South African Distribution Code

Tariff Code

Version 6.0

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This document is approved by the National Energy Regulator of South Africa (NERSA)

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1. Introduction

(1) This code sets out the objectives for *pricing and tariff structures for distribution retail and network services.* The *NERSA* shall regulate the setting of prices and the structure of tariffs for all distribution related services.

(2) *Service-providers* shall therefore be regulated on the prices and tariff structures they may charge *customers*.

(3) *Customers* and the *service provider* shall *contract* with each other for the payment of charges related to *distribution* services. These charges shall reflect the different services provided, the standard applicable tariff, standard charges as well as any non-standard charges. These shall be explained by the *service provider* on request.

2. Scope

(1) The *tariff code* applies to all regulated *tariff structures* (components and level) and negotiated pricing agreements under the jurisdiction of NERSA (governed by the relevant legislation and national policy) including international pricing agreements impacting prices for local customers.

(2) The determination of the revenue requirement is managed by a process and rules set by the *NERSA*. The *NERSA* shall determine a methodology for regulation of distribution revenue, currently not dealt with in this code.

(3) The tariff code applies to the following generic retail charges:

- (a) Energy charges including recovery of losses
- (b) Network charges, including ancillary services
- (c) Customer services charges
- (d) Connection charges.

3. Objectives

(1) To outline the process for the design of the *Distribution* tariffs, which shall be achieved taking cognisance of the following:

- (a) Meeting *customer* requirements.
- (b) *Tariffs* and *connection charges* should provide the means to recover the regulated revenue requirement in the most cost effective way so that the business is financially viable and *customers* can receive an acceptable level of service.
- (c) *Tariffs* should promote overall demand and supply side economic efficiency, and be structured to encourage sustainable, efficient and effective usage of electricity.
- (d) *Tariffs* should recover the cost of *customers'* current capacity and usage.
- (e) *Tariffs* should be non-discriminatory and transparent subject to the specific tariff qualification criteria. The following principles shall apply:

i. *Network tariffs* (*DUOS charges*) should be relative to the utilisation of the networks and not be dependant on what the *customer* uses the network capacity for

ii. It should be clear to *customers* how these prices are determined

iii. Where cross-subsidies exist between *customers,* they should be justifiable and where quantifiable explicitly identified.

(2) To allow and facilitate cross-subsidisation in accordance with government policy.

(3) *Tariff rates* and *structures* should, subject to the *NERSA* approved cross-subsidy framework, accurately reflect the cost to supply different *tariff categories*. Where prudent, tariff structures should reflect the underlying cost structure.

(4) Tariffs should reflect the ring-fenced cost of retail and network services where this can be accommodated.

(5) There should be stability and predictability in *tariffs* in order to facilitate *customer* choices.

(6) There should be an optimal range of tariffs based on usage patterns to, as practically as possible, meet *customers'* requirements.

(7) *Tariffs* should be simple, transparent and understandable to the relevant target customer base.

(8) *Customers* should be charged *connection charges* for the cost of providing required capacity as prescribed in *NRS069* and/or other relevant *NERSA* approved documents

(9) Where objectives are in conflict with each other, the *NERSA* will achieve an optimal balance through regulation. Where *service providers* are unable to meet all of the above objectives, they shall be required to prioritise and motivate the above objectives based on their specific economic and social circumstances.

4. Principles for the determination of *tariffs*

(1) This section sets out the principles to be applied to the application and development of *distribution network* and retail tariffs. These principles are divided into two areas – principles associated with the allocation of costs for tariff design and principles associated with tariff design:

4.1 Principles for the allocation and recovery of costs in tariffs

(1) *Tariffs* should recover current regulated revenue requirement but may reflect future cost drivers in their structure to provide clear p*ricing* signals to the customer, that promote economic efficiency.

(2) Costs shall typically be differentiated on the following; capacity, voltage, load factor load profile, density and geographic location.

(3) Each Distributor's electricity costs (including purchases) must be ring fenced from other non-electricity related costs.

(4) *DUoS charges / network charges* for loads will reflect costs allocated to pooled voltage levels, density and geographic location where relevant. The *customer* grouping for pooling and therefore averaging of costs must be justifiable, such that it ensures sustainable approved cross-subsidies.

(5) *Cost pooling* (