffs: WEPS, Megaflex, Miniflex, and Nightsave Urban (non-local-authority)

Large power user non-local-authority tariffs															
Urban non-local authority tariffs															
Transmission zone	Voltage	High-demand season TOU active energy charges (WEPS, Megaflex and Miniflex)			Low-demand season TOU active energy charges (WEPS, Megaflex and Miniflex)			Generation capacity charge R/kVA	High-demand season energy demand charge	Low-demand season energy demand charge	High-demand season active energy charge	Low-demand season active energy charge	Network capacity charge R/kVA	Transmssion network charge R/kVA
		Peak	Standard	Off-Peak	Peak	Standard	Off-Peak		Nightsave	Nightsave	Nightsave	Nightsave	Miniflex	WEPS, Megaflex and Nightsave
<300km	<500V	348.54c	87.13c	58.09c	144.64c	81.32c	58.09c	R 30.15	R 158.98	R 35.03	74.71c	71.23c	R 39.84	R 8.31
	≥500V & <66kV	342.88c	85.71c	57.15c	142.29c	80.00c	57.15c	R 69.78	R 156.40	R 34.47	73.50c	70.07c	R 38.09	R 8.13
	≥66kV & <132kV	320.90c	80.22c	53.48c	133.17c	74.87c	53.48c	R 60.03	R 146.37	R 32.26	68.78c	65.58c	R 18.28	R 7.52
	>132kV*	302.77c	75.69c	50.46c	125.65c	70.64c	50.46c	R 70.28	R 138.10	R 30.43	64.90c	61.87c	R 11.14	R 11.14
>300km to <= 600km	<500V	352.02c	88.00c	58.67c	146.09c	82.14c	58.67c	R 30.15	R 160.57	R 35.38	75.45c	71.94c	R 39.93	R 8.40
	≥500V & <66kV	346.30c	86.57c	57.72c	143.71c	80.80c	57.72c	R 69.78	R 157.96	R 34.81	74.23c	70.77c	R 38.18	R 8.22
	≥66kV & <132kV	324.10c	81.02c	54.02c	134.50c	75.62c	54.02c	R 60.03	R 147.83	R 32.58	69.47c	66.23c	R 18.35	R 7.59
	>132kV*	305.78c	76.44c	50.96c	126.90c	71.35c	50.96c	R 70.28	R 139.48	R 30.74	65.54c	62.49c	R 11.26	R 11.26
>600km to <= 900km	<500V	355.50c	88.87c	59.25c	147.53c	82.95c	59.25c	R 30.15	R 162.15	R 35.73	76.20c	72.65c	R 40.01	R 8.48
	≥500V & <66kV	349.72c	87.42c	58.29c	145.13c	81.60c	58.29c	R 69.78	R 159.52	R 35.15	74.96c	71.47c	R 38.23	R 8.27
	≥66kV & <132kV	327.30c	81.82c	54.55c	135.83c	76.37c	54.55c	R 60.03	R 149.29	R 32.90	70.16c	66.89c	R 18.43	R 7.67
	>132kV*	308.80c	77.20c	51.47c	128.15c	72.05c	51.47c	R 70.28	R 140.86	R 31.04	66.19c	63.11c	R 11.37	R 11.37
>900km	<500V	358.97c	89.74c	59.83c	148.97c	83.76c	59.83c	R 30.15	R 163.74	R 36.08	76.94c	73.36c	R 40.10	R 8.57
	≥500V & <66kV	353.14c	88.28c	58.86c	146.55c	82.40c	58.86c	R 69.78	R 161.08	R 35.50	75.69c	72.17c	R 38.34	R 8.38
	≥66kV & <132kV	330.50c	82.62c	55.08c	137.16c	77.12c	55.08c	R 60.03	R 150.75	R 33.22	70.84c	67.54c	R 18.50	R 7.74
	>132kV*	311.82c	77.95c	51.97c	129.41c	72.76c	51.97c	R 70.28	R 142.23	R 31.34	66.84c	63.72c	R 11.48	R 11.48
WEPS rate excluding losses		301.98c	75.49c	50.33c	125.32c	70.46c	50.33c							

*Transmission connected

Distribution network charges Urban							
Voltage	NCC R/kVA (Megaflex, Nightsave and WEPS)	NDC R/kVA (Megaflex, Nightsave and WEPS)	NDC c/kWh (Miniflex)	LV subsidy charge R/kVA (All LPU)	Ancillary service charge c/kWh (All LPU)	ERS charge c/kWh (All LPU)	Affordability subsidy charge c/kWh (All LPU)
<500V	R 31.53	R 31.98	18.25c	0.00	0.22c	7.16c	1.82c
≥500V & <66kV	R 29.96	R 27.80	15.15c	0.00	0.22c	7.16c	1.82c
≥66kV & <132kV	R 10.76	R 11.83	10.71c	R 2.83	0.21c	7.16c	1.82c
>132kV*	R 0	R 0	R 0	R 2.83	0.19c	7.16c	1.82c

*132kV/Transmission connected

Urban retail charges based on MUC (All LPU)	Service charge R/POD/day	Admin charge R/POD/day	Service charge R/Acc/day
≤ 100 kVA	R 10.95	R 0.83	
> 100 kVA & ≤ 500 kVA	R 71.69	R 13.00	
> 500 kVA & ≤ 1 MVA	R 233.22	R 19.17	
> 1 MVA	R 233.22	R 19.17	
Key customers	R 788.40	R 19.17	

Reactive energy c/kVArh (high demand season only)	
Megaflex	Miniflex
19.19	8.36

Table 35: Rural LPU tariffs: Ruraflex and Nightsave Rural (non-local-authority)

Rural non-local-authority tariffs															
Transmission zone	Voltage	High-demand season TOU active energy charges (Ruraflex)			Low-demand season TOU active energy charges (Ruraflex)			Generation capacity charge R/kVA	High-demand season energy demand charge	Low-demand season energy demand charge	High-demand season active energy charge	Low-demand season active energy charge	Network demand charge (R/kVA)	Transmssion network charge R/kVA fyi only
		Peak	Standard	Off-Peak	Peak	Standard	Off-Peak		Nightsave	Nightsave	Nightsave	Nightsave	Bundled (Transmission and Distribution)	Unbundled
<300km	<500V	353.75c	88.43c	58.96c	146.80c	82.54c	58.96c	R 32.21	R 137.14	R 33.17	75.67c	72.22c	R 41.56	R 8.47
	≥500V & <66kV	348.88c	87.21c	58.15c	144.78c	81.40c	58.15c	R 43.55	R 135.25	R 32.71	74.62c	71.22c	R 47.33	R 8.31
	≥66kV & <132kV													
	>132kV													
>300km to <= 600km	<500V	357.28c	89.31c	59.55c	148.27c	83.36c	59.55c	R 32.21	R 138.51	R 33.50	76.42c	72.94c	R 41.64	R 8.55
	≥500V & <66kV	352.36c	88.08c	58.73c	146.23c	82.21c	58.73c	R 43.55	R 136.60	R 33.04	75.37c	71.93c	R 47.41	R 8.39
	≥66kV & <132kV													
	>132kV													
>600km to <= 900km	<500V	360.81c	90.20c	60.13c	149.73c	84.19c	60.13c	R 32.21	R 139.88	R 33.83	77.18c	73.66c	R 41.73	R 8.64
	≥500V & <66kV	355.84c	88.95c	59.31c	147.67c	83.03c	59.31c	R 43.55	R 137.95	R 33.36	76.11c	72.64c	R 47.49	R 8.47
	≥66kV & <132kV													
	>132kV													
>900km	<500V	364.34c	91.08c	60.72c	151.20c	85.01c	60.72c	R 32.21	R 141.24	R 34.16	77.93c	74.38c	R 41.81	R 8.72
	≥500V & <66kV	359.32c	89.82c	59.89c	149.11c	83.84c	59.89c	R 43.55	R 139.30	R 33.69	76.86c	73.35c	R 47.58	R 8.56
	≥66kV & <132kV													
	>132kV													

Distribution network charges Rural							
Voltage	NCC R/kVA	NDC R/kVA	NDC c/kWh	LV subsidy R/kVA charge	Ancillary Service Charge c/kWh	ERS charge c/kWh	Affordability subsidy charge c/kWh
<500V			21.26		0.23		
≥500V & <66kV			18.53		0.22		
≥66kV & <132kV							
>132kV*							

