Eskom's Retail Tariff Plan 2020/21 Submission

Contents

1. Executive summary 5
2. Eskom's 2017 strategic direction and tariff design principles for Eskom's standard tariffs 8
3. Economic drivers for change 9
4. Tariff design process 12
4.1. Tariffs based on the CTS study 14
4.2. Eskom-proposed changes to the tariffs and their charges 16
4.3. How the standard tariff charges have been calculated 18
4.4. TOU changes 20
4.4.1. TOU proposed period changes 20
4.4.2. TOU proposed peak, standard, and off-peak rate changes: 21
4.5. Municipal tariff rationalisation 22
4.6. Network-related charges 23
4.6.1. Distribution use-of-system (DUoS) network charges 23
4.6.2. Distribution use-of-system losses charges 25
4.6.3. Transmission use-of-system (TUoS) charges 25
4.6.3.1. Transmission network charges for loads 26
4.6.3.2. Transmission network charge for generators. 26
4.6.3.3. Ancillary service charges 27
4.6.3.4. Transmission losses payable by loads 27
4.6.3.5. Transmission losses payable by Transmission-connected generators 28
4.7. Residential tariffs 28
4.7.1. Homepower 28
4.7.2. Residential TOU – Homeflex 29
4.7.3. Homelight 30
4.8. Service charges converted to R/POD and not R/account 31
4.9. Nightsave changes 32
4.10. Subsidies 32
4.10.1. Inter-tariff subsidies 33
4.10.1.1. Homelight inter-tariff subsidies 33
4.10.1.2. Rural inter-tariff subsidies 34
4.10.2. Intra-tariff subsidies 35
4.10.3. Calculation of the ERS charges and the affordability subsidy charge 35
5. Impact of changes per tariff 36
6. Conclusion 39

Annexures

Annexure A – Local-authority tariff impacts 41
Annexure B - Non-local-authority tariff impacts 57
Annexure C – Motivation for the changes to the TOU Wholesale Energy Purchase Structure 64
Annexure D – Proposed changes to rate components 71
Annexure E – New residential TOU Homeflex and offset motivation 84
Annexure F – Proposed retail rates in 2019/20 rand values (excluding VAT) 90
Annexure G – Department of Mineral Resources and Energy Electricity Pricing Policy positions 99
Annexure H – Eskom responses to National Treasury and SALGA inputs 108

Tables

Table 1: Summary of costs, existing revenue and revised revenue 8
Table 2: Summary of proposed changes to Eskom's retail tariffs 16
Table 3: Tariff design basis 19
Table 4: Wholesale purchase TOU rates excluding losses 21
Table 5: Updated Distribution loss factors 25
Table 6: Updated Transmission network charges for loads 26
Table 7: Updated ancillary service charges 27
Table 8: Updated Transmission loss factors 27
Table 9: Homepower impact (R million) 29
Table 10: Homepower current average month bill versus revised monthly bill 29
Table 11: Homelight current tariffs 31
Table 12: Homelight cost-reflective rates 31
Table 13: Homelight revised tariffs 31
Table 14: Inter-tariff subsidies 33
Table 15: ERS charge and affordability charge calculation 36
Table 16: Revenue and cost summary per tariff 37
Table 17: Summary of impact, per tariff category for energy, network 38
Table 18: Summary of rand impact, per charge, per tariff category 39
Table 19: Rand impact per local-authority tariff 41
Table 20: Rand and percentage impact per tariff category 42
Table 21: Rand impact per local-authority tariff in alphabetical order 46
Table 22: R impact per local-authority tariff in order of % impact 51
Table 23: Total impact per voltage for the LPU tariffs 63
Table 24: Existing and proposed TOU periods 69
Table 25: Current and proposed WEPS energy costs and ratios (excluding losses) 70
Table 26: Structure of the service and administration charges 71
Table 27: Structure for the active energy charges 72
Table 28: Network charge calculation categories 75
Table 29: Structure of the network charges 77
Table 30: Structure of the ancillary service charges 80
Table 31: Structure of the ERS charge and the affordability subsidy charge 81
Table 32: Structure for the reactive energy charge 82
Table 33: The proposed Homeflex tariff 87
Table 34: Urban LPU tariffs: WEPS, Megaflex, Miniflex, and Nightsave Urban (non-local-authority) 90
Table 35: Rural LPU tariffs: Ruraflex and Nightsave Rural (non-local-authority) 91

Table 36: SPU tariffs: Businessrate, Landrate, Homelight, Homepower and Public Lighting (non-local-authority) 92
Table 37: LPU tariff: Municflex – 12-month view before adjustment for July increase 93
Table 38: SPU tariff: Municrate – 12-month view before adjustment for July increase 93
Table 39: LPU tariff: Municflex – adjusted for a nine-month view (July increase) 94
Table 40: SPU tariffs: Municrate and Public Lighting – adjusted for a nine-month view (July increase) 94
Table 41: Gen-DUoS tariff 95
Table 42: Gen-TUoS tariffs 96
Table 43: Gen-wheeling tariffs 96
Table 44: Gen-offset tariffs 97
Table 45: Gen-purchase tariffs 97

Figures

Figure 1: Why tariff changes are being proposed 5
Figure 2: Eskom's tariff objectives 9
Figure 3: Drivers for tariff changes 9
Figure 4: Eskom volume risk exposure 10
Figure 5: Example of cost structure versus tariff structure 11
Figure 6: How technology is changing the way the grid is used 11
Figure 7: Tariff change process 13
Figure 8: Tariff design process 14
Figure 9: Percentage impact of updating charges with the CTS 15
Figure 10: Proposed changes to the peak, standard and off-peak periods of the TOU tariffs 21
Figure 11: Impact of the municipal tariff rationalisation per local-authority tariff 23
Figure 12: Network charge design and associated risks 24
Figure 13: Homelight 20A and Homelight 60A - cost, current tariff, and revised tariff 30
Figure 14: Current and revised inter-tariff subsidies 33
Figure 15: Rand impact per tariff charge type 38
Figure 16: Percentage impact per tariff charge type for urban LPU and Municflex 39
Figure 17: Businessrate compared to Municrate at different consumption levels 42
Figure 18: Landrate compared to Municrate at different consumption levels 43
Figure 19: Homepower compared to Municrate at different consumption levels 43
Figure 20: Histogram of the total number of PODs negatively or positively affected 44
Figure 21: Current Megaflex local-authority tariff and proposed Municflex comparison 44
Figure 22: Current Miniflex local-authority tariff and proposed Municflex comparison 45
Figure 23: Current Nightsave local-authority tariff and proposed Municflex comparison 45
Figure 23: Current Ruraflex local-authority tariff and proposed Municflex comparison 46
Figure 24: Businessrate non-local-authority tariffs impact at different consumption levels 57
Figure 25: Businessrate 1 and 2 non-local-authority tariffs comparison of cost-reflective, current, and proposed tariffs 57
Figure 26: Businessrate 3 and 4 non-local-authority tariffs comparison of cost-reflective, current, and proposed tariffs 57
Figure 27: Landrate non-local-authority tariffs impact at different consumption levels 58
Figure 28: Landrate 1 and 2 non-local-authority tariffs comparison of cost-reflective, current, and proposed tariffs 58
Figure 29: Landrate 3 and 4 non-local-authority tariffs comparison of cost-reflective, current, and proposed tariffs 58

Figure 30: Landlight 20A and 60A non-local-authority tariffs comparison of cost-reflective, current, and proposed tariffs 59
Figure 31: Homepower non-local-authority tariffs impact at different consumption levels 59
Figure 32: Homepower 1 and 2 non-local-authority tariffs comparison of cost-reflective, current, and proposed tariffs 59
Figure 33: Homepower 3 and 4 non-local-authority tariffs comparison of cost-reflective, current, and proposed tariffs 60
Figure 34: Public Lighting All-Night and 24-Hour non-local-authority tariffs comparison of cost-reflective, current, and proposed tariffs 60
Figure 35: Public Lighting Fixed non-local-authority tariff comparison of cost-reflective, current, and proposed tariffs 60
Figure 36: Current Megaflex non-local-authority tariff compared to the proposed tariff 61
Figure 37: Current Nightsave Urban non-local-authority tariff compared to the proposed tariff 61
Figure 38: Current Miniflex non-local-authority tariff compared to the proposed tariff 61
Figure 39: Current Ruraflex non-local-authority tariff compared to the proposed tariff 62
Figure 40: Current Nightsave Rural non-local-authority tariffs compared to the proposed tariff 62
Figure 41: Current Nightsave Rural and Ruraflex non-local-authority tariffs compared to the proposed tariffs 62
Figure 42: Eskom's System Operator overview and requirements to optimally manage the power system 66
Figure 43: Scaled winter and summer average week of the national system profile from 1995 to 2019 67
Figure 44: Average summer and winter weekday system profile in 2025 and 2030 68
Figure 45: Eskom's Corporate Plan and Eskom's Strategic Pricing Direction alignment with the proposed changes to the TOU tariff 69
Figure 46: Eskom's Strategic Pricing Direction alignment with the proposed Homeflex tariff 85

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 based on a cost-of-supply[1] (or cost-to-serve/CTS) study. Since then, technology has developed at a fast pace, customer needs have changed and continue to change, and the tariff charges no longer accurately reflect the Eskom cost splits for energy, networks, and retail. To add to this, it has been decided that Eskom would be unbundled into separate divisions, requiring future tariffs to be designed to reflect the unbundled divisions. This unbundling will require tariffs to accurately reflect current divisional cost to avoid volume and trading risk and to reflect cost drivers more accurately.

All of the above requires an updated tariff design to take place.

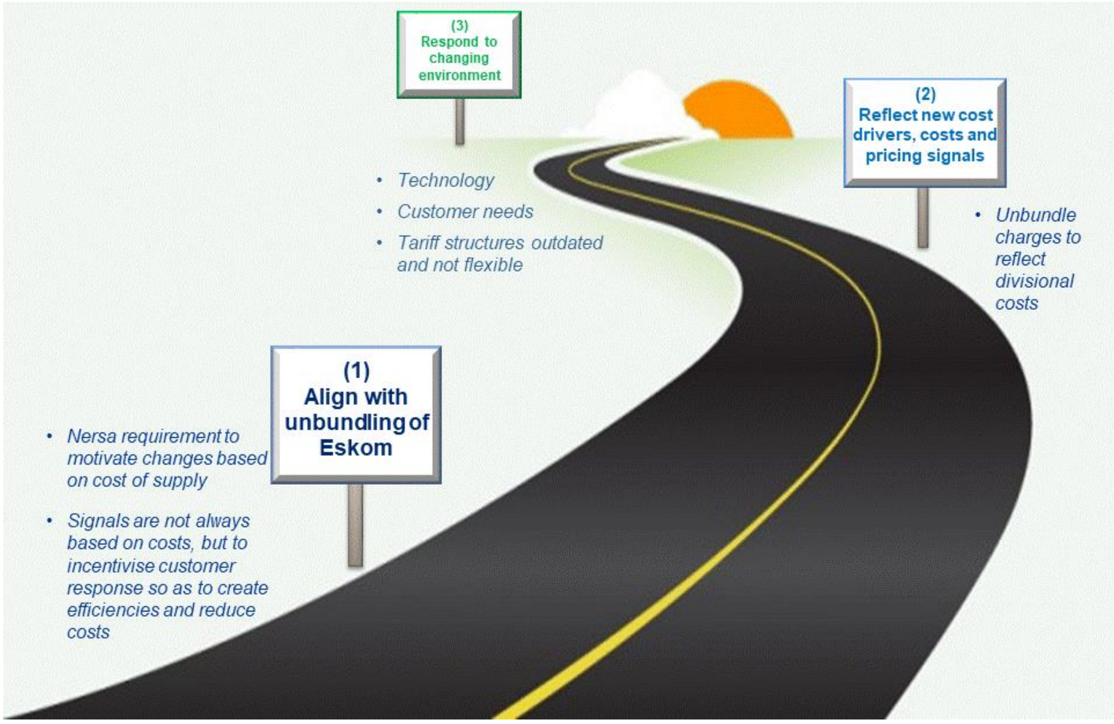


Figure 1: Why tariff changes are being proposed

As per NERSA's request for tariffs to be motivated based on the cost-of-supply, Eskom updated its cost-of-supply study (further referred to as the cost-to-serve or CTS). Eskom has designed all the tariffs in this document based on the CTS results, and included specific objectives/signals to incentivise more optimal use of the system, which is not necessarily cost based, but forward-looking.

Existing tariff structures are outdated and need to be modernised to reflect the changing electricity environment and difficult decisions in this regard need to be made to protect the electricity industry. For example, it is no longer appropriate to recover fixed costs 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

[1] The cost-to-serve 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 cost-to-serve study assumes the approved revenue requirement as the basis.

A cost-of-supply study takes place every time structural changes are made and used to allocate costs for tariff design purposes and to understand subsidies. In order for Eskom to restructure/ revise tariffs, a CTS is required.

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 time-of-use (TOU) residential tariff with an offset rate for net billing.

When updating tariffs using a CTS study and implementing structural changes, it is not possible to have zero impact on all customers. So, while the total tariff revenue due to the structural changes is revenue-neutral, 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. 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 total tariff revenue due to the structural changes is revenue-neutral, 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.

This retail tariff plan uses an updated CTS study to propose changes to Eskom's tariffs.

The following are the main objectives of this tariff submission:

- Updating tariffs with the latest CTS (that is, cost allocation and segmentation, **not** cost justification)
- Optimising customer response and use of the system by revising pricing signals to reflect the current system, such as changing TOU rates and times
- Providing for more economic recovery of cost-reflective tariffs (structurally):
    - Reducing volume risk by increasing fixed charges to reflect fixed costs
    - Reducing the burden on higher voltages by reducing the subsidies on lower voltages for urban LPU tariffs
- Simplifying tariff options, removing IBT, and rationalising municipal tariffs
- Modernising tariff structures in light of evolving customer needs and technology – residential TOU

The following major structural changes[2] are proposed:

1. Updating all charges using the repacked forecast volumes, cost split, and cost allocation methods:
    a. Energy rates to reflect updated wholesale energy costs; 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
    b. Network charges to reflect updated Transmission and Distribution network costs
2. Increasing the Distribution fixed-charge network charges component, with a commensurate reduction of the variable charge for all tariffs with network charges
3. Rationalising the local-authority tariffs into only three tariff categories: a large power user (LPU) version called Municflex, a small power user (SPU) version called Municrate, and a Public Lighting tariff for non-metered lighting supplies
4. Increasing the lower-voltage charges for urban LPU tariffs, thereby reducing the contribution to the low-voltage (LV) subsidies
5. Basing service charges on the number of points of delivery (PODs) and not per account

[2] 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.

6. Removing IBT for Homepower and Homelight tariffs
7. Introducing a residential TOU tariff plus a new net billing offset rate for customers with small-scale embedded generation (SSEG)

How the tariffs in this submission were designed can be described as follows:

- The multi-year price determination (MYPD) approved 2019/20 volumes and cost splits for the three Eskom licensees were the foundation for this submission, as these were the most recent NERSA-approved values at the time of doing the CTS study.
- The forecast energy-related volumes in the CTS (TOU energy in peak, standard, and off-peak periods, chargeable demands, and reactive energy) were repacked into the new TOU volumes using the proposed changes to the TOU periods. The overall volumes did not change.
- The energy costs comprise the Eskom Generation costs plus the independent power producer (IPP) costs, and these were then converted into a new wholesale purchase price (called WEPS) with the new TOU periods and rates, excluding losses. These new periods provide a signal that reflects system changes. This now becomes the WEPS costs on which the retail energy tariffs are calculated.
- Distribution asset values were updated based on new asset values.
- Transmission and Distribution loss factors were updated based on representative network studies.
- At this stage, no changes have been made to the transmission zones for loads.
- **All rates in this document exclude VAT and are in 2019/20 rand values. The Eskom price increase process will be applied to the rates to bring them to the year of approval.**

The proposed changes will affect customers as follows:

- **In order to recover the approved MYPD revenue, structural changes and updating tariffs with the CTS mean that some customers will pay more and others less. It is not possible to make all customers pay the same.**
- **All tariffs are affected by the changes being proposed, and such changes, except for the changes to the rural tariffs and Homelight, are interlinked. This means that, if a change is approved for one tariff and not for another, this will then have an impact on the overall revenue recovery.**
- **Combining tariffs where one tariff is cheaper than another means increases to the former tariff.**
- **A change to TOU ratios and periods means that, depending on load profile, some will benefit, while others will pay more.**
- **It is not possible to determine the impact of response, as this is not known at the time of doing the design and is also not included in the MYPD values.**

The overall impact per tariff category is shown in the next table. To be noted is that the difference in total revenue for all the changes is minimal and due to the rounding of all tariff charges to two decimal places

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

	CTS allocated allowed costs Rm.	Current revenue Rm.	Current subsidy/difference revenue and cost Rm.	Restuctured revenue Rm	Difference new revenue and cost Rm.	Revised subsidy c/kWh	% change in revenue	Diff. in revenue Rm.	% change in c/kWh subsidy
Total all tariffs	R 200 582	R 200 585	R 3	R 200 580	-R 2	(0.00)	0.00%	-R 5	
Local-authority tariffs	R 82 257	R 86 324	R 4 068	R 85 702	R 3 445	4.01	-0.72%	-R 623	-15.30%
Municflex	R 81 827	R 85 935	R 4 107	R 85 269	R 3 441	4.02	-0.78%	-R 666	-16.22%
Municrate	R 192	R 215	R 22	R 196	R 4	3.78	-8.72%	-R 19	-83.39%
Public Lighting munic	R 237	R 175	-R 62	R 237	R 0	0.00	35.50%	R 62	-100.01%
Urban tariffs non-local-authority	R 77 493	R 81 576	R 4 083	R 82 025	R 4 532	5.73	0.55%	R 449	14.49%
Megaflex	R 65 651	R 68 896	R 3 246	R 69 559	R 3 908	5.62	0.96%	R 663	20.42%
Nightsave Large	R 1 959	R 2 188	R 229	R 2 209	R 251	15.22	0.97%	R 21	9.23%
Nightsave Small	R 797	R 838	R 41	R 904	R 107	17.18	7.89%	R 66	160.85%
Miniflex	R 4 232	R 4 111	-R 122	R 4 275	R 43	1.27	4.00%	R 164	-135.22%
Transflex 1	R 2 831	R 2 996	R 165	R 2 975	R 145	5.88	-0.69%	-R 21	-12.58%
Transflex 2	R 482	R 524	R 42	R 503	R 20	6.34	-4.07%	-R 21	-51.24%
Businessrate	R 1 541	R 2 022	R 482	R 1 599	R 59	5.49	-20.92%	-R 423	-87.84%
Rural tariffs non-local-authority	R 20 806	R 18 931	-R 1 875	R 18 931	-R 1 875	(17.62)	0.00%	R 0	77.86%
Ruraflex	R 7 782	R 6 306	-R 1 477	R 6 574	-R 1 208	(25.14)	4.25%	R 268	-18.17%
Nightsave rural	R 2 550	R 2 628	R 78	R 2 360	-R 190	(12.15)	-10.20%	-R 268	-345.48%
Landrate &Landlight	R 10 474	R 9 997	-R 476	R 9 997	-R 476	(11.16)	0.00%	R 0	0.03%
Residential tariffs non-local-authority	R 19 988	R 13 726	-R 6 262	R 13 699	-R 6 289	(59.98)	-0.20%	-R 27	31.47%
Homepower	R 2 700	R 2 727	R 27	R 2 700	R 0	0.01	-0.99%	-R 27	-99.39%
Homelight 20A	R 10 203	R 6 280	-R 3 923	R 6 280	-R 3 923	(70.49)	0.00%	R 0	0.00%
Homelight 60A	R 7 084	R 4 719	-R 2 366	R 4 719	-R 2 366	(68.17)	0.00%	R 0	0.00%
Public lighting non-local-authority	R 39	R 28	-R 11	R 39	R 0	0.18	39.38%	R 11	-100.46%
Public Lighting All Night	R 38	R 27	-R 11	R 38	R 0	(0.00)	40.94%	R 11	-100.00%
Public Lighting Urban Fixed	R 1.14	R 1.21	R 0.07	R 1.14	R 0.00	(0.01)	-5.69%	R 0	-100.10%
Public Lighting 24 Hours	R 0.16	R 0.06	-R 0.10	R 0.22	R 0.06	107.31	242.04%	R 0	-156.96%
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	0.00%

The start of an evolving journey …

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

- annual updating of different rates due to Eskom unbundled and separate divisional increases – no longer a single average increase applied to all rates;
- further changes to the TOU rates and periods to accommodate managing a changing system profile;
- restructuring the energy charges into fixed and variable components through the introduction of payment for energy capacity;
- further rationalisation of tariffs by removing Miniflex and Nightsave tariff versions as options (that is, only having Megaflex for urban 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.

2. Eskom's 2017 strategic direction and tariff design principles for Eskom's standard tariffs

In 2017, Eskom updated its Strategic Pricing Direction on future tariff design. Pricing strategy is about determining where tariff design and structure should be heading, taking into account the changing business environment. In a deregulated market, pricing strategy will be a lot more flexible and responsive to constraints and surpluses, but as Eskom is regulated, pricing flexibility is limited to what national policy will provide for and NERSA's implementation of the policy through regulation. Refer to www.eskom.co.za/tariffs for the full document on Eskom's 2017 strategic direction and tariff design principles for Eskom's standard tariffs.

The objectives given in the strategic direction document are as follows:

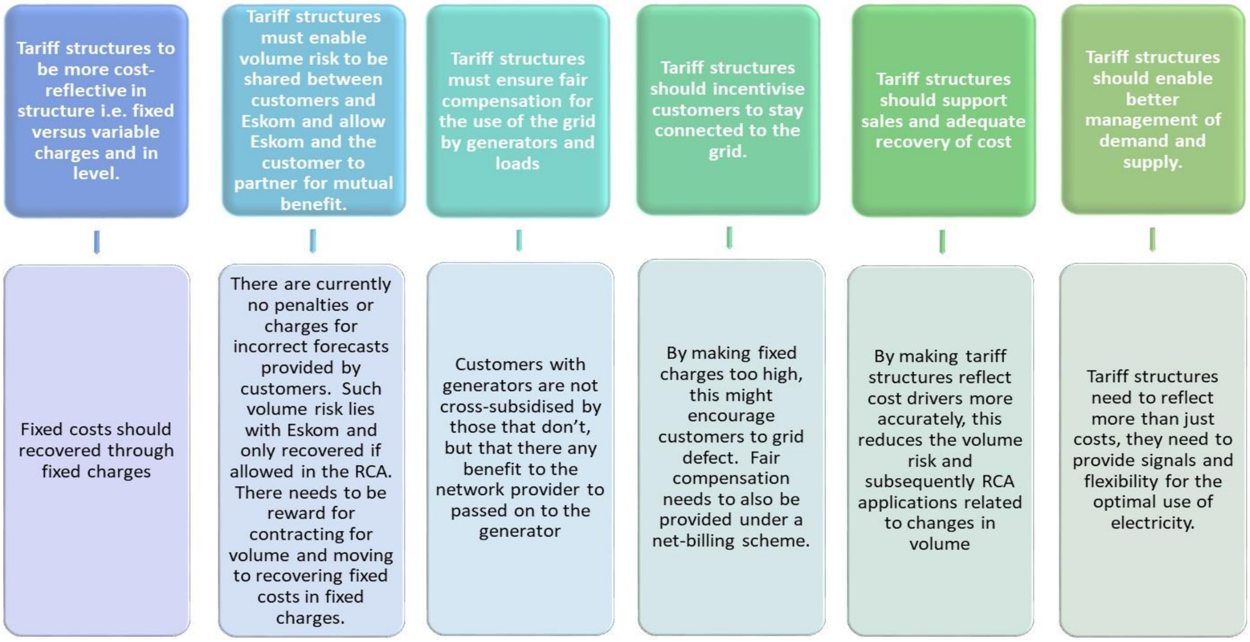


Figure 2: Eskom's tariff objectives

3. Economic drivers for change

Traditionally, tariffs had to achieve two main objectives. First of all, they had to generate the income required to cover all the costs of supplying electricity. Secondly, they had to send the right economic signals to each customer to ensure that the customer used the service in the most efficient way. However, in recent years, there have been developments in tariff design[3] internationally to deal with the changing utility environment, especially due to the impact of embedded generation and storage. The following have been identified as drivers for change in tariff design:

Figure 3: Drivers for tariff changes

1. **Customer needs**
   For example, reducing cross-subsidies, removing inclining block tariffs (IBTs) due to customer unhappiness, accommodating embedded generation, allowing wheeling, and greater flexibility in tariffs.

2. **Competition**
   For example, modernising and updating tariffs to accommodate changes to the way the grid is used due to embedded generation and also providing the correct economic signal (such as removing IBT) in light of small-scale embedded generation (SSEG).

[3] Tariff design is the conversion of costs into tariff structures, taking into account cost drivers, pricing signals, impact on customers, affordability, metering capabilities, customer understanding, and subsidies.

3. **Smart working**
   For example, a TOU tariff for residential customers plus compensating for energy exported onto the grid (net billing).

4. **Technology and the green economy**
   For example, how alternative energy technology will change the way energy is purchased and the grid is used, leading to unbundled tariffs, fairer compensation for network usage, adequate revenue recovery, and optimal system usage.

5. **Efficiency and recovery of costs**
   For example, updating tariffs to reduce volume risk and to reflect cost causation using the latest CTS study (cost allocation and segmentation) to more transparently reflect energy, network, and retail costs separately. The figure below demonstrates the volume risk to which Eskom is exposed by recovering fixed generation, network, and retail costs though variable c/kWh charges (amounting to about R113 billion).

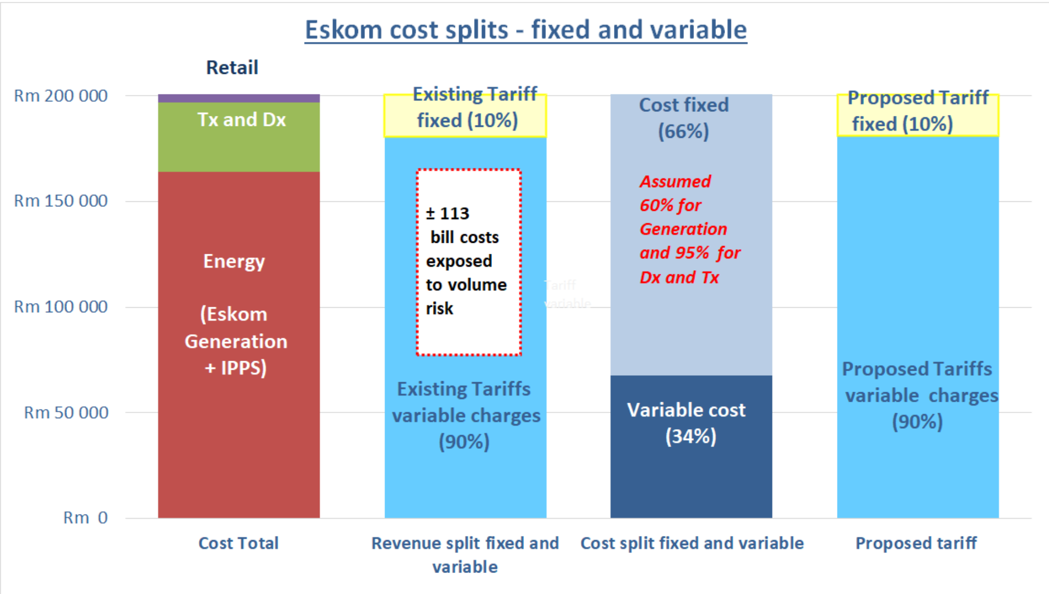
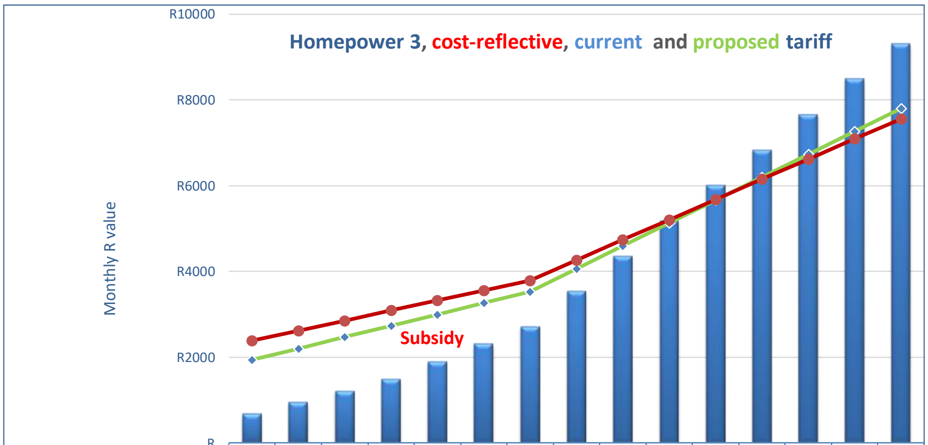


Figure 4: Eskom volume risk exposure

While to above figure indicates no change in the overall fixed versus variable tariff charge recovery, this is mainly due to energy costs increasing at a higher percentage than network and retail costs. If no changes were made structurally, the 10% value would have been less. Refer further to paragraph 4.1 and Figure 9: Percentage impact of updating charges with the CTS, where this is discussed in more detail.

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	R675	R942	R1210	R1478	R1890	R2302	R2714	R3538	R4362	R5186	R6011	R6835	R7659	R8483	R9307
Homepower 3 proposed	R1934	R2200	R2467	R2733	R3000	R3267	R3533	R4066	R4599	R5132	R5666	R6199	R6732	R7265	R7798
Homepower 3 cost-reflective	R2381	R2617	R2852	R3088	R3324	R3559	R3795	R4266	R4738	R5209	R5680	R6152	R6623	R7094	R7565

Figure 5: Example of cost structure versus tariff structure

For customers with decreasing consumption, the current tariff structure (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.

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.

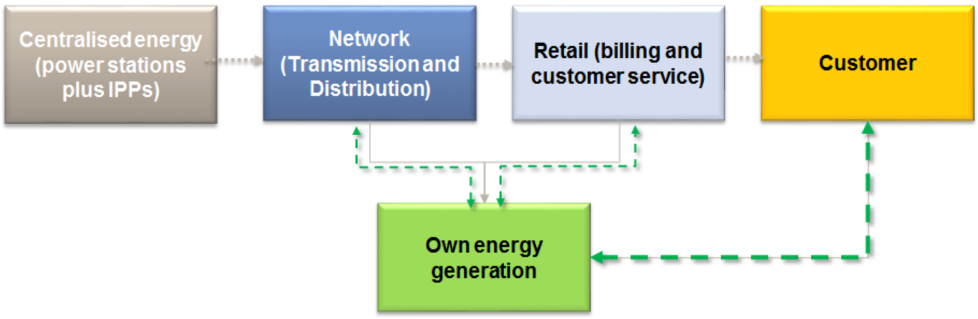


Figure 6: How technology is changing the way the grid is used

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.

The R2/kWh charge should, therefore, 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 energy cost of the utility versus energy cost of the alternative **and** not including network cost in the analysis.

It is also important to realise **the value of being grid-connected** 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 increasing 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 on 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 in a responsible way and to avoid unwarranted and non-economic cross-subsidies.

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

- The grid provides backup, storage, and the ability to get compensation for energy exported for 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 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.

4. Tariff design process

There are three key steps to the tariff design process

1. **Determine the revenue requirement** – the regulated revenue (the costs needed to run the business plus a return); for Eskom, it is determined through the MYPD process.
2. **Allocate the required revenue (costs) among the customer categories** – a cost allocation and segmentation study (a CTS study) is done, where these costs are allocated according to cost drivers and volumes. The third step follows once these costs are understood.

3. **Design tariffs to recover costs** – after the CTS has been performed, tariffs are designed to collect Eskom's allowed revenue.

The revenue requirement MYPD process is the cost justification process, whereas the cost allocation and segmentation study (CTS) is a cost allocation process based on the already NERSA-approved revenue requirement and volumes. Tariff design then follows the CTS exercise.

However, tariff design is not just about reflecting costs; it is also about reflecting price signals that drive forward-looking customer response to increase system operational efficiency and cost-efficiency, which are passed on to customers through tariffs.

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

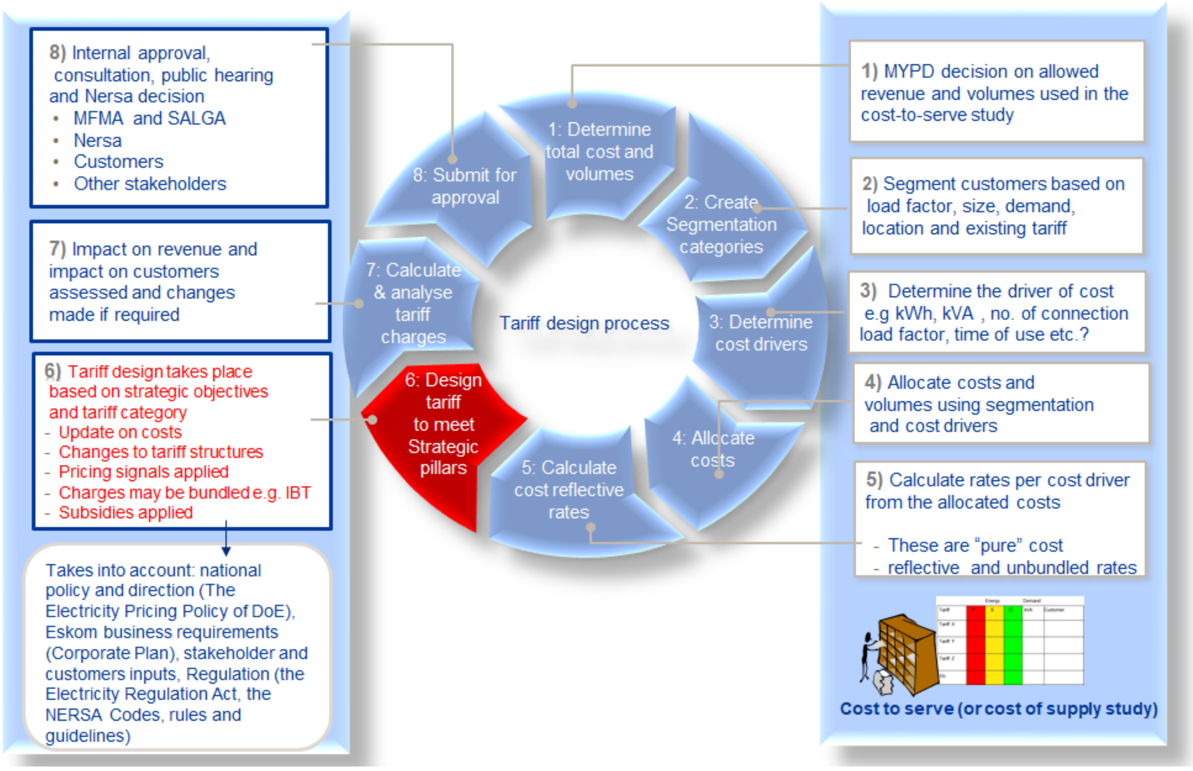


Figure 7: Tariff change process

The tariff design process (point 6 in the figure above) is described further in the next figure.

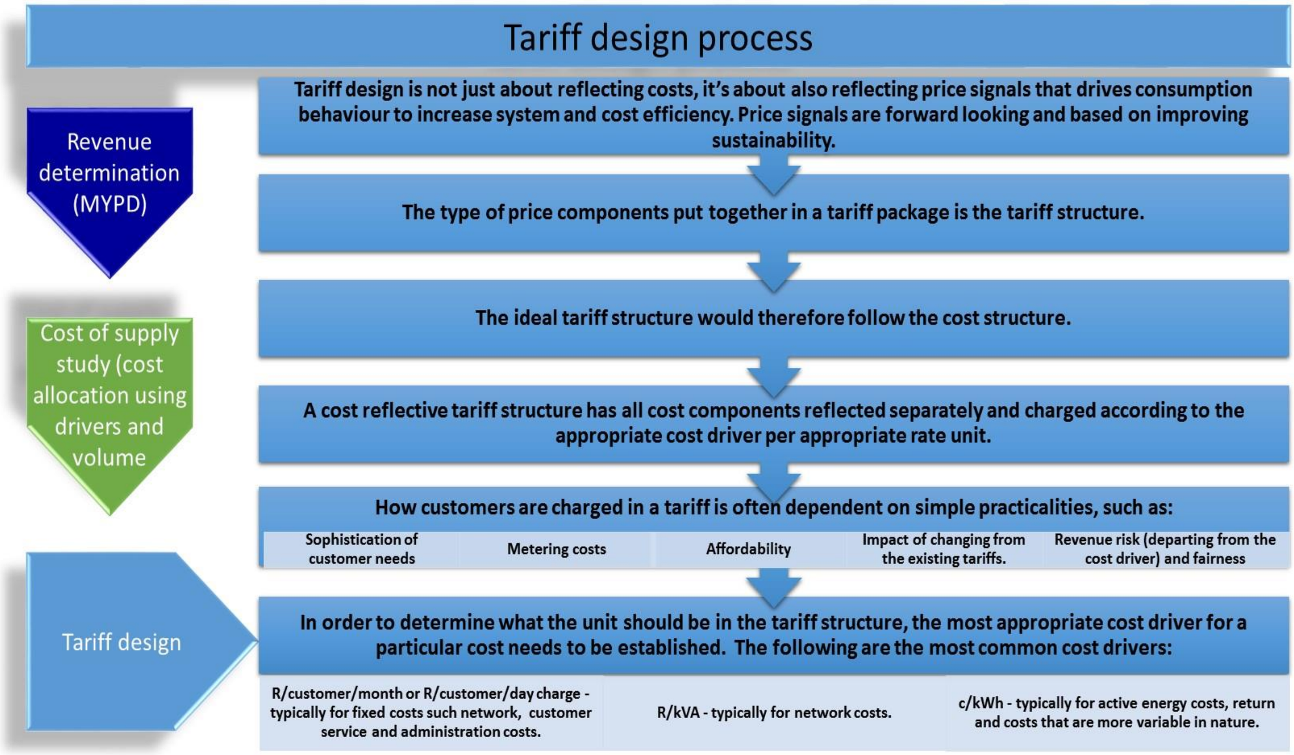


Figure 8: Tariff design process

4.1. Tariffs based on the CTS study

Cost justification is done by Eskom through the NERSA MYPD rules and approval process, where Eskom motivates revenue to cover return, depreciation, and operating cost, and NERSA decides on the amount to be approved through the MYPD process. The approved revenue requirement and (repacked due to TOU changes) volumes are the values used in the CTS exercise.

The CTS is a cost-allocation exercise for tariff design purposes and understanding subsidies and <u>not</u> a cost justification exercise.

The tariff design uses cost units from the CTS study. The CTS study is an embedded[4] 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 supply voltage and location density.

The CTS study cost allocation is guided by a cost causation principle[5]; 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 points of delivery (PODs).

The unit costs from the CTS study used in the tariff design are the standard tariff customers' energy purchases in c/kWh (sales energy, distribution, and transmission network electrical losses), transmission

[4] 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.

[5] 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.

network capacity in R/kVA, ancillary services in c/kWh, distribution network capacity in R/kVA, and retail services unit costs in R/POD/day.

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 figure shows how updating the charges with the CTS has affected each charge type for the large power tariffs and Municflex.

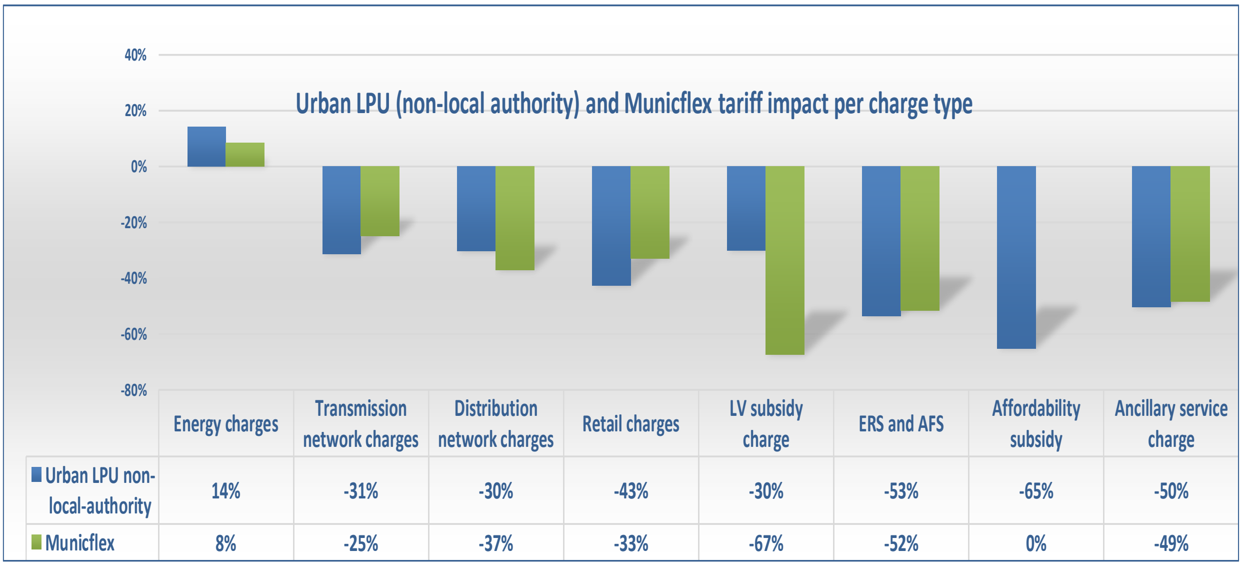


Figure 9: Percentage impact of updating charges with the CTS

- 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 network charges reduced.
- This means the ratio of fixed charge to variable charges have remained almost the same even though the fixed charge component weighting has increased.
- If the existing tariff rates were adjusted only to reflect divisional costs, the percentage of fixed charges would be less than 10%.

The approach used in the CTS study complies with the applicable government policies, guidelines and rules as contained in the Electricity Pricing Policy (EPP), the Codes (Distribution and SA Grid code) and the MYPD methodology (October 2016).

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

In addition to basing the tariff rates and structures on the CTS and cost causation, included in the tariff design are specific objectives and pricing signals, such as changes to the TOU tariffs that incentivise a more optimal use of the system.

A summary of the changes per tariff are 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	• No structural change • Energy charges – 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 – Motivation for the changes to the TOU Wholesale Energy Purchase Structure and Annexure D – Proposed changes to rate components
Transflex	• No structural change • Energy charges – updated with new TOU ratios and periods • Service charge converted from R/account to R/POD	• Refer to Annexure C – Motivation for the changes to the TOU Wholesale Energy Purchase Structure and Annexure D – Proposed changes to rate components
Nightsave Urban Large and Small	• No structural change • Energy charges – 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 – Motivation for the changes to the TOU Wholesale Energy Purchase Structure and Annexure D – Proposed changes to rate components
Ruraflex and Nightsave Rural	• No structural change, but increases applied to Ruraflex and reduction of Nightsave Rural • Energy charges – 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 – Motivation for the changes to the TOU Wholesale Energy Purchase Structure and Annexure D – Proposed changes to rate components
Businessrate	• Structural change by introducing the electrification and rural subsidy (ERS) charge • Network charges – increasing NCC and commensurate reduction of NDC	• Refer to Annexure D – Proposed changes to rate components

Tariff	Change	Comments
Landrate	• No structural change • 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 – increased the NCC	• Refer to Annexure D – Proposed changes to rate components
Homelight 20 and 60A	• Structural changes proposed by removing IBT • Introducing single energy charge (c/kWh)	• Refer to Annexure D – Proposed changes to rate components • Refer to paragraph 4.7 concerning IBT
Public Lighting	• No structural changes	
Non- municipal		
Municflex	• Structural change • 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 – updated with new TOU ratios and periods • Network – increasing NCC and commensurate reduction of NDC • Service charge converted from R/account to R/POD	• Refer to paragraph 4.5 concerning munic tariff rationalisation and Annexure D – Proposed changes to rate components
Municrate	• Structural change • Local-authority SPU tariffs are combined into a single tariff called Municrate (based on the existing Businessrate structure) • Introduction of the ERS charge to this tariff category	• Refer to paragraph 4.5 concerning munic tariff rationalisation and Annexure D – Proposed changes to rate components

	Generator-related tariffs	
Gen-wheeling	• No structural change • Updated with new TOU ratios and periods	• Refer to Annexure D – Proposed changes to rate components
Gen-offset	• No change	• 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 (not part of this submission)	• Not applicable

4.3. 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 4.4.
    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, or 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.3.
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 2019/20 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	Transmission network charges	Ancillary service charges	Distribution network charges	Retail charges	Subsidies
Megaflex, Miniflex	TOU c/kWh cost	Cost R/kVA	Cost c/kWh	Designed based on cost, but with inter- and intra-tariff subsidies	Cost R/POD	Pays subsidies
Nightsave Urban	Designed based on cost, split into R/kVA and c/kWh	Cost R/kVA	Cost c/kWh	Designed based on cost, but with inter- and intra-tariff subsidies	Cost R/POD	Pays subsidies
Ruraflex	TOU c/kWh cost	Cost R/kVA	Cost c/kWh	Designed based on cost, but with inter- and intra-tariff subsidies	Cost R/POD	Receives subsidies
Nightsave Rural	Designed based on cost split into R/kVA and c/kWh	Cost R/kVA	Cost c/kWh	Designed based on cost, but with inter- and intra-tariff subsidies	Cost	Receives subsidies
Businessrate	Designed based on average profile cost	Cost R/POD	Cost c/kWh	Designed based on cost	Cost R/POD	Pays subsidies
Landrate	Designed based on average profile cost	Cost R/POD	Cost c/kWh	Designed based on cost, but with inter- and intra-tariff subsidies, and aligned to current inter-tariff subsidies level	Cost R/POD	Receives subsidies
Homepower	Designed based on average profile cost	Cost R/POD	Cost c/kWh	Designed based on cost and with intra-tariff subsidies	Cost R/POD	No subsidies
Homelight	Designed based on current tariff revenue					Receives subsidies
Public Lighting	Designed based on average profile cost	Designed based on cost	Designed based on cost	Designed based on cost	Designed based on cost	No subsidies

4.4. 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. 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 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, resulting in the energy rates increasing due to higher increases over time to Eskom Generation costs (and reducing Distribution and Transmission cost);
- increasing the evening peak to three hours (from two hours) and reducing morning peak to two hours (from three hours); see Figure 10: Proposed changes to the peak, standard and off-peak periods;
- introducing a two hour standard period on a Sunday evening; see Figure 10: 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.

The proposed changes are not based on actual costs in each TOU period, but rather on analysis of the current and future system profile and price signals to optimise the profile. Additionally, actual costs vary greatly depending on constraints and surplus and also over time; for example, it is possible that, in certain hours, the summer peak costs might be more expensive than the winter peak costs. These changes will continue to evolve over time as the industry and market evolve.

4.4.1. 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 10: Proposed changes to the peak, standard and off-peak periods of the TOU tariffs

4.4.2. 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 10 considered the effect and impact of changing the rates.

Too much of a reduction of the winter (high-demand season) rates would increase the summer rates (low-demand season) drastically as well as reducing 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 on only cost, but rather on price signals to ensure that demand would be managed in times of constraints and times of 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

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 WEPS existing TOU ratios c/kWh	296.43	89.79	48.77	96.73	66.55	42.23
Updated CTS WEPS existing TOU ratios c/kWh	349.70	100.97	51.58	109.28	73.00	43.71
4) New ratios	6.00	1.50	1.00	2.49	1.40	1.00
5) Existing WEPS new TOU ratios c/kWh	253.40c	63.35c	42.23c	105.16c	59.13c	42.23c
6) Updated CTS WEPS new TOU ratios c/kWh	304.82c	76.20c	50.80c	126.50c	71.13c	50.80c
ference between current and new ratios c/kWh	8.39c	-13.59c	2.03c	29.77c	4.58c	8.57c
ference existing WEPS vs New CTS TOU c/kWh	53.27c	11.18c	2.81c	12.55c	6.45c	1.48c

When comparing the proposed WEPS rates to the existing WEPS rates, the following can be noted:

- 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 before updating the energy costs with the CTS reduced the winter prices and increased the summer prices (see points 2 and 5 above).
- All energy rates updated with the CTS energy cost, before the ratio change (see points 2 and 3 above) and after the ratio changes (see points 2 and 6 above), have been increased. This is due to the

application, over the years, of the average price increase to the WEPS rates, resulting in the current energy rates being lower than the actual average energy costs.

4.5. 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, no change was proposed for 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 using new tariff rates based on the CTS, as follows:

- A new LPU tariff 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 and with the introduction of the ERS charge
- 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 4.10)
- 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 of April to March) and in nine-month values (based on three-month April to June current tariffs, nine months at the revised CTS-based tariffs.) Refer to Annexure F – Proposed retail rates in 2019/20 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.

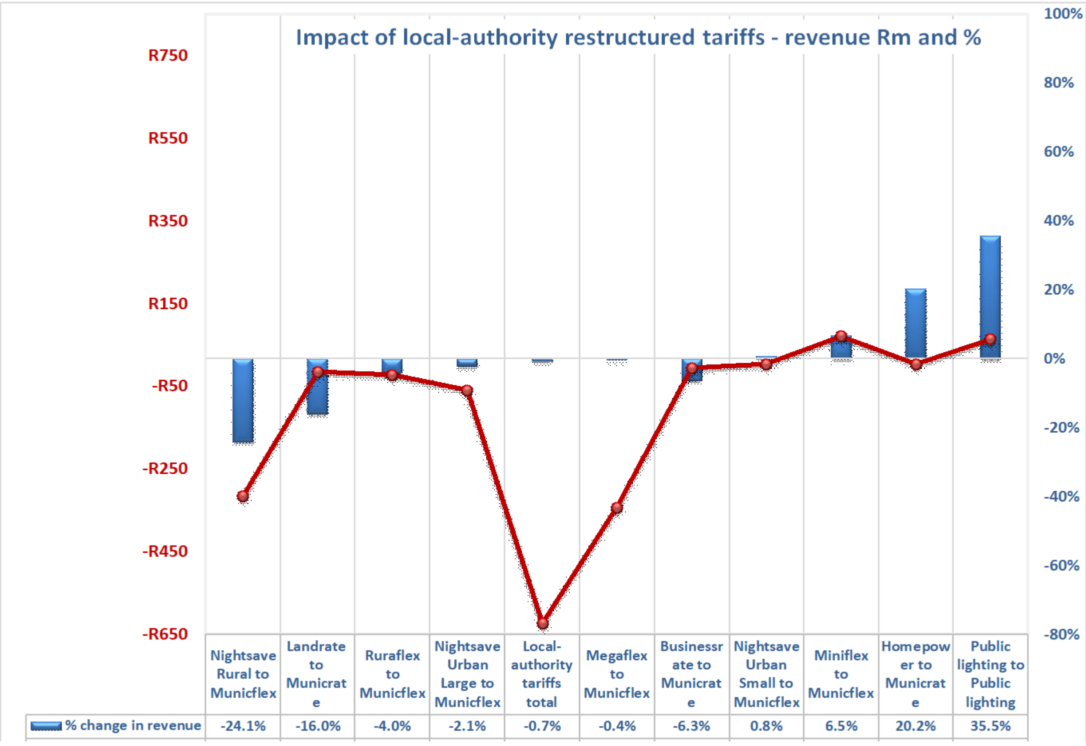


Figure 11: Impact of the municipal tariff rationalisation per local-authority tariff

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

4.6. Network-related charges

4.6.1. 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 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 not a 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, but also reduces 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.

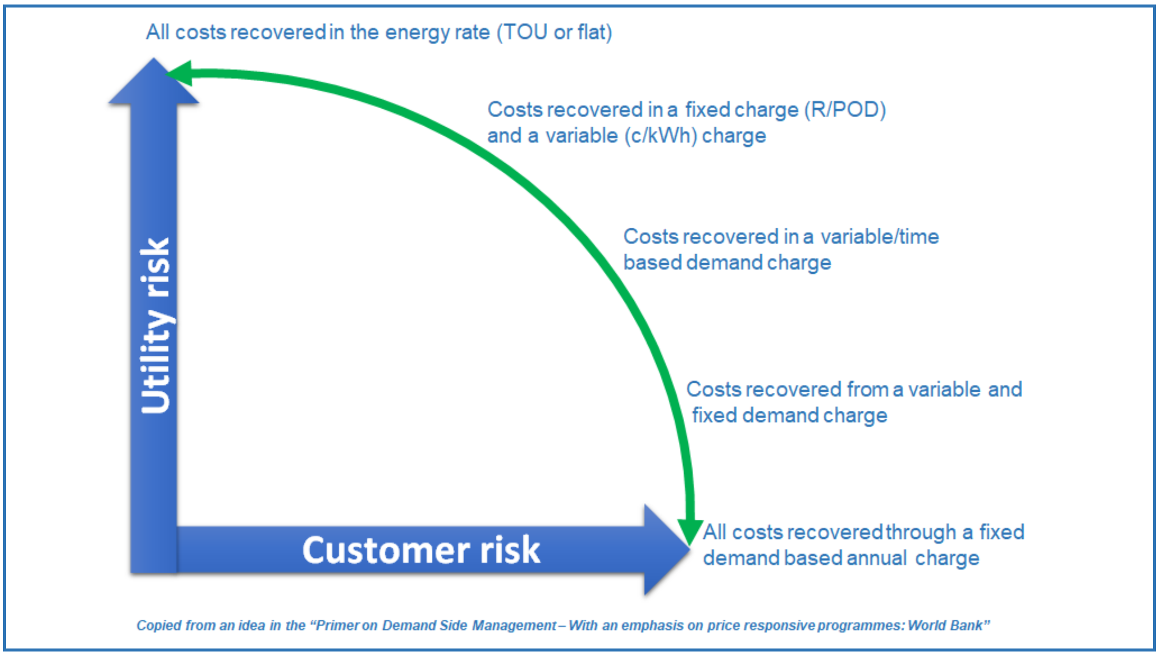


Figure 12: Network charge design and associated risks

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 who do have 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 due to 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 5, which shows the total impact per tariff charge type and Annexure D – Proposed changes to rate components, paragraph D.3.

4.6.2. Distribution use-of-system losses charges

For Distribution-connected loads, the loss factors were updated based on the CTS. 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	1.1483	1.1656
≥ 500V & < 66kV	1.1298	1.1495
≥ 66kV & ≤ 132kV	1.0580	0.0000
> 132kV/Transmission connecte	1.0000	0.0000

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

Eskom sets the Transmission use-of-system (TUoS) tariffs as specified in the Transmission Tariff Code. TUoS tariffs comprise network, losses, and ancillary services charges. These tariffs are intended to provide locational signals to customers on the transmission cost of connecting to the Transmission system in the different areas of the country and to recover the NERSA-approved revenue requirement. The TUoS charges reflect the extent to which the customers make use of the Transmission network and the impact they have on the network.

Eskom Transmission recovers 50% of its revenue from generators and 50% from demand (load) customers. Transmission-connected generators and loads pay a charge based on the geographical pricing zone in which they are located.

- 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.

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. For simplicity, the cost of losses is added to the energy rates. However, for transparency, Eskom publishes an energy rate that excludes losses (the WEPS rate, excluding losses, which is equal to the Megaflex rate, excluding losses). 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.

4.6.3.1. Transmission network charges for loads

The TUoS tariffs for loads are based on a concentric-pricing approach, based on a 300 km cumulative radius from Johannesburg. 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 from the calculated base charge.

- 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 in the Distribution network than the direct TUoS network charge, as the cost is divided by a greater volume.

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

Table 6: Updated Transmission network charges for loads

Transmission connected loads	NCC R/kVA	Ancillary service charge c/kWh
≤ 300km	R 8.61	0.2214
> 300km & ≤ 600km	R 8.70	0.2134
> 600km & ≤ 900km	R 8.79	0.1896
> 900km	R 8.88	0.1850

4.6.3.2. Transmission network charge for generators.

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 is based on a DC load-flow model. The model calculates the network charges on a nodal basis. Nodes are subsequently allocated into their respective generation zones, and the charges are aggregated per zone.
- The majority of generation is located in the north of the country, and power predominantly flows from north to south. It follows that the transmission pricing regime imposes relatively high charges on generation in the north in line with the extent to which these generators utilise the transmission assets.
- The generators that are located in the south of the country predominantly relieve the network congestion and are, therefore, not liable for network charges; that is, their rate is set at zero.

4.6.3.3. 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 7: Updated ancillary service charges

Voltage	Ancillary service charge
< 500V	0.2186c
≥ 500V & < 66kV	0.2151c
≥ 66kV & ≤ 132kV	0.2014c
> 132kV*	0.1904c

4.6.3.4. 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 losses costs.

- For loads connected directly to the transmission system, the loss factors are determined by geographical location based on the concentric zones. The further away the customer is from Johannesburg, the greater the technical losses charge.
- For distribution-embedded customers, loss factors are determined by voltage and the geographic location (transmission pricing zone). The lower the nominal voltage is to which the customer connects, the higher the losses are, as electricity has to travel greater distances and through multiple transformations. In addition, 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 the amount 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: Updated Transmission loss factors

Transmission connected loads	Loss factor
≤ 300km	1.0021
> 300km & ≤ 600km	1.0122
> 600km & ≤ 900km	1.0222
> 900km	1.0322

4.6.3.5. Transmission losses payable by Transmission-connected generators

The loss factors at each point of connection reflect the relative impact of the generator on the transmission network losses. 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 South African Grid Code prescribes that the approach for calculating the transmission loss factors has to be based on load-flow studies and a marginal loss factor methodology. Eskom is proposing a change to the loss factors for generators (to be done in a separate submission).

4.7. Residential tariffs

Residential tariffs need an overhaul. IBT as a tariff structure is no longer appropriate due to customer perceptions and provides uneconomic incentives for customers that install embedded generation.

Eskom proposes the removal of the IBT structure, the reintroduction of a fixed, more cost-reflective network and retail charges for Homepower, and the introduction of a TOU residential tariff with an offset rate for net billing.

4.7.1. Homepower

Eskom proposes the amendment of the Homepower structure so that it is aligned 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 due to 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 33 and Figure 34, 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 cost-reflective network, ancillary service, and service/administration costs. The changes proposed will result in increased fixed charges, but the revenue from Homepower will, on average, decrease slightly in order 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. The aim of this change is not 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 the Homepower tariff sub-category revenues are higher than cost based on current tariffs and, for others, are lower than cost. In addition, when converting from a non-cost-reflective IBT structure to a more cost-reflective structure, this will mean a correction of the subsidies that low-consumption Homepower customers currently receive. For low-consumption Homepower 4 customers, they 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 9: Homepower impact (R million)

Homepower summary	Current revenue Rm.	Revised revenue Rm.	% impact	Cost Rm.
Homepower 1	R 1 208	R 1 133	-6%	R 1 093
Homepower 2	R 240	R 243	1%	R 244
Homepower 3	R 107	R 103	-4%	R 101
Homepower 4	R 1 170	R 1 220	4%	R 1 261
Homepower Bulk	R 1	R 1	-9%	R 2
Total	R 2 727	R 2 701	-1%	R 2 700

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

Table 10: Homepower current average month bill versus revised monthly bill

	Current monthly bill versus proposed monthly bill				
Homepower	Current average monthly bill	Proposed average monthly bill	Difference R	Difference %	Average monthly consumption
Homepower 1	R 2 418	R 2 268	-R 150	-6%	1 279
Homepower 2	R 2 436	R 2 469	R 33	1%	1 200
Homepower 3	R 6 750	R 6 471	-R 279	-4%	3 404
Homepower 4	R 1 089	R 1 135	R 46	4%	594

4.7.2. Residential TOU – Homeflex

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 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 plus cost-reflective network, ancillary service, and service/administration charges for the residential customer category. It has the same network, retail, and ancillary service charges as Homepower, but the energy charges are TOU rates. Also refer to

Time-of-use for residential is in compliance with the Department of Mineral Resources and Energy's Electricity Pricing Policy (EPP) Policy Position 12, Policy Position 13, Policy Position 31, Policy Position 32, Policy Position 36, and Policy Position 58. (Note, however, that these policy positions do not accommodate inclining block tariffs.) Refer to Annexure G – Department of Mineral Resources and Energy Electricity Pricing Policy positions.

This tariff will be mandatory for customers with SSEG, with the approved post-paid smart metering device and, voluntary for all other residential customers.

4.7.3.Homelight

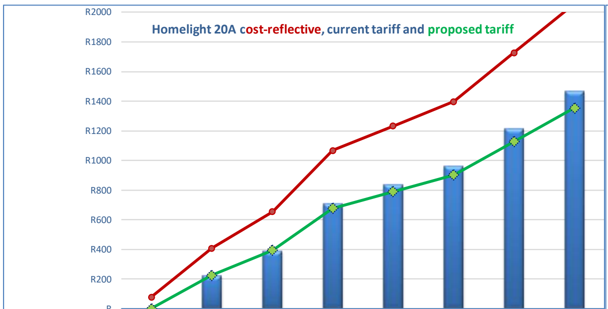
For the Homelight tariff, the aim is to move away from the IBT structure into a single energy rate structure based on the average Homelight current revenue/total sales. IBT is an unpopular structure, is difficult for customers to understand, and causes perverse behaviour when purchasing at the high block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

Perceptions of IBT are that:

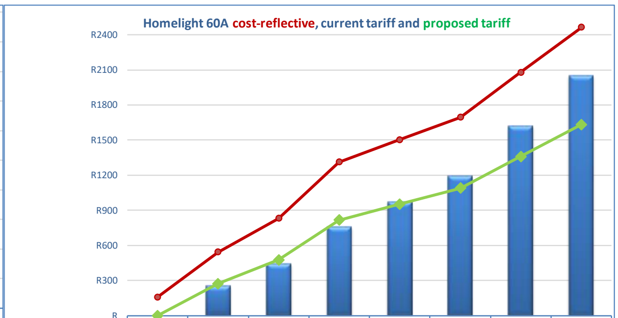
- it is difficult to budget with this tariff (the more I buy, the less I get – or the more I use, the more I pay);
- it does not allow customers to pre-buy for months ahead when money is available (such as a December bonus);
- it is very confusing and difficult to understand; and
- it is very unpopular in community discussions.

For large low-income/multiple-family dwellings, it cannot be assumed that low consumption equals poor. In many areas, multiple dwellings may be supplied from a single electricity supply point. An IBT structure has a significant impact on these customers.

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	R224	R392	R708	R835	R962	R1215	R1469
Cost reflective	R78	R408	R655	R1067	R1232	R1397	R1727	R2056
Proposed tariff	R	R226	R395	R677	R790	R903	R1128	R1354



	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	R253	R443	R760	R975	R1190	R1621	R2051
Cost reflective	R158	R543	R831	R1311	R1503	R1695	R2080	R2464
Proposed tariff	R	R272	R476	R816	R952	R1088	R1360	R1632

Figure 13: 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 even recover energy costs fully and does not recover network, retail, or ancillary service costs.

Table 11: Homelight current tariffs

	Current Tariff book rates and revenues (2019/20)						
	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	111.87c	126.76c	0.00c	0.00c	R 0.00	R 0.00	R 6 279 874 638
Homelight 60A	126.61c	215.21c	0.00c	0.00c	R 0.00	R 0.00	R 4 718 714 781
							R 10 998 589 419

Table 12: Homelight cost-reflective rates

	Cost reflective						Current revenue versus cost			
	Cost reflective energy charge c/kWh	Cost reflective ancillary costs c/kWh	Cost reflective network demand charge	Cost reflective network capacity charges R/POD	Cost reflective service & admin charge R/POD	Service and admin charge c/kWh	Cost reflective R/y	Difference between cost and current revenue	% subsidy received	Total costs c/kWh
Homelight 20A	112.98c	0.22c	51.65c	R 1.89	R 0.68	*18.49c*	R 9 211 405 490	R 2 931 530 852	47%	183.34c
Homelight 60A	111.34c	0.22c	80.56c	R 4.53	R 0.68	*12.03c*	R 6 690 349 489	R 1 971 634 708	42%	204.15c
	112.35c	0.22c	62.75c	R 2.65	R 0.68	*16.01c*	R 15 901 414 287	R 4 903 165 560	45%	191.34c

Table 13: Homelight revised tariffs

	Proposed tariff rates			
	Block 1 energy charge	Block 2 energy charge	Single energy charge	New revenue
Homelight 20A	NA	NA	112.85c	R 6 279 874 638
Homelight 60A	NA	NA	135.98c	R 4 718 714 781
	Total			R 10 998 589 419

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 contained in this document, as it is not based on cost.

4.8. 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 who has 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.

4.9. 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 again combine these tariffs into one category, based on the total cost for the Nightsave Urban tariff as a whole.

This decision was made as a step in the direction of 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.

4.10. 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).
- Subsidies may, furthermore, 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 be 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 due to 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.

4.10.1. Inter-tariff subsidies

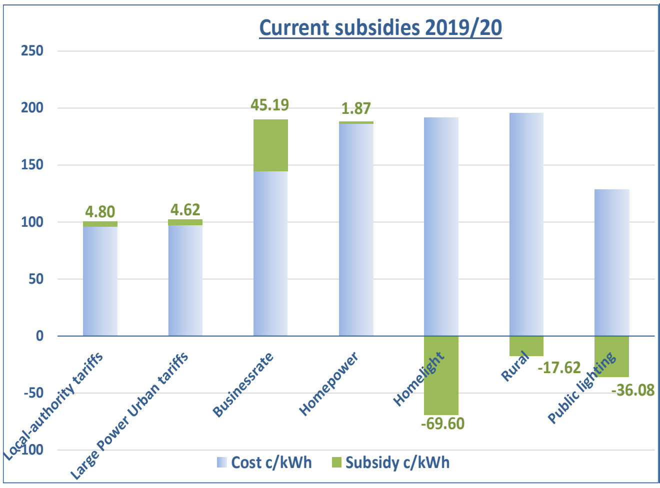
The inter-tariff subsidies are those paid by other tariffs to the Homelight 20A, Homelight 60A, Landrate, Ruraflex, and Nightsave Rural tariffs. The inter-tariff subsidies are currently recovered through the ERS charge from all the urban LPU tariffs and through the affordability subsidy from only the 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 in order to better align these tariffs

Table 14: Inter-tariff subsidies

Subsidies received 2019/20	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 10 474	R 9 997	-R 476	(11.16)	R 9 997	-R 476	(11.16)
Ruraflex	R 7 782	R 6 306	-R 1 477	(30.72)	R 6 574	-R 1 208	(25.14)
Nightsave Rural	R 2 550	R 2 628	R 78	4.95	R 2 360	-R 190	(12.15)
Homelight 20A	R 10 203	R 6 280	-R 3 923.0	(70.49)	R 6 280	-R 3 923.0	(70.49)
Homelight 60A	R 7 084	R 4 719	-R 2 365.7	(68.17)	R 4 719	-R 2 365.7	(68.17)
Total	R 38 093	R 29 929	-R 8 164	(38.64)	R 29 929	-R 8 164	(38.64)

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



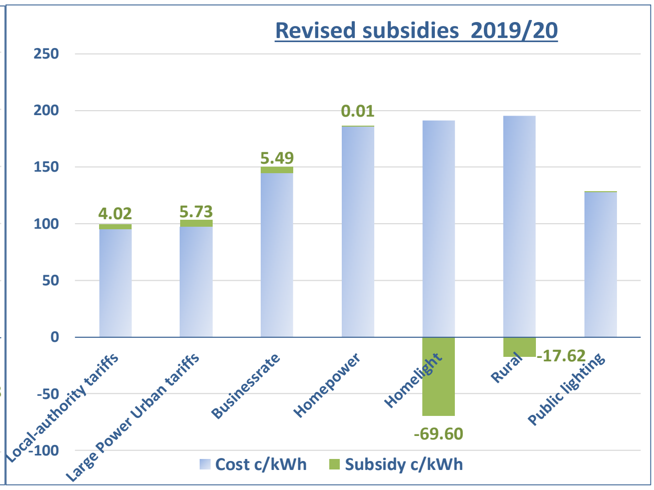


Figure 14: Current and revised inter-tariff subsidies

4.10.1.1. 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 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 government, the ongoing costs are, therefore, not fully recovered by the tariff. Current subsidies are R6,2 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.