Rural retail charges based on MUC	Service charge R/POD/day	Admin charge R/POD/day	Service charge R/Acc/day
≤ 100 kVA	R 22.23	R 1.46	
> 100 kVA & ≤ 500 kVA	R 71.69	R 13.00	
> 500 kVA & ≤ 1 MVA	R 233.22	R 19.17	
> 1 MVA	R 233.22	R 19.17	
Key customers	R 788.40	R 19.17	

Reactive energy c/kVArh (high demand season only)
Ruraflex
12.00

Table 36: SPU tariffs: Businessrate, Landrate, Homelight, Homepower and Public Lighting (non-local-authority)

Non-local-authority small power user tariffs

Businessrate	Energy charge c/kWh	Generation capacity charge R/POD/day	Ancillary service charge c/kWh	NDC c/kWh	NCC R/POD/day	Service and admin charge R/POD/day	ERS + afford. subsidy charge	
1	101.57c	R 16.60	0.22c	16.94c	R 15.52	R 11.13	8.99c	
2	101.57c	R 25.14	0.22c	16.94c	R 23.52	R 11.13	8.99c	
3	101.57c	R 61.35	0.22c	16.94c	R 57.38	R 11.13	8.99c	
4	166.67c	0.00c	0.22c	16.94c			8.99c	192.82c

Landrate	Energy charge c/kWh*	Generation capacity charge R/POD/day	Ancillary service charge c/kWh	NDC c/kWh	NCC R/POD/day	Service and admin charge R/POD/day
1	128.90c	R 10.81	0.23c	38.79c	R 36.33	R 21.99
2	128.90c	R 21.63	0.23c	38.79c	R 60.06	R 21.99
3	128.90c	R 43.26	0.23c	38.79c	R 83.24	R 21.99
4	246.15c	R 6.92	0.23c	38.79c	R 27.07	
Landrate Dx						R 64.49
Landlight 20A	359.01c					
Landlight 20A	491.93c					

*Included in the above energy charges is the GCC c/kWh variable component of 27.26c

Homepower	Energy charge c/kWh*	Generation capacity charge R/POD/day	Ancillary service charge c/kWh	NDC c/kWh	NCC R/POD/day	Service and admin charge R/POD/day
1	126.32c	R 3.36	0.22c	9.01c	R 21.77	R 5.72
2	126.32c	R 5.84	0.22c	9.01c	R 38.02	R 5.72
3	126.32c	R 14.40	0.22c	9.01c	R 91.93	R 5.72
4	126.32c	R 2.16	0.22c	9.01c	R 10.59	R 5.72
Homepower Bulk	126.32c	R 23.26/KVA	0.22c	9.01c	R 73.19/KVA	R 11.78

*Included in the above energy charge is the GCC c/kWh variable component of 10.53c

Homeflex	High			Low							
	Peak c/kWh*	Standard c/kWh*	Off-peak c/kWh*	Peak c/kWh*	Standard c/kWh*	Off-peak c/kWh*	Generation capacity charge R/POD/day	Ancillary service charge c/kWh	NDC c/kWh	NCC R/POD/day	Service and admin charge R/POD/day
1	359.06c	97.66c	68.62c	155.17c	91.85c	68.62c	R 3.36	0.22c	9.01c	R 21.77	R 5.72
2	359.06c	97.66c	68.62c	155.17c	91.85c	68.62c	R 5.84	0.22c	9.01c	R 38.02	R 5.72
3	359.06c	97.66c	68.62c	155.17c	91.85c	68.62c	R 14.40	0.22c	9.01c	R 91.93	R 5.72
4	359.06c	97.66c	68.62c	155.17c	91.85c	68.62c	R 2.16	0.22c	9.01c	R 10.59	R 5.72

*Included in the above energy charges is the GCC c/kWh variable component of

Net-billing offset rate	348.53	87.13	58.09	144.64	81.32	58.09

Homelight	Energy charge c/kWh Block 1	Energy charge c/kWh Block 2	Single rate
20A			141.15c
60A			169.10c

Public Lighting Non Munic	All night	R/100W/month
All night c/kWh	153.53c	R 51.17
24 hours c/kWh	132.32c	R 96.60
Fixed charge R/day	R 25.85	
Maintenance charge	**Per luminaire**	**Per High mast luminaire**
	R 60.30	R 1 403.69

Table 37: LPU tariff: Municflex – 12-month view before adjustment for July increase

Large power user local-authority tariffs (12 month view, unadjusted for 3 month and 9 months financial year)

Municflex (12 month view)

Transmission zone	Voltage	High-demand season TOU active energy charges			Low-demand season TOU active energy charges			Generation capacity charge R/kVA	Transmission network charge R/kVA
		Peak	Standard	Off-Peak	Peak	Standard	Off-Peak		
<300km	<500V	349.14c	87.28c	58.20c	144.90c	81.47c	58.21c	R 30.62	R 8.36
	≥500V & <66kV	342.90c	85.72c	57.15c	142.30c	80.01c	57.15c	R 68.45	R 8.14
	≥66kV & <132kV	320.90c	80.22c	53.48c	133.17c	74.87c	53.48c	R 61.15	R 7.52
	>132kV*	302.77c	75.69c	50.46c	125.65c	70.64c	50.46c	R 70.28	R 11.14
>300km to <= 600km	<500V	355.87c	88.96c	59.33c	147.71c	83.05c	59.34c	R 30.62	R 8.53
	≥500V & <66kV	346.98c	86.74c	57.85c	143.99c	80.95c	57.85c	R 68.45	R 8.24
	≥66kV & <132kV	324.10c	81.02c	54.02c	134.50c	75.62c	54.02c	R 61.15	R 7.59
	>132kV*	305.78c	76.44c	50.96c	126.90c	71.35c	50.96c	R 70.28	R 11.26
>600km to <= 900km	<500V	359.37c	89.80c	59.88c	149.14c	83.83c	59.89c	R 30.62	R 8.61
	≥500V & <66kV	350.24c	87.56c	58.40c	145.35c	81.72c	58.40c	R 68.45	R 8.32
	≥66kV & <132kV	327.30c	81.82c	54.55c	135.83c	76.37c	54.55c	R 61.15	R 7.67
	>132kV*	308.80c	77.20c	51.47c	128.15c	72.05c	51.47c	R 70.28	R 11.37
>900km	<500V	363.06c	90.75c	60.50c	150.64c	84.70c	60.51c	R 30.62	R 8.68
	≥500V & <66kV	353.78c	88.44c	58.98c	146.80c	82.54c	58.98c	R 68.45	R 8.40
	≥66kV & <132kV	330.50c	82.62c	55.08c	137.16c	77.12c	55.08c	R 61.15	R 7.74
	>132kV*	311.82c	77.95c	51.97c	129.41c	72.76c	51.97c	R 70.28	R 11.48
WEPS rate excluding losses		301.98c	75.49c	50.33c	125.32c	70.46c	50.33c		

*Transmission connected

Distribution network charges

Voltage	NCC R/kVA	NDC R/kVA		LV subsidy charge R/kVA	Ancillary service charge c/kWh	ERS charge c/kWh	Affordability subsidy charge c/kWh
< 500V	R 36.85	R 69.89		0.00	0.22c	7.16c	NA
≥ 500V & < 66kV	R 26.58	R 25.17		0.00	0.22c	7.16c	NA
≥ 66kV & ≤ 132kV	R 14.35	R 13.16		R 6.56	0.21c	7.16c	NA
> 132kV*				R 6.56	0.19c	7.16c	NA

*132kV/Transmission connected

Size based on MUC	Service charge R/POD/day	Admin charge R/POD/day	Service charge R/Acc/day
≤ 100 kVA	R 10.95	R 0.83	
> 100 kVA & ≤ 500 kVA	R 71.69	R 13.00	
> 500 kVA & ≤ 1 MVA	R 233.22	R 19.17	
> 1 MVA	R 233.22	R 19.17	
Key customers	R 788.40	R 19.17	

Reactive energy c/kVArh (high demand season only	
Municflex	
19.19	

Table 38: SPU tariff: Municrate – 12-month view before adjustment for July increase

Local-authority small power user tariffs (12 month view average unadjusted for 3 months and 9 months financial year)