4.10.1.2. 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 for “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. The excess of this line allowance where applicable, 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 R2 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 argument put forward that customers have already paid for their network costs through connection charges and, therefore, should not be paying network charges is unfortunately 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 do have higher costs than the costs for those in urban areas due to 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.

4.10.2. 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.

4.10.3. 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:

$$\sum \text{Total cost}^1 - \sum \text{Total revised revenue}^1 = \text{Total subsidy}$$

$$\text{The greater of Total subsidy or } \sum \text{Total network cost}^1 = \text{ERS allocation}$$

$$\text{ERS allocation} / \sum \text{Total GWh}^2 \times 100 = \text{ERS c/kWh}$$

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, Municflex and Municrate

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

$$\sum \text{Total subsidy}^3 - \sum \text{Total network cost}^3 = \text{Affordability subsidy allocation}$$

$$\text{Affordability subsidy allocation} / \sum \text{Total GWh}^4 \times 100 = \text{ERS c/kWh}$$

[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 charges and affordably charge applied to the tariff. As the proposed Businessrate is significantly reduced due to the tariff being updated with the CTS values, this change does not result in an increase in the current tariff. The same application of the ERS charge also applies to Municrate.

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 downwards.

Table 15: ERS charge and affordability charge calculation

Tariff	Costs Rm.	New tariff Rm.	Subsidy Rm.	ERS (network cost) Rm.	allocation Rm.	charge c/kWh	ERS charge scaled c/kWh	AFS charge c/kWh	
Landrate	Rm 10 474	Rm 9 997	-Rm 476	-Rm 476	Rm 0	0.29	0.26		
Ruraflex	Rm 7 782	Rm 6 574	-Rm 1 208	-Rm 1 208	Rm 0	0.73	0.67		
Nightsave Rural	Rm 2 550	Rm 2 360	-Rm 190	-Rm 190	Rm 0	0.12	0.11		
Homelight 20A	Rm 10 203	Rm 6 280	-Rm 3 923	-Rm 2 874	-Rm 1 049	1.75	1.60	1.33	
Homelight 60A	Rm 7 084	Rm 4 719	-Rm 2 366	-Rm 2 366	Rm 0	1.44	1.31		
									% adjusted to be revenue neutral
Total	Rm 38 093	Rm 29 929	-Rm 8 164	-Rm 7 115	-Rm 1 049	**4.32**	**3.95**	**1.33**	-8.52%

5. 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 energy costs by 14% 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 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. 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; this is mainly due to 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 due to updating with the CTS, with Nightsave Small having a larger negative impact.
- Businessrate sees a big reduction due to 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, based on applying subsidies. Landrate 2 and 3 see a negative impact based on design to reduce the significant subsidies in these categories, and 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 R/day charge result in lower-consumption customers paying more (and vice versa).

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

Table 16: Revenue and cost summary per tariff

REVENUE SUMMARY

	GWh	CTS allocated allowed costs Rm.	Current revenue Rm.	Cost reflective c/kWh	Current revenue average c/kWh	Diff current revenue and cost	Current subsidy c/kWh paid (+) received (-)	% required to be cost reflective	Restuctured revenue Rm	Restructured revenue c/kWh	Difference new revenue and cost Rm.	Revised subsidy c/kWh	% change in revenue due to restructuring	Difference in revenue Rm. due to restructuring
Total all tariffs	186 064	R 200 582	R 200 585	107.80c	107.80c	R 3	0.00c		R 200 580	107.80c	-R 2	0.00c	0.00%	-R 5
Local-authority tariffs	85 815	R 82 257	R 86 324	95.85c	100.59c	R 4 068	4.74	-4.9%	R 85 702	99.87c	R 3 445	4.01	-0.7%	-R 623
Municflex	85 529	R 81 827	R 85 935	95.67	100.47	R 4 107	4.80	-5.0%	R 85 269	99.70	R 3 441	4.02	-0.8%	-R 666
Municrate	99	R 192	R 215	195.11	217.88	R 22	22.77	-11.7%	R 196	198.89	R 4	3.78	-8.7%	-R 19
Public Lighting munic	188	R 237	R 175	126.58	93.42	-R 62	(33.16)	26.2%	R 237	126.59	R 0.01	0.00	35.5%	R 62
Urban tariffs non-local-authority	79 090	R 77 493	R 81 576	97.98c	103.14c	R 4 083	5.01	-5.1%	R 82 025	103.71c	R 4 532	5.73	0.6%	R 449
Megaflex	69 602	R 65 651	R 68 896	94.32	98.99	R 3 246	4.66	-4.9%	R 69 559	99.94	R 3 908	5.62	1.0%	R 663
Nightsave Large	1 646	R 1 959	R 2 188	118.99	132.92	R 229	13.93	-11.7%	R 2 209	134.21	R 251	15.22	1.0%	R 21
Nightsave Small	624	R 797	R 838	127.67	134.26	R 41	6.59	-5.2%	R 904	144.85	R 107	17.18	7.9%	R 66
Miniflex	3 372	R 4 232	R 4 111	125.52	121.92	-R 122	(3.61)	2.9%	R 4 275	126.79	R 43	1.27	4.0%	R 164
Transflex 1	2 460	R 2 831	R 2 996	115.08	121.81	R 165	6.73	-5.8%	R 2 975	120.96	R 145	5.88	-0.7%	-R 21
Transflex 2	321	R 482	R 524	150.47	163.47	R 42	13.00	-8.6%	R 503	156.81	R 20	6.34	-4.1%	-R 21
Businessrate	1 066	R 1 541	R 2 022	144.57	189.76	R 482	45.19	-31.3%	R 1 599	150.06	R 59	5.49	-20.9%	-R 423
Rural tariffs non-local-authority	10 643	R 20 806	R 18 931	195.49c	177.87c	-R 1 875	(9.91)	5.1%	R 18 931	177.87c	-R 1 875	(17.62)	0.0%	R 0
Ruraflex	4 807	R 7 782	R 6 306	161.90	131.18	-R 1 477	(30.72)	19.0%	R 6 574	136.76	-R 1 208	(25.14)	4.3%	R 268
Nightsave rural	1 568	R 2 550	R 2 628	162.68	167.63	R 78	4.95	-3.0%	R 2 360	150.53	-R 190	(12.15)	-10.2%	-R 268
Landrate &Landlight	4 269	R 10 474	R 9 997	245.37	234.21	-R 476	(11.16)	4.5%	R 9 997	234.21	-R 476	(11.16)	0.0%	R 0
Residential tariffs non-local-authority	10 485	R 19 988	R 13 726	190.62c	130.91c	-R 6 262	(45.62)	23.9%	R 13 699	130.65c	-R 6 289	(59.98)	-0.2%	-R 27
Homepower	1 450	R 2 700	R 2 727	186.20	188.07	R 27	1.87	-1.0%	R 2 700	186.21	R 0	0.01	-1.0%	-R 27
Homelight 20A	5 565	R 10 203	R 6 280	183.34	112.85	-R 3 923	(70.49)	38.4%	R 6 280	112.85	-R 3 923	(70.49)	0.0%	R 0
Homelight 60A	3 470	R 7 084	R 4 719	204.15	135.98	-R 2 366	(68.17)	33.4%	R 4 719	135.98	-R 2 366	(68.17)	0.0%	R 0
Public lighting non-local-authority	30	R 39	R 28	128.17c	92.09c	-R 11	(39.18)	30.6%	R 39	128.35c	R 0	0.18	39.4%	R 11
Public Lighting All Night	29	R 38	R 27	128.07	90.87	-R 11	(37.20)	29.0%	R 38	128.07	R 0	(0.00)	40.9%	R 10.92
Public Lighting Urban Fixed	1	R 1	R 1	121.10	128.39	R 0	7.30	-6.0%	R 1	121.09	R 0	(0.01)	-5.7%	-R 0.07
Public Lighting 24 Hours	0.1	R 0.16	R 0.06	310.55	122.17	-R 0.10	(188.38)	60.7%	R 0.22	417.86	R 0.06	107.31	242.0%	R 0.15
Generator TUoS and DUoS revenue									R 184					R 184

Municipal tariffs	GWh	CTS allocated allowed costs Rm.	Current revenue Rm.	Cost reflective c/kWh	Current average c/kWh	Current subsidy/difference revenue and cost Rm.	Current subsidy c/kWh paid (+) received (-)	% required to be cost reflective	Restuctured revenue Rm	Restructured revenue c/kWh	Revised subsidy/difference 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	85 815	R 82 257	R 86 324.44	95.85c	100.59c	R 4 068	4.74c	-0.05c	R 85 702	99.87c	R 3 445	4.01c	-0.7%	-R 623
Megaflex to Municflex	80 264	R 75 723	R 79 668	94.34	99.26	R 3 945	4.91	-5.2%	R 79 324	98.83	R 3 601	4.49	-0.4%	-R 344
Miniflex to Municflex	1 017	R 1 146	R 1 097	112.69	107.86	-R 49	(4.83)	4.3%	R 1 168	114.87	R 22	2.18	6.5%	R 71
Nightsave Urban Large to Municflex	2 502	R 2 709	R 2 813	108.27	112.44	R 104	4.16	-3.8%	R 2 753	110.04	R 44	1.77	-2.1%	-R 60
Nightsave Urban Small to Municflex	425	R 471	R 492	110.85	115.85	R 21	5.00	-4.5%	R 496	116.80	R 25	5.95	0.8%	R 4
Ruraflex to Municflex	445	R 622	R 555	139.84	124.84	-R 67	(15.00)	10.7%	R 533	119.81	-R 89	-20.03	-4.0%	-R 22
Nightsave Rural to Municflex	876	R 1 156	R 1 309	131.97	149.41	R 153	17.44	-13.2%	R 994	113.44	-R 162	-18.53	-24.1%	-R 315
Businessrate to Municrate	46	R 76	R 100	163.68	214.79	R 24	51.11	-31.2%	R 93	201.27	R 17	37.59	-6.3%	-R 6
Landrate to Municrate	42	R 101	R 99	237.21	232.14	-R 2	(5.08)	2.1%	R 83	194.99	-R 18	-42.22	-16.0%	-R 16
Homepower to Municrate	10	R 15.6	R 16.5	160.88	170.23	R 0.9	9.35	-5.8%	R 19.9	204.64	R 4	43.76	20.2%	R 3
Public lighting to Public lighting	188	R 237.4	R 175.2	126.58	93.42	-R 62.2	(33.16)	26.2%	R 237.5	126.59	R 0	0.00	35.5%	R 62

The following figure shows the impact per tariff charge type, per tariff category, in rand value.

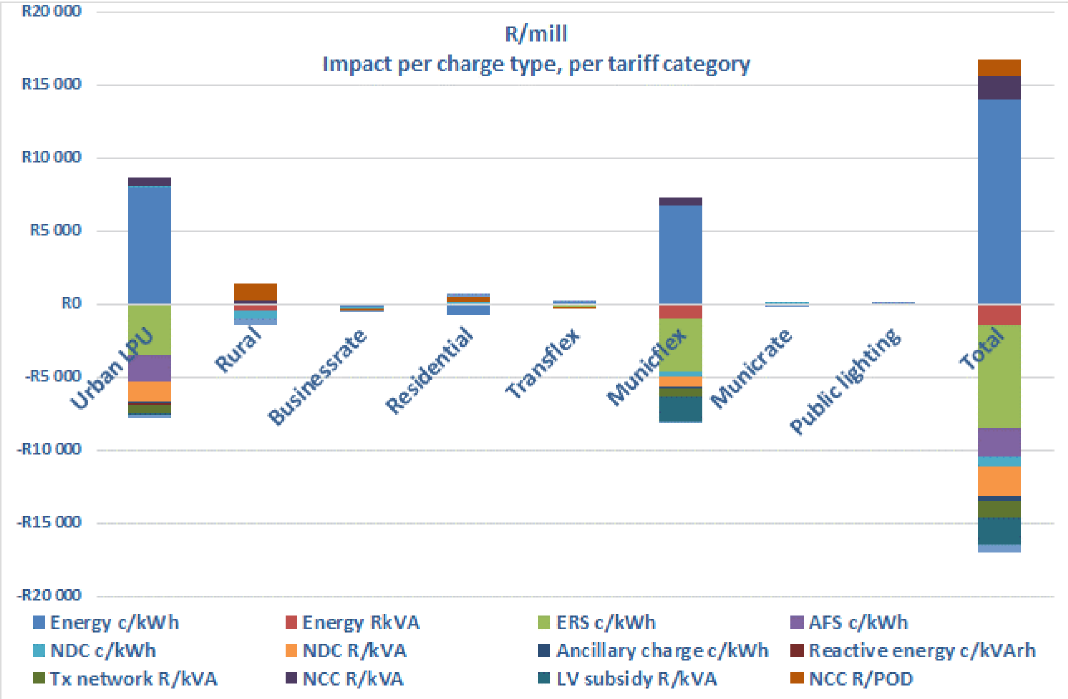


Figure 15: Rand impact per tariff charge type

To be noted in the figure above is that current energy charge revenue, when aligned with the 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 17: Summary of impact, per tariff category for energy, network

Rm. impact of changes to rates	Urban LPU non-local-authority	Rural LPU non-local-authority	Urban SPU non-local-authority	Rural SPU non-local-authority	Public lighting non-local authority	Homelight	Local-authority LPU	Local-authority SPU	Local-authority Public lighting	Total
Network charge current	R 10 564	R 2 608	R 779	R 3 668	R 0	R 0	R 7 458	R 65	R 0	**R 25 142**
Network charges proposed	R 9 068	R 2 594	R 1 091	R 4 554	R 0	R 0	R 6 340	R 67	R 0	**R 23 713**
% difference	-14%	-1%	40%	24%	0%	0%	-15%	3%	0%	**-6%**
Energy charges current	R 58 214	R 5 888	R 3 760	R 4 990	R 28	R 10 999	R 68 860	R 123	R 175	**R 153 036**
Energy charges proposed	R 66 390	R 5 995	R 2 810	R 4 477	R 39	R 10 999	R 74 613	R 109	R 237	**R 165 669**
% difference	14%	2%	-25%	-10%	39%	0%	8%	-11%	35%	**8%**
Retail charges current	R 540	R 438	R 210	R 1 339	R 0.06	R 0.00	R 215	R 27	R 0.258	**R 2 770**
Retail charges proposed	R 400	R 345	R 342	R 966	R 0.22	R 0.00	R 144	R 16	R 0.290	**R 2 215**
% difference	-26%	-21%	63%	-28%	242%	0%	-33%	-39%	12%	**-20%**
ERS and AS charges current	R 9 597	R 0	R 0	R 0	R 0	R 0	R 6 977	R 0	R 0	**R 16 574**
ERS and AF charges proposed	R 4 120	R 0	R 56	R 0	R 0	R 0	R 3 378	R 4	R 0	**R 7 558**
% difference	-57%	0%	0%	0%	0%	0%	-52%	0%	0%	**-54%**
LV subsidy current	R 639	R 0	R 0	R 0	R 0	R 0	R 2 424	R 0	R 0	**R 3 063**
LV subsidy proposed	R 448	R 0	R 0	R 0	R 0	R 0	R 793	R 0	R 0	**R 1 240**
% difference	-30%	0%	0%	0%	0%	0%	-67%	0%	0%	**-60%**
IPP revenue										**R 184**
Total current	R 79 554	R 8 933	R 4 750	R 9 997	R 28	R 10 999	R 85 935	R 215	R 175	**R 200 585**
Total proposed	R 80 426	R 8 934	R 4 300	R 9 997	R 39	R 10 999	R 85 269	R 196	R 238	**R 200 580**
R Difference	R 872	R 0	-R 450	R 0	R 11	R 0	-R 666	-R 19	R 62	**-R 5**
% difference	1%	0%	-9%	0%	40%	0%	-1%	-9%	35%	**0%**

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

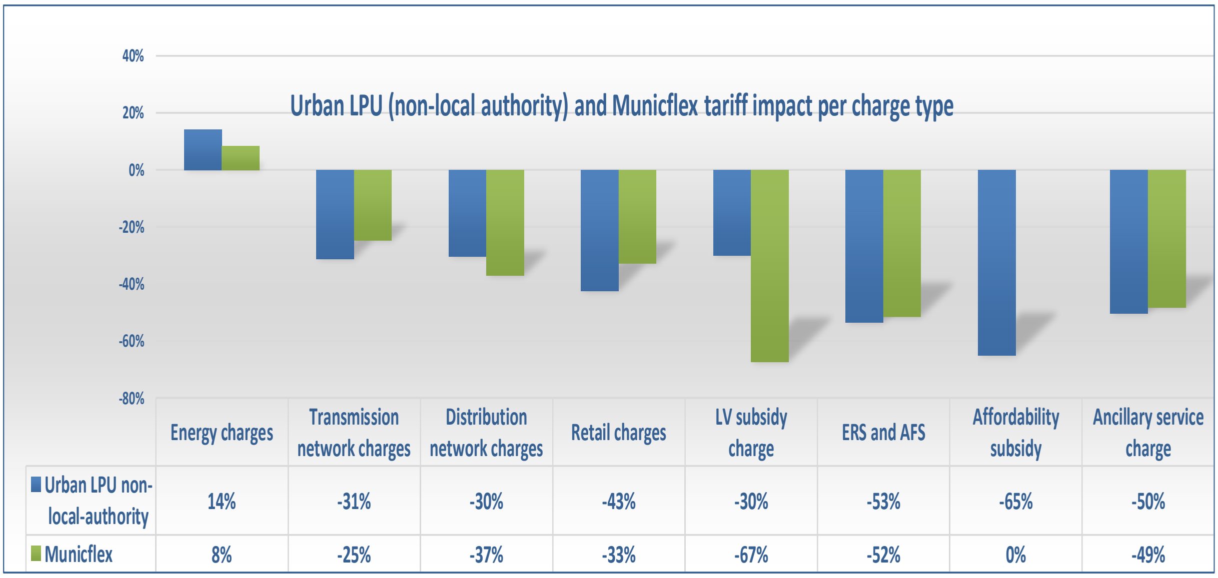


Figure 16: Percentage impact per tariff charge type for urban LPU and Municflex

The following table shows the impact in more detail, per charge, and for all tariffs.

Table 18: Summary of rand impact, per charge, per tariff category

Rm. difference/charge	Urban LPU non-local-authority	Rural non-local-authority	Businessrate non-local-authority	non-local-authority	Homelight non-local-authority	Transflex 1	Transflex 2	Municflex	Municrate	Public lighting	Total
Energy c/kWh	R8 018	R1	-R172	-R777	R0	R187	R12	R6 715	-R14	R73	R14 042
Energy RkVA	-R41	-R407	R0	R0	R0	R0	R0	-R961	R0	R0	-R1 409
ERS c/kWh	-R3 409	R0	R56	R0	R0	-R111	-R15	-R3 599	R4	R0	-R7 073
AFS c/kWh	-R1 874	R0	R0	R0	R0	-R61	-R8	R0	R0	R0	-R1 943
NDC c/kWh	R99	-R525	-R103	R224	R0	R0	R0	-R377	R8	R0	-R674
NDC R/kVA	-R1 331	R0	R0	R0	R0	R0	R0	-R677	R0	R0	-R2 008
Ancillary charge c/kWh	-R160	-R23	-R2	R3	R0	-R5	-R1	-R163	R0	R0	-R352
Reactive energy c/kVArh	-R48	R0	R0	R0	R0	R0	R0	R3	R0	R0	-R45
Tx network R/kVA	-R549	R0	R0	R0	R0	R0	R0	-R545	R0	R0	-R1 094
NCC R/kVA	R606	R322	R0	R0	R0	R0	R0	R641	R0	R0	R1 569
LV subsidy R/kVA	-R191	R0	R0	R0	R0	R0	R0	-R1 632	R0	R0	-R1 823
NCC R/POD	R0	R1 099	-R89	R278	R0	-R92	-R15	R0	-R6	R0	R1 175
Retail R/POD	-R206	-R466	-R113	R245	R0	R62	R5	-R71	-R10	R0	-R555
Generator Uos											R184
Total	R914	R0	-R423	-R27	R0	-R21	-R21	-R666	-R19	R73	-R5.4

6. 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.

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 difficult decisions in this regard need to be made to protect the electricity industry.

For municipal customers, 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 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 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 accurately reflect current divisional cost 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 are 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:

- annual updating of different rates due to Eskom unbundled and separate divisional increases – no longer a single average increase applied to all rates;
- further changes to the TOU rates and periods to accommodate managing a changing system profile;
- restructuring the energy charges into fixed and variable components through the introduction of payment for energy capacity;
- further rationalisation of tariffs by removing Miniflex and Nightsave tariff versions as options (that is, only having Megaflex for urban 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
- introducing 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 supplies and with the introduction of the ERS charge.
- 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 2019/20 rand values (excluding VAT), Table 35, Table 36, Table 37, and Table 38.
- 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 19: Rand impact per local-authority tariff

Municipal tariffs	CTS allocated allowed costs Rm.	Current revenue Rm.	Current subsidy/difference revenue and cost Rm.	Restuctured revenue Rm	Revised subsidy/difference revenue and cost Rm.	Revised subsidy c/kWh	% change in revenue	Diff. in revenue Rm.	% change in subsidy c/kWh
Local-authority tariffs total	R 82 257	R 86 324	R 4 068	R 85 702	R 3 445	5.95	-1%	-R 623	(0.15)
Megaflex to Municflex	R 75 723	R 79 668	R 3 945	R 79 324	R 3 601	4.49	-0.43%	-R 344	-8.72%
Miniflex to Municflex	R 1 146	R 1 097	-R 49	R 1 168	R 22	2.18	6.50%	R 71	-145.05%
Nightsave Urban Large to Municflex	R 2 709	R 2 813	R 104	R 2 753	R 44	1.77	-2.13%	-R 60	-57.49%
Nightsave Urban Small to Municflex	R 471	R 492	R 21	R 496	R 25	5.95	0.82%	R 4	19.02%
Ruraflex to Municflex	R 622	R 555	-R 67	R 533	-R 89	(20.03)	-4.03%	-R 22	33.53%
Nightsave Rural to Municflex	R 1 156	R 1 309	R 153	R 994	-R 162	(18.53)	-24.07%	-R 315	-206.28%
Businessrate to Municrate	R 76	R 100	R 24	R 93	R 17	37.59	-6.30%	-R 6	-26.46%
Landrate to Municrate	R 101	R 99	-R 2	R 83	-R 18	(42.22)	-16.00%	-R 16	731.95%
Homepower to Municrate	R 16	R 17	R 1	R 20	R 4	43.76	20.21%	R 3	367.90%
Public lighting to Public lighting	R 237	R 175	-R 62	R 237	R 0.01	0.00	35.50%	R 62	-100.01%

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, 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 R71 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 R3 million, and this is mainly due to removal of the non-cost-reflective IBT structure.

- Nightsave Urban Small is increased by R4 million, and this can mainly be attributed to the updating of 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 20: Rand and percentage impact per tariff category

Rm. impact of changes to rates	Municflex	Municrate	Local-authority Public lighting	Total local authority tariffs
Network charge current	R 7 458	R 65	R 0	R 7 523.4
Network charges proposed	R 6 340	R 67	R 0	R 6 406.7
% difference	-15%	3%	0%	-15%
Energy charges current	R 68 860	R 123	R 175	R 69 157.7
Energy charges proposed	R 74 613	R 109	R 237	R 74 959.4
% difference	8%	-11%	35%	8%
Retail charges current	R 215	R 27	R 0.2578	R 242.3
Retail charges proposed	R 144	R 16	R 0.2899	R 161.2
% difference	-33%	-39%	12%	-33%
ERS and AS charges current	R 6 977	R 0	R 0	R 6 977.0
ERS and AF charges proposed	R 3 378	R 4	R 0	R 3 382.3
% difference	-52%	0%	0%	-52%
LV subsidy current	R 2 424	R 0	R 0	R 2 424.3
LV subsidy proposed	R 793	R 0	R 0	R 792.5
% difference	-67%	0%	0%	-67%
Total current	R 85 935	R 215	R 175	R 86 324.7
Total proposed	R 85 269	R 196	R 238	R 85 702.1
R Difference	-R 666	-R 19	R 62	-R 622.5
% Difference	-1%	-9%	35%	-1%

It can be noted in the above table, that in most cases the energy charges have increased and all other charges reduced.

The following figures provide the potential impacts per tariff category at different consumption levels.

A.1 Businessrate compared to Municrate

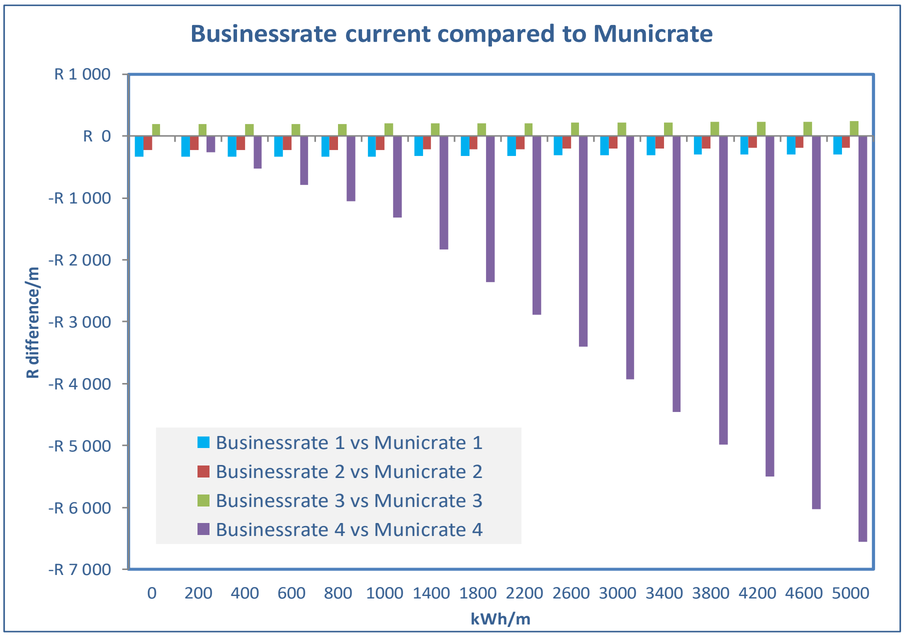


Figure 17: Businessrate compared to Municrate at different consumption levels

A.2 Landrate compared to Municrate

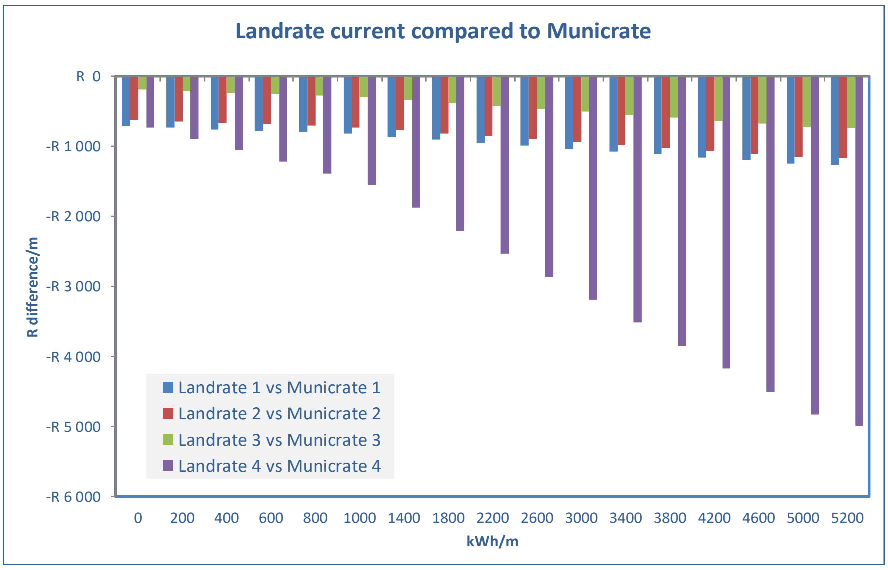


Figure 18: Landrate compared to Municrate at different consumption levels

A.3 Homepower compared to Municrate

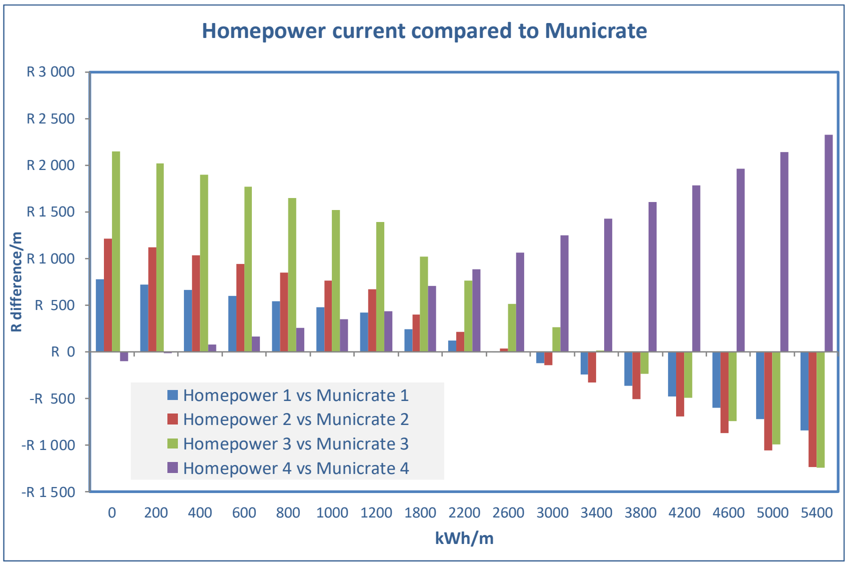


Figure 19: Homepower compared to Municrate at different consumption levels

The following figure provide a comparison between current local-authority LPU tariffs and Municflex, based showing the number of PODs per tariff paying less and more, based on 2018/19 actuals Actual values were used in order to include the SPU accounts and non-individually forecast customers.

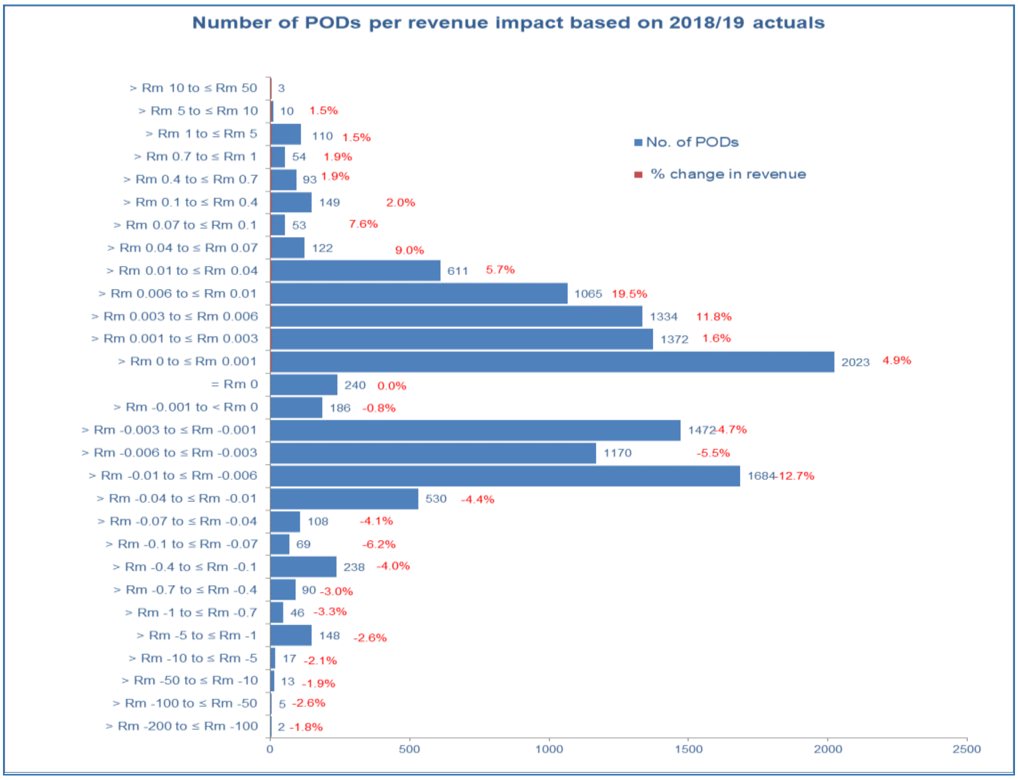


Figure 20: Histogram of the total number of PODs negatively or positively affected

The following set of 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

A.4 Megaflex local-authority compared to Municflex

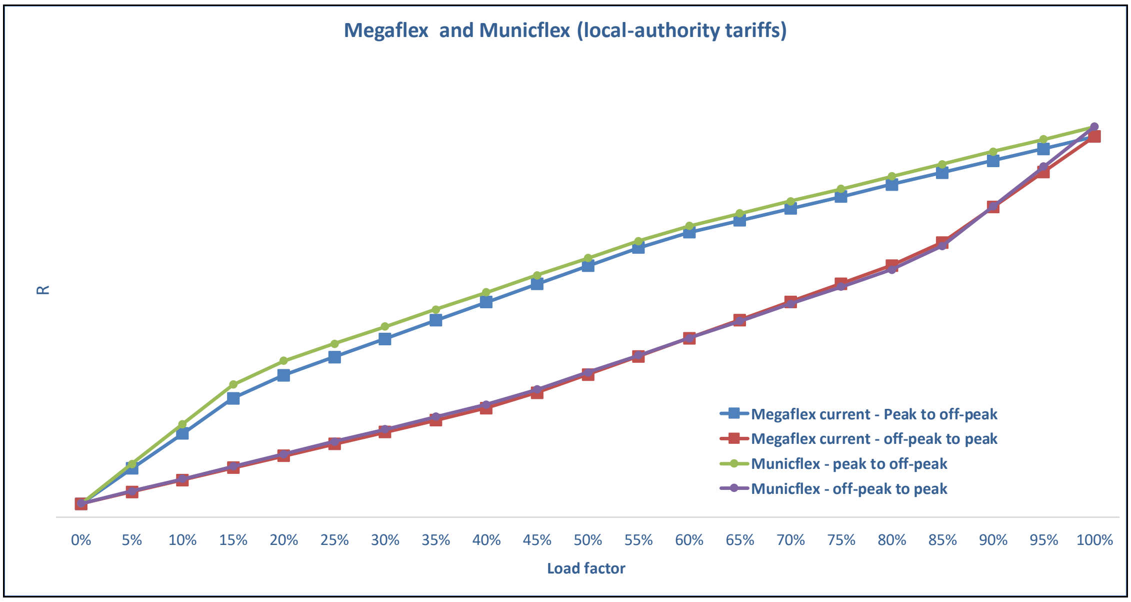


Figure 21: Current Megaflex local-authority tariff and proposed Municflex comparison

A.5 Miniflex local-authority compared to Municflex

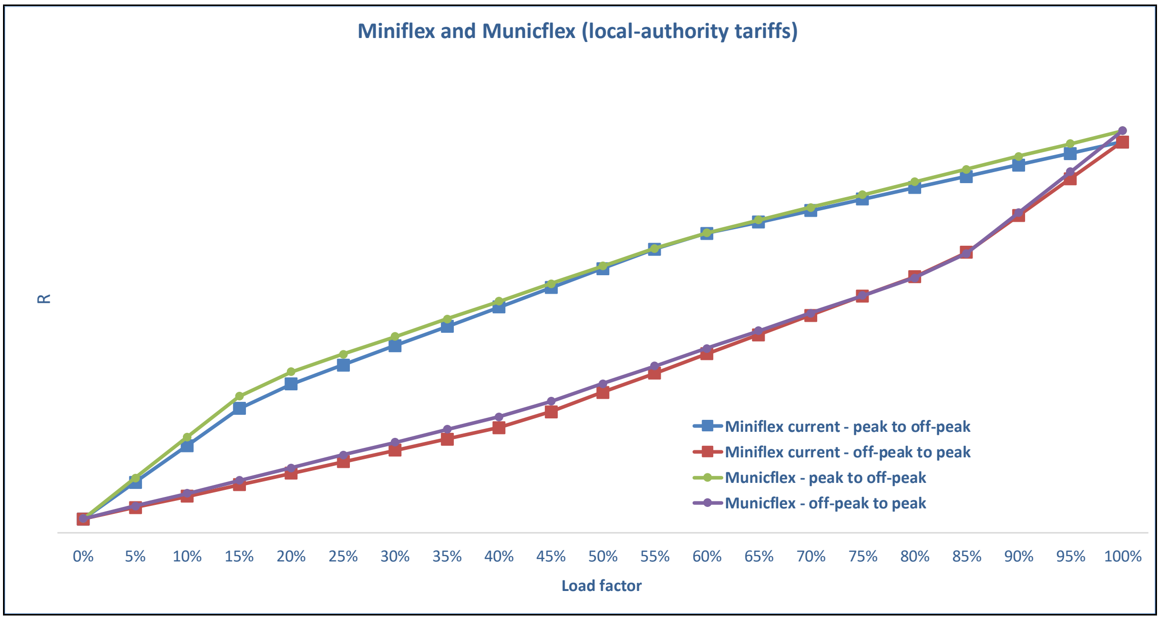


Figure 22: Current Miniflex local-authority tariff and proposed Municflex comparison

A.6 Nightsave local-authority compared to Municflex

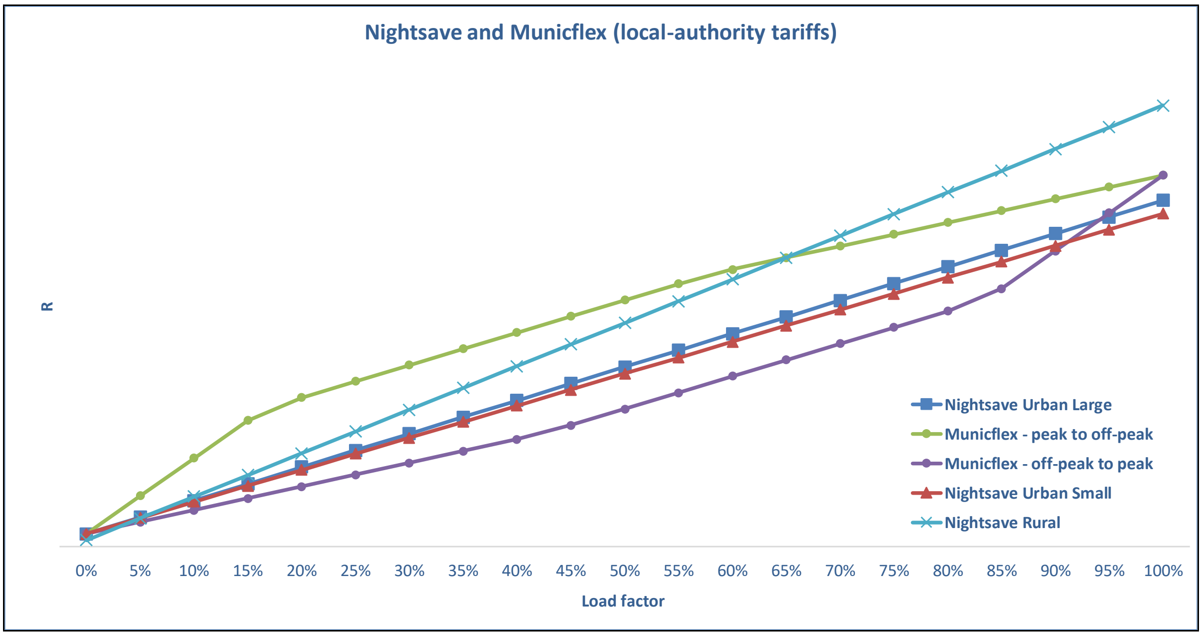


Figure 23: Current Nightsave local-authority tariff and proposed Municflex comparison

A.7 Ruraflex local-authority compared to Municflex

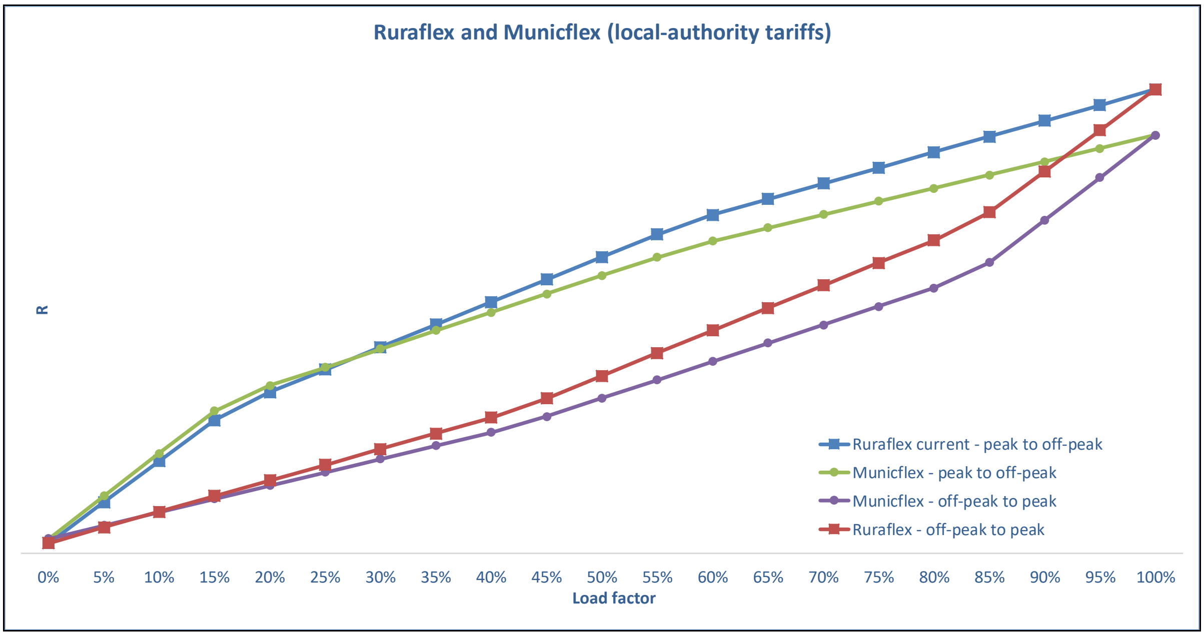


Figure 24: Current Ruraflex local-authority tariff and proposed Municflex comparison

The next two tables provide the impact per municipality based on 2018/19 actual volumes. The actual volumes were used, in order to be able to include smaller PODs that are not individually forecast.

Table 21: Rand impact per local-authority tariff in alphabetical order

Municipal name (alphabetical)	Change in revenue	Current revenue	Proposed revenue	No of Pods	% Revenue change from current bill
!Kheis Local Municipality	-Rm 0.10	Rm 0.62	Rm 1	1	-17%
AbaQulusi Local Municipality	-Rm 7.25	Rm 176.01	Rm 169	6	-4%
Alfred Duma Local Municipality	-Rm 5.38	Rm 259.50	Rm 254	2	-2%
Alfred Nzo District Municipality	-Rm 0.11	Rm 5.06	Rm 5	9	-2%
Amahlathi Local Municipality	-Rm 1.05	Rm 34.11	Rm 33	4	-3%
Amajuba District Municipality	-Rm 0.08	Rm 0.63	Rm 1	1	-13%
Amathole District Municipality	Rm 0.07	Rm 11.48	Rm 12	21	1%
Ba-Phalaborwa Local Municipality	Rm 1.38	Rm 89.63	Rm 91	7	2%
Beaufort West Local Municipality	-Rm 1.72	Rm 62.16	Rm 60	7	-3%
Bela-Bela Local Municipality	Rm 1.50	Rm 94.27	Rm 96	2	2%
Bergrivier Local Municipality	Rm 1.14	Rm 91.10	Rm 92	8	1%
Bitou Local Municipality	-Rm 1.79	Rm 127.39	Rm 126	9	-1%
Blouberg Local Municipality	-Rm 5.28	Rm 35.71	Rm 30	22	-15%
Blue Crane Route Local Municipality	-Rm 2.58	Rm 91.20	Rm 89	1	-3%
Breede Valley Local Municipality	Rm 2.70	Rm 636.54	Rm 639	12	0%
Buffalo City Metropolitan	Rm 17.25	Rm 977.45	Rm 995	16	2%
Bushbuckridge Local Municipality	-Rm 0.04	Rm 2.29	Rm 2	14	-2%
Cape Agulhas Local Municipality	-Rm 3.87	Rm 92.65	Rm 89	8	-4%
Capricorn District Municipality	-Rm 0.17	Rm 0.83	Rm 1	2	-20%
Cederberg Local Municipality	-Rm 1.66	Rm 69.96	Rm 68	10	-2%
Chief Albert Luthuli Local Municipality	-Rm 2.42	Rm 48.93	Rm 47	16	-5%

Municipal name (alphabetical)	Change in revenue	Current revenue	Proposed revenue	No of Pods	% Revenue change from current bill
Chris Hani District Municipality	-Rm 0.25	Rm 5.03	Rm 5	12	-5%
City of Cape Town Metropolitan	-Rm 265.84	Rm 9 604.48	Rm 9 339	107	-3%
City of Ekurhuleni Metropolitan	Rm 58.77	Rm 11 132.03	Rm 11 191	111	1%
City of Johannesburg Metropolitan	-Rm 208.80	Rm 10 664.38	Rm 10 456	105	-2%
City of Matlosana Local Municipality	Rm 9.03	Rm 640.39	Rm 649	10	1%
City of Mbombela Local Municipality	-Rm 12.24	Rm 839.81	Rm 828	32	-1%
City of Tshwane Metropolitan	-Rm 117.90	Rm 9 023.02	Rm 8 905	40	-1%
City of uMhlathuze Local Municipality	-Rm 8.44	Rm 941.48	Rm 933	13	-1%
Collins Chabane Local Municipality	-Rm 0.11	Rm 264.12	Rm 264	9	0%
Dawid Kruiper Local Municipality	Rm 0.19	Rm 207.62	Rm 208	2	0%
Dihlabeng Local Municipality	Rm 1.59	Rm 152.63	Rm 154	16	1%
Dikgatlong Local Municipality	-Rm 4.71	Rm 28.19	Rm 23	5	-17%
Dipaleseng Local Municipality	Rm 1.36	Rm 64.81	Rm 66	7	2%
Ditsobotla Local Municipality	Rm 1.21	Rm 129.66	Rm 131	4	1%
Dr Beyers Naudé Local Municipality	-Rm 6.34	Rm 95.04	Rm 89	10	-7%
Dr JS Moroka Local Municipality	-Rm 4.31	Rm 25.35	Rm 21	10	-17%
Dr Nkosazana Dlamini Zuma Local Municipality	-Rm 0.02	Rm 0.48	Rm 0	2	-4%
Drakenstein Local Municipality	-Rm 3.23	Rm 751.43	Rm 748	7	0%
eDumbe Local Municipality	-Rm 0.64	Rm 25.79	Rm 25	1	-2%
Elias Motsoaledi Local Municipality	Rm 0.80	Rm 82.03	Rm 83	4	1%
Elundini Local Municipality	Rm 0.64	Rm 5.99	Rm 7	3	11%
eMadlangeni Local Municipality	Rm 0.54	Rm 13.92	Rm 14	2	4%
Emakhazeni Local Municipality	Rm 1.42	Rm 55.48	Rm 57	8	3%
Emalahleni Local Municipality	-Rm 6.61	Rm 1 078.52	Rm 1 072	13	-1%
Emfuleni Local Municipality	-Rm 27.59	Rm 1 876.60	Rm 1 849	20	-1%
Emthanjeni Local Municipality	-Rm 3.19	Rm 71.87	Rm 69	14	-4%
Endumeni Local Municipality	Rm 0.89	Rm 72.79	Rm 74	2	1%
Engcobo Local Municipality	-Rm 0.02	Rm 0.33	Rm 0	1	-6%
Enoch Mgijima Local Municipality	-Rm 1.73	Rm 250.83	Rm 249	8	-1%
Ephraim Mogale Local Municipality	Rm 0.57	Rm 38.25	Rm 39	1	1%
eThekwini Metropolitan	-Rm 107.12	Rm 10 026.73	Rm 9 920	10	-1%
Fetakgomo Tubatse Local Municipality	-Rm 0.13	Rm 5.13	Rm 5	5	-3%
Gamagara Local Municipality	Rm 2.36	Rm 118.20	Rm 121	4	2%
Garden Route District Municipality	-Rm 2.81	Rm 12.34	Rm 10	3	-23%
Ga-Segonyana Local Municipality	-Rm 2.47	Rm 88.03	Rm 86	2	-3%
George Local Municipality	-Rm 2.18	Rm 505.20	Rm 503	5	0%
Govan Mbeki Local Municipality	Rm 5.42	Rm 674.49	Rm 680	12	1%
Grand Total	-Rm 929.65	Rm 87 900.24	Rm 86 971	1907	-1%
Great Kei Local Municipality	Rm 0.08	Rm 0.83	Rm 1	1	9%
Greater Giyani Local Municipality	-Rm 0.09	Rm 1.16	Rm 1	5	-8%
Greater Kokstad Local Municipality	-Rm 1.90	Rm 102.10	Rm 100	2	-2%
Greater Letaba Local Municipality	-Rm 0.54	Rm 17.43	Rm 17	2	-3%
Greater Taung Local Municipality	-Rm 0.69	Rm 4.04	Rm 3	1	-17%
Greater Tzaneen Local Municipality	-Rm 4.96	Rm 379.13	Rm 374	3	-1%
Hantam Local Municipality	-Rm 2.86	Rm 22.87	Rm 20	6	-13%
Harry Gwala District Municipality	Rm 0.00	Rm 4.38	Rm 4	15	0%

Municipal name (alphabetical)	Change in revenue	Current revenue	Proposed revenue	No of Pods	% Revenue change from current bill
Hessequa Local Municipality	-Rm 3.32	Rm 109.00	Rm 106	10	-3%
iLembe District Municipality	-Rm 0.45	Rm 11.08	Rm 11	17	-4%
Impendle Local Municipality	Rm 0.00	Rm 0.09	Rm 0	1	-3%
Ingquza Hill Local Municipality	Rm 0.01	Rm 0.27	Rm 0	2	5%
Inkosi Langalibalele Local Municipality	Rm 2.35	Rm 200.87	Rm 203	2	1%
Inxuba Yethemba Local Municipality	-Rm 2.12	Rm 80.49	Rm 78	2	-3%
JB Marks Local Municipality	-Rm 2.15	Rm 531.54	Rm 529	7	0%
Joe Gqabi District Municipality	-Rm 1.03	Rm 6.24	Rm 5	4	-16%
Joe Morolong Local Municipality	-Rm 0.43	Rm 8.05	Rm 8	2	-5%
Jozini Local Municipality	Rm 0.08	Rm 0.39	Rm 0	2	21%
Kagisano-Molopo Local Municipality	Rm 0.05	Rm 0.19	Rm 0	1	26%
Kai !Garib Local Municipality	-Rm 1.48	Rm 63.74	Rm 62	3	-2%
Kamiesberg Local Municipality	-Rm 3.40	Rm 18.28	Rm 15	12	-19%
Kannaland Local Municipality	-Rm 0.12	Rm 37.44	Rm 37	4	0%
Kareeberg Local Municipality	-Rm 2.55	Rm 13.12	Rm 11	2	-19%
Karoo Hoogland Local Municipality	-Rm 1.77	Rm 9.11	Rm 7	2	-19%
Kgatelopele Local Municipality	Rm 0.95	Rm 19.62	Rm 21	1	5%
Kgetlengrivier Local Municipality	Rm 0.44	Rm 33.64	Rm 34	3	1%
King Cetshwayo District Municipality	-Rm 0.20	Rm 21.06	Rm 21	19	-1%
King Sabata Dalindyebo Local Municipality	-Rm 7.11	Rm 287.58	Rm 280	4	-2%
Knysna Local Municipality	-Rm 3.82	Rm 191.14	Rm 187	7	-2%
Kouga Local Municipality	-Rm 1.41	Rm 221.78	Rm 220	8	-1%
Koukamma Local Municipality	-Rm 0.23	Rm 4.39	Rm 4	6	-5%
KwaDukuza Local Municipality	Rm 12.97	Rm 703.51	Rm 716	3	2%
Laingsburg Local Municipality	-Rm 0.46	Rm 8.77	Rm 8	1	-5%
Lekwa Local Municipality	-Rm 10.97	Rm 407.46	Rm 396	4	-3%
Lepelle-Nkumpi Local Municipality	-Rm 0.14	Rm 1.86	Rm 2	5	-8%
Lephalale Local Municipality	Rm 2.60	Rm 121.25	Rm 124	5	2%
Lesedi Local Municipality	Rm 0.29	Rm 268.22	Rm 269	6	0%
Letsemeng Local Municipality	-Rm 3.51	Rm 30.66	Rm 27	6	-11%
Madibeng Local Municipality	-Rm 0.96	Rm 414.88	Rm 414	8	0%
Mafube Local Municipality	Rm 0.89	Rm 82.63	Rm 84	4	1%
Magareng Local Municipality	-Rm 3.90	Rm 20.34	Rm 16	1	-19%
Mahikeng Local Municipality	-Rm 0.13	Rm 2.71	Rm 3	4	-5%
Makana Local Municipality	-Rm 5.03	Rm 73.53	Rm 68	6	-7%
Makhuduthamaga Local Municipality	-Rm 0.01	Rm 0.35	Rm 0	1	-3%
Maluti-A-Phofung Local Municipality	Rm 2.38	Rm 625.89	Rm 628	10	0%
Mamusa Local Municipality	-Rm 1.25	Rm 34.10	Rm 33	2	-4%
Mandeni Local Municipality	-Rm 0.28	Rm 11.37	Rm 11	1	-2%
Mangaung Metropolitan	-Rm 13.73	Rm 1 783.51	Rm 1 770	24	-1%
Mantsopa Local Municipality	Rm 0.66	Rm 45.59	Rm 46	4	1%
Maphumulo Local Municipality	Rm 0.04	Rm 0.36	Rm 0	1	10%
Maquassi Hills Local Municipality	Rm 1.38	Rm 57.14	Rm 59	6	2%
Maruleng Local Municipality	Rm 0.00	Rm 0.24	Rm 0	1	-1%
Masilonyana Local Municipality	Rm 0.58	Rm 37.76	Rm 38	10	2%
Matatiele Local Municipality	-Rm 1.27	Rm 46.23	Rm 45	1	-3%
Matjhabeng Local Municipality	Rm 4.74	Rm 498.92	Rm 504	22	1%

Municipal name (alphabetical)	Change in revenue	Current revenue	Proposed revenue	No of Pods	% Revenue change from current bill
Matzikama Local Municipality	-Rm 9.18	Rm 100.79	Rm 92	8	-9%
Mbizana Local Municipality	-Rm 6.46	Rm 35.23	Rm 29	2	-18%
Merafong City Local Municipality	Rm 1.61	Rm 270.07	Rm 272	9	1%
Metsimaholo Local Municipality	Rm 0.99	Rm 242.63	Rm 244	8	0%
Mhlontlo Local Municipality	Rm 0.00	Rm 0.43	Rm 0	1	0%
Midvaal Local Municipality	-Rm 2.26	Rm 267.47	Rm 265	8	-1%
Mkhambathini Local Municipality	-Rm 0.01	Rm 0.26	Rm 0	1	-5%
Mkhondo Local Municipality	-Rm 6.63	Rm 131.38	Rm 125	5	-5%
Modimolle-Mookgophong Local Municipality	Rm 2.16	Rm 164.75	Rm 167	10	1%
Mogalakwena Local Municipality	Rm 2.87	Rm 213.81	Rm 217	6	1%
Mogale City Local Municipality	Rm 8.35	Rm 744.13	Rm 752	6	1%
Molemole Local Municipality	-Rm 1.96	Rm 10.68	Rm 9	3	-18%
Mopani District Municipality	-Rm 2.30	Rm 23.75	Rm 21	17	-10%
Moqhaka Local Municipality	-Rm 3.39	Rm 264.40	Rm 261	8	-1%
Moses Kotane Local Municipality	-Rm 0.15	Rm 3.83	Rm 4	12	-4%
Mossel Bay Local Municipality	-Rm 2.68	Rm 324.92	Rm 322	9	-1%
Mpofana Local Municipality	Rm 1.12	Rm 72.33	Rm 73	1	2%
Msinga Local Municipality	-Rm 0.01	Rm 0.27	Rm 0	1	-5%
Msukaligwa Local Municipality	-Rm 12.15	Rm 240.16	Rm 228	9	-5%
Msunduzi Local Municipality	-Rm 15.63	Rm 1 775.68	Rm 1 760	3	-1%
Mthonjaneni Local Municipality	-Rm 4.72	Rm 24.97	Rm 20	1	-19%
Mtubatuba Local Municipality	Rm 0.00	Rm 0.29	Rm 0	1	0%
Musina Local Municipality	Rm 0.94	Rm 96.23	Rm 97	5	1%
Nala Local Municipality	Rm 1.48	Rm 84.51	Rm 86	5	2%
Naledi Local Municipality	Rm 1.35	Rm 95.69	Rm 97	5	1%
Nama Khoi Local Municipality	-Rm 8.02	Rm 76.18	Rm 68	6	-11%
Ndlambe Local Municipality	-Rm 1.55	Rm 56.81	Rm 55	11	-3%
Nelson Mandela Bay Metropolitan	-Rm 21.70	Rm 3 505.97	Rm 3 484	7	-1%
Newcastle Local Municipality	-Rm 10.22	Rm 500.00	Rm 490	4	-2%
Ngaka Modiri Molema District Municipality	-Rm 0.27	Rm 2.87	Rm 3	6	-9%
Ngwathe Local Municipality	Rm 5.92	Rm 224.38	Rm 230	8	3%
Nkandla Local Municipality	Rm 0.55	Rm 12.09	Rm 13	1	5%
Nkangala District Municipality	Rm 0.00	Rm 0.24	Rm 0	1	0%
Nketoana Local Municipality	Rm 1.29	Rm 58.92	Rm 60	4	2%
Nkomazi Local Municipality	-Rm 7.25	Rm 138.50	Rm 131	56	-5%
Okhahlamba Local Municipality	-Rm 0.02	Rm 0.37	Rm 0	1	-5%
OR Tambo District Municipality	-Rm 1.13	Rm 10.78	Rm 10	18	-10%
Oudtshoorn Local Municipality	Rm 1.31	Rm 159.04	Rm 160	3	1%
Overberg District Municipality	-Rm 0.10	Rm 2.56	Rm 2	1	-4%
Overstrand Local Municipality	Rm 1.75	Rm 274.09	Rm 276	14	1%
Phokwane Local Municipality	-Rm 6.59	Rm 70.72	Rm 64	4	-9%
Phumelela Local Municipality	Rm 1.25	Rm 21.88	Rm 23	6	6%
Pixley Ka Seme District Municipality	-Rm 0.57	Rm 56.31	Rm 56	5	-1%
Polokwane Local Municipality	-Rm 7.00	Rm 706.95	Rm 700	12	-1%
Prince Albert Local Municipality	Rm 0.57	Rm 11.53	Rm 12	1	5%
Ramotshere Moiloa Local Municipality	Rm 0.71	Rm 56.18	Rm 57	2	1%
Rand West City Local Municipality	Rm 5.15	Rm 547.03	Rm 552	11	1%

Municipal name (alphabetical)	Change in revenue	Current revenue	Proposed revenue	No of Pods	% Revenue change from current bill
Ratlou Local Municipality	Rm 0.05	Rm 0.87	Rm 1	3	5%
Ray Nkonyeni Local Municipality	Rm 1.5	Rm 104.0	Rm 105.5	4	1%
Raymond Mhlaba Local Municipality	-Rm 2.63	Rm 54.53	Rm 52	3	-5%
Renosterberg Local Municipality	-Rm 2.27	Rm 11.15	Rm 9	3	-20%
Richtersveld Local Municipality	-Rm 2.87	Rm 15.14	Rm 12	3	-19%
Rustenburg Local Municipality	Rm 26.40	Rm 2 117.39	Rm 2 144	7	1%
Sakhisizwe Local Municipality	-Rm 2.40	Rm 14.25	Rm 12	3	-17%
Saldanha Bay Local Municipality	-Rm 13.14	Rm 264.14	Rm 251	9	-5%
Sekhukhune District Municipality	-Rm 1.53	Rm 16.10	Rm 15	23	-10%
Senqu Local Municipality	-Rm 0.52	Rm 31.52	Rm 31	5	-2%
Setsoto Local Municipality	Rm 2.38	Rm 73.74	Rm 76	13	3%
Siyancuma Local Municipality	-Rm 8.82	Rm 45.13	Rm 36	5	-20%
Siyathemba Local Municipality	-Rm 3.95	Rm 20.44	Rm 16	1	-19%
Sol Plaatje Local Municipality	-Rm 9.03	Rm 536.79	Rm 528	4	-2%
Stellenbosch Local Municipality	-Rm 4.99	Rm 387.99	Rm 383	15	-1%
Steve Tshwete Local Municipality	-Rm 11.35	Rm 483.51	Rm 472	12	-2%
Sundays River Valley Local Municipality	Rm 0.82	Rm 20.27	Rm 21	4	4%
Swartland Local Municipality	Rm 3.11	Rm 213.64	Rm 217	7	1%
Swellendam Local Municipality	Rm 1.21	Rm 59.33	Rm 61	2	2%
Thaba Chweu Local Municipality	-Rm 4.31	Rm 174.94	Rm 171	12	-2%
Thabazimbi Local Municipality	-Rm 0.92	Rm 70.61	Rm 70	3	-1%
Theewaterskloof Local Municipality	Rm 1.18	Rm 73.75	Rm 75	13	2%
Thembisile Hani Local Municipality	-Rm 3.26	Rm 16.96	Rm 14	12	-19%
Thulamela Local Municipality	-Rm 0.12	Rm 3.75	Rm 4	11	-3%
Tokologo Local Municipality	-Rm 5.68	Rm 29.18	Rm 23	7	-19%
Tsantsabane Local Municipality	-Rm 1.83	Rm 42.13	Rm 40	4	-4%
Tswaing Local Municipality	-Rm 1.95	Rm 46.31	Rm 44	8	-4%
Tswelopele Local Municipality	Rm 0.21	Rm 35.30	Rm 36	5	1%
Ubuhlebezwe Local Municipality	-Rm 0.04	Rm 0.73	Rm 1	2	-6%
Ubuntu Local Municipality	-Rm 3.53	Rm 19.05	Rm 16	3	-19%
Ugu District Municipality	-Rm 3.25	Rm 59.37	Rm 56	34	-5%
Ulundi Local Municipality	Rm 1.27	Rm 82.87	Rm 84	1	2%
Umdoni Local Municipality	Rm 0.01	Rm 1.70	Rm 2	6	0%
uMfolozi Local Municipality	Rm 0.04	Rm 0.41	Rm 0	2	10%
uMgungundlovu District Municipality	Rm 0.01	Rm 0.08	Rm 0	1	13%
Umkhanyakude District Municipality	-Rm 3.40	Rm 39.48	Rm 36	29	-9%
uMlalazi Local Municipality	-Rm 1.04	Rm 59.81	Rm 59	2	-2%
uMngeni Local Municipality	-Rm 6.73	Rm 100.55	Rm 94	6	-7%
uMshwathi Local Municipality	-Rm 0.02	Rm 0.42	Rm 0	1	-5%
Umsobomvu Local Municipality	-Rm 0.60	Rm 29.78	Rm 29	4	-2%
Umuziwabantu Local Municipality	-Rm 0.77	Rm 31.39	Rm 31	1	-2%
Umvoti Local Municipality	-Rm 1.47	Rm 57.61	Rm 56	3	-3%
uMzimkhulu Local Municipality	-Rm 0.15	Rm 1.66	Rm 2	5	-9%
uMzinyathi District Municipality	Rm 0.11	Rm 1.10	Rm 1	5	10%
Umzumbe Local Municipality	Rm 0.10	Rm 0.31	Rm 0	2	31%
uPhongolo Local Municipality	Rm 0.46	Rm 30.78	Rm 31	1	1%
uThukela District Municipality	-Rm 6.86	Rm 58.09	Rm 51	76	-12%
Vhembe District Municipality	-Rm 2.84	Rm 32.65	Rm 30	51	-9%

Municipal name (alphabetical)	Change in revenue	Current revenue	Proposed revenue	No of Pods	% Revenue change from current bill
Victor Khanye Local Municipality	Rm 1.84	Rm 127.73	Rm 130	2	1%
Walter Sisulu Local Municipality	-Rm 3.14	Rm 102.47	Rm 99	6	-3%
West Coast District Municipality	-Rm 2.67	Rm 21.55	Rm 19	10	-12%
Witzenberg Local Municipality	Rm 5.39	Rm 208.91	Rm 214	9	3%
Zululand District Municipality	Rm 0	Rm 29	Rm 29	28	0%

Table 22: R impact per local-authority tariff in order of % impact

Municipal name (order of impact)	Change in revenue	Current revenue	Proposed revenue	No of Pods	% Revenue change from current bill
Garden Route District Municipality	-Rm 2.81	Rm 12.34	Rm 10	3	-23%
Renosterberg Local Municipality	-Rm 2.27	Rm 11.15	Rm 9	3	-20%
Capricorn District Municipality	-Rm 0.17	Rm 0.83	Rm 1	2	-20%
Siyancuma Local Municipality	-Rm 8.82	Rm 45.13	Rm 36	5	-20%
Tokologo Local Municipality	-Rm 5.68	Rm 29.18	Rm 23	7	-19%
Kareeberg Local Municipality	-Rm 2.55	Rm 13.12	Rm 11	2	-19%
Karoo Hoogland Local Municipality	-Rm 1.77	Rm 9.11	Rm 7	2	-19%
Siyathemba Local Municipality	-Rm 3.95	Rm 20.44	Rm 16	1	-19%
Thembisile Hani Local Municipality	-Rm 3.26	Rm 16.96	Rm 14	12	-19%
Magareng Local Municipality	-Rm 3.90	Rm 20.34	Rm 16	1	-19%
Richtersveld Local Municipality	-Rm 2.87	Rm 15.14	Rm 12	3	-19%
Mthonjaneni Local Municipality	-Rm 4.72	Rm 24.97	Rm 20	1	-19%
Kamiesberg Local Municipality	-Rm 3.40	Rm 18.28	Rm 15	12	-19%
Ubuntu Local Municipality	-Rm 3.53	Rm 19.05	Rm 16	3	-19%
Mbizana Local Municipality	-Rm 6.46	Rm 35.23	Rm 29	2	-18%
Molemole Local Municipality	-Rm 1.96	Rm 10.68	Rm 9	3	-18%
Greater Taung Local Municipality	-Rm 0.69	Rm 4.04	Rm 3	1	-17%
Dr JS Moroka Local Municipality	-Rm 4.31	Rm 25.35	Rm 21	10	-17%
!Kheis Local Municipality	-Rm 0.10	Rm 0.62	Rm 1	1	-17%
Sakhisizwe Local Municipality	-Rm 2.40	Rm 14.25	Rm 12	3	-17%
Dikgatlong Local Municipality	-Rm 4.71	Rm 28.19	Rm 23	5	-17%
Joe Gqabi District Municipality	-Rm 1.03	Rm 6.24	Rm 5	4	-16%
Blouberg Local Municipality	-Rm 5.28	Rm 35.71	Rm 30	22	-15%
Amajuba District Municipality	-Rm 0.08	Rm 0.63	Rm 1	1	-13%
Hantam Local Municipality	-Rm 2.86	Rm 22.87	Rm 20	6	-13%
West Coast District Municipality	-Rm 2.67	Rm 21.55	Rm 19	10	-12%
uThukela District Municipality	-Rm 6.86	Rm 58.09	Rm 51	76	-12%
Letsemeng Local Municipality	-Rm 3.51	Rm 30.66	Rm 27	6	-11%
Nama Khoi Local Municipality	-Rm 8.02	Rm 76.18	Rm 68	6	-11%
OR Tambo District Municipality	-Rm 1.13	Rm 10.78	Rm 10	18	-10%
Mopani District Municipality	-Rm 2.30	Rm 23.75	Rm 21	17	-10%
Sekhukhune District Municipality	-Rm 1.53	Rm 16.10	Rm 15	23	-10%
Ngaka Modiri Molema District Municipality	-Rm 0.27	Rm 2.87	Rm 3	6	-9%
Phokwane Local Municipality	-Rm 6.59	Rm 70.72	Rm 64	4	-9%
uMzimkhulu Local Municipality	-Rm 0.15	Rm 1.66	Rm 2	5	-9%
Matzikama Local Municipality	-Rm 9.18	Rm 100.79	Rm 92	8	-9%
Vhembe District Municipality	-Rm 2.84	Rm 32.65	Rm 30	51	-9%