Municrate	Energy charge c/kWh	Generation capacity charge R/POD/day	Ancillary service charge c/kWh	NDC c/kWh	NCC R/POD/day	Service and admin charge R/POD/day	ERS + afford. subsidy charge	
1	124.66c	R 8.81	0.22c	37.39c	R 22.46	R 14.66	0.00c	
2	124.66c	R 14.66	0.22c	37.39c	R 43.48	R 14.66	0.00c	
3	124.66c	R 35.14	0.22c	37.39c	R 98.36	R 14.66	0.00c	
4	207.84c		0.22c	37.39c	0.00c	0.00c	0.00c	245.45c

Public Lighting munic	All night	R/100W/month
All night c/kWh	152.59c	R 50.86
24 hours c/kWh	155.80c	R 113.74
Fixed charge R/day	R 21.84	
Maintenance charge	Per luminaire	Per High mast luminaire
	R 63.74	R 1 488.65

Table 39: LPU tariff: Municflex – adjusted for a nine-month view (July increase)

Local-authority Municflex large power user tariff (9 month view)									
Transmission zone	Voltage	High-demand season TOU active energy charges			Low-demand season TOU active energy charges			Generation capacity charge R/kVA	Transmission network charge R/kVA
		Peak	Standard	Off-Peak	Peak	Standard	Off-Peak		
<300km	<500V	359.16c	89.78c	59.87c	149.07c	83.81c	59.88c	R 31.50	R 8.60
	≥500V & <66kV	352.75c	88.18c	58.79c	146.39c	82.31c	58.79c	R 70.42	R 8.37
	≥66kV & <132kV	330.12c	82.52c	55.02c	136.99c	77.02c	55.02c	R 62.91	R 7.73
	>132kV*	311.47c	77.86c	51.91c	129.26c	72.67c	51.91c	R 72.30	R 11.46
>300km to <= 600km	<500V	366.09c	91.52c	61.03c	151.95c	85.43c	61.05c	R 31.50	R 8.77
	≥500V & <66kV	356.94c	89.23c	59.51c	148.12c	83.28c	59.51c	R 70.42	R 8.48
	≥66kV & <132kV	333.41c	83.35c	55.57c	138.36c	77.79c	55.57c	R 62.91	R 7.81
	>132kV*	314.56c	78.64c	52.42c	130.54c	73.40c	52.42c	R 72.30	R 11.58
>600km to <= 900km	<500V	369.69c	92.38c	61.60c	153.43c	86.24c	61.61c	R 31.50	R 8.86
	≥500V & <66kV	360.30c	90.07c	60.08c	149.52c	84.07c	60.08c	R 70.42	R 8.56
	≥66kV & <132kV	336.70c	84.17c	56.12c	139.73c	78.56c	56.12c	R 62.91	R 7.89
	>132kV*	317.67c	79.42c	52.95c	131.83c	74.12c	52.95c	R 72.30	R 11.70
>900km	<500V	373.49c	93.36c	62.24c	154.97c	87.13c	62.25c	R 31.50	R 8.93
	≥500V & <66kV	363.94c	90.98c	60.67c	151.02c	84.91c	60.67c	R 70.42	R 8.65
	≥66kV & <132kV	339.99c	84.99c	56.66c	141.10c	79.33c	56.66c	R 62.91	R 7.97
	>132kV*	320.78c	80.19c	53.46c	133.13c	74.85c	53.46c	R 72.30	R 11.81
WEPS rate excluding losses		310.66c	77.66c	51.78c	128.92c	72.48c	51.78c		

*Transmission connected

Distribution network charges							
Voltage	NCC R/kVA	NDC R/kVA		LV subsidy charge R/kVA	Ancillary service charge c/kWh	ERS charge c/kWh	Affordability subsidy charge c/kWh
<500V	R 37.91	R 71.90		0.00	0.2300c	7.37c	NA
≥500V & <66kV	R 27.34	R 25.89		0.00	0.2300c	7.37c	NA
≥66kV & <132kV	R 14.76	R 13.54		R 6.75	0.2200c	7.37c	NA
>132kV*				R 6.75	0.2000c	7.37c	NA

*132kV/Transmission connected

Size based on MUC	Service charge R/POD/day	Admin charge R/POD/day
≤ 100 kVA	R 11.26	R 1.00
> 100 kVA & ≤ 500 kVA	R 73.75	R 13.37
> 500 kVA & ≤ 1 MVA	R 239.92	R 19.72
> 1 MVA	R 239.92	R 19.72
Key customers	R 811.04	R 19.72

Reactive energy c/kVArh (high demand season only
Municflex
19.74

Table 40: SPU tariffs: Municrate and Public Lighting – adjusted for a nine-month view (July increase)

Local-authority small power user tariffs (9 month view)							
Municrate	Energy charge c/kWh	Generation capacity charge R/POD/day	Ancillary service charge c/kWh	NDC c/kWh	NCC R/POD/day	Service and admin charge R/POD/day	ERS + afford. subsidy charge
1	128.25c	R 9.06	0.23c	38.46c	R 23.10	R 15.08	R 0.00
2	128.25c	R 15.08	0.23c	38.46c	R 44.72	R 15.08	R 0.00
3	128.25c	R 36.15	0.23c	38.46c	R 101.17	R 15.08	R 0.00
4	213.80c		0.23c	38.46c	R 0.00	R 0.00	R 0.00

Public Lighting munic	All night	R/100W/month
All night c/kWh	156.96c	R 52.32
24 hours c/kWh	160.26c	R 116.99
Fixed charge R/day	R 22.47	
Maintenance charge	Per luminaire	Per High mast luminaire
	R 63.74	R 1 488.65

Table 41: Gen-DUoS tariff

Gen-DUoS

DUoS network charges for generators	
Voltage	Network capacity charge [R/kW]
< 500V	
≥ 500V & < 66kV	
≥ 66kV & ≤ 132kV	R 17.93

Distribution loss factors for Distribution connected generators		
Voltage	Urban loss factor	Rural loss factor
< 500V	1.1512	1.1684
≥ 500V & < 66kV	1.1325	1.1523
≥ 66kV & ≤ 132kV	1.0599	0.0000
> 132kV/Transmission connected	1.0000	0.0000

Transmission loss factors for Distribution connected generators	
Voltage	Zone
≤ 300km	1.0026
> 300km & ≤ 600km	1.0126
> 600km & ≤ 900km	1.0226
> 900km	1.0326

Voltage	Ancillary service charge c/kWh (Urban)	Ancillary service charge c/kWh (Rural)
<500V	0.22	0.23
≥500V & <66kV	0.22	0.22
≥66kV & <132kV	0.21	0.00
>132kV*	0.19	0.00

Urban retail charges based on MEC	Service charge R/POD/day	Admin charge R/POD/day
≤ 100 kVA/kW	**R 10.95**	**R 0.83**
> 100 kVA/kW & ≤ 500 kVA/kW	**R 71.69**	**R 13.00**
> 500 kVA/kW & ≤ 1 MVA/MW	**R 233.22**	**R 19.17**
> 1 MVA/MW	**R 233.22**	**R 19.17**
Transmission connected	**R 788.40**	**R 19.17**

Rural retail charges based on MEC	Service charge R/POD/day	Admin charge R/POD/day
≤ 100 kVA/kW	**R 22.23**	**R 1.46**
> 100 kVA/kW & ≤ 500 kVA/kW	**R 71.69**	**R 13.00**
> 500 kVA/kW & ≤ 1 MVA/MW	**R 233.22**	**R 19.17**
> 1 MVA/MW	**R 233.22**	**R 19.17**

ERS charge c/kWh (Urban LPU) c/kWh
7.16

Table 42: Gen-TUoS tariffs

Gen-TUoS		
Loss factors and network charges for Transmission connected generators		
Zone	Loss factor	Network charge [R/kW]
Cape	1.00000	R 0.00
Karoo	1.00000	R 0.00
Kwazulu-Natal	1.01495	R 3.05
Vaal	1.00026	R 10.15
Waterberg	1.01352	R 13.01
Mpumalanga	1.01487	R 12.07

Ancillary service charge for Transmission connected generators	Ancillary service charge [c/kWh]
Generators	0.1900

Retail charges based on MEC	Service charge R/POD/day	Admin charge R/POD/day
Transmission connected	R 788.40	R 19.17