Municipal name (order of impact)	Change in revenue	Current revenue	Proposed revenue	No of Pods	% Revenue change from current bill
Umkhanyakude District Municipality	-Rm 3.40	Rm 39.48	Rm 36	29	-9%
Greater Giyani Local Municipality	-Rm 0.09	Rm 1.16	Rm 1	5	-8%
Lepelle-Nkumpi Local Municipality	-Rm 0.14	Rm 1.86	Rm 2	5	-8%
Makana Local Municipality	-Rm 5.03	Rm 73.53	Rm 68	6	-7%
uMngeni Local Municipality	-Rm 6.73	Rm 100.55	Rm 94	6	-7%
Dr Beyers Naudé Local Municipality	-Rm 6.34	Rm 95.04	Rm 89	10	-7%
Engcobo Local Municipality	-Rm 0.02	Rm 0.33	Rm 0	1	-6%
Ubuhlebezwe Local Municipality	-Rm 0.04	Rm 0.73	Rm 1	2	-6%
Ugu District Municipality	-Rm 3.25	Rm 59.37	Rm 56	34	-5%
Joe Morolong Local Municipality	-Rm 0.43	Rm 8.05	Rm 8	2	-5%
Koukamma Local Municipality	-Rm 0.23	Rm 4.39	Rm 4	6	-5%
Laingsburg Local Municipality	-Rm 0.46	Rm 8.77	Rm 8	1	-5%
Okhahlamba Local Municipality	-Rm 0.02	Rm 0.37	Rm 0	1	-5%
Nkomazi Local Municipality	-Rm 7.25	Rm 138.50	Rm 131	56	-5%
Msinga Local Municipality	-Rm 0.01	Rm 0.27	Rm 0	1	-5%
Mkhambathini Local Municipality	-Rm 0.013	Rm 0.26	Rm 0.25	1	-5%
Msukaligwa Local Municipality	-Rm 12.15	Rm 240.16	Rm 228	9	-5%
Mkhondo Local Municipality	-Rm 6.63	Rm 131.38	Rm 125	5	-5%
Chris Hani District Municipality	-Rm 0.25	Rm 5.03	Rm 5	12	-5%
uMshwathi Local Municipality	-Rm 0.02	Rm 0.42	Rm 0	1	-5%
Saldanha Bay Local Municipality	-Rm 13.14	Rm 264.14	Rm 251	9	-5%
Chief Albert Luthuli Local Municipality	-Rm 2.42	Rm 48.93	Rm 47	16	-5%
Mahikeng Local Municipality	-Rm 0.13	Rm 2.71	Rm 3	4	-5%
Raymond Mhlaba Local Municipality	-Rm 2.63	Rm 54.53	Rm 52	3	-5%
Emthanjeni Local Municipality	-Rm 3.19	Rm 71.87	Rm 69	14	-4%
Tsantsabane Local Municipality	-Rm 1.83	Rm 42.13	Rm 40	4	-4%
Tswaing Local Municipality	-Rm 1.95	Rm 46.31	Rm 44	8	-4%
Dr Nkosazana Dlamini Zuma Local Municipality	-Rm 0.02	Rm 0.48	Rm 0	2	-4%
Cape Agulhas Local Municipality	-Rm 3.87	Rm 92.65	Rm 89	8	-4%
AbaQulusi Local Municipality	-Rm 7.25	Rm 176.01	Rm 169	6	-4%
iLembe District Municipality	-Rm 0.45	Rm 11.08	Rm 11	17	-4%
Moses Kotane Local Municipality	-Rm 0.15	Rm 3.83	Rm 4	12	-4%
Overberg District Municipality	-Rm 0.10	Rm 2.56	Rm 2	1	-4%
Mamusa Local Municipality	-Rm 1.25	Rm 34.10	Rm 33	2	-4%
Makhuduthamaga Local Municipality	-Rm 0.01	Rm 0.35	Rm 0	1	-3%
Thulamela Local Municipality	-Rm 0.12	Rm 3.75	Rm 4	11	-3%
Impendle Local Municipality	Rm 0.00	Rm 0.09	Rm 0	1	-3%
Greater Letaba Local Municipality	-Rm 0.54	Rm 17.43	Rm 17	2	-3%
Amahlathi Local Municipality	-Rm 1.05	Rm 34.11	Rm 33	4	-3%
Walter Sisulu Local Municipality	-Rm 3.14	Rm 102.47	Rm 99	6	-3%
Hessequa Local Municipality	-Rm 3.32	Rm 109.00	Rm 106	10	-3%
Blue Crane Route Local Municipality	-Rm 2.58	Rm 91.20	Rm 89	1	-3%
Ga-Segonyana Local Municipality	-Rm 2.47	Rm 88.03	Rm 86	2	-3%
Beaufort West Local Municipality	-Rm 1.72	Rm 62.16	Rm 60	7	-3%
City of Cape Town Metropolitan	-Rm 265.84	Rm 9 604.48	Rm 9 339	107	-3%

Municipal name (order of impact)	Change in revenue	Current revenue	Proposed revenue	No of Pods	% Revenue change from current bill
Matatiele Local Municipality	-Rm 1.27	Rm 46.23	Rm 45	1	-3%
Ndlambe Local Municipality	-Rm 1.55	Rm 56.81	Rm 55	11	-3%
Lekwa Local Municipality	-Rm 10.97	Rm 407.46	Rm 396	4	-3%
Inxuba Yethemba Local Municipality	-Rm 2.12	Rm 80.49	Rm 78	2	-3%
Fetakgomo Tubatse Local Municipality	-Rm 0.13	Rm 5.13	Rm 5	5	-3%
Umvoti Local Municipality	-Rm 1.47	Rm 57.61	Rm 56	3	-3%
King Sabata Dalindyebo Local Municipality	-Rm 7.11	Rm 287.58	Rm 280	4	-2%
eDumbe Local Municipality	-Rm 0.64	Rm 25.79	Rm 25	1	-2%
Thaba Chweu Local Municipality	-Rm 4.31	Rm 174.94	Rm 171	12	-2%
Umuziwabantu Local Municipality	-Rm 0.77	Rm 31.39	Rm 31	1	-2%
Mandeni Local Municipality	-Rm 0.28	Rm 11.37	Rm 11	1	-2%
Cederberg Local Municipality	-Rm 1.66	Rm 69.96	Rm 68	10	-2%
Steve Tshwete Local Municipality	-Rm 11.35	Rm 483.51	Rm 472	12	-2%
Kai !Garib Local Municipality	-Rm 1.48	Rm 63.74	Rm 62	3	-2%
Alfred Nzo District Municipality	-Rm 0.11	Rm 5.06	Rm 5	9	-2%
Alfred Duma Local Municipality	-Rm 5.38	Rm 259.50	Rm 254	2	-2%
Newcastle Local Municipality	-Rm 10.22	Rm 500.00	Rm 490	4	-2%
Umsobomvu Local Municipality	-Rm 0.60	Rm 29.78	Rm 29	4	-2%
Knysna Local Municipality	-Rm 3.82	Rm 191.14	Rm 187	7	-2%
City of Johannesburg Metropolitan	-Rm 208.80	Rm 10 664.38	Rm 10 456	105	-2%
Greater Kokstad Local Municipality	-Rm 1.90	Rm 102.10	Rm 100	2	-2%
uMlalazi Local Municipality	-Rm 1.04	Rm 59.81	Rm 59	2	-2%
Sol Plaatje Local Municipality	-Rm 9.03	Rm 536.79	Rm 528	4	-2%
Senqu Local Municipality	-Rm 0.52	Rm 31.52	Rm 31	5	-2%
Bushbuckridge Local Municipality	-Rm 0.04	Rm 2.29	Rm 2	14	-2%
Emfuleni Local Municipality	-Rm 27.59	Rm 1 876.60	Rm 1 849	20	-1%
City of Mbombela Local Municipality	-Rm 12.24	Rm 839.81	Rm 828	32	-1%
Bitou Local Municipality	-Rm 1.79	Rm 127.39	Rm 126	9	-1%
Greater Tzaneen Local Municipality	-Rm 4.96	Rm 379.13	Rm 374	3	-1%
City of Tshwane Metropolitan	-Rm 117.90	Rm 9 023.02	Rm 8 905	40	-1%
Thabazimbi Local Municipality	-Rm 1	Rm 71	Rm 70	3	-1%
Stellenbosch Local Municipality	-Rm 4.99	Rm 387.99	Rm 383	15	-1%
Moqhaka Local Municipality	-Rm 3.39	Rm 264.40	Rm 261	8	-1%
Maruleng Local Municipality	Rm 0.00	Rm 0.24	Rm 0	1	-1%
eThekwini Metropolitan	-Rm 107.12	Rm 10 026.73	Rm 9 920	10	-1%
Grand Total	-Rm 929.65	Rm 87 900.24	Rm 86 971	1907	-1%
Pixley Ka Seme District Municipality	-Rm 0.57	Rm 56.31	Rm 56	5	-1%
Polokwane Local Municipality	-Rm 7.00	Rm 706.95	Rm 700	12	-1%
King Cetshwayo District Municipality	-Rm 0.20	Rm 21.06	Rm 21	19	-1%
City of uMhlathuze Local Municipality	-Rm 8.44	Rm 941.48	Rm 933	13	-1%
Msunduzi Local Municipality	-Rm 15.63	Rm 1 775.68	Rm 1 760	3	-1%
Midvaal Local Municipality	-Rm 2.26	Rm 267.47	Rm 265	8	-1%
Mossel Bay Local Municipality	-Rm 2.68	Rm 324.92	Rm 322	9	-1%

Municipal name (order of impact)	Change in revenue	Current revenue	Proposed revenue	No of Pods	% Revenue change from current bill
Mangaung Metropolitan	-Rm 13.73	Rm 1 783.51	Rm 1 770	24	-1%
Enoch Mgijima Local Municipality	-Rm 1.73	Rm 250.83	Rm 249	8	-1%
Kouga Local Municipality	-Rm 1.41	Rm 221.78	Rm 220	8	-1%
Nelson Mandela Bay Metropolitan	-Rm 21.70	Rm 3 505.97	Rm 3 484	7	-1%
Emalahleni Local Municipality	-Rm 6.61	Rm 1 078.52	Rm 1 072	13	-1%
George Local Municipality	-Rm 2.18	Rm 505.20	Rm 503	5	0%
Drakenstein Local Municipality	-Rm 3.23	Rm 751.43	Rm 748	7	0%
JB Marks Local Municipality	-Rm 2.15	Rm 531.54	Rm 529	7	0%
Mtubatuba Local Municipality	Rm 0.00	Rm 0.29	Rm 0	1	0%
Kannaland Local Municipality	-Rm 0.12	Rm 37.44	Rm 37	4	0%
Madibeng Local Municipality	-Rm 0.96	Rm 414.88	Rm 414	8	0%
Collins Chabane Local Municipality	-Rm 0.11	Rm 264.12	Rm 264	9	0%
Zululand District Municipality	Rm 0.00	Rm 28.52	Rm 29	28	0%
Mhlontlo Local Municipality	Rm 0.00	Rm 0.43	Rm 0	1	0%
Dawid Kruiper Local Municipality	Rm 0.19	Rm 207.62	Rm 208	2	0%
Harry Gwala District Municipality	Rm 0.00	Rm 4.38	Rm 4	15	0%
Lesedi Local Municipality	Rm 0.29	Rm 268.22	Rm 269	6	0%
Umdoni Local Municipality	Rm 0.01	Rm 1.70	Rm 2	6	0%
Maluti-A-Phofung Local Municipality	Rm 2.38	Rm 625.89	Rm 628	10	0%
Metsimaholo Local Municipality	Rm 0.99	Rm 242.63	Rm 244	8	0%
Breede Valley Local Municipality	Rm 2.70	Rm 636.54	Rm 639	12	0%
Nkangala District Municipality	Rm 0.00	Rm 0.24	Rm 0	1	0%
City of Ekurhuleni Metropolitan	Rm 58.77	Rm 11 132.03	Rm 11 191	111	1%
Merafong City Local Municipality	Rm 1.61	Rm 270.07	Rm 272	9	1%
Tswelopele Local Municipality	Rm 0.21	Rm 35.30	Rm 36	5	1%
Amathole District Municipality	Rm 0.07	Rm 11.48	Rm 12	21	1%
Overstrand Local Municipality	Rm 1.75	Rm 274.09	Rm 276	14	1%
Govan Mbeki Local Municipality	Rm 5.42	Rm 674.49	Rm 680	12	1%
Oudtshoorn Local Municipality	Rm 1.31	Rm 159.04	Rm 160	3	1%
Ditsobotla Local Municipality	Rm 1.21	Rm 129.66	Rm 131	4	1%
Rand West City Local Municipality	Rm 5.15	Rm 547.03	Rm 552	11	1%
Matjhabeng Local Municipality	Rm 4.74	Rm 498.92	Rm 504	22	1%
Elias Motsoaledi Local Municipality	Rm 0.80	Rm 82.03	Rm 83	4	1%
Musina Local Municipality	Rm 0.94	Rm 96.23	Rm 97	5	1%
Dihlabeng Local Municipality	Rm 1.59	Rm 152.63	Rm 154	16	1%
Mafube Local Municipality	Rm 0.89	Rm 82.63	Rm 84	4	1%
Mogale City Local Municipality	Rm 8.35	Rm 744.13	Rm 752	6	1%
Inkosi Langalibalele Local Municipality	Rm 2.35	Rm 200.87	Rm 203	2	1%
Endumeni Local Municipality	Rm 0.89	Rm 72.79	Rm 74	2	1%
Rustenburg Local Municipality	Rm 26.40	Rm 2 117.39	Rm 2 144	7	1%
Ramotshere Moiloa Local Municipality	Rm 0.71	Rm 56.18	Rm 57	2	1%
Bergrivier Local Municipality	Rm 1.14	Rm 91.10	Rm 92	8	1%
Kgetlengrivier Local Municipality	Rm 0.44	Rm 33.64	Rm 34	3	1%
Modimolle-Mookgophong Local Municipality	Rm 2.16	Rm 164.75	Rm 167	10	1%
Mogalakwena Local Municipality	Rm 2.87	Rm 213.81	Rm 217	6	1%

Municipal name (order of impact)	Change in revenue	Current revenue	Proposed revenue	No of Pods	% Revenue change from current bill
City of Matlosana Local Municipality	Rm 9.03	Rm 640.39	Rm 649	10	1%
Naledi Local Municipality	Rm 1.35	Rm 95.69	Rm 97	5	1%
Victor Khanye Local Municipality	Rm 1.84	Rm 127.73	Rm 130	2	1%
Mantsopa Local Municipality	Rm 0.66	Rm 45.59	Rm 46	4	1%
Ray Nkonyeni Local Municipality	Rm 1.5	Rm 104.0	Rm 105.5	4	1%
Swartland Local Municipality	Rm 3.11	Rm 213.64	Rm 217	7	1%
uPhongolo Local Municipality	Rm 0.46	Rm 30.78	Rm 31	1	1%
Ephraim Mogale Local Municipality	Rm 0.57	Rm 38.25	Rm 39	1	1%
Masilonyana Local Municipality	Rm 0.58	Rm 37.76	Rm 38	10	2%
Ulundi Local Municipality	Rm 1.27	Rm 82.87	Rm 84	1	2%
Ba-Phalaborwa Local Municipality	Rm 1.38	Rm 89.63	Rm 91	7	2%
Mpofana Local Municipality	Rm 1.12	Rm 72.33	Rm 73	1	2%
Bela-Bela Local Municipality	Rm 1.50	Rm 94.27	Rm 96	2	2%
Theewaterskloof Local Municipality	Rm 1.18	Rm 73.75	Rm 75	13	2%
Nala Local Municipality	Rm 1.48	Rm 84.51	Rm 86	5	2%
Buffalo City Metropolitan	Rm 17.25	Rm 977.45	Rm 995	16	2%
KwaDukuza Local Municipality	Rm 12.97	Rm 703.51	Rm 716	3	2%
Gamagara Local Municipality	Rm 2.36	Rm 118.20	Rm 121	4	2%
Swellendam Local Municipality	Rm 1.21	Rm 59.33	Rm 61	2	2%
Dipaleseng Local Municipality	Rm 1.36	Rm 64.81	Rm 66	7	2%
Lephalale Local Municipality	Rm 2.60	Rm 121.25	Rm 124	5	2%
Nketoana Local Municipality	Rm 1.29	Rm 58.92	Rm 60	4	2%
Maquassi Hills Local Municipality	Rm 1.38	Rm 57.14	Rm 59	6	2%
Emakhazeni Local Municipality	Rm 1.42	Rm 55.48	Rm 57	8	3%
Witzenberg Local Municipality	Rm 5.39	Rm 208.91	Rm 214	9	3%
Ngwathe Local Municipality	Rm 5.92	Rm 224.38	Rm 230	8	3%
Setsoto Local Municipality	Rm 2.38	Rm 73.74	Rm 76	13	3%
eMadlangeni Local Municipality	Rm 0.54	Rm 13.92	Rm 14	2	4%
Sundays River Valley Local Municipality	Rm 0.82	Rm 20.27	Rm 21	4	4%
Nkandla Local Municipality	Rm 0.55	Rm 12.09	Rm 13	1	5%
Kgatelopele Local Municipality	Rm 0.95	Rm 19.62	Rm 21	1	5%
Prince Albert Local Municipality	Rm 0.57	Rm 11.53	Rm 12	1	5%
Ingquza Hill Local Municipality	Rm 0.01	Rm 0.27	Rm 0	2	5%
Ratlou Local Municipality	Rm 0.05	Rm 0.87	Rm 1	3	5%
Phumelela Local Municipality	Rm 1.25	Rm 21.88	Rm 23	6	6%
Great Kei Local Municipality	Rm 0.08	Rm 0.83	Rm 1	1	9%
uMzinyathi District Municipality	Rm 0.11	Rm 1.10	Rm 1	5	10%
Maphumulo Local Municipality	Rm 0.04	Rm 0.36	Rm 0	1	10%
uMfolozi Local Municipality	Rm 0.04	Rm 0.41	Rm 0	2	10%
Elundini Local Municipality	Rm 0.64	Rm 5.99	Rm 7	3	11%
uMgungundlovu District Municipality	Rm 0.01	Rm 0.08	Rm 0	1	13%
Jozini Local Municipality	Rm 0.08	Rm 0.39	Rm 0	2	21%
Kagisano-Molopo Local Municipality	Rm 0.05	Rm 0.19	Rm 0	1	26%
Umzumbe Local Municipality	Rm 0.10	Rm 0.31	Rm 0	2	31%

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

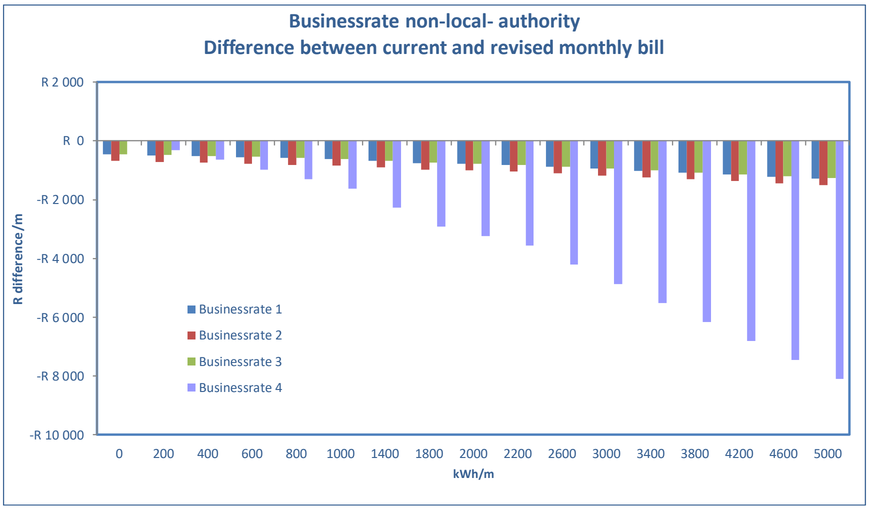
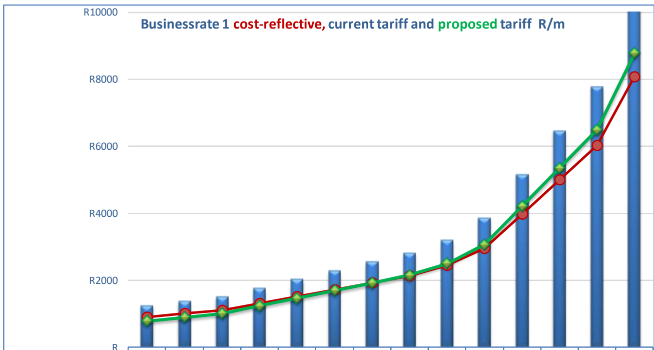
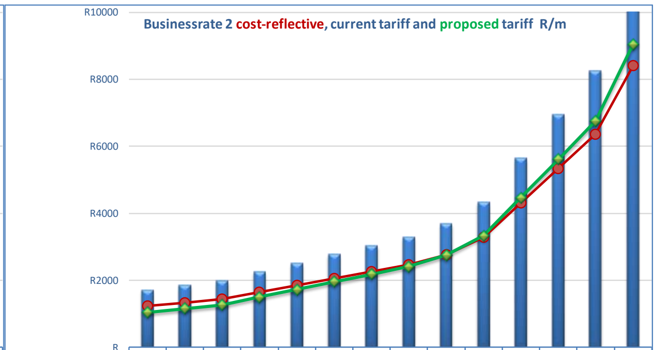


Figure 25: Businessrate non-local-authority tariffs impact at different consumption levels

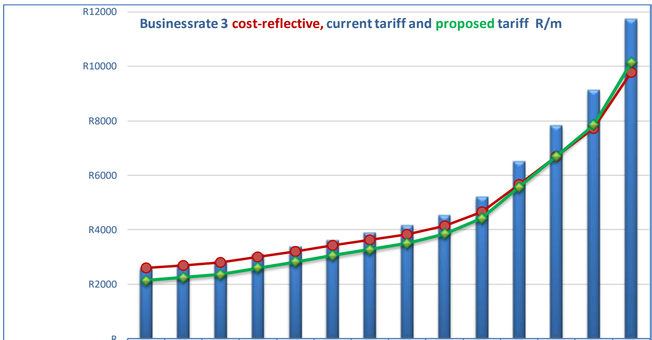


	0 kWh/m	100 kWh/m	200 kWh/m	400 kWh/m	600 kWh/m	800 kWh/m	1 000 kWh/m	1 200 kWh/m	1 500 kWh/m	2 000 kWh/m	3 000 kWh/m	4 000 kWh/m	5 000 kWh/m	7 000 kWh/m
Current tariff	R1238	R1369	R1500	R1761	R2023	R2284	R2546	R2807	R3200	R3853	R5161	R6468	R7776	R10391
Cost reflective	R908	R1010	R1113	R1318	R1523	R1728	R1933	R2138	R2446	R2958	R3983	R5008	R6033	R8084
Proposed tariff	R782	R897	R1011	R1240	R1468	R1697	R1925	R2154	R2497	R3068	R4211	R5354	R6496	R8782

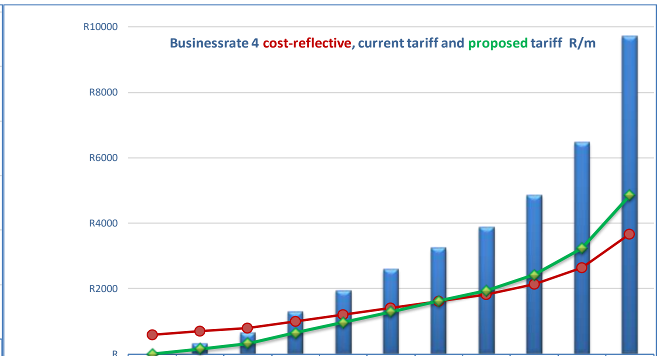


	0 kWh/m	100 kWh/m	200 kWh/m	400 kWh/m	600 kWh/m	800 kWh/m	1 000 kWh/m	1 200 kWh/m	1 500 kWh/m	2 000 kWh/m	3 000 kWh/m	4 000 kWh/m	5 000 kWh/m	7 000 kWh/m
Current tariff	R1720	R1851	R1982	R2243	R2505	R2766	R3028	R3289	R3682	R4335	R5643	R6950	R8258	R10873
Cost reflective	R1231	R1333	R1436	R1641	R1846	R2051	R2256	R2461	R2768	R3281	R4306	R5331	R6356	R8407
Proposed tariff	R1041	R1155	R1269	R1498	R1726	R1955	R2184	R2412	R2755	R3326	R4469	R5612	R6755	R9040

Figure 26: 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	R2584	R2715	R2845	R3107	R3368	R3630	R3891	R4153	R4545	R5199	R6506	R7814	R9121	R11736
Cost reflective	R2599	R2701	R2804	R3009	R3214	R3419	R3624	R3829	R4136	R4649	R5674	R6699	R7724	R9774
Proposed tariff	R2135	R2249	R2364	R2592	R2821	R3049	R3278	R3506	R3849	R4421	R5563	R6706	R7849	R10135



	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	R324	R648	R1295	R1943	R2591	R3239	R3886	R4858	R6477	R9716
Cost reflective	R599	R701	R804	R1009	R1214	R1419	R1624	R1829	R2137	R2649	R3674
Proposed tariff	R	R162	R324	R647	R971	R1294	R1618	R1941	R2427	R3236	R4854

Figure 27: Businessrate 3 and 4 non-local-authority tariffs comparison of cost-reflective, current, and proposed tariffs

B.2 Landrate and Landlight non-local-authority

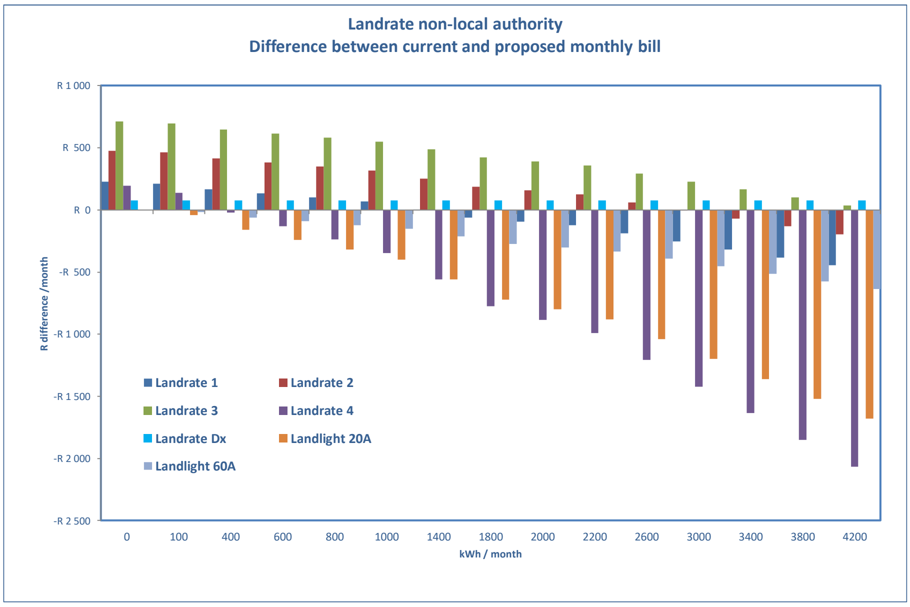
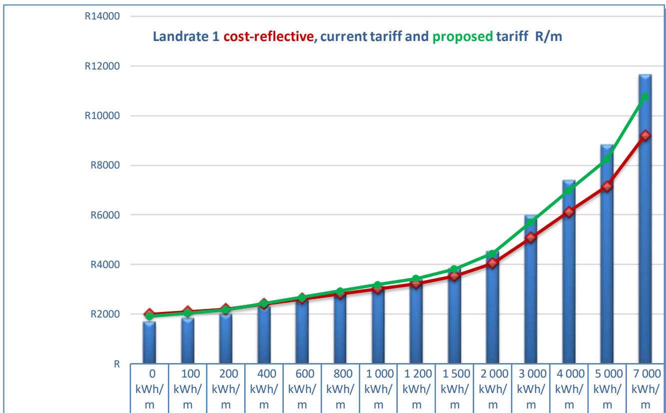
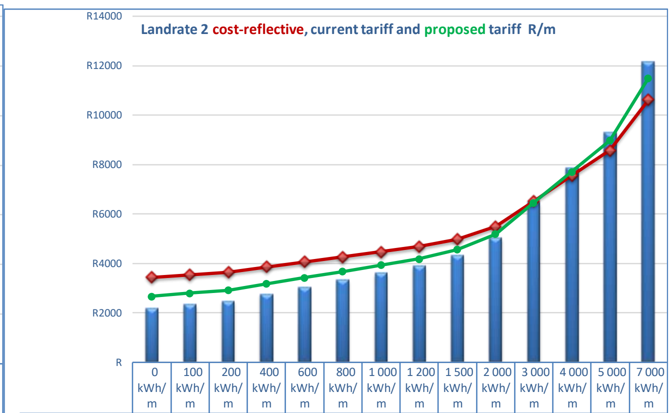


Figure 28: Landrate non-local-authority tariffs impact at different consumption levels

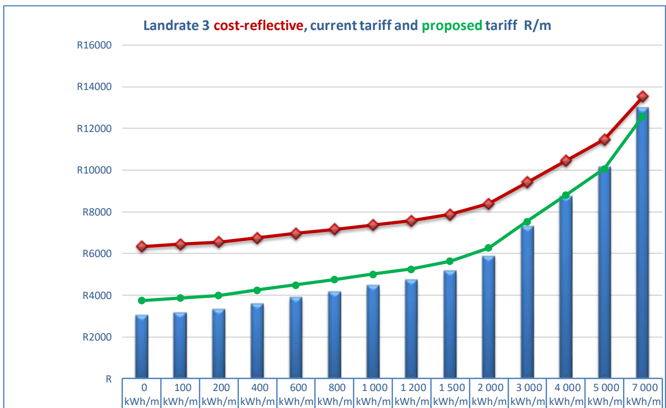


	0 kWh/m	100 kWh/m	200 kWh/m	400 kWh/m	600 kWh/m	800 kWh/m	1 000 kWh/m	1 200 kWh/m	1 500 kWh/m	2 000 kWh/m	3 000 kWh/m	4 000 kWh/m	5 000 kWh/m	7 000 kWh/m
Current tariff	R1690	R1832	R1975	R2259	R2544	R2829	R3114	R3399	R3827	R4539	R5963	R7388	R8813	R11662
Cost reflective	R1991	R2094	R2197	R2403	R2610	R2816	R3022	R3228	R3537	R4052	R5082	R6112	R7143	R9203
Proposed tariff	R1919	R2045	R2172	R2424	R2677	R2930	R3183	R3435	R3815	R4446	R5710	R6974	R8238	R10765

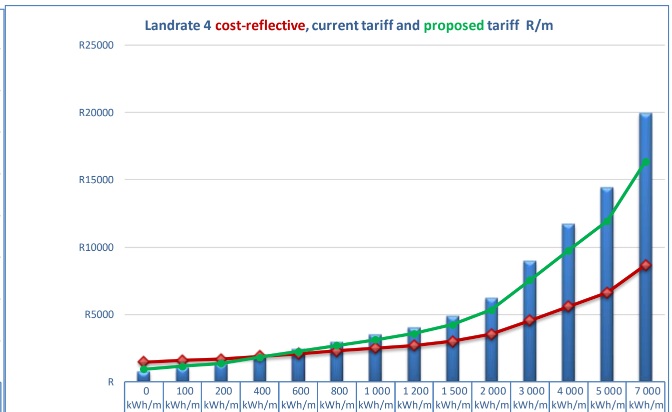


	0 kWh/m	100 kWh/m	200 kWh/m	400 kWh/m	600 kWh/m	800 kWh/m	1 000 kWh/m	1 200 kWh/m	1 500 kWh/m	2 000 kWh/m	3 000 kWh/m	4 000 kWh/m	5 000 kWh/m	7 000 kWh/m
Current tariff	R2185	R2328	R2470	R2755	R3040	R3325	R3610	R3895	R4322	R5035	R6459	R7884	R9308	R12158
Cost reflective	R3442	R3544	R3647	R3852	R4058	R4263	R4469	R4674	R4982	R5495	R6522	R7549	R8576	R10630
Proposed tariff	R2664	R2790	R2917	R3169	R3422	R3675	R3928	R4180	R4559	R5191	R6455	R7719	R8983	R11510

Figure 29: Landrate 1 and 2 non-local-authority tariffs comparison of cost-reflective, current, and proposed tariffs

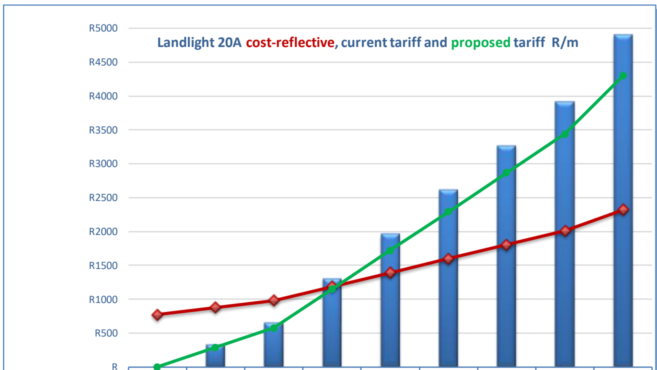


	0 kWh/m	100 kWh/m	200 kWh/m	400 kWh/m	600 kWh/m	800 kWh/m	1 000 kWh/m	1 200 kWh/m	1 500 kWh/m	2 000 kWh/m	3 000 kWh/m	4 000 kWh/m	5 000 kWh/m	7 000 kWh/m
Current tariff	R3035	R3177	R3320	R3605	R3890	R4175	R4460	R4744	R5172	R5884	R7309	R8733	R10158	R13007
Cost reflective	R6342	R6445	R6548	R6753	R6958	R7163	R7368	R7573	R7881	R8394	R9419	R10445	R11471	R13522
Proposed tariff	R3747	R3873	R4000	R4252	R4505	R4758	R5011	R5263	R5642	R6274	R7538	R8802	R10066	R12593