Table 43: Gen-wheeling tariffs

Gen-wheeling		
Tariff name	Type of charge	Rate
Gen-wheeling non Munic urban	Energy charge (credit)	WEPS non-local-authority tariff energy rates excluding losses
	Affordability subsidy charge (credit)	WEPS non-local-authority affordability subsidy charge
	Administration charge	WEPS non-local-authority tariff administration charge
	All other tariff charges	NA
Gen-wheeling non Munic rural	Energy charge (credit)	WEPS non-local-authority tariff energy rates excluding losses
	Administration charge	Ruraflex non-local-authority tariff administration charge
	All other tariff charges	NA
Gen-wheeling Munic urban	Energy charge (credit)	Municflex local-authority tariff WEPS energy rates excluding losses
	Administration charge	WEPS local-authority tariff administration charge
	All other tariff charges	NA
Gen-wheeling Munic rural	Energy charge (credit)	NA
	Administration charge	NA
	All other tariff charges	NA

Table 44: Gen-offset tariffs

Gen-offset		
Tariff name	Type of charge	Rate
Gen-offset urban	Energy charge (credit)	WEPS non-local authority tariff energy rates per Transmission Zone and voltage
	Ancillary service charge (credit)	WEPS non-local authority tariff ancillary service charge
	Affordability subsidy charge (credit)	WEPS non-local authority tariff affordability subsidy charge
	Administration charge	WEPS non-local authority tariff administration charge
	All other tariff charges	NA
Gen-offset rural	Energy charge (credit)	Ruraflex non-local authority tariff energy rates per Transmission Zone and voltage
	Ancillary service charge (credit)	Ruraflex non-local authority tariff ancillary service charge
	Administration charge	Ruraflex non-local authority tariff administration charge
	All other tariff charges	NA

Table 45: Gen-purchase tariffs

Gen-puchase		
Tariff name	Type of charge	Rate
Gen-purchase- urban	Energy charge	WEPS non-local-authority tariff energy rates excluding losses
	Affordability subsidy charge	WEPS non-local-authority affordability subsidy charge
	Administration charge	WEPS non-local-authority tariff administration charge
	All other tariff charges	NA
Gen-purchase-rural	Energy charge	WEPS non-local-authority tariff energy rates excluding losses
	Administration charge	Ruraflex non-local authority tariff administration charge
	All other tariff charges	NA
Gen-purchase Munic	Energy charge	Municflex local-authority tariff WEPS energy rates excluding losses
	Administration charge	Municflex local-authority affordability subsidy charge
	All other tariff charges	NA

Annexure G – Survey on the customer perceptions and understanding of the Inclining block tariff (IBT)

One of the structural changes proposed in the Retail Tariff Restructuring Plan initially submitted to NERSA in August 2020 was for Eskom to amend the structure of the existing inclining block tariff (IBT) for residential customers. After the receipt of the retail plan submission by NERSA, there was a request for Eskom to explain the motivation for the proposed changes further, and a question was raised on whether the motivation can be substantiated with evidence from a customer survey.

To address this request by NERSA, Eskom conducted a customer feedback survey on the inclining block tariff in January 2022. The purpose of the survey was to assess customer understanding of the current inclining block rate tariff, and to get their opinions about the tariff.

Methodology

The customer feedback research project was divided into two distinct sections:

Section 1: Comprehensive online survey

- An MS Teams customer survey tool was developed.
- The survey content included a section on biographic information and tariff-specific questions to determine the customers' understanding of and opinions about the inclining block tariff (IBT).
- The data collected through the internal survey with all the Eskom employees.
- The short ten-question survey included multiple choice-, rating - and open-ended questions.
- The online survey was shared via e-mail with all Eskom employees on 18 January 2022 and the closing date was on 31 January 2022.

Section 2: Customer SMS survey

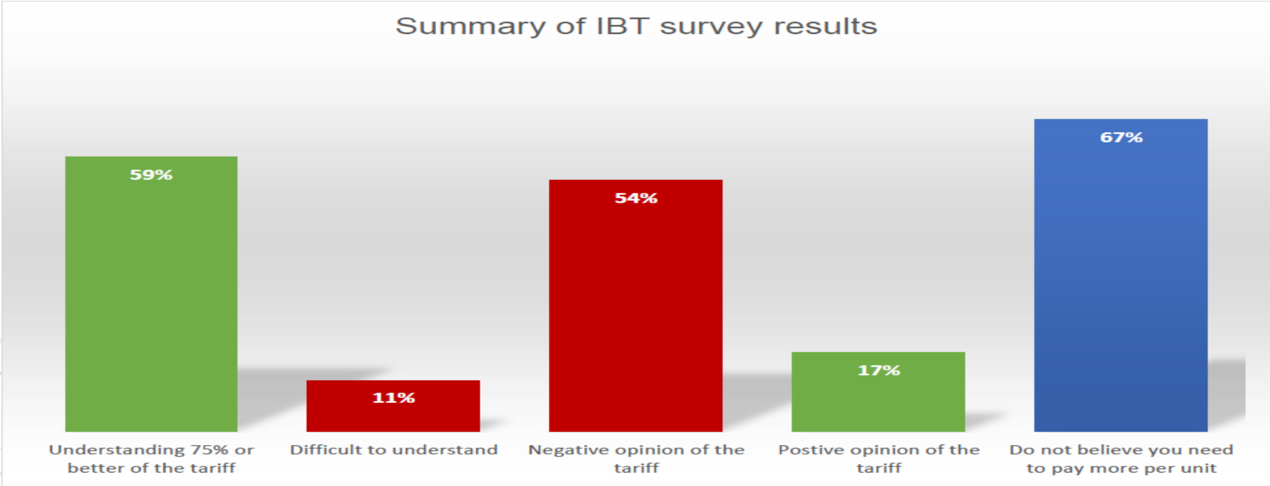
- A single question was compiled to share with Eskom Distribution customers via SMS
- The question was translated into 11 official languages in South Africa was posed as follows: "*Dear Eskom Customer Please reply with YES if you are satisfied with a stepped tariff or NO: it is confusing and it costs more if I buy more. Thank you*"
- The number of SMSs is 100 000 per Operating Unit, totalling 900 000 customers in the 9 Operating Units

Summary of the survey results – online survey

Feedback received from the online survey indicated:

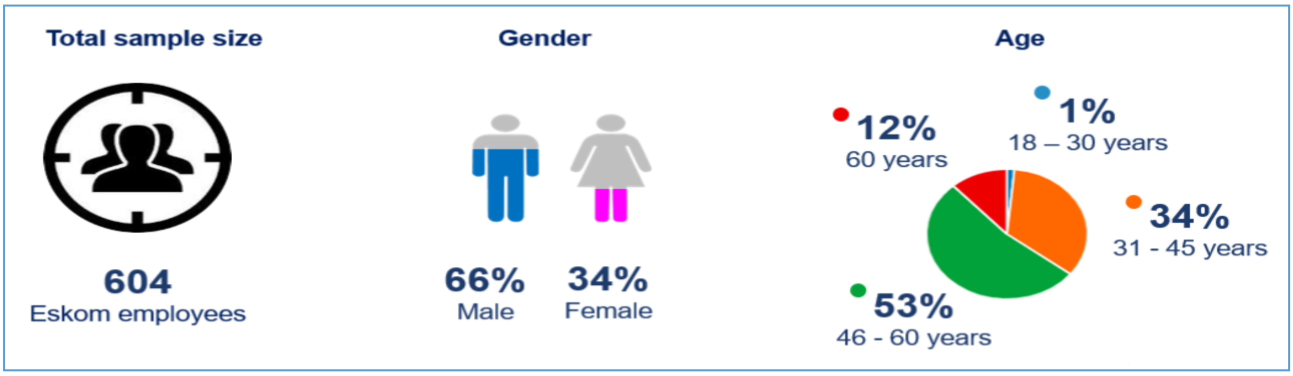
- 59% of the participants have a 75% - 100% understanding of how the tariff works,
- 11% of the participants found it difficult to understand and hard to explain the tariff to customers.
- 54% of the participants indicated that they have a negative opinion about the tariff, because the tariff is being perceived as punitive and unfair, and they state challenges around affordability and the high cost of living.
- 17% indicated that they support the tariff and that it promotes an energy efficient culture.