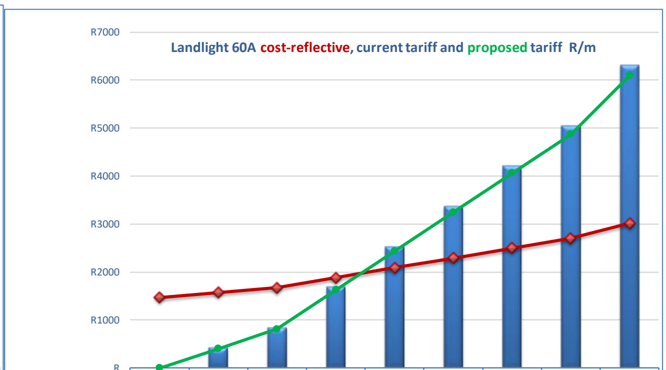


	0 kWh/m	100 kWh/m	200 kWh/m	400 kWh/m	600 kWh/m	800 kWh/m	1 000 kWh/m	1 200 kWh/m	1 500 kWh/m	2 000 kWh/m	3 000 kWh/m	4 000 kWh/m	5 000 kWh/m	7 000 kWh/m
Current tariff	R735	R1009	R1283	R1832	R2380	R2929	R3477	R4026	R4849	R6220	R8962	R11705	R14447	R19932
Cost reflective	R1469	R1572	R1675	R1881	R2087	R2293	R2499	R2704	R3013	R3528	R4557	R5586	R6616	R8674
Proposed tariff	R928	R1149	R1369	R1810	R2251	R2692	R3132	R3573	R4235	R5337	R7541	R9745	R11950	R16358

Figure 30: 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	R327	R653	R1307	R1960	R2614	R3267	R3921	R4901
Cost reflective	R773	R876	R979	R1185	R1391	R1597	R1803	R2009	R2318
Proposed tariff	R	R287	R573	R1147	R1720	R2294	R2867	R3441	R4301



	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	R421	R842	R1685	R2527	R3370	R4212	R5054	R6318
Cost reflective	R1469	R1572	R1675	R1881	R2087	R2293	R2499	R2704	R3013
Proposed tariff	R	R406	R812	R1624	R2436	R3249	R4061	R4873	R6091

Figure 31: Landlight 20A and 60A non-local-authority tariffs comparison of cost-reflective, current, and proposed tariffs

B.3 Homepower non-local-authority

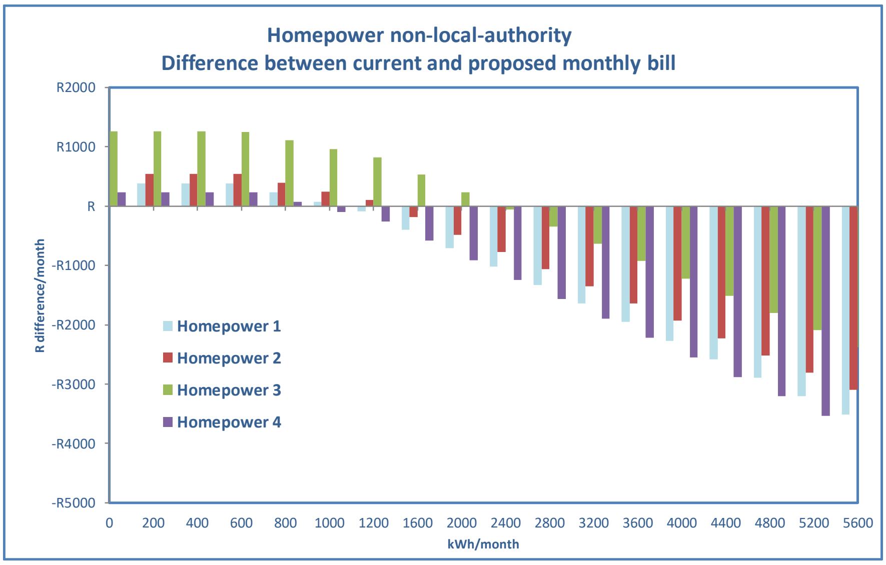
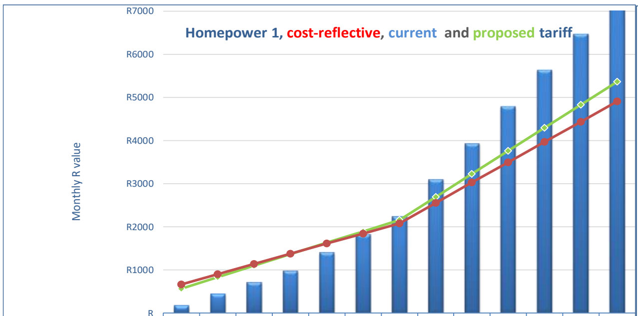
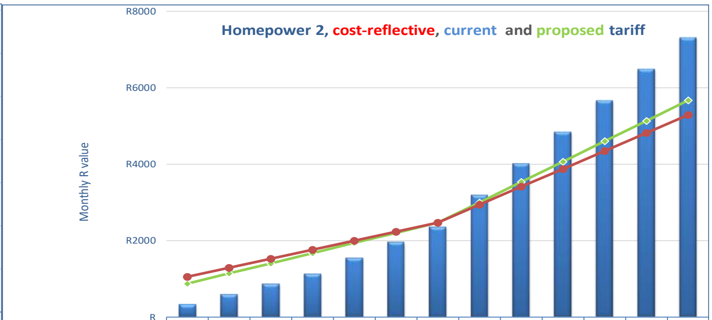


Figure 32: Homepower non-local-authority tariffs impact at different consumption levels

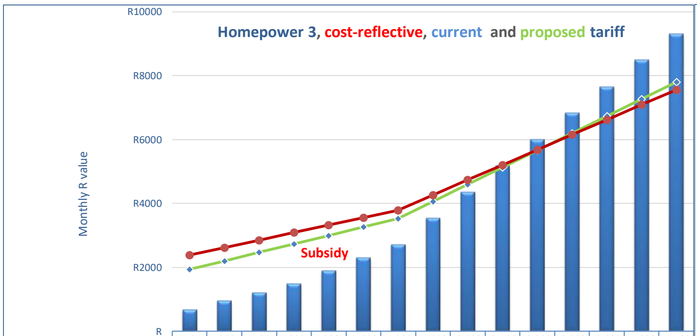


Monthly consumption	0 kWh	200 kWh	400 kWh	600 kWh	800 kWh	1 000 kWh	1 200 kWh	1 600 kWh	2 000 kWh	2 400 kWh	2 800 kWh	3 200 kWh	3 600 kWh
Homepower 1 current	R174	R442	R710	R977	R1400	R1823	R2245	R3090	R3936	R4781	R5626	R6472	R7317
Homepower 1 proposed	R563	R830	R1096	R1363	R1629	R1896	R2162	R2696	R3229	R3762	R4295	R4828	R5361
Homepower 1 cost-reflective	R668	R903	R1139	R1375	R1610	R1846	R2082	R2553	R3024	R3496	R3967	R4438	R4909

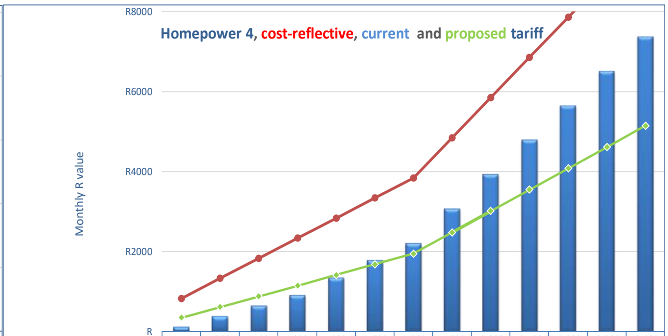


Monthly consumption	0 kWh	200 kWh	400 kWh	600 kWh	800 kWh	1 000 kWh	1 200 kWh	1 600 kWh	2 000 kWh	2 400 kWh	2 800 kWh	3 200 kWh	3 600 kWh
Homepower 2 current	R327	R594	R862	R1130	R1542	R1954	R2366	R3190	R4014	R4838	R5663	R6487	R7311
Homepower 2 proposed	R870	R1137	R1403	R1670	R1936	R2203	R2469	R3002	R3535	R4069	R4602	R5135	R5668
Homepower 2 cost-reflective	R1051	R1287	R1523	R1758	R1994	R2229	R2465	R2936	R3408	R3879	R4350	R4822	R5293

Figure 33: Homepower 1 and 2 non-local-authority tariffs comparison of cost-reflective, current, and proposed tariffs



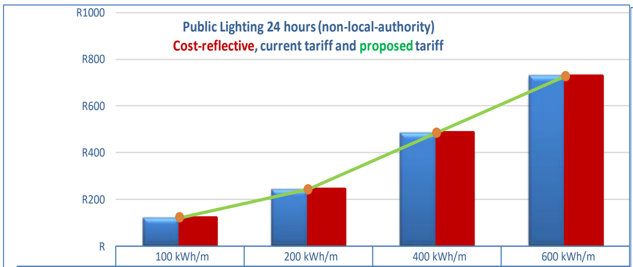
Monthly consumption	0 kWh	200 kWh	400 kWh	600 kWh	800 kWh	1 000 kWh	1 200 kWh	1 600 kWh	2 000 kWh	2 400 kWh	2 800 kWh	3 200 kWh	3 600 kWh	4 000 kWh	4 400 kWh
Homepower 3 current	R675	R942	R1210	R1478	R1890	R2302	R2714	R3538	R4362	R5186	R6011	R6835	R7659	R8483	R9307
Homepower 3 proposed	R1934	R2200	R2467	R2733	R3000	R3267	R3533	R4066	R4599	R5132	R5666	R6199	R6732	R7265	R7798
Homepower 3 cost-reflective	R2381	R2617	R2852	R3088	R3324	R3559	R3795	R4266	R4738	R5209	R5680	R6152	R6623	R7094	R7565



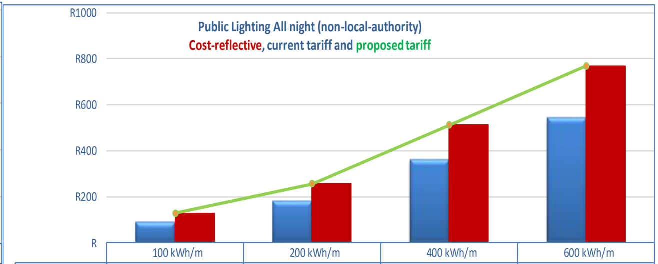
Monthly consumption	0 kWh	200 kWh	400 kWh	600 kWh	800 kWh	1 000 kWh	1 200 kWh	1 600 kWh	2 000 kWh	2 400 kWh	2 800 kWh	3 200 kWh	3 600 kWh
Homepower 4 current	R106	R374	R642	R909	R1340	R1770	R2201	R3062	R3922	R4783	R5644	R6505	R7366
Homepower 4 cost-reflective	R480	R716	R951	R1187	R1423	R1658	R1894	R2365	R2837	R3308	R3779	R4250	R4722
Homepower 4 proposed	R344	R610	R877	R1143	R1410	R1677	R1943	R2476	R3009	R3542	R4076	R4609	R5142

Figure 34: Homepower 3 and 4 non-local-authority tariffs comparison of cost-reflective, current, and proposed tariffs

B.4 Public Lighting non-local-authority

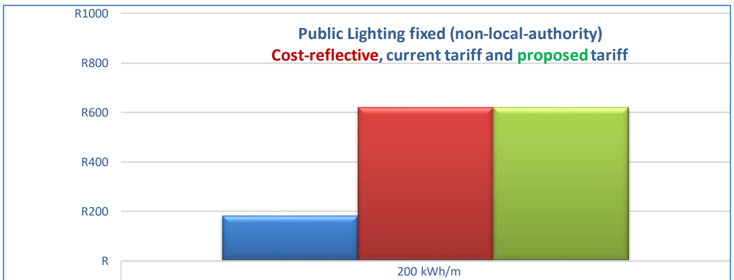


	100 kWh/m	200 kWh/m	400 kWh/m	600 kWh/m
Current tariff	R122	R243	R487	R730
Cost reflective	R121	R242	R484	R727
Proposed tariff	R121	R242	R484	R727



	100 kWh/m	200 kWh/m	400 kWh/m	600 kWh/m
Current tariff	R91	R182	R363	R545
Cost reflective	R128	R256	R512	R768
Proposed tariff	R128	R256	R512	R768

Figure 35: Public Lighting All-Night and 24-Hour non-local-authority tariffs comparison of cost-reflective, current, and proposed tariffs



	200 kWh/m
Current tariff	R182
Cost reflective	R621
Proposed tariff	R621

Figure 36: 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

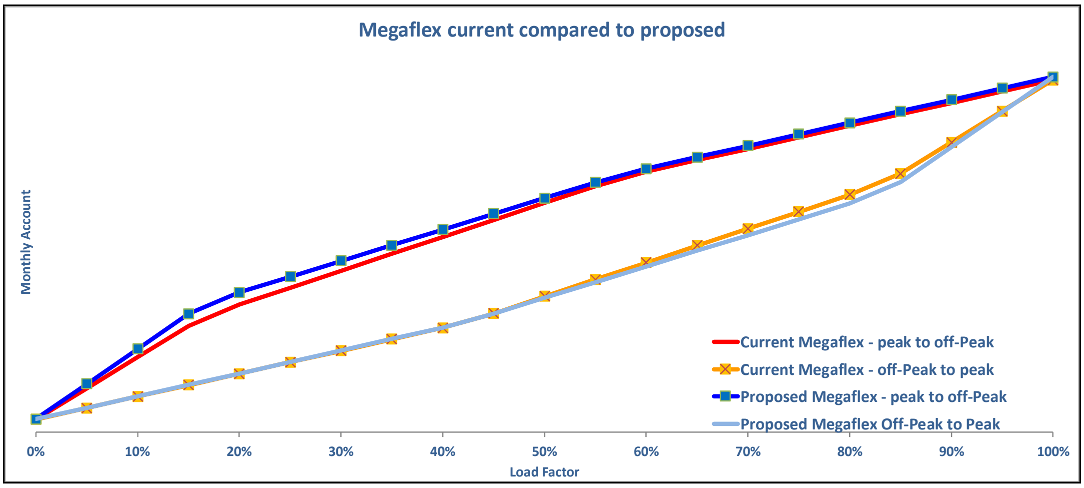


Figure 37: Current Megaflex non-local-authority tariff compared to the proposed tariff

B.6 Nightsave Urban non-local-authority

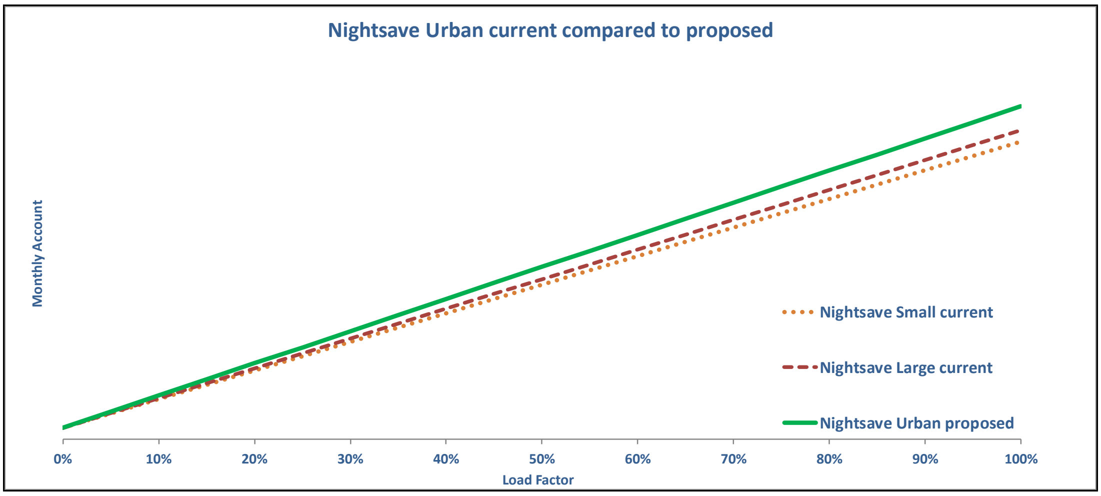


Figure 38: Current Nightsave Urban non-local-authority tariff compared to the proposed tariff

B.7 Miniflex non-local-authority

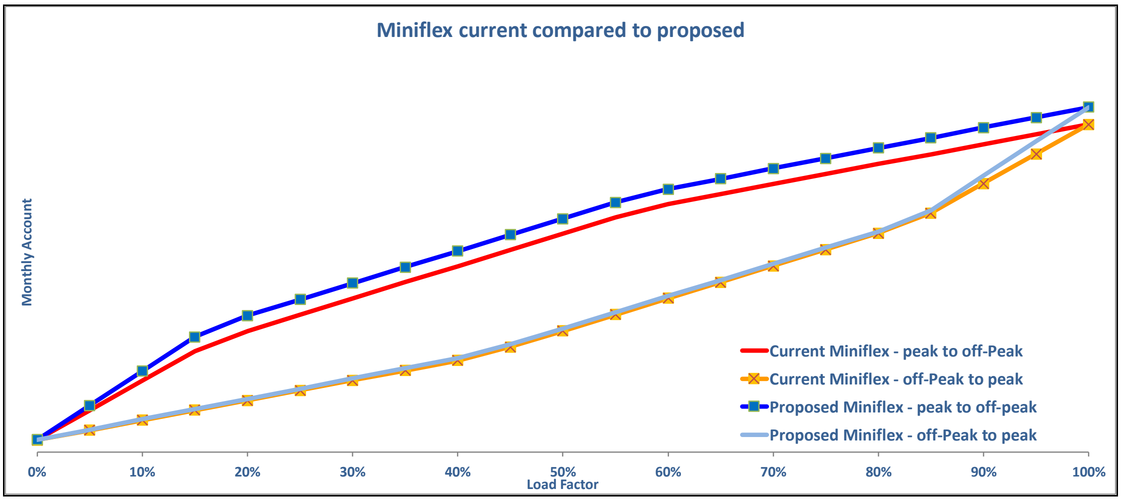


Figure 39: Current Miniflex non-local-authority tariff compared to the proposed tariff

B.8 Ruraflex non-local-authority

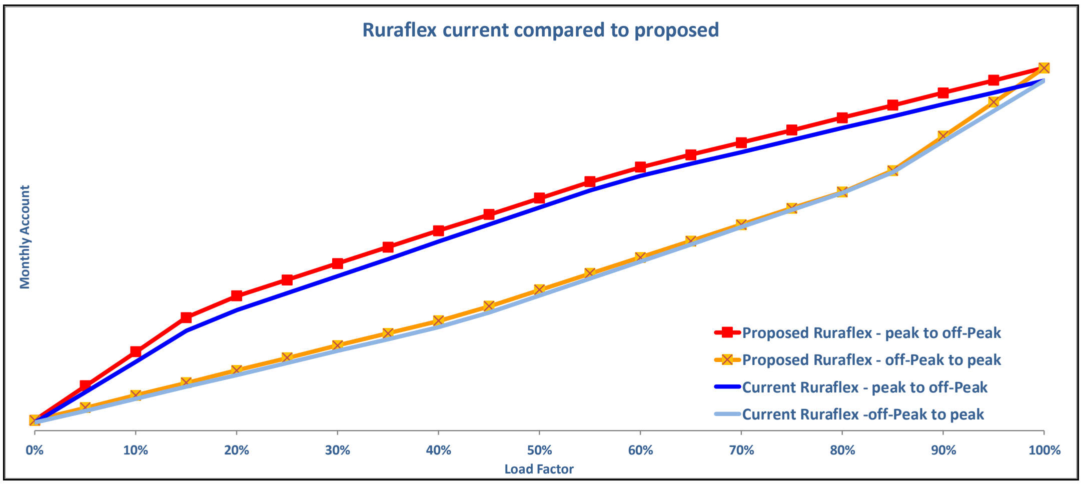


Figure 40: Current Ruraflex non-local-authority tariff compared to the proposed tariff

B.9 Nightsave Rural non-local-authority

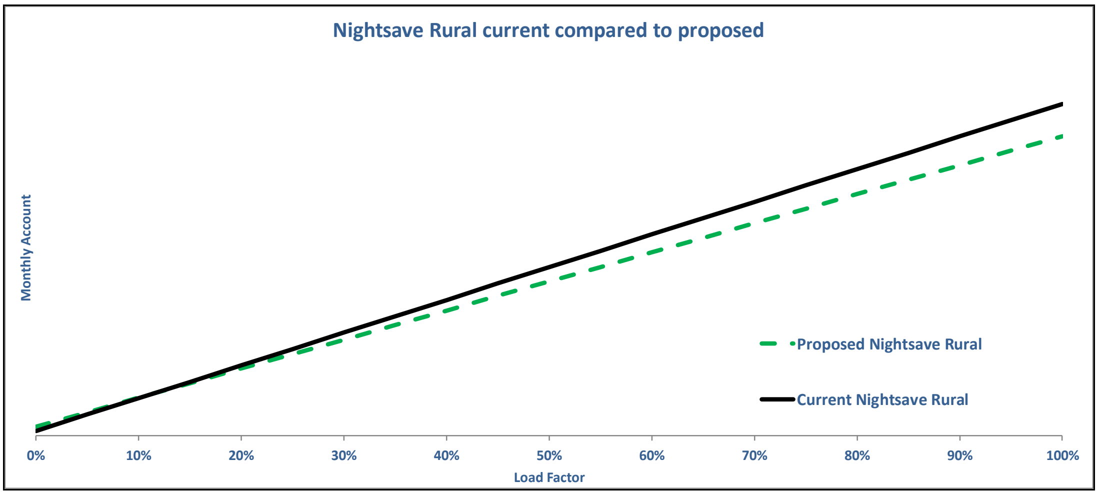


Figure 41: Current Nightsave Rural non-local-authority tariffs compared to the proposed tariff

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

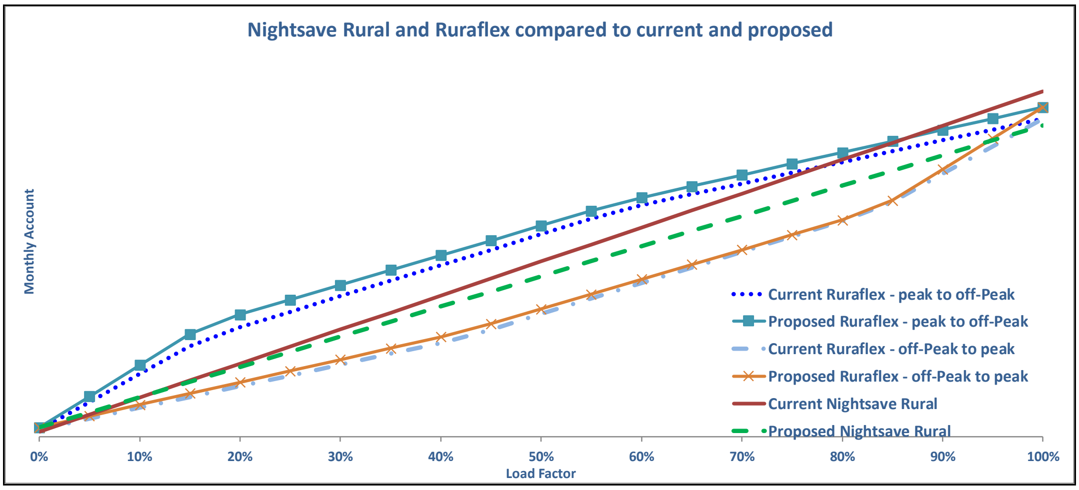


Figure 42: Current Nightsave Rural and Ruraflex non-local-authority tariffs compared to the proposed tariffs

B.11 Total impacts for LPU tariffs per voltage

The following table provides the impact per voltage for the LPU tariffs.

Table 23: Total impact per voltage for the LPU tariffs

LPU tariffs impact per voltage (%)	Megaflex	Miniflex	Nightsave Large	Nightsave Small	Transflex 1	Transflex 2	Ruraflex	Nightsave Rural
<500V	-2.2%	3.6%	-0.5%	8.1%			3.8%	-11.9%
≥500V & <66kV	1.7%	4.6%	2.0%	7.6%	1.8%	-3.6%	5.0%	-8.5%
≥66kV & <132kV	-3.0%	-2.9%	-2.1%	1.2%	-1.3%	-4.7%		
>132kV	-1.3%				-0.5%			
Total	**1.0%**	**4.0%**	**1.0%**	**7.9%**	**-0.7%**	**-4.1%**	**4.3%**	**-10.2%**

LPU tariffs impact per voltage (Rm.)	Megaflex	Miniflex	Nightsave Large	Nightsave Small	Transflex 1	Transflex 2	Ruraflex	Nightsave Rural
<500V	-R 0.2	R 49.7	-R 3.3	R 41.7			R 148.3	-R 154.7
≥500V & <66kV	R 919.7	R 118.6	R 27.8	R 24.4	R 9.7	-R 11.3	R 120.0	-R 113.3
≥66kV & <132kV	-R 128.7	-R 3.6	-R 3.4	R 0.1	-R 30.3	-R 10.0	R 0.0	R 0.0
>132kV	-R 128.1	-R 0.4	R 0.0	R 0.0	-R 0.2	R 0.0	R 0.0	R 0.0

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 Wholesale Energy Purchase Structure

C.1 Background

The Wholesale Energy Purchase Structure (called WEPS) is the basis for all Eskom retail TOU tariffs. The current WEPS structure does not reflect the present system requirements. Eskom proposes changes to the WEPS 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 WEPS structure were used in the CTS to develop the retail tariffs, using the revised WEPS c/kWh[6] energy costs, proposed TOU hours and, the tariff ratios 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.

The proposed changes to the WEPS structures feeding into the retail tariffs are aligned with the Department of Mineral Resources and Energy's Electricity Pricing Policy (EPP) Policy Position 12, Policy Position 13, Policy Position 31, and Policy Position 32 (as shown in Annexure G).

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

The current WEPS structure no longer reflects the present system requirements and costs incurred 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 WEPS structure will optimise the management of the power system, enable an increase in sales, incentivise growth, and reduce Eskom's revenue risks (moving some of the winter revenue risk to summer). The changes to the structure will also drive cost-efficiencies to support Eskom's long-term price path.

This proposed change is the initial step, with a relatively small change to limit the impact on Eskom and customers. After these proposed changes have been implemented, the TOU tariffs 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, unbundling to reflect variable and fixed energy costs, and customer needs to achieve Eskom's long-term price path.

[6] Eskom will be proposing future changes to the WEPS structure to unbundle variable (c/kWh) and fixed capacity-related energy costs (R/kW/kVA).

C.3 System Operator's requirements

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

a) The ideal system load profile is a flat profile, 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, in particular, 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. The minimum load on the power system is generally at 22 000 MW to 23 000 MW, while an additional 11 000 MW or more 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 due to PV energy production dropping off, while demand is increasing.

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.

The System Operator's requirements to optimally manage the power system are shown in the figure below.

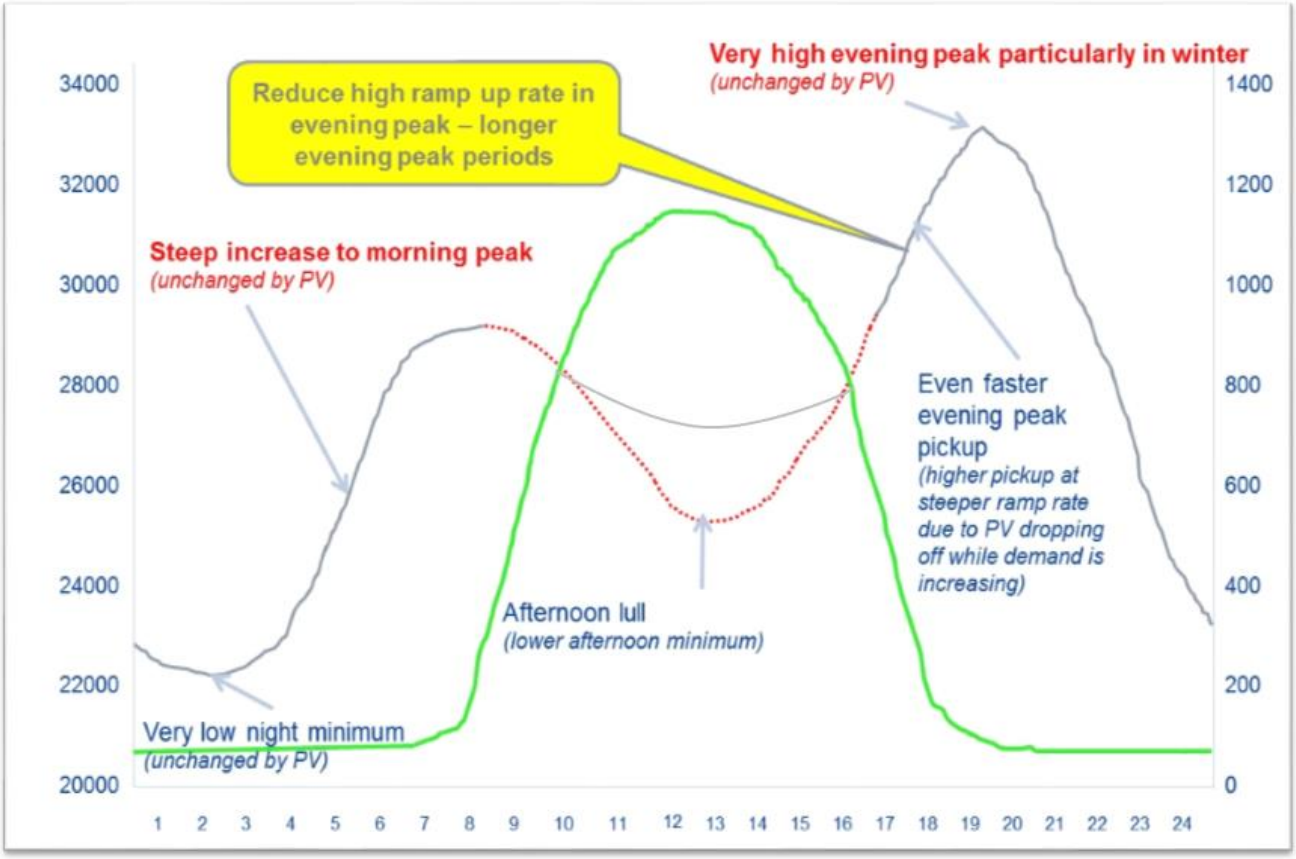


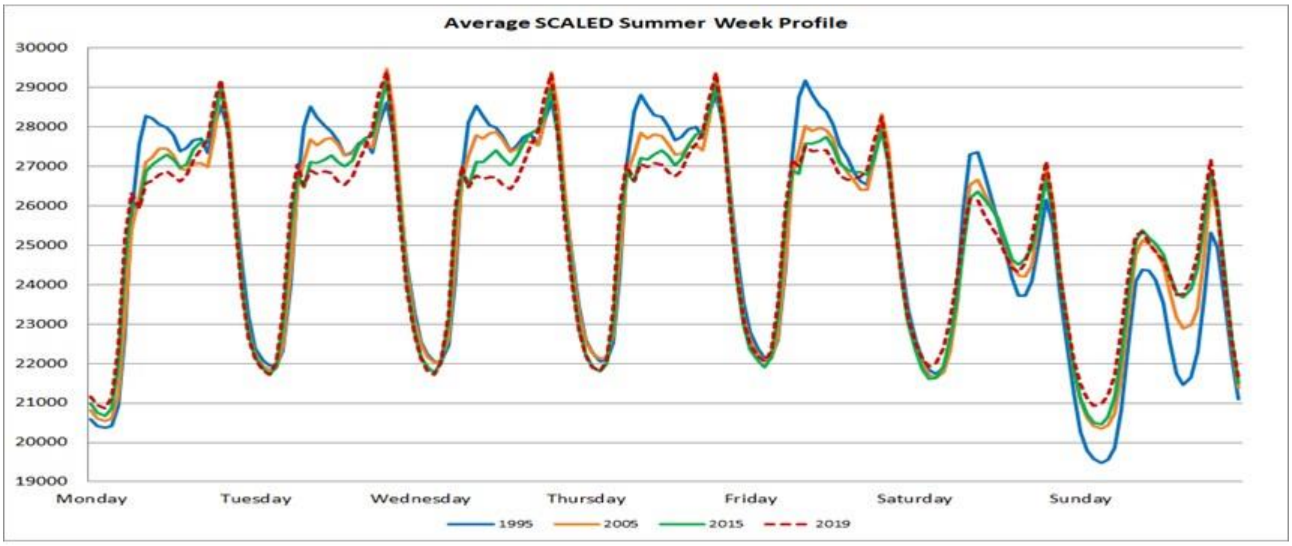
Figure 43: Eskom's System Operator overview and requirements to optimally manage the power system

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, and this response has contributed to the flattening of Eskom's load profile and the management of demand, in particular in the winter TOU periods (June to August). The changes in the Eskom system load profile over a period of 20 years (normalised) from 1995 to 2019 are shown the next figure.

Analysis of the scaled winter and summer average week of the national system profile from 1995 to 2016 shows the following changes in the system profile:

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



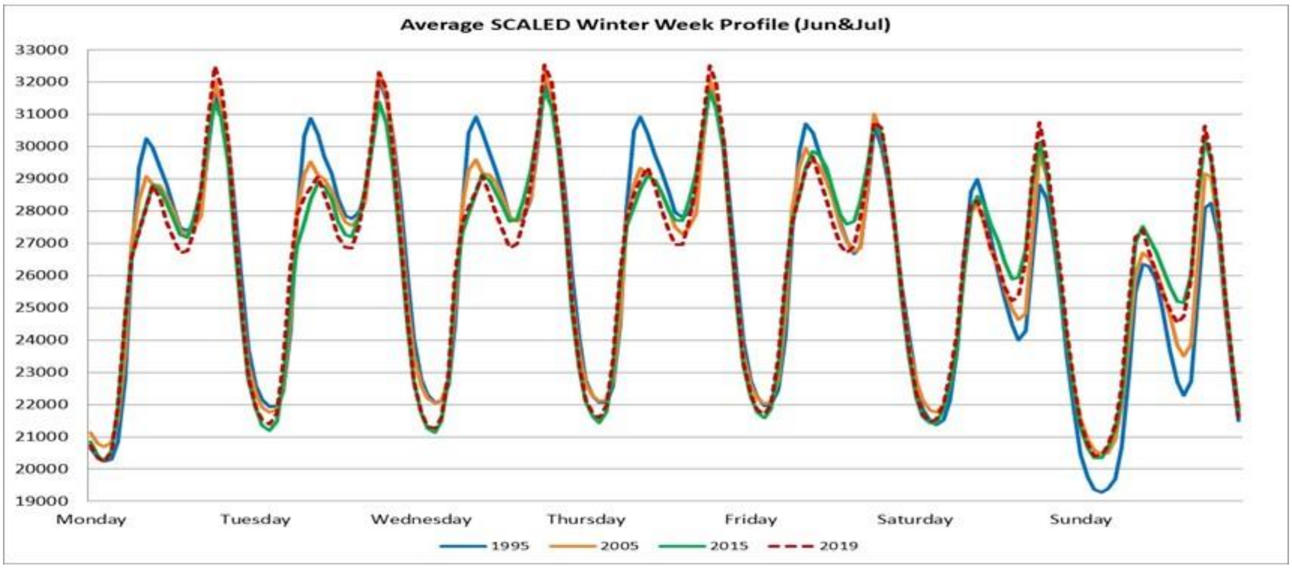


Figure 44: Scaled winter and summer average week of the national system profile from 1995 to 2019

From the changes to the system profile over the last 24 years, it is evident that customers have responded to the time-of-use price signals.

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.

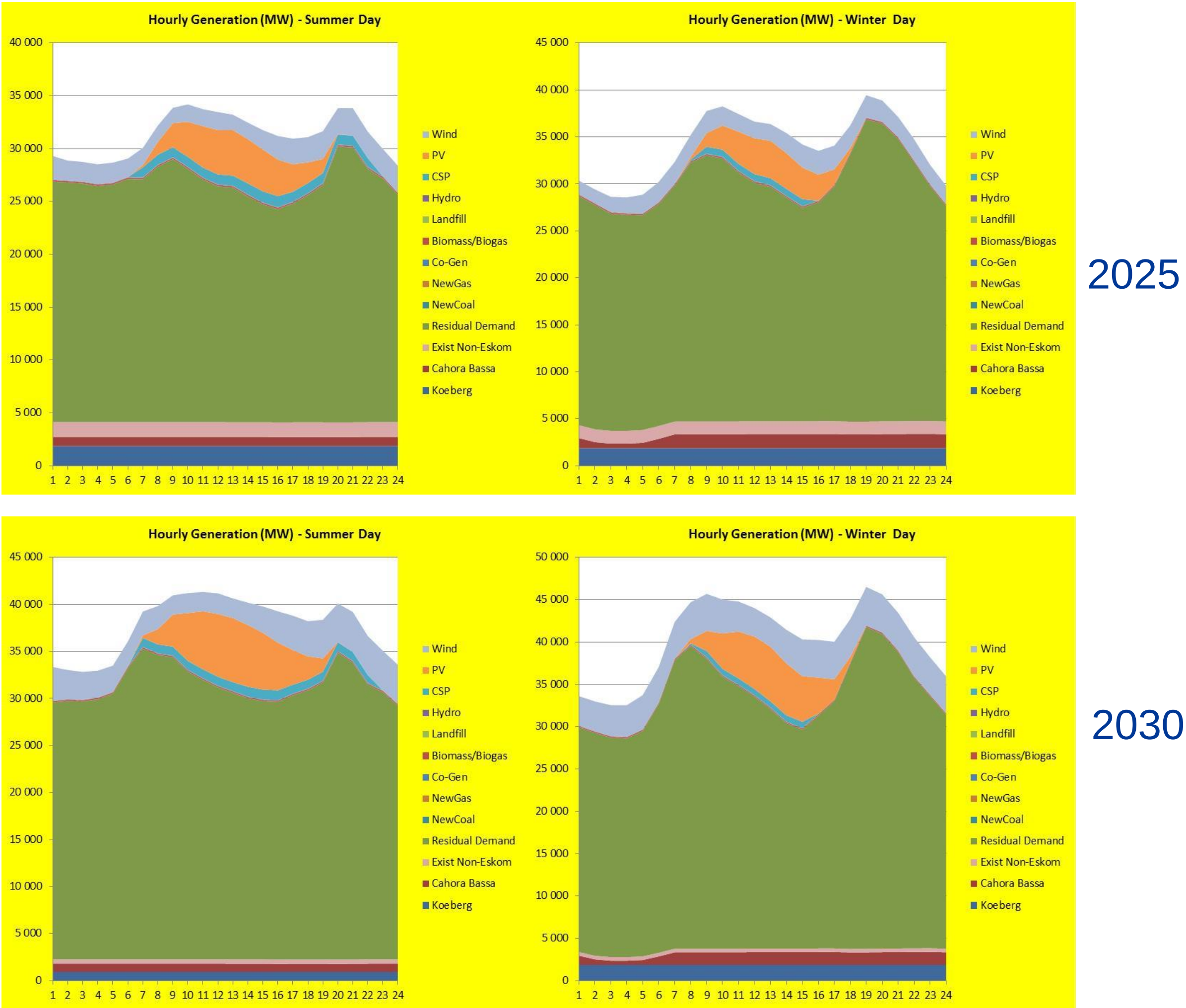


Figure 45: Average summer and winter weekday system profile in 2025 and 2030

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

The changes to the WEPS and retail TOU tariff have been designed for alignment with the objectives of Eskom's Corporate Plan and Eskom's Strategic Pricing Direction. The figure below shows the alignment of the changes to the TOU tariff design objectives with those of Eskom's Corporate Plan Strategic Pillars and Eskom's Strategic Pricing Direction objectives.

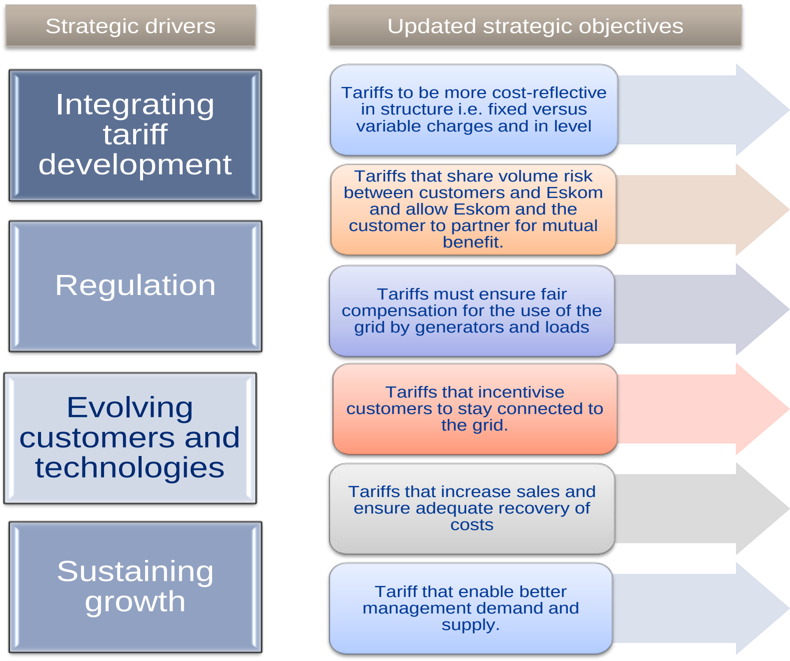


Figure 46: Eskom's Corporate Plan and Eskom's Strategic Pricing Direction alignment with the proposed changes to the TOU tariff

C.6 The features of the proposed changes to the WEPS and retail TOU tariffs

The proposed changes to the WEPS 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 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 WEPS and retail tariffs are shown in the following table.

Table 24: 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 WEPS 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 WEPS peak, standard, and off-peak ratios and rates, including the changes to the hours, are shown in the table below.

Table 25: Current and proposed WEPS energy costs and ratios (excluding losses)

	WEPS 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 WEPS existing TOU ratios c/kWh	296.43	89.79	48.77	96.73	66.55	42.23
Updated CTS WEPS existing TOU ratios c/kWh	349.70	100.97	51.58	109.28	73.00	43.71
4) New ratios	6.00	1.50	1.00	2.49	1.40	1.00
5) Existing WEPS new TOU ratios c/kWh	253.40c	63.35c	42.23c	105.16c	59.13c	42.23c
6) Updated CTS WEPS new TOU ratios c/kWh	304.82c	76.20c	50.80c	126.50c	71.13c	50.80c
ference between current and new ratios c/kWh	8.39c	-13.59c	2.03c	29.77c	4.58c	8.57c
ference existing WEPS vs New CTS TOU c/kWh	53.27c	11.18c	2.81c	12.55c	6.45c	1.48c
9) Difference New CTS TOU vs Old CTS TOU	-44.88c	-24.77c	-0.78c	17.22c	-1.87c	7.09c

When comparing the proposed WEPS rates to the existing WEPS rates, 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).
- This ratio change before updating the energy costs with the CTS, has reduced the winter prices and increased the summer prices (see points 2 and 5 above).
- That all energy rates updated with the CTS energy cost, before the ratio change (see points 2 and 3 above) and after the ratio changes (see points 2 and 6 above), have been increased. This is due to the application over the years of the average price increase, to the WEPS rates, resulting in the energy rates being lower than the actual average energy costs.

As mentioned before, the changes to the TOU tariffs are aligned with the Department of Mineral Resources and Energy's Electricity Pricing Policy (EPP) Policy Position 12, Policy Position 13, Policy Position 31, and Policy Position 32 (as shown in Annexure G).

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 26: 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 • Refer to paragraph 0 concerning changes to service charges
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, also refer to paragraph 0
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, and periods and the updated loss factors.

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

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 27: Structure for the active energy charges

Tariff	Charge unit	Features
Non-local-authority tariffs		
Businessrate 1, 2, 3	• Single active energy c/kWh charge	• Structurally no change from current tariffs • Reflecting energy costs only • Single average rate based on representative TOU profile
Businessrate 4	• Single active energy c/kWh	• Structurally no change from current tariffs • 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	• Structurally no change from current tariffs • Reflecting energy costs only • Single average rate based on representative TOU profile • For Landrate 4, combined with the c/kWh service and administration charge • Is subsidised
Landrate Dx	• R/POD/day	• Structurally no change from current tariffs • Single average rate calculated based on representative TOU profile, bundled together

Tariff	Charge unit	Features
Non-local-authority tariffs		
		with other costs, and converted into a R/POD/day charge based on 200 kWh/m
Landlight 20A and 60A,	• Single active energy c/kWh charge	• Structurally no change from current tariffs • Single average energy charge based on representative TOU profile, bundled together with 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 energy charge based on representative TOU profile • Also refer to paragraph 4.7.1 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 representative TOU profile, bundled together with other costs, and converted into a single c/kWh charge • Is subsidised
WEPS, Megaflex, Miniflex, Ruraflex, Megaflex Gen, Ruraflex Gen, Transflex 1 and 2	• Active energy c/kWh charges • TOU, seasonally, voltage (reflecting losses), and transmission zone differentiated.	• Structurally no change from current tariffs, except for changes to the TOU ratios and periods • Reflecting TOU WEPS structure and 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.	• Structurally no change from current tariffs, but Nightsave Urban Large and Small combined • Reflecting TOU WEPS costs plus losses, separated into seasonal c/kWh energy charges, and, R/kVA seasonal demand charges applicable in peak and standard periods
Gen DUoS, Gen TUoS	• The TOU active energy charges are used to calculate the losses charge applied to the DUoS and TUoS network charges	• Structurally no change from current tariffs
Gen-offset	• Negative TOU-based c/kWh charges	• Structurally no change from current tariffs • Credit for energy exported

Tariff	Charge unit	Features
Non-local-authority tariffs		
	• Time, seasonally, voltage (reflecting losses), and transmission zone differentiated	• These rates are equal to the applicable tariff TOU active energy charges
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, bundled together with other costs, and converted into a single c/kWh charge
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
Gen-wheeling	• Negative TOU-based c/kWh active energy charges, excluding losses	• Structurally no change from current tariffs. • Credit for energy exported • These rates are equal to the WEPS active energy charges less losses
Gen-purchase	• Positive TOU-based c/kWh active energy charges, excluding losses	• Structurally no change from current tariff • Add-back of Eskom purchased energy, but consumed by the customer • The rates are equal to the WEPS 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	• Reflecting TOU WEPS structure and 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 • Single average rate calculated based on a combined representative TOU profile energy cost • 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	• Homepower costs cost represented on a TOU basis, also refer to paragraph 4.7.2 • Offset rate equal to the TOU active energy charge

D.3 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
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 due to 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 has to 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 the majority 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 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 cost for the two lower voltage categories has then 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)

Tariff	Charge unit	Features
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 • 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 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	• Not applicable
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) • LV subsidy charge reflecting only LV subsidy on local-authority urban tariffs

Tariff	Charge unit	Features
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.4 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
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

Tariff	Charge unit	Features
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.5 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	• Not applicable	• Receives subsidies

Tariff	Charge unit	Features
Landrate Dx	• Not applicable	• Receives subsidies
Landlight 20A and 60A	• Not applicable	• Receives subsidies
Homepower 1, 2, 3, 4	• Not applicable	• 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	• Not applicable	• Receives subsidies
Gen-DUoS, Gen-TUoS	• Not applicable	• Generators do not contribute to subsidies
Gen-offset	• Not applicable	• 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	• NA	• Does not receive or pay subsidies
Public Lighting Fixed Charge tariff	• NA	• 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	• c/kWh ERS charge	• Reflecting contribution to network subsidies
Residential tariffs		
Homeflex 1, 2, 3, 4	• NA	• Does not receive or pay subsidies

D.6 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	• Not applicable	• Does not have a reactive energy charge
Businessrate 4	• Not applicable	• Does not have a reactive energy charge
Landrate 1, 2, 3, 4	• Not applicable	• Does not have a reactive energy charge
Landrate Dx	• Not applicable	• Does not have a reactive energy charge
Landlight 20A and 60A	• Not applicable	• Does not have a reactive energy charge
Homepower 1, 2, 3, 4	• Not applicable	• 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

Tariff	Charge unit	Features
Nightsave Urban, Nightsave Rural	• Not applicable	• Does not have a reactive energy charge
Gen-Duo, Gen-TUoS	• Not applicable	• Does not have a reactive energy charge
Gen Offset	• Not applicable	• 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	• Not applicable	• Does not have a reactive energy charge
Public Lighting Fixed charge tariff	• Not applicable	• Does not have a reactive energy charge
Gen-wheeling	• Not applicable	• Does not have a reactive energy charge
Gen-purchase	• Not applicable	• 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	• Not applicable	• Does not have a reactive energy charge
Residential tariffs		
Homeflex 1, 2, 3, 4	• Not applicable	• Does not have a reactive energy charge

Annexure E – New residential TOU Homeflex and 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 and 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.

Time-of-use for residential customers is in compliance with the Department of Mineral Resources and Energy's EPP Policy Position 12, Policy Position 13, Policy Position 31, Policy Position 32, Policy Position 36, and Policy Position 58. (Note, however, that these policy positions do not accommodate inclining block tariffs.) Refer to Annexure G – Department of Mineral Resources and Energy Electricity Pricing Policy positions.

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 a cost-reflective tariff. 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%[7] to the peak demand, but do not pay rates that reflect the peak cost.
- Residential TOU provides a market tool to deal with 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.
- Research studies estimate that revenue lost to PV has been ~R642[8] million (2013 to 2017), which is projected to increase to ~R3,5 billion to R4,1 billion by 2021[9]. South Africa's residential PV contribution is ~10%.

Furthermore, the Homeflex tariff has been designed for alignment with the objectives of Eskom's Strategic Pricing Direction. The figure below shows the alignment of the Homeflex tariff design objectives with Eskom's Strategic Pricing Direction objectives.

Figure 47: Eskom's Strategic Pricing Direction alignment with the proposed Homeflex tariff

---

[7] IDM Electrical Usage 2013
[8] Preliminary Status of Small Scale Solar PV penetration in SA, Aradhna Ramdeyal, RT&D, February 2018
[9] Prospects for Small to Medium Scale Solar PV in South Africa: 2017-2020, K Kemper & U Minnaar, March 2018

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; and
f) 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. As stated in Eskom's Strategic Pricing Direction design principle below, the net billing rates may be revised based on the power system constraints or surpluses.

Design Principle 21: Avoided energy costs

- *The net-billing customer will receive compensation for the energy exported onto the grid and used by Eskom to at least the avoided energy cost to Eskom and never higher than the average energy cost for the relevant tariff.*
- *The avoided energy cost will reflect the value to Eskom of the energy exported. No subsidies will be provided to the customer through the net-billing tariff.*

There is no EPP policy position addressing the calculation of avoided energy cost.

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

Homeflex	High			Low						
	Peak c/kWh	Standard c/kWh	Off-peak c/kWh	Peak c/kWh	Standard c/kWh	Off-peak c/kWh	Ancillary service charge c/kWh	NDC c/kWh	NCC R/POD/day	Service and admin charge R/POD/day
1	350.77c	87.69c	58.46c	145.57c	81.85c	58.46c	0.2186c	15.45c	R 13.74	R 4.77
2	350.77c	87.69c	58.46c	145.57c	81.85c	58.46c	0.2186c	15.45c	R 23.83	R 4.77
3	350.77c	87.69c	58.46c	145.57c	81.85c	58.46c	0.2186c	15.45c	R 58.81	R 4.77
4	350.77c	87.69c	58.46c	145.57c	81.85c	58.46c	0.2186c	15.45c	R 6.53	R 4.77
Offset rate	350.77	87.69	58.46	145.57	81.85	58.46				

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 of energy. This energy is not purchased by the utility; the energy still belongs to the customer. Depending on legislation, this customer may or may not be required to apply for a licence.

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 can 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 in order 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.

The design of Homeflex and net billing is also aligned with Design Principle 20 of Eskom's Strategic Pricing Direction, which states the following:

Design Principle 20: Net billing tariffs

- *Net-billing will be allowed, subject to any licensing or registration required by law and in compliance with NERSA rules.*
- *The net-billing customer will be required to be at least on a time-of-use tariff and, where applicable, dynamic tariffs.*
- *The net-billing customer will be required to pay the relevant DUoS and TUoS charges for the use of the grid associated with consumption.*
- *The net-billing customer will be required to pay the relevant DUoS or TUoS charges for the use of the grid associated with export of energy. This charge may be c/kWh, R/day, or R/kVA, depending on the tariff category.*
- *A credit rate for energy exported will be given based on avoided energy cost; see 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. As stated in Eskom's Strategic Pricing Direction design principle below, the net billing rates may be revised based on the power system constraints or surpluses.
- Design Principle 21: Avoided energy costs.
- *DUoS, TUoS, and retail charges will always be payable and will not be credited against the value of energy exported.*
- *This compensation will be done on a time-of-use basis for the value of the energy exported and over the period of a year; the compensation will be capped to be no higher than energy consumed over 12 months.*
- *An additional retail charge will be raised to cover the additional cost associated with the additional billing transaction.*
- *There may be charges and/or compensation for the ancillary service provided.*

There are no EPP policy positions addressing net billing.

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, for export in the off-peak or standard periods, lower rates are applied.

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 not possible 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 due to 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 electricity 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 2019/20 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)			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	350.76c	87.68c	58.46c	145.56c	81.85c	58.46c	R 176.11	R 39.53	86.71c	82.66c	R 29.58	R 5.98
	≥500V & <66kV	345.11c	86.27c	57.51c	143.22c	80.53c	57.51c	R 173.27	R 38.89	85.31c	81.33c	R 26.79	R 5.85
	≥66kV & <132kV	323.18c	80.79c	53.86c	134.12c	75.41c	53.86c	R 162.26	R 36.42	79.89c	76.16c	R 13.83	R 5.41
	>132kV*	305.46c	76.36c	50.91c	126.77c	71.28c	50.91c	R 153.37	R 34.43	75.51c	71.98c	R 8.61	R 8.61
>300km to <= 600km	<500V	354.30c	88.57c	59.05c	147.03c	82.68c	59.05c	R 177.89	R 39.93	87.58c	83.49c	R 29.64	R 6.04
	≥500V & <66kV	348.59c	87.14c	58.09c	144.66c	81.34c	58.09c	R 175.02	R 39.29	86.17c	82.15c	R 26.85	R 5.91
	≥66kV & <132kV	326.43c	81.60c	54.40c	135.47c	76.17c	54.40c	R 163.90	R 36.79	80.69c	76.92c	R 13.88	R 5.46
	>132kV*	308.54c	77.13c	51.42c	128.04c	72.00c	51.42c	R 154.91	R 34.77	76.27c	72.71c	R 8.70	R 8.70
>600km to <= 900km	<500V	357.80c	89.44c	59.63c	148.48c	83.49c	59.63c	R 179.64	R 40.32	88.45c	84.32c	R 29.70	R 6.10
	≥500V & <66kV	352.03c	88.00c	58.67c	146.09c	82.15c	58.67c	R 176.75	R 39.67	87.02c	82.96c	R 26.91	R 5.97
	≥66kV & <132kV	329.66c	82.41c	54.94c	136.81c	76.93c	54.94c	R 165.52	R 37.15	81.49c	77.68c	R 13.94	R 5.52
	>132kV*	311.59c	77.89c	51.93c	129.31c	72.71c	51.93c	R 156.44	R 35.12	77.02c	73.43c	R 8.79	R 8.79
>900km	<500V	361.30c	90.32c	60.21c	149.94c	84.31c	60.21c	R 181.40	R 40.72	89.31c	85.14c	R 29.76	R 6.16
	≥500V & <66kV	355.47c	88.86c	59.24c	147.52c	82.95c	59.24c	R 178.48	R 40.06	87.87c	83.77c	R 26.97	R 6.03
	≥66kV & <132kV	332.88c	83.22c	55.48c	138.15c	77.68c	55.48c	R 167.14	R 37.52	82.29c	78.44c	R 13.99	R 5.57
	>132kV*	314.64c	78.65c	52.44c	130.57c	73.42c	52.44c	R 157.97	R 35.46	77.78c	74.14c	R 8.88	R 8.88
WEPS rate excluding losses		304.82c	76.20c	50.80c	126.50c	71.13c	50.80c						

*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 23.60	R 36.44	20.96c	0.00	0.2186c	3.95c	1.33c
≥ 500V & < 66kV	R 20.94	R 21.13	12.13c	0.00	0.2151c	3.95c	1.33c
≥ 66kV & ≤ 132kV	R 8.42	R 9.54	8.49c	R 10.74	0.2014c	3.95c	1.33c
> 132kV*				R 10.74	0.1904c	3.95c	1.33c

*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 8.82	R 1.06	
> 100 kVA & ≤ 500 kVA	R 60.97	R 15.00	
> 500 kVA & ≤ 1 MVA	R 198.34	R 21.15	
> 1 MVA	R 198.34	R 21.15	
Key customers	R 690.47	R 21.15	

Reactive energy c/kVArh (high demand season only)	
Megaflex	Miniflex
15.34	6.68

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)			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)
		Peak	Standard	Off-Peak	Peak	Standard	Off-Peak	Nightsave	Nightsave	Nightsave	Nightsave	Bundled (Transmission and Distribution)
<300km	<500V	356.04c	89.01c	59.34c	147.76c	83.08c	59.34c	R 144.60	R 35.01	80.55c	76.88c	R 25.38
	≥500V & <66kV	351.13c	87.78c	58.52c	145.72c	81.94c	58.52c	R 142.60	R 34.52	79.43c	75.82c	R 24.06
	≥66kV & <132kV											
	>132kV											
>300km to <= 600km	<500V	359.63c	89.90c	59.93c	149.25c	83.92c	59.93c	R 146.06	R 35.36	81.36c	77.66c	R 25.45
	≥500V & <66kV	354.67c	88.66c	59.11c	147.19c	82.76c	59.11c	R 144.04	R 34.87	80.23c	76.59c	R 24.12
	≥66kV & <132kV											
	>132kV											
>600km to <= 900km	<500V	363.19c	90.79c	60.53c	150.72c	84.75c	60.53c	R 147.50	R 35.71	82.16c	78.43c	R 25.51
	≥500V & <66kV	358.17c	89.54c	59.69c	148.64c	83.58c	59.69c	R 145.46	R 35.22	81.03c	77.34c	R 24.18
	≥66kV & <132kV											
	>132kV											
>900km	<500V	366.74c	91.68c	61.12c	152.20c	85.58c	61.12c	R 148.94	R 36.06	82.96c	79.19c	R 25.57
	≥500V & <66kV	361.67c	90.41c	60.27c	150.09c	84.40c	60.27c	R 146.89	R 35.56	81.82c	78.10c	R 24.24
	≥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			22.91		0.2219		
≥ 500V & < 66kV			20.39		0.2188		
≥ 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 17.63	R 1.50	
> 100 kVA & ≤ 500 kVA	R 60.97	R 15.00	
> 500 kVA & ≤ 1 MVA	R 198.34	R 21.15	
> 1 MVA	R 198.34	R 21.15	
Key customers	R 690.47	R 21.15	

Reactive energy c/kVArh (high
Ruraflex
9.59

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	Ancillary service charge c/kWh	NDC c/kWh	NCC R/POD/day	Service and admin charge R/POD/day	ERS + afford. subsidy charge
1	102.29c	0.2186c	6.49c	R 16.49	R 9.23	5.28c
2	102.29c	0.2186c	6.49c	R 24.99	R 9.23	5.28c
3	102.29c	0.2186c	6.49c	R 60.96	R 9.23	5.28c
4	149.80c	0.2186c	6.49c			5.28c

Landrate	Energy charge c/kWh	Ancillary service charge c/kWh	NDC c/kWh	NCC R/POD/day	Service and admin charge R/POD/day
1	102.53c	0.2219c	23.62c	R 45.30	R 17.79
2	102.53c	0.2219c	23.62c	R 69.79	R 17.79
3	102.53c	0.2219c	23.62c	R 105.39	R 17.79
4	196.59c	0.2219c	23.62c	R 30.51	
Landrate Dx					R 56.63
Landlight 20A	286.73c				
Landlight 20A	406.06c				

Homepower	Energy charge c/kWh	Ancillary service charge c/kWh	NDC c/kWh	NCC R/POD/day	Service and admin charge R/POD/day
1	117.61c	0.2186c	15.45c	R 13.74	R 4.77
2	117.61c	0.2186c	15.45c	R 23.83	R 4.77
3	117.61c	0.2186c	15.45c	R 58.81	R 4.77
4	117.61c	0.2186c	15.45c	R 6.53	R 4.77
Homepower Bulk	117.61c	0.2186c	15.45c	R 45.17/KVA	R 9.88

Homeflex	High			Low						
	Peak c/kWh	Standard c/kWh	Off-peak c/kWh	Peak c/kWh	Standard c/kWh	Off-peak c/kWh	Ancillary service charge c/kWh	NDC c/kWh	NCC R/POD/day	Service and admin charge R/POD/day
1	350.77c	87.69c	58.46c	145.57c	81.85c	58.46c	0.2186c	15.45c	R 13.74	R 4.77
2	350.77c	87.69c	58.46c	145.57c	81.85c	58.46c	0.2186c	15.45c	R 23.83	R 4.77
3	350.77c	87.69c	58.46c	145.57c	81.85c	58.46c	0.2186c	15.45c	R 58.81	R 4.77
4	350.77c	87.69c	58.46c	145.57c	81.85c	58.46c	0.2186c	15.45c	R 6.53	R 4.77
Offset rate	350.77	87.69	58.46	145.57	81.85	58.46				

Homelight	Energy charge c/kWh Block 1	Energy charge c/kWh Block 2	Single rate	
20A			112.85c	Apply single n Yes
60A			135.98c	Apply single n Yes

Public Lighting Non Munic	All night	R/100W/month
All night c/kWh	128.07c	R 42.69
24 hours c/kWh	121.09c	R 88.40
Fixed charge R/day	R 20.42	
Maintenance charge	**Per luminaire**	**Per High mast luminaire**
	R 48.19	R 1 121.70

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			Transmission network charge R/kVA
		Peak	Standard	Off-Peak	Peak	Standard	Off-Peak	
<300km	<500V	351.02c	87.75c	58.50c	145.68c	81.91c	58.50c	R 5.99
	≥500V & <66kV	345.16c	86.28c	57.52c	143.24c	80.54c	57.52c	R 5.85
	≥66kV & <132kV	323.18c	80.79c	53.86c	134.12c	75.41c	53.86c	R 5.41
	>132kV*	305.46c	76.36c	50.91c	126.77c	71.28c	50.91c	R 8.61
>300km to <= 600km	<500V	357.38c	89.36c	59.60c	148.38c	83.44c	59.60c	R 6.13
	≥500V & <66kV	349.30c	87.32c	58.24c	144.95c	81.50c	58.24c	R 5.93
	≥66kV & <132kV	326.43c	81.60c	54.40c	135.47c	76.17c	54.40c	R 5.46
	>132kV*	308.54c	77.13c	51.42c	128.04c	72.00c	51.42c	R 8.70
>600km to <= 900km	<500V	361.89c	90.44c	60.31c	150.18c	84.43c	60.31c	R 6.20
	≥500V & <66kV	352.51c	88.13c	58.77c	146.30c	82.26c	58.77c	R 5.99
	≥66kV & <132kV	329.66c	82.41c	54.94c	136.81c	76.93c	54.94c	R 5.52
	>132kV*	311.59c	77.89c	51.93c	129.31c	72.71c	51.93c	R 8.79
>900km	<500V	365.30c	91.32c	60.88c	151.60c	85.24c	60.88c	R 6.24
	≥500V & <66kV	356.05c	89.01c	59.35c	147.75c	83.08c	59.35c	R 6.04
	≥66kV & <132kV	332.88c	83.22c	55.48c	138.15c	77.68c	55.48c	R 5.57
	>132kV*	314.64c	78.65c	52.44c	130.57c	73.42c	52.44c	R 8.88
WEPS rate excluding losses		304.82c	76.20c	50.80c	126.50c	71.13c	50.80c	

*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 27.01	R 43.07		0.00	0.2188c	3.95c	NA
≥ 500V & < 66kV	R 20.46	R 19.12		0.00	0.2151c	3.95c	NA
≥ 66kV & ≤ 132kV	R 10.26	R 9.71		R 4.89	0.2014c	3.95c	NA
> 132kV*				R 4.89	0.1904c	3.95c	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 8.82	R 1.06	
> 100 kVA & ≤ 500 kVA	R 60.97	R 15.00	
> 500 kVA & ≤ 1 MVA	R 198.34	R 21.15	
> 1 MVA	R 198.34	R 21.15	
Key customers	R 690.47	R 21.15	

Reactive energy c/kVArh (high demand season only	
Municflex	
15.34	

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	Ancillary service charge c/kWh	NDC c/kWh	NCC R/POD/day	Service and admin charge R/POD/day	ERS charge
1	104.43c	0.2186c	27.99c	R 18.42	R 12.82	3.95c
2	104.43c	0.2186c	27.99c	R 37.63	R 12.82	3.95c
3	104.43c	0.2186c	27.99c	R 79.56	R 12.82	3.95c
4	166.33c	0.2186c	27.99c			3.95c

Public Lighting munic	All night	R/100W/month
All night c/kWh	126.42c	R 42.14
24 hours c/kWh	132.95c	R 97.05
Fixed charge R/day	R 18.37	
Maintenance charge	Per luminaire	Per High mast luminaire
	R 50.62	R 1 182.14

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

Local-authority tariffs

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			Transmission network charge R/kVA
		Peak	Standard	Off-Peak	Peak	Standard	Off-Peak	
<300km	<500V	361.95c	90.48c	60.32c	150.22c	84.46c	60.32c	R 6.18
	≥500V & <66kV	355.91c	88.97c	59.32c	147.70c	83.05c	59.32c	R 6.04
	≥66kV & <132kV	333.25c	83.31c	55.54c	138.30c	77.76c	55.54c	R 5.58
	>132kV*	314.98c	78.74c	52.50c	130.72c	73.50c	52.50c	R 8.88
>300km to <= 600km	<500V	368.52c	92.14c	61.45c	153.00c	86.04c	61.45c	R 6.32
	≥500V & <66kV	360.18c	90.04c	60.05c	149.47c	84.04c	60.05c	R 6.11
	≥66kV & <132kV	336.60c	84.14c	56.09c	139.69c	78.54c	56.09c	R 5.63
	>132kV*	318.15c	79.53c	53.02c	132.03c	74.24c	53.02c	R 8.97
>600km to <= 900km	<500V	373.16c	93.26c	62.19c	154.86c	87.06c	62.19c	R 6.39
	≥500V & <66kV	363.49c	90.87c	60.60c	150.85c	84.83c	60.60c	R 6.17
	≥66kV & <132kV	339.93c	84.98c	56.65c	141.07c	79.33c	56.65c	R 5.69
	>132kV*	321.30c	80.32c	53.55c	133.34c	74.98c	53.55c	R 9.06
>900km	<500V	376.68c	94.17c	62.78c	156.33c	87.90c	62.78c	R 6.44
	≥500V & <66kV	367.15c	91.78c	61.20c	152.36c	85.67c	61.20c	R 6.23
	≥66kV & <132kV	343.25c	85.81c	57.21c	142.45c	80.10c	57.21c	R 5.74
	>132kV*	324.44c	81.10c	54.07c	134.64c	75.71c	54.07c	R 9.16
WEPS rate excluding losses		314.32c	78.57c	52.39c	130.45c	73.35c	52.39c	

*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 27.85	R 44.41		0.00	0.2256c	4.08c	NA
≥500V & <66kV	R 21.10	R 19.72		0.00	0.2218c	4.08c	NA
≥66kV & <132kV	R 10.58	R 10.01		R 5.01	0.2077c	4.08c	NA
>132kV*				R 5.01	0.1963c	4.08c	NA

*132kV/Transmission connected

Size based on MUC	Service charge R/POD/day	Admin charge R/POD/day
≤ 100 kVA	R 9.09	R 1.00
> 100 kVA & ≤ 500 kVA	R 62.87	R 15.47
> 500 kVA & ≤ 1 MVA	R 204.52	R 21.81
> 1 MVA	R 204.52	R 21.81
Key customers	R 711.98	R 21.81

Reactive energy c/kVArh (high demand season only	
Municflex	
13.89	

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	Ancillary service charge c/kWh	NDC c/kWh	NCC R/POD/day	Service and admin charge R/POD/day	ERS + afford. subsidy charge
1	107.68c	0.2254c	28.86c	R 18.99	R 13.22	4.08c
2	107.68c	0.2254c	28.86c	R 38.80	R 13.22	4.08c
3	107.68c	0.2254c	28.86c	R 82.04	R 13.22	4.08c
4	171.51c	0.2254c	28.86c			4.08c

Public Lighting munic	All night	R/100W/month
All night c/kWh	130.36c	R 43.45
24 hours c/kWh	137.09c	R 100.07
Fixed charge R/day	R 18.94	
Maintenance charge	Per luminaire	Per High mast
	R 50.62	R 1 182.14

Table 41: Gen-DUoS tariff

Gen-DUoS

DUoS network charges for generators	
Voltage	Network capacity charge [R/kW]
< 500V	
≥ 500V & < 66kV	
≥ 66kV & ≤ 132kV	14.08

Distribution loss factors for Distribution connected generators		
Voltage	Urban loss factor	Rural loss factor
< 500V	1.1483	1.1656
≥ 500V & < 66kV	1.1298	1.1495
≥ 66kV & ≤ 132kV	1.0580	0.0000
> 132kV/Transmission connected	1.0000	0.0000

Transmission loss factors for Distribution connected generators	
Voltage	Zone
≤ 300km	1.0021
> 300km & ≤ 600km	1.0122
> 600km & ≤ 900km	1.0222
> 900km	1.0322

Voltage	Ancillary service charge c/kWh (Urban)	Ancillary service charge c/kWh (Rural)
< 500V	0.22	0.22
≥ 500V & < 66kV	0.22	0.22
≥ 66kV & ≤ 132kV	0.20	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	8.82	1.06
> 100 kVA/kW & ≤ 500 kVA/kW	60.97	15.00
> 500 kVA/kW & ≤ 1 MVA/MW	198.34	21.15
> 1 MVA/MW	198.34	21.15
Transmission connected	690.47	21.15

Rural retail charges based on MEC	Service charge R/POD/day	Admin charge R/POD/day
≤ 100 kVA/kW	17.63	1.50
> 100 kVA/kW & ≤ 500 kVA/kW	60.97	15.00
> 500 kVA/kW & ≤ 1 MVA/MW	198.34	21.15
> 1 MVA/MW	198.34	21.15

Table 42: Gen-TUoS tariffs

Gen-TUoS

Loss factors and network charges for Transmission connected generators		
Zone	Loss factor	Network charge [R/kW]
Cape	0.0971	R 0.00
Karoo	0.0995	R 0.00
Kwazulu-Natal	1.0040	R 1.98
Vaal	1.0200	R 6.59
Waterberg	1.0230	R 8.44
Mpumalanga	1.0210	R 7.83

Ancillary service charge for Transmission connected generators	Ancillary service charge [c/kWh]
Generators	0.1904

Retail charges based on MEC	Service charge R/POD/day	Admin charge R/POD/day
Transmission connected	690.47	21.15

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 administration charge
	All other tariff charges	NA

Annexure G – Department of Mineral Resources and Energy Electricity Pricing Policy positions

The CTS and tariff design were based on the guidelines and rules as contained in the Electricity Pricing Policy (EPP) as stated, on the policy positions below.