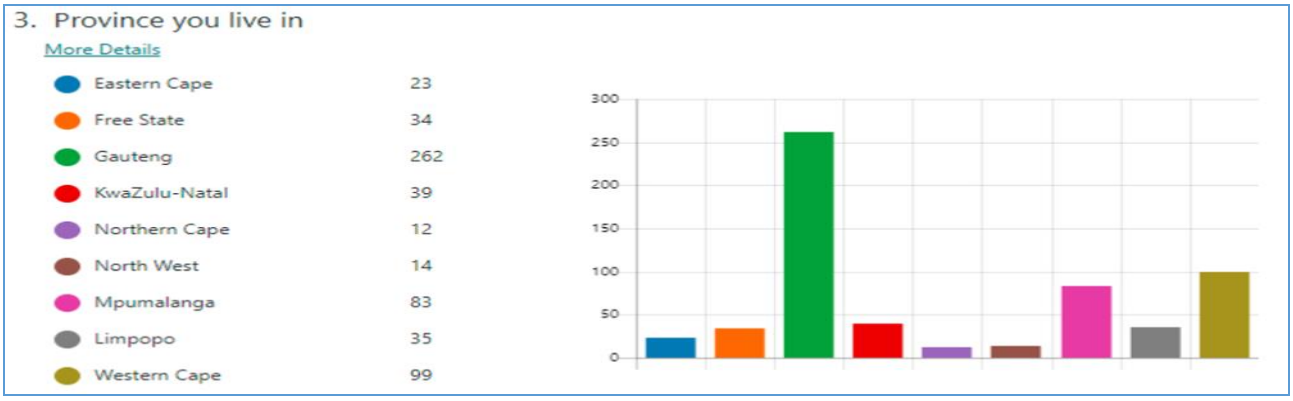
- 67% of the participants also shared that they do not believe you need to pay more per unit if you use more electricity.



The details of the survey questionnaire and results are summarised below:

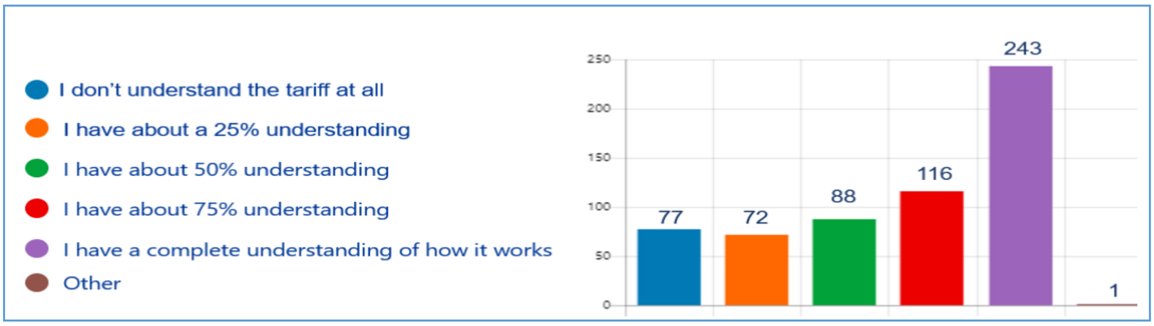
The number of survey respondents was 604 employees across all provinces, with the majority of respondents in Gauteng and Western Cape.

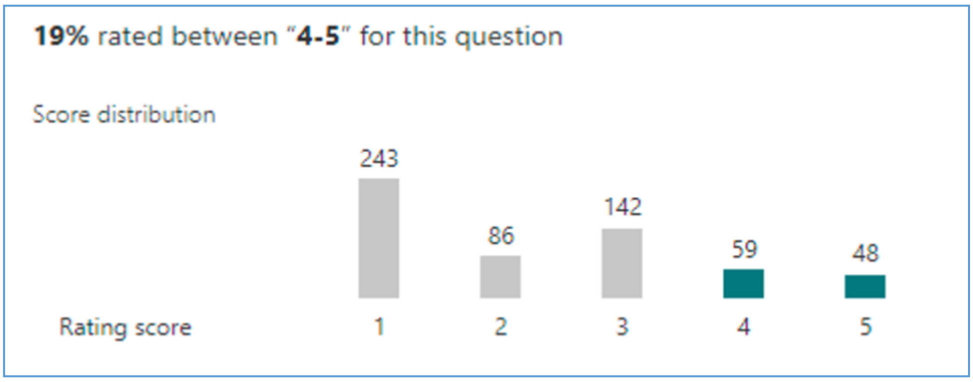


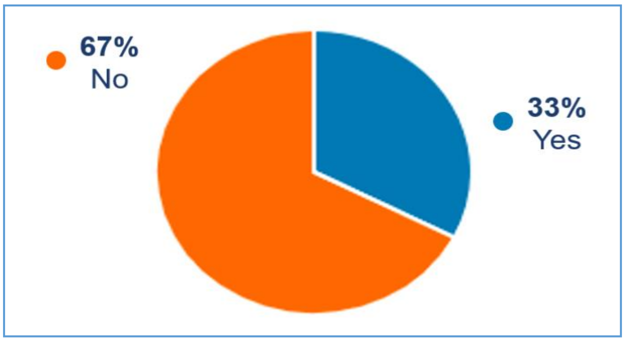


When asked about their electricity usage a month, most of the customers indicated that they pay over a R1000 per month which implies that their consumption is in the second energy block of the IBT tariff.

The customers were also asked to rate their understanding of the tariff, and 59% of the respondents indicated that they have a complete understanding of the tariff. However, when asked to rate their opinion of the tariff on a scale of 1-5, with 1 being "I don't like it at all" and 5 being "I like this tariff", 54% of the customers expressed their dislike and only 19% indicated that they like the tariff. Of the participants 67% also shared that they do not believe that you need to pay more per unit if you use more electricity.







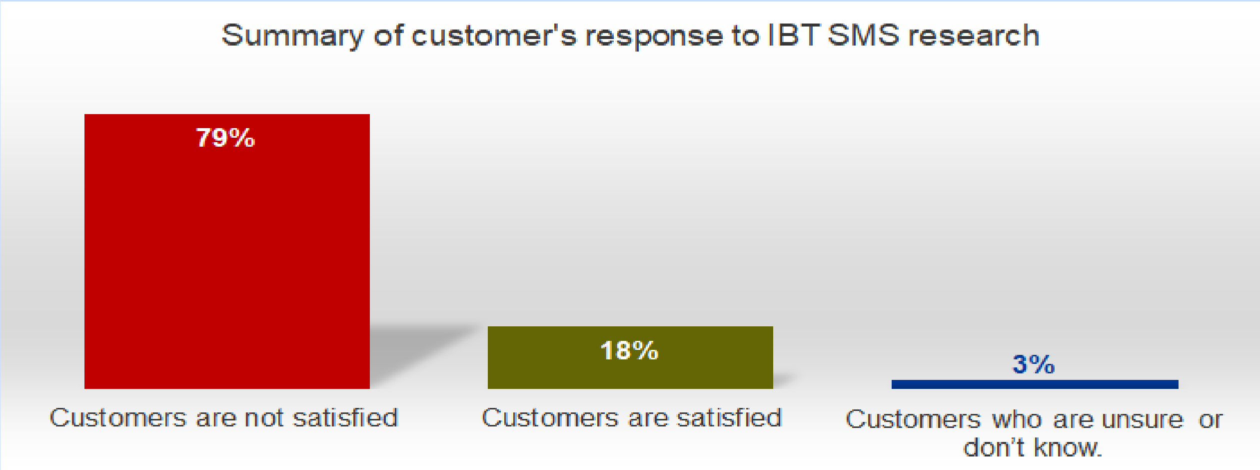
Summary of the survey results – customer sms survey

Feedback received from the sms survey indicated:

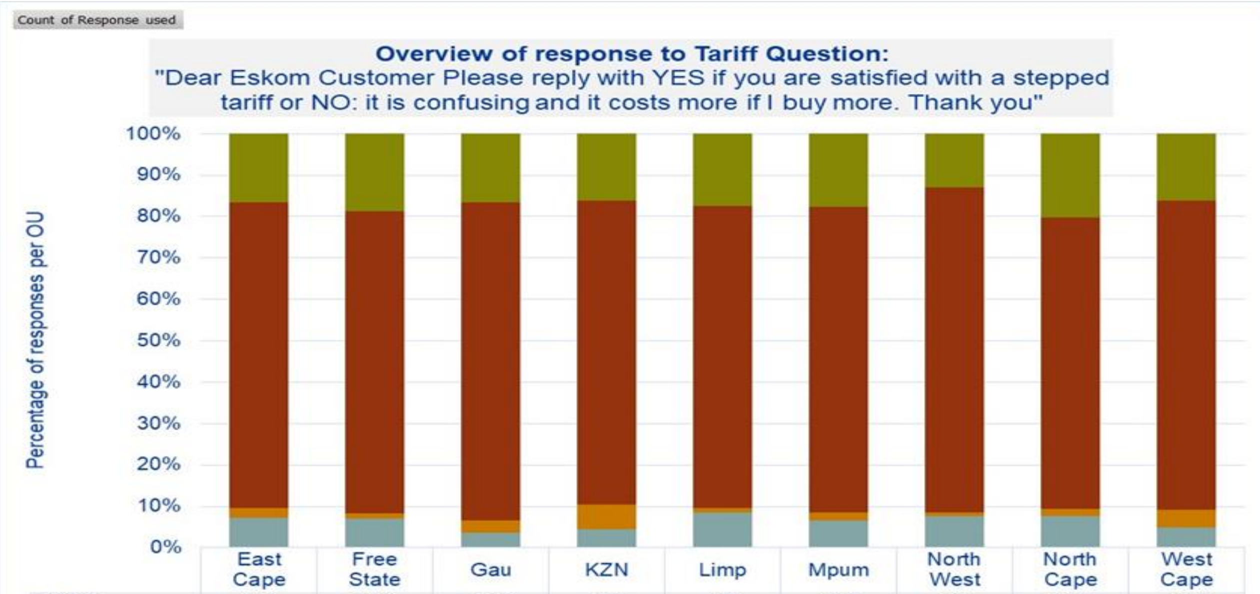
- 79% of the participants are not satisfied with the IBT tariff, as it costs more,
- 18% of the participants are satisfied. Some customers who responded that they are satisfied, gave us a further comment which shows that they want to buy more, but cannot afford to, so they are resorting to alternative energy which may be unsafe in our unpredictable climate.
- 5% of the participants are unsure or don't know.

Customers further, explained that they cannot afford electricity, which is a basic human right, as it is becoming expensive. They also want to purchase more, but cannot, as they are penalized for using more.

There were responses from SASSA recipients who would like to see special tariffs created for them or concessions and deductions.



The following are the customers' responses to our survey grouped per province.



	East Cape	Free State	Gau	KZN	Limp	Mpum	North West	North Cape	West Cape
YES	474	220	729	356	458	399	192	215	397
NO	2102	862	3375	1616	1904	1667	1169	750	1827
DON'T KNOW	64	15	132	131	29	42	12	18	101
0	207	84	158	98	223	148	114	81	121

"Don't Know" is the same as "Unsure" in this survey.

"0" refers to customers who did not answer our question, but they commented on an electricity problem that they are experiencing.

The survey sent to customers is shown below:

Customer survey on the inclining block rate tariff

Your response to this survey very important. The results will form part of the customer information that Eskom submits to the National Electricity Regulator of South Africa (NERSA)related to the residential electricity tariffs that are currently implemented by both Eskom and the various municipalities.

The purpose of the survey is to assess **customer understanding** of the current inclining block rate tariff, as well as opinions about the tariff.

The information you provide will be treated with the strictest confidentiality. The survey is completed anonymously, and **you will not be identified**. All data hosting, statistical analyses and interpretation will be conducted by an internal team.

What is an inclining block rate tariff?

The inclining block rate tariff is a stepped tariff used for residential customers and is applied by both Eskom and municipalities as a requirement by NERSA. This tariff has different charges for blocks of consumption, with higher charges on each step as you consume more, that is, the charge for a unit of electricity increases as consumption moves from one block to the next over a period of a month

Below is an example to illustrate the tariff (as Eskom and municipalities' have different tariffs that they use):

- the first block or step will be for the first 300 kWh in a month at a rate of say R1,20 per kWh, and
- the next block for any consumption above 300 kWh in a month will be charged at R2,30 per kWh.

Quick survey overview

1. The survey will take approximately 5 - 10 minutes to complete, with only 5 questions. Please complete it in **one** session if possible.
2. Make sure the survey is complete by clicking the 'submit' button at the end of the survey. If you do not complete the entire survey and submit your responses, your responses will be lost.
3. **Kindly respond by 20 January 2021.** Feedback on the results of this survey will be conveyed to you once the data has been analysed and shared with Eskom's senior leadership.

Biographic Information

This section is a biographic section where we ask questions about you to add context to the results.

Please answer the following questions by responding to the appropriate options provided.

Gender

- ○ Male
- ○ Female

Age group

- ○ 18 – 30
- ○ 31 – 45
- ○ 46 – 60
- ○ > 60

Province you live in:

- ○ Eastern Cape
- ○ Free State
- ○ Gauteng
- ○ KwaZulu-Natal
- ○ Northern Cape
- ○ North West
- ○ Mpumalanga
- ○ Limpopo
- ● Western Cape

Customer's feedback on the Inclining block rate tariff

Please answer the following questions **only if you are on an inclining block** (stepped) residential tariff, whether you are supplied by Eskom or a municipality

1) Please rate your understanding of the tariff on a scale of 1 -5, **1** – I don't understand the tariff at all, **2** - I have about a 25% understanding, **3** -I understand it about 50%, **4** about 75% understanding and **5** - I completely understand how it works.

	1	2	3	4	5
Please rate your understanding of the tariff					

2) Explaining the tariff

	Yes	No
Do you believe that your electricity supplier could do better with explaining the tariff?		

3) Please rate your opinion of the tariff on a scale of 1-5, 1 being "I don't like it at all" and 5 being "I like this tariff".

	1	2	3	4	5
Please rate your opinion of the tariff					

4) Please provide a reason for your rating in question 3).

5) – Price of electricity

	Yes	No
Do you believe that you need to pay more per unit if you use more electricity?		

6) Please provide a reason for your rating in question 5

Annexure H – Eskom responses to National Treasury and SALGA inputs

H.1 SALGA comments

Below is Eskom's response on the comments received from SALGA.

1. *"Wholesale tariffs should be primarily energy-based (c/kWh) and should not include Generation Capacity Charges or other fixed charges. If South Africa is going to encourage private sector investment and establish power pools (as set out in the draft amendment to the Electricity Regulation Act), all generators must bid at competitive and comparable wholesale energy prices (c/kWh). It will be unfair for the Eskom Generation to have anti-competitive fixed prices, that does not encourage the industry development and investments."*

Eskom response

The wholesale tariff structure needs to reflect the true costs in the supply chain and highlight different products and services arising from changes in the industry. Wholesale purchase costs form the basis for the retail tariffs, and these costs comprise fixed and variable costs. Refer to Section 5 on why it is vital for retail tariffs to have the same level and structure of the wholesale purchase costs.

2. *"Likewise, transmission pricing should have fixed prices set as a minimum, with major prices set equally at energy and capacity rates for all generators putting energy onto the grid (IPPs and Eskom Generation) and all off-takers (Municipal Distributors, Eskom Distribution and transmission connected customers) . Fixed charges should be restricted to end consumers (at retail level) to recover distribution fixed costs and should be minimal at wholesale level."*

Eskom response

Customers should receive the appropriate economic pricing signal for location, capacity installed and for usage for both generators and loads.

3. *"The separation of Eskom Distribution as a separate entity is not reflected in the pricing. Eskom Distribution should be on the same footing as other Municipal Distributors and should purchase their energy at the same wholesale tariffs as those charged to Municipal Distributors. The Eskom Retail Tariff Plan 2023/24 is based on the previous integrated Eskom methodology. A separate cost of supply and tariff design for Eskom Distribution should be undertaken, based on Eskom Distribution purchasing at the same wholesale tariffs as Municipalities. This will prevent the cross subsidization of Eskom Distribution customers by Municipal Distribution customers. Eskom Distribution tariffs should also be regulated in the same way and alongside Municipal Distribution tariffs to ensure equitable comparison of costs."*

Eskom response

The proposed unbundling of the tariffs and aligning the retail charges with the wholesale rates, sets up pricing to be on a level playing field between Eskom Distribution and municipal licensees. The remaining issue is how subsidies would be treated, as this is subject to national policy, in particular how this would be treated when the wholesale trading environment is enabled.

4. *"While cost reflective tariffs are supported in general, splitting these too far may actually result in a detrimental effect in that it may chase customers away from Eskom supplies altogether, with the fixed*

charges being too high a component of the overall account. This is especially true of those low-consumption customers with the means to invest alternative solutions that will be most impacted by Eskom's proposed tariff restructuring. Rather than encouraging those customers to remain grid-tied, this plan strengthens the business case for them to go completely off-grid to the detriment of Eskom, municipal distributers and, most importantly, those consumers without the means to go off-grid. "

Eskom response

The approach by Eskom is already a phased approach and attempts were made to limit the impact as far as possible. However, any reductions of fixed costs, for example, will mean tariffs are less cost-reflective and do not reflect divisional costs and Nersa's decision. Currently fixed costs form 76% of Eskom's total costs, and with the proposed changes only 24% of the tariff charges is fixed. This illustrates how far Eskom's tariffs are from being truly cost reflective. If fixed charges are not raised, then customers without embedded generation will have to subsidise those with embedded generation. This is not equitable or fair. It is vital to have a tariff structure that reflects the cost of service and value provided to customers with embedded generation.

5. *"A related but separate issue is that of the volumetric revenue risk. By moving towards more cost reflective tariffs through increasing the fixed components (according to the document, Eskom is aiming to recover approximately 24% of their costs from fixed components, while some 76% of their costs are not linked to volumes and should be recovered from fixed charges), Eskom reduces their revenue risk (and therefore reduces upwards pressure on volumetric prices). However, Eskom acknowledges that charging such a high fixed charge is not feasible and have adjusted accordingly. In the City's view, the shift to 24% fixed tariffs is still not feasible, especially in the current energy constrained context. Should NERSA accept the principle of this transition, we argue that the regulator should set out a far more gradual evolution that protects past investments and encourages planned investments in independent power production and SSEG."*

Eskom response

As highlighted in comment 4, if Eskom does not introduce fixed charges, it would be to the detriment of all customers as it would introduce cross-subsidies. This would mean future higher price increases for these customers which would ultimately result in a utility death spiral. This is explained in Section 4 of the document.

6. *"A change in the ratio between fixed and variable costs on the Eskom account will impact on the cost to serve at a municipal level, as the amount of revenue required from fixed charges will increase. This will pose a significant challenge to municipalities, given that there is considerable public resistance to fixed charges. If assented to, these charges will result in not only an increase in the revenue risk to municipalities, but also upward pressure on prices as a result of any reduction in sales that may occur due to consumers with the means electing to go completely off grid (thus hastening the Utility Death Spiral). Note. this does not mean that the decision to increase fixed charges by Eskom is incorrect or unsupported, but this needs to be done at a rate that can be absorbed by reasonable increases in municipal fixed charges. which would become even more imperative than they already are."*

Eskom response

The approach by Eskom is already a phased approach and attempts were made to limit the impact as far as possible. The recovery of fixed costs through fixed charges is still far from where it ought to be, however, Eskom needs to start somewhere. The generation capacity charge is being phased in 50/50 for small power user tariffs to minimise the impact.

7. *"Given that NERSA released a new document for the determination of prices after Eskom submitted its plan, it would make more sense to refer this plan back and ask that Eskom take this new potential framework into account. To avoid litigation and delays in the entire tariff process, placing municipal distributors at significant risk, the municipalities recommend that NERSA and Eskom work together to finalise both in a way that addresses all stakeholders' concerns."*

Eskom response

There are many aspects of the NERSA methodology that are unclear and would require significant updating of many of the NERSA rules and Codes before the proposed methodology would be able to be implemented. This is expected to take a period of time and therefore it is important that Eskom is allowed to move forward to unbundle the tariffs to provide the correct economic signals and in preparation for a wholesale environment. Eskom and the industry, however, cannot delay the restructuring of tariffs as the current tariffs are sending an incorrect pricing signal which customers are using as a basis to make investments.

8. *"It is not possible with the information readily available on Pricing, and without extensive modelling, which time limitations do not permit, to determine the impact these changes will have on the municipalities' accounts. Given the time constraints. and the number of variables changing (the time periods as well as the ratios between the time periods, the rationalisation of the municipal tariffs, and the addition and adjustment of new tariff components). it would take a fairly comprehensive modelling exercise to determine the exact impact."*

Eskom response

Eskom will provide customers with tools to determine how the tariff changes will affect them. These tools will be made available when the retail tariff plan is published after submission to NERSA.

9. *"Section 5.9 (Residential Tariffs): The move away from inclining block tariffs (IBT) towards a two-part tariff (service charge and flat energy rate) is both understood and supported. Any benefits that were going to be achieved in terms of efficiencies from the IBT either have now been achieved or will never be achieved. There is thus little benefit in continuing with this structure, with the associated customer confusion about how it works. The inclusion of a more cost-reflective service charge is also welcomed. and is the right direction to move if the intent is to reduce the revenue risk from reducing sales, and therefore to protect other customers from having to provide a higher subsidy to these customers. A more cost-reflective pricing signal at this level also provides a better economic signal for the business case for alternative supply sources. It is important to note that lower-middle- and middle-income households. most of which fall within the consumption levels targeted by Eskom for significant overall tariff increases, are currently facing a cost-of-living crisis with rising inflation and interest rates. The impact of the significant increase in proposed service charges (while, from Eskom's perspective, understandable) is going to cause major duress for these smaller consumers. who will see massive increases in their monthly accounts. While this is acknowledged by Eskom. it would perhaps be a better process to phase this increase in over several pre-defined years, so as to mitigate these impacts. It is, however. of further concern that the graphical representation of the tariff increases (Annexure B.3 - proposed, cost reflective, and current) do not actually always represent the numbers in the tables below, which creates a misleading picture of the situation."*

Eskom response

Overall the retail charges are reducing due to updating with the cost-to-serve study. Only customers with many points of delivery consolidated into one account will see an increase due to the changes to the service charge. The issue of fairness is behind this proposal by Eskom as a customer with one point of delivery and one account pays the same as a customer with many points of delivery linked to one account currently pays the same service charge, even though there are more costs and resources used for the latter customer. This creates an unintended subsidy.

10. *"Section 5 .2 (How the standard tariff charges have been calculated} and Section 5.3.2 (TOU proposed peak, standard, and off-peak rate changes): These sections refer to the recalibration of the Wholesale Energy Price in order to take into account Eskom's actual cost of production, given the poor availability of older, coal fleet generation, which results in reliance on newer, but significantly more expensive. coalfleet and even more expensive diesel plant. This recalibration is not supported, as this is a clear instance where Eskom is seeking to be compensated by the general public for its own inefficiencies and its shareholder's poor policy choices. In this instance. Eskom should rather focus on resolving the issues, instead of simply passing on a more expensive cost to their customers, who are not responsible for the failures of Eskom, and therefore should not be made to pay for it. As mentioned previously, the costs of past errors need to be addressed through restructuring, recapitalisation, and leveraging Eskom's viable assets - particularly its transmission network. NERSA have a legislated requirement to allow an efficient licensee to recover their full costs of operation, with efficient being the operative term in this scenario. At least, the existing TOU (Table 4) ratios should be retained."*

Eskom response

The objective of the TOU changes is to assist the system operator in managing the system, future changes to the profile, by providing TOU signals to facilitate customer response. This response must take into account all the supply and demand options that exist in the system. Refer to Annexure C – Motivation for the changes to the TOU Wholesale Energy Purchase Structure in the document for the rationale for the changes.

11. *"Section 5.7 (Transmission network-related charges}: This section refers to the promotion of net-billing. While the ideal scenario for net-billing is a TOU setup (both for consumption and generation), the metering requirements for this are very expensive. Within the municipal environment, this will require two AMI meters to be installed - one in each direction), which comes at a high cost just for the metering. There is no way this can be recovered through the feed-in tariff during the lifespan of the system thus negating the aim of promoting such systems."*

Eskom response

It is assumed the heading is incorrect as this relates to net-billing. Two AMI meters would not be required, Eskom uses one bi-directional meter that can measure energy on a TOU and bidirectional basis and the cost of this metering has significantly reduced. Smart-metering needs to be a priority for all utilities in South Africa, especially due to the President's recent speech to promote generation. Bi-directional smart metering that measures on a TOU basis would be vital to enable this.

12. *"Section 5.6.2 (Distribution use-of-system losses charges): This section refers to Distribution Loss Factors. These are considerably higher than those contained in the NERSA-approved Cost of Supply Framework and, if utilised, will likely result in the overall distribution losses exceeding the NERSA l0-123 benchmark. If these loss factors are based on what Eskom is actually seeing in terms of distribution losses, then these are not supported as, again, they do not align with the current definition of an efficient licensee, and the customer should not be required to pay for them. Rather, Eskom should improve its revenue protection measures in order to reduce the losses. It is also not clear whether these factors are total losses, or whether they are just technical losses. If these are only technical losses, then the situation is even worse, and Eskom should seek to improve its network performance in order to reduce these. Design and age of networks impact on the technical losses to a large extent, and these are controllable factors that can be improved upon.*
"

Eskom response

For Distribution-connected loads, the loss factors were updated as contained in the CTS and the overall losses are 8.5%. These are loss-factors based on voltage and density. The lower the voltage the more assets have to be used and the higher the technical losses. The same is true for areas with low densities such as rural areas where electricity has to be delivered over longer distances between customers. The inverse is true for customer's connected at higher voltage and in more densely populated areas. These loss factors are approved as part of the Schedule of Standard tariffs approved by NERSA.