For the full document go to

http://www.energy.gov.za/files/policies/Electricity%20Pricing%20Policy%2019Dec2008.pdf

Policy Position 1

a) The revenue requirement for a regulated licensee must be set at a level which covers the full cost of production, including a reasonable risk adjusted margin or return on appropriate asset values. The regulator, after consultation with stakeholders, must adopt an asset valuation methodology that accurately reflects the replacement value of those assets such as to allow the electricity utility to obtain reasonably priced funding for investment; to meet Government defined economic growth.
b) In addition, the regulatory methodology should anticipate investment cycles and other cost trends to prevent unreasonable price volatility and shocks while ensuring financial; viability, continuity, fundability and stability over the short, medium and long term assuming an efficient and prudent operator.

Policy Position 2

Electricity Tariffs must reflect the efficient cost of rendering electricity services as accurately as practical.

a) The average level of all the tariffs must be set to recover the approved revenue requirement.
b) The tariff structures must be set to recover costs as follows:
    - The energy costs for a particular customer category.
    - The network usage cost for a particular t consumer category and
    - Service costs associated therewith.

Policy Position 3

The customer bill must comply with NRS 047

Policy Position 4

All forms of discriminatory pricing practices must be identified and removed, other than those permitted under specific cross-subsidisation / developmental programmes, or be transparently reflected to unlock the full potential of electricity to all.

Policy Position 5

a) Fair and non-discriminatory access to and use of networks to all users of the relevant networks.
b) The full cost to operate the networks is reflected in the various connection and use of system charges and, therefore, no additional charges for wheeling of electricity will be levied unless the wheeling action introduces incremental costs.
c) Any incremental wheeling costs associated with a specific wheeling transaction and its fair share must be recovered as a connection charge.
d) Wheeling of electricity can only be permitted if the action complies with all technical, safety and commercial requirements.
e) A methodology for transmission and distribution wheeling, including the treatment of network congestion, must be developed by NERSA.

Policy Position 6

In addition to the standard range of pricing products provision must also made for the development and introduction of special products and prices to achieve specific goals, the cost of which will be treated according to the regulatory methodology.

Policy Position 7

NERSA, after consulting with stakeholders, should develop and publish a multiyear price path on an annual basis.

Policy Position 8

a) Electricity from both licensed generators in South Africa and from all approved importers of electricity to South Africa must fall within the scope of the EPP.
b) NERSA may apply certain exclusions in terms of predetermined criteria as prescribed by DME (e.g. private generators producing electricity for own use on the same site).

Policy Position 9

a) Generating pricing structures must reflect the cost-of-supply of the generator or alternatively any approved PPA.
b) Generator pricing structure can consist of the following; Capacity, energy and ancillary service charges.
c) Customers, who are able, must be given the opportunity to sell ancillary services to the market on a fair and non-discriminatory basis.
d) Generator pricing structures must not hinder efficient and least cost dispatch of the generating units.

Policy Position 10

a) The price paid for electricity generated in South Africa or imported to South Africa must be based on either the appropriate and approved regulatory method or on conditions set out in the approved PPA.
b) Electricity purchases from new supply options must be evaluated and approved subject to ex ante approval of the power purchase agreements
c) NERSA may approve a framework to expedite the determination and approval of prices from supply options (e.g. short term purchase!)

Policy Position 11

a) Preferably, renewable generators will compete with non-renewables in terms of price taking into account all forms of support (for examples. grants. soft loads. CDM, feed-in tariffs, green tariffs, tax incentive).
b) Alternatively, in the case where renewable support mechanisms are insufficient and State targets for renewables are thus not reached, renewables could be introduced at a price premium relative to non-renewables, subject to approval by NERSA.
c) Renewable power can be traded by the single buyer licensers or customers. Renewable power can be sold at a special price or the cost can be pooled with energy cost and form part of the charges to all customers.
d) The DME will develop a renewable energy guideline to support the introduction of renewable energy.
e) Any policy proposals on environmental support for electricity generators must be done by DME after consultation with DEAT and other relevant stakeholders.

Policy Position 12

a) Wholesale energy prices must encourage the efficient use of electricity at all times and must reflect the TOU structure differentiated cost-of-supply.
b) The wholesale energy price structure must be periodically reviewed and updated by the single buyer· and approved by NERSA.

Policy Position 13

a) Wholesale energy prices must cover the cost of wholesale purchases, including capacity, energy and ancillary services.
b) Wholesale energy prices must consist of the generator prices, plus the single buyer own costs.
c) NERSA must develop an over/under recovery mechanism to deal with mismatches between wholesale energy purchases and sales.

Policy Position 14

a) NPAs are permitted, but must be structured in a way so as to minimise price distortions.
b) Commodity price risk exposure must be hedged outside of the ESI.
c) Existing NPAs will be honoured until the end of contract.
d) The evaluation of NPAs at inception must be based on the cost-of-supply (excluding cross-subsidies) on a discounted cash flow basis over the period of the agreement.
   - The cost-of-supply for NPAs intended for the sale and consumption of electricity in South Africa must be defined by the electricity price forecast which will be based on the prevailing regulatory methodologies in South Africa inclusive of an appropriate risk premium.
e) DME *(now DoE)* must develop a transparent NPA application and approval process to ensure adequate evaluation and consultation with key stakeholders, including National Treasury.
f) DME *(now DoE)* must update the NPA pricing framework setting out the evaluation criteria. NERSA will approve and monitor NP As in accordance with the framework.
g) All applications must be treated in accordance with the approved processes and frameworks and be approved by NERSA.

Policy Position 15

a) NERSA must develop and implement a frame work for the pricing of international sales contracts.
b) International customers connected to the transmission system must not receive subsidies intended
c) For South African customers. South African customers must not subsidise the export of electricity.
d) International contracts will be subject to South African energy conservation legislation, regulations and rules.

Policy Position 16

a) The cost of ancillary services must form part of the wholesale prices.
b) The cost of providing generator standby services to all customers (including customers with own generator), must form part of the wholesale prices.

Policy Position 17

a) Transmission tariffs must be unbundled (e.g. charges for: TUOS. line losses. customer services and connection) to reflect more accurately the cost-of-supply.
b) Connection charges must be fair and calculated in accordance to a standard to be approved by NERSA.
c) The transmission tariff structure must reflect the cost-of-supply and could consist of a combination of capacity energy loss factors and fixed charges.

Policy Position 18

a) The transmission tariffs need to be set at a level that must allow the licensee to earn its approved revenue requirement.
b) Tariff levels must be determined in accordance with approved standards, codes, frameworks and other regulatory requirements.

Policy Position 19

a) Transmission network costs must be apportioned 50/50 between generators and customers to more accurately reflect the cost-of-supply.
b) Transmission losses costs will be allocated directly to loads.
c) Transmission service and other costs must be allocated rationally between loads and generators and must reflect the cost to provide the service.
d) The apportionment between generators and customers must be reviewed from time to time to ensure compliance with regional approaches in order not to disadvantage South African based generators.

Policy Position 20

a) The current transmission geographic differentials for customers must remain until it is succeed by an approved redefinition of geographic differentials.
b) The transmission licence holder, DME *(now DoE)* and NERSA must evaluate the redefinition of geographic differentials for customers assessing the price stability, comparing the current generation mix with that foreseen in the next 10 years.
c) The transmission license holder, DME *(now DoE)* and NERSA must investigate different options and adopt the most appropriate method for allocating costs between generators.

Policy Position 21

a) International SAPP operating members connected to the transmission network will pay the regulated transmission tariffs.
b) International customers will be required to pay connection charges in accordance with the connection charge policy.
c) The financing of connection assets for international customers will be in accordance with the connection charge policy.
d) Any wheeling by SAPP members through the Transmission network in South Africa must result in a payment to the transmission licensee for the wheeling service provided. The payment will be in accordance with SAPP rules for wheeling charges and will be recovered from SAPP members the approved trading entity.

Policy Position 22

a) Wholesale energy and transmission prices must be available on a fair and non-discriminatory basis to all qualifying wholesale electricity traders.
b) DME *(now DoE)* in consultation with NERSA must determine qualification criteria for wholesale traders and
c) NERSA determine implementation guidelines.

Policy Position 23

Electricity distributors shall undertake COS studies at least every five years, but at least when significant licensee structure changes occur, such as in customer base, relationships between cost components and sales volumes. This must be done according to the approved NERSA standard to reflect changing costs and customer behaviour. The cost of service methodology used to derive tariffs must accompany applications to the regulator for changes to tariff structures.

Policy Position 24

a) Licensees must undertake the required analyses to determine the extent of back log of maintenance / refurbishment and put strategies in place to catch up.
b) NERSA must give due cognisance to requests for additional funds to provide for capital and operating expenditure, including staff to manage such projects and undertake the required work.
c) The above must be done with due cognisance where proper ring fencing is not done and much of the needed funds are removed in a non-transparent fashion from the electricity sector.

Policy Position 25

a) NERSA must develop acceptable standards for non-technical losses and provision for bad debt.
b) The component of non-technical losses and bad debt which exceeds the approved standard must be considered unacceptable and be removed from the approved revenue base that would otherwise impact on the return of owners.

Policy Position 26

a) The number of consumer categories for tariff purposes should be justifiable to NERSA based on cost drivers and customer base:
   - consumption patterns e.g. usage in different times load factor and average consumption
   - type of supply (l phase or 3 phase, capacity level, overhead or underground. urban versus farms, multiple connection points);
   - type of metering (conventional or pre-payment, kWh, demand, TOU;) and
   - Position on the network (not geographic location).
   - Voltage of the supply and the system from which the supply is taken.
b) A new category must be created where costs differ by at least 10% between a group of customers and another based on the above criteria.
c) Sub-categories could also be created where only one or more components of costs differ significantly.

Policy Position 27

NERSA must see within five years that cost-reflective tariffs shall reflect all the following cost components as far as possible:

- Energy costs in c/kWh;
- Network demand charges in R/kVA/period covering;
  - Network capacity charges in R/kVA/month or R/Amp/month based on annual capacity;
- Customer service charges in R/cust/months;
- Point of supply costs R/POS/month; and
- Cost of poor power factor.

Policy Position 28

As a result of metering and billing constraints, tariffs for some customer categories will not reflect all the above components. The applicable charges must cover the full cost of all the above cost components.

Policy Position 29

Tariff structure and levels shall be aligned with the results from the COS studies in which the resultant income will equal the revenue requirement.

Policy Position 30

Cost-reflective tariffs are considered the most effective pricing signal to be provided to customers. Any additional pricing signals over and above the costs must be motivated specifically and be approved by NERSA.

Policy Position 31

Tariffs must include TOU energy rates as follows:

- All customers supplied at MV or above within two years;
- All customers above 100 kVA within five years;
- All cases where the metering provides such features within five years; and
- All other customers where it is warranted.

Policy Position 32

TOU tariff energy charges must be differentiated by:
- All the components as reflected by the WEPS
- In addition an approved super peak rate to reflect the short terms costs could be applied during emergencies in which case customers need to be informed in advance.

Policy Position 33

Tariffs charged to customers on the network will be cost-reflective within the relevant electricity utility. No geographic differentiation based on location will be applied within the area of a licensee except for farms (low density agriculture) and supplies associated with lower density.

Policy Position 34

Licensees shall apply pooling of costs per consumer category to achieved reasonable tariff.

Policy Position 35

Voltage and supply position differentials must be applied in tariffs within a licensed distributor as I follows:
- based on the supply and system voltage;
- based on the cost differences from the cost-of-supply study;
- to be applied as different energy & demand / capacity charges not as a percentage on all charge; and
- NERSA must drive a plan for phased increases in tariffs 01 lower voltages and demand of tariffs at higher voltages.

Policy Position 36

Domestic tariffs to become more cost-reflective, offering a suite of supply options with progressive capacity-differentiated tariffs and connection fees:
- At the one end a single energy rate tariff with no basic charge, limited to 20 Amps and nominal! connection charge (details under section on cross-subsidies);
- At the next level a tariff which could contain tariff charges to reflect a basic charge, customer service charge, capacity charge and energy charge with cost-reflective connection charges; and
- At the next level a tariff which could contain tariff charges to reflect a basic charge, customer service charge, capacity charge and energy charge with cost-reflective connection charges; and
- At the final level TOU tariffs must be instituted on the same basis as above, but with TOU energy rates.

Policy Position 37

NERSA shall rationalise existing electricity distribution tariffs into a set of electricity tariff structures for the EDI. The number of these sets will be governed by rationalising the number of distribution licensees through the restructuring process.

Policy Position 38

a) Any assets which are not financed by the distributor, but from sources such as: State grants, customer capital contributions and connection fees, developer networks handed to the utilities and networks transferred to new utilities debt free, shall be excluded from the asset base for the purpose of determining depreciation and return on assets and in the same way these costs be excluded from: COS studies.
b) The provision for the replacement of these assets when it becomes due shall form part of the Licensee's revenue requirements as set out in 2.2
c) These assets would, however, be included for provisions relating to all operating expenses.

Policy Position 39

A consistent methodology must be applied in the industry to govern the determination of capital contributions by customers / developers to ensure a fair and non-discriminating practice for all participants.

Policy Position 40

Public lighting, including street lights, high mast lights, parking area lights and traffic lights are considered as consumers of electricity and are not part of electricity supply. The associated charges must cover capital and operating costs associated with: energy, electricity network, dedicated lighting networks and lighting services. Such services may be provided by electricity utilities, but such costs must be charged to the appropriate owner, in most cases the municipality. The municipality can in turn fund such service from the MSOE

Policy Position 41

The network standard shall be set to ensure that the cost of redundancy of distribution networks matches the socio / economic implications of power outages and willingness to pay to avoid such disruptions. Charges for all customers shall thus be based on the standard applied at each level in the network. The recovery of revenue by the licensee and charges for all consumers shall thus be based on the standard applied at each level in the network and in line with the investment criteria set out in the respective Grid codes of NERSA.

Policy Position 42

NERSA shall develop and implement an effective system, which must include compensation to the customer, to ensure that quality customer services are provided by distributors.

Policy Position 43

a) Non-licensed traders of electricity shall provide the electricity at terms, tariffs and services not less favourably than that provided by the licensed distributor in the area.
b) NERSA shall provide guidelines to resellers regarding resale principles.

Policy Position 44

a) The application of only specifically approved cross-subsidies, subsidies, levies and surcharges must be instituted in the ESI to address certain socio / political/environment needs.
b) Cross-subsidies should have a minimal impact on price of electricity to consumers in the productive sector of the economy.

Policy Position 45

a) All levies, subsidies and cross-subsidies shall be made transparent, while moving towards cost-reflective and transparent tariffs in the ESI.
b) Licensees are required to establish and publicise the average level of cross-subsidy between customer categories.

Policy Position 46

a) The subsidisation of capital cost to connect new electrification (neglected communities) customers will be the main mechanism for National Government funded from the budget to achieve the required rate of electrification at affordable price levels.
b) As refurbishment / upgrade of these networks are required, consideration should be to include provision for such in the State mechanism.

Policy Position 47

The capital costs incurred by distributors over and above those funded by State funds to affect electrification must be ring fenced and a mechanism found to address this in a transparent way before and after restructuring, preferably per licensee.

Policy Position 48

Qualifying customers shall be subsidised through the application of a life line tariff:

a) a single energy rate tariff;
b) with no fixed charge;
c) limited in capacity 1020 Amps ;and
d) nominal connection fee.

Policy Position 49

The level of the life line tariff should be set to breakeven with the cost-reflective tariff of the licensee for a 20 Amp supply at a recommended consumption level of 350kWh per month.

Policy Position 50

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

Policy Position 51

Where LGs wish to apply free electricity in excess of the amount provided for by the equitable share to more customers or for more kWhs, such amount shall by funded by municipal revenue and not from electricity income.

Policy Position 52

There shall be no special electricity tariffs or terms for the State or State funded institutions including schools and clinics / hospitals. These shall be required to budget for the full cost of electricity services anticipated in the financial year in question. Any subsidies must be procured through intergovernmental transfers.

Policy Position 53

a) Cost-of-supply studies must be undertaken featuring pooling strategies which separate significant groups of customers that differ significantly from other customers. One such category which must be treated separately relates to supplies on farms.
b) The current cross-subsidy mechanism for supplies on farms must be continued for the time being and the impact shall be shown as a transparent levy in electricity bills where practical.
c) DME must undertake a study to consider the introduction of alternative subsidy / cross-subsidy mechanisms to address the challenges relating to farm network replacements.
    - A RED electricity levy applied at the RED level and it thus managed by the RED.
    - A national electricity levy applied at the wholesale level and thus managed by DME / agent of DME

Policy Position 54

a) Under no circumstances shall the new MSOE be introduced in addition to the current non transparent / unring-fenced surpluses.
b) NERSA shall regulate the electricity prices excluding the transparent MSOE.

Policy Position 55

The State, as the owner of public entities, must consider forfeiting dividend payments, making equity contributions and/or offering guarantee, if needed, to assist electricity utilities in maintaining appropriate gearing ratios and business indicators while incurring capital expenditure for the expansion and refurbishment of existing networks where appropriate increases in the tariff are not sufficient.

Policy Position 56

a) Cost-reflective tariff levels and structures as discussed in the EPP shall be the first main driver of DSM and efficient use in the ESI for this reason unbundled cost-reflective charges must be charged to customers.
b) This is to be applied as one of the NERSA tariff evaluation criteria.

Policy Position 57

a) NERSA must consider the impact and the effectiveness of DSM and energy efficiency in determining revenue requirements of licensees.
b) These implications must also be ringfenced and be reported on annually by licensees.

Policy Position 58

Sophisticated TOU tariffs with dynamic emergency price signals, DSM and load management features with support of smart meters on an integrated basis must be planned for rapid implementation where economically viable and practical. Mechanisms for special funding for this purpose need to be made by DME.

Policy Position 59

a) The industry must apply emergency measures to avoid the interruption of groups of customers because of shortage of supply.
b) Power rationing and similar measures must be applied to obtain mandatory reductions in power usage to such level to match supply and demand with the following provisions:
   - Penalties in price and/or interruption must be applied to those who do not reach their targets.
   - To limit the economic impact of ongoing industrial load reductions more dynamic price options, such as a TOU tariff with a super peak rate during times when interruptions are effected, should be offered at the COE applicable to rationing quantities not saved
   - Mechanisms to encourage economic growth in line with system availability must be incorporated
c) NERSA must investigate a mechanism to link charges payable by customers to the quality of supply in cases where it moves outside of the accepted norms and standards, e.g. Capacity Charge = MW x MD Charge x (Actual supplied/Max Target hours)
d) NERSA must ensure that ongoing power interruptions because of capacity / energy shortages feature in the performance management systems of licensees and its management.

Policy Position 60

a) The regulator must decide on the amount of funds to be allocated to energy efficiency based on requests made by the licensee.
b) The funds shall be applied and prioritised on a security of supply and/or least cost per saved MW basis.
c) All parties in the ESI shall be treated fairly and independently based on the measure to which the application meets the qualification criteria developed by NERSA.

Annexure H – Eskom responses to National Treasury and SALGA inputs

H.1 SALGA comments

Below is based on a draft response received from SALGA.

1. *"While this reform is fully supported, more consideration of the impacts on the proposed step-change in tariffs is needed. If current tariffs are not reformed to recover network costs appropriately, there is a risk that the burden of these network costs may be placed on low income customers (as wealthier customers cost shift through SSEG installation that doesn't cover full grid costs) who cannot afford alternative sources of electricity."*

Eskom response

This comment regarding the burden placed on other customers is supported, is the intent of the submission and is discussed section 3 in the document. On average the fixed network charges have all increased. Refer also to response in point 6 below.

2. *"However, communicating (simply and saliently) the impact of these changes is essential to gain the understanding and buy in of municipal and private customers throughout this transition. Therefore, a more thorough understanding of the impacts on municipal/household electricity bills, how these impacts were calculated, and how they can be managed through a transition plan is needed before the proposed tariff plan can be fully endorsed. "*

Eskom response

A transition plan will need to be developed going forward for future tariff changes, as this is the first step in this direction. Nersa would also have to allow cost impacts to be passed-through to the municipal end-customer for those impacted by the structural changes (positive and negative). This would also include municipalities being allowed to make structural changes to their tariffs to reflect their purchase costs more accurately.

Eskom can explain how the municipal impacts were calculated and this was done using the 2019/20 forecast volumes. These volumes were multiplied by the existing rates to get existing revenues and then compared against the revised 2019/20 tariffs contained in this plan at the same volumes, but adjusted for the TOU change. The impact is accurate based on the MYPD decision volumes.

3. *"The impact of the proposed tariffs on municipalities' revenue streams is a great concern. While it is understood that the overall impact of the tariffs is revenue neutral to the MYPD decision, each municipality is uniquely impacted depending on their current tariffs and load profile. In many cases this impact is severely negative (31% increase in bill for Umzumbe, R26 million increase in bill for Rustenberg) while in many other cases the impact is significantly positive (23% reduction in bill for Garden Route, R12 million reduction in bill for Msukaligwa).*

- *More clarity is needed on how these revenue impacts were calculated as to understand how best work with municipalities to manage these impacts.*
- *In response to these impacts, municipalities will need to adjust their tariffs accordingly. It is therefore preferred that the proposed changes to municipal bills are phased in over 2-3 years as to avoid shocking the end customers. A sensible approach may be to cap the forecasted change in bill to 5% per annum. Furthermore, a commission may be needed to work with municipalities that are negative impacted."*

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 means tariffs are less cost-reflective and not reflect divisional costs and Nersa's decision. Phasing also means a total recalculation of all rates and just delays future developments. It is not possible to cap all impacts to 5%.
- Municipalities should be allowed to pass-through these increases.

4. *"The proposed changes to the TOU rates, namely the reduction in standard period tariffs and the increase in off peak tariffs, along with the removal of the last morning peak hour, means that the value of avoided purchases from solar PV own generation will be reduced. While it is understood that this is not intended to be an "anti-renewables" move, but rather to support the connection of alternative resources in a responsible way, it does have the potential to significantly hamper the uptake of SSEG.*
   - *The challenge is that current tariffs have sent incorrect tariff signals to end customers creating a falsely attractive business case for own generation. While a transition to renewable energy is hugely important, SSEG cannot be subsidized by other households and businesses (unless this is specific and transparent policy decision). And so, communicating that Eskom is commitment to renewable energy and that the reasons for these tariff changes is to responsibly allow alternative resources is vital to ensure the entire energy sector is working in harmony towards affordable, reliable and sustainable electricity.*
   - *The Homeflex tariff is a clear indication that Eskom intends to allow customers to install SSEG on their low voltage networks. This is commended."*

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.
- Customers using PV systems during the day means that there is a drop in the demand for electricity during the day. The highest drop in system demand happens in the middle of the day. This midday demand drop (called the "duck curve") and 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.
- Eskom does not agree that the changes will hamper the uptake of SSEG, but rather that more correct and economic signals are provided when making alternative energy choices. As stated by SALGA above, current tariff structures provide unintended subsidies to customers that make alternative energy choices.

5. *"The proposed changes to the residential tariffs are significant. A residential customer with an 80A connection will go from paying R190/month + 145c/kWh for the first 600 units to R490/month + 133 c/kWh. This means that customers consuming more than 1200 kWh per month will see a reduction in*

their monthly bill but customers consuming 300-800 kWh per month will see an increase of roughly R300 per month.

- *The proposed change to the Homepower tariff is a drastic step change and the affordability of this change must be questioned. Increasing fixed charges suddenly is also a disincentive for efficient consumption and immediately shifts the risk onto the customer. Many municipalities are facing enormous push back from customers around increased fixed monthly charges. A transition plan is therefore needed whereby fixed charges are gradually increased over a few years.*
- *The rationale to remove the IBT tariff is plausible and supported. NERSA needs to make a decision on the sustainability of the IBT tariff so that the entire country can move in the same direction. Again, a transition plan will be needed to educate and inform customers of the proposed changes and the impact of the changes on their electricity bill."*

Eskom response

- The move by Eskom is a phased approach (only a percentage of fixed costs recovered through fixed charges), should set the standard for residential tariffs going forward to having more cost-reflective unbundled tariffs. This standard is defendable as it provides a more correct economic signal, it protect revenue streams and vulnerable customers and, is about sustainability of the industry. The changes being proposed by Eskom are supported by the comment made by SALGA in Point 1 above.
- A transition plan is supported for the gradual increase in the fixed charges.
- Whenever fixed charges are increased or introduced and also moving away from an IBT structure, this will result in higher consumption customers paying less and lower consumption customers paying more. Eskom has attempted on the average customer to keep the impact minimal, but some balancing was required between the Homepower categories, in particular to reduce the subsidies on Homepower 4.
- Refer further to Table 10: Homepower current average month bill versus revised monthly bill. On average Homepower sees a slight revenue reduction.
- The proposed changes to Homepower are needed, are not considered that significant, and affordability for poorer customers is addressed by having the Homelight tariffs as options. A low consumption customer on Homepower due to a PV installation, should be fairly contributing to the costs of the network associated with providing availability.
- It is accepted that there will be push back around fixed charges, but this requires customer education and communication for the reasons to do so. This submission does provide the rationale for modernising tariffs due to the changing energy environment. To not do so, will cause the utility death spiral and increase the prices to those that are vulnerable.
- Eskom supports the statement regarding IBT.

6. *"One of the rationales for the tariff reform was to reduce Eskom's exposure to volume risk. However, figure 4 indicates that the proposed tariffs do not reduce Eskom's volume risk. Clarity is needed around how the proposed tariffs reduce Eskom's volume risk. Many municipalities are facing the same challenges of volume risk and learning from Eskom's approach may allow SALGA to assist municipalities."*

Eskom response

- Due to the divisional cost increases over time, energy costs have increased at a higher rate than network and retail costs. So even with the increases to the fixed costs, this still means that energy makes now a higher percentage of overall costs. Eskom in future is considering unbundling energy costs into also fixed and variable, which will reduce the volume risk. This is now better explained in the main document in paragraph 4.1.
- Volume risk is a great concern to Eskom and impacts customers in the future through high price increases and RCA applications.
- Nersa must support Eskom and municipalities in moving to recovering fixed costs through fixed charges.

7. *"It is recommended that SALGA set up a meeting with Eskom in order to:*
   a. *Discuss the detail of the municipal impacts to generate a list of the most impacted municipalities (percentage and absolute amounts) and a more nuanced understanding of where the costs are likely to fall (household or commercial/industrial);*
   b. *Develop a commitment to a tariff transition pathway and associated resources to support most affected municipalities to understand and implement the corresponding changes required within their distribution business;*
   c. *Consider how to transition the Homepower tariff to mitigate the big impact proposed;*
   d. *Consider how to begin to develop simple and salient communications relating to tariffs in support of getting more cost reflective tariffs in place – and the important reasons for the need for this."*

Eskom response

- Eskom has presented to SALGA and municipalities on the 31st July 2020 (after the 40 days), where the plan was shared.
- Eskom supports engagement with the municipalities that are negatively impacted, to discuss and create awareness for the causes. For the larger municipalities, a detailed impact analysis would assist Eskom in understanding the impacts. This can be done as part of the consultation before public hearings.
- Eskom supports a forward-looking transition plan, that will assist all parties in developing tariffs in the future. Upon approval of this retail tariff plan, this should be the next step/phase.
- Refer to Table 10: Homepower current average month bill versus revised monthly bill, which indicates the impact on Homepower customers. Homepower 4 customers have the option to go to Homelight 60A which will be cheaper for them.

H.2 National Treasury comments

With respect to the detail of the submission, National Treasury has the following comments:

1. National Treasury agrees on the need to update and change Eskom's electricity tariff model to account for the unbundling of Eskom, accounting for changes in the cost drivers for Eskom and to respond to changes in technology and customers leaving the grid.

2. National Treasury accepts that updates cannot be done with no impact on the amounts charged to some customers. We appreciate Eskom's efforts to limit the scale of changes to individual customers.

3. National Treasury supports Eskom's intention to reduce the complexity of the tariff model and to update the links between tariffs charged to customers and the cost of supply.

4. National Treasury appreciates the need to change the structure of electricity tariffs so that those customers considering installing their own generation capacity will face appropriate price signals in making this decision.

5. The factors leading to the proposed changes to Eskom tariff structures have many parallels in municipal electricity distributors. As such, municipalities will want to make similar changes to their tariff structures and will come under pressure from their customers to adopt some of these changes. We would therefore suggest that NERSA should allow that, where applicable, municipalities should be able to implement the same tariff structures approved for Eskom for municipal customers without each municipality having to complete a separate cost of supply study.

6. The revised tariff structure will mean that future changes in energy generation, transmission and distribution costs will be translated into customer tariffs through these new tariff structures. In addition to the detailed analysis comparing the proposed new tariff structure to the existing tariff structures, we would like to request that Eskom prepares scenarios for different energy price and infrastructure investment scenarios to show how tariffs for different customers would be impacted under each of these scenarios. This will help NERSA to make an informed decision when considering the proposed tariff structure.

7. We are concerned that several large power users have adjusted their consumption patterns to account for the lower demand for electricity in the summer and that the proposed reduction in the difference between seasonal tariffs may lead these users to change their demand, thereby placing additional pressure on the national grid.

Eskom response

- Point 1 to 4, indicated National Treasury support for the changes proposed.
- Point 5, is raised to Nersa to allow any Eskom structural changes approved, to also be passed-through to municipalities. This is supported.
- Point 6 deals with Eskom providing Nersa different scenarios for different energy price and infrastructure scenarios. If required by Nersa, Eskom will be willing to provide such scenarios going forward for future retail tariff plans, but more detail will need to be provided as to exactly what information is required.
- Point 7 concerns the impact on large industrial customers due to the TOU changes where the winter prices have been commensurately reduced against the summer TOU prices. The potential risk about the pressure on the grid is valid, but Eskom is trying to also address concerns raised by customers about the high winter tariffs. Therefore the proposed change have been made in a phased-approach and customer response will be evaluated periodically, and further changes will be informed by the customer response.