13. *"Annexure A (Local-authority tariff impacts): This table shows the overall impact of the change to the Local Authority tariffs. It is highly concerning that Municipal customers are providing a considerable level of subsidy to Eskom customers jot the order of 63%). This means that, before any municipally imposed subsidies, municipal customers are already paying 63 more than they should be and, given the "double jeopardy" nature of these subsidies municipal customers paying more than they should means that Eskom customers get to pay less), the differential between equivalent customers within (potentially) the same municipal boundary will be somewhat more than this amount. Sales to other licensed distributors should be done at pure cost-reflective tariffs, without any subsidies applied, in order to produce the fairest possible outcome to all customers and to provide the most accurate possible economic signals to all customers, both Eskom-supplied and municipal)."*

Eskom response

Eskom cannot find where in the submission that municipalities are providing a 63% subsidy to Eskom customers. Municipal tariffs provide a subsidy in the form of the ERS charge of 5.8% of their total sales. To be noted this is not a subsidy to Eskom, but to Eskom customers mainly in poorer areas of the country in municipal jurisdictions. This is national issue.

14. *"Annexure C.7 (The correlation and support of the proposed changes to the wholesale purchase structure and rates and retail TOU tariffs with short-run marginal costs): The study commissioned by Eskom indicates that there is some level of misalignment between the current retail TOU and the SMC, and the urgent need to realign the TOU definition and costs. One of the main drivers of this, however, is the extreme usage of Eskom's OCGT plant during peak periods, which drives up the SMC during these periods. What is not noted, however, is the impact of the poor performance of Eskom's coal fleet's in the usage of these OCGTs. As has previously been indicated, NERSA are only required to provide for the costs of an efficient licensee, and not merely allow an inefficient licensee to embed those costs incurred through their inefficiency into their base revenues. If the peak period prices are being driven up by the use of more expensive generation capacity as a result of the failure of the cheaper generation capacity, then this should not be passed through to the customer in terms of pricing structure [thus embedding the inefficiency in the price forever]."*

Eskom response

This submission deals with the unbundling of tariffs and not cost items. The performance of Eskom's fleet is addressed through the MYPD process. The proposed changes to the TOU tariffs is based on the management of the power system and ramping up and reducing of energy consumed on an average day. Eskom has also reduced the peak prices in winter which will assist municipal licensees.

H.2 National Treasury comments

Below is Eskom's response on the comments received from National Treasury.

1. *"While the National Treasury is appreciative of Eskom's revenue collection challenges, among other factors, the proposed retail tariff restructuring plan, if approved and implemented, would have catastrophic implications for the financial sustainability of local government in the short-medium term. It is based on the projected impact of 30% on the tariffs charged to municipalities (local authorities) on public lighting, as shown in table 1, showing the summary of costs for existing revenue and revised revenue."*

Eskom response

Public lighting tariffs have been severely under-stated as a result of applying an average price increase over the years, and barely recovers energy costs alone and therefore is subsidised. Updating the tariffs with the cost to serve study has corrected this misalignment and Public lighting tariff is now cost reflective for both municipal and non-municipal tariffs.

2. *"It is unclear to what extent the previous comments were considered and whether NERSA approved or rejected the previous submission, and if this proposal was rejected, the reasons for rejection would have been helpful."*

Eskom response

The previous comments received from National Treasury were responded to in the previous 2020 submission, however, NERSA never made a decision on this submission. This current Retail Tariff Plan is based on the 2020 plan with additional changes.

3. *"Since the new proposed TOU periods will result in higher increases, while customers are already facing electric price increases, it's imperative that there's a balance between the new proposed ratios and TOU periods. Otherwise, it may not relieve customers from the current pressures but will lead to unintended consequences for the economy. It will also be costly to use electricity during high peak-hours if Eskom aims to introduce a TOU tariff for its urban residential customers."*

Eskom response

The proposed TOU changes are firstly aligned with updated energy related costs and provide the correct signal for consumption and secondly are not intended to earn Eskom any additional revenue above that approved by NERSA. A TOU residential tariff is aligned with the DMRE's Electricity Pricing Policy and at this stage will only be mandatory if there is grid tied generation. This tariff will not recover any more revenue than is already recovered and if customers do respond they will be able to save on their electricity bill.

4. *"**Impact on tariffs due to changing electricity-** Eskom applying TOU and adjusting charges will not decrease the number of customers who are switching to other means of energy sources because, most people/ customers are at places of work during the day, so applying TOU won't assist in making electricity less for them, let alone stopping them from switching as suggested by this new tariff plan."*

Eskom response

The aim of making changes to TOU is to assist the system operator in managing the system, and not to decrease the number of customers who are switching to other means of energy sources. Customers using SSEG systems such as PV, will reduce the energy in the system during the day but will not change the current morning and evening peak period system demand. TOU pricing signals, therefore, will continue to be needed to manage the high system demand in the morning and evening peak periods as well as to manage the variation of system demand levels between the high- and low-demand months (summer and winter months.) The System Operator requires the evening ramp-up rate currently being experienced in the system to be managed, as the current generators can only ramp up to meet the steep increase in the evening peak at a technically limited rate. If the ramp-up rate to the evening peak is not addressed, the system will not be able to meet the demand at these times, and this will affect security of supply.

5. *"**Migrate to TOU tariffs-** Eskom plans on developing a tariff migration programme that will move all customers to TOU tariffs except for low-income customers and further states that they will cover the cost of registration. It is appreciated that registration costs will be covered, but it is concerning that the costs of changing meters and installation will not be paid for, which undermines the idea that fairness will be achieved by requiring consumers to foot the bill."*

Eskom response

The migration programme is not part of this submission but is a recommendation from a study commissioned by Eskom to assess among other things how tariffs would need to change to address this changing landscape. This study supported the motivations and the structural changes proposed in this submission. Any developments in this space will be guided by the DMRE's Electricity Pricing policy

6. *"In terms of the TOU changes, evening peak hours should have remained at two hours and not increased to three, as this means that customers will pay more for electricity in the evening."*

Eskom response

The System Operator requires the evening ramp-up rate currently being experienced in the system to be managed, as the current generators can only ramp up to meet the steep increase in the evening peak at a technically limited rate. If the ramp-up rate to the evening peak is not addressed, the system will not be able to meet the demand at these times, and this will affect security of supply.

This system requirement means that the evening peak hours need to be increased in order to reduce the ramp-up rate in the evenings. The proposed TOU hour changes include an increase in the evening peak for both summer and winter; currently, there are two evening peak hours, and it is proposed that there be three evening peak hours.

Customers using PV systems during the day means that there is a drop in the demand for electricity during the day – with the highest drop in system demand in the middle of the day. This midday demand drop (called the "duck curve") affects the power system negatively as it means that the generators have to ramp up at an even faster rate than before to meet the evening peak demand. This is a higher pickup at a steeper ramp rate due to PV energy production dropping off, while demand is increasing.

If this is not done it would pose a huge risk to the security of the system. Again this is a revenue neutral exercise as it will not recover more revenue from customers than that allowed by NERSA. Municipalities in particular should be encouraged in turn to introduce TOU tariffs to their customers. TOU pricing will become more and more important due to the additional energy generation that will be added to the grid in the coming years.

7. *"Considering the afore concerns raised and given the ongoing review of the MYPD 5 by the Energy Regulator (NERSA), the National Treasury recommends that Eskom awaits the finalisation and outcome of the review of the MYPD 5 by NERSA prior to introducing such drastic reforms. This is important given the implications of the restructuring plan on the local government fiscal framework, as indicated on page 10 that individual customers will be affected differently, "others might have to pay more, while others might have to pay less, depending on the customer's consumption profile."*

Eskom response

This was also used to motivate as one of the reasons for the non-approval of the 2020 retail tariff plan and therefore cannot be continually used as a reason to delay tariff restructuring. If these tariff changes are not made and delayed, it means there will increasing misalignment between the tariffs and the Eskom divisional costs resulting in large pricing shocks for customers in the future, resulting from the unbundling of Eskom and other industry changes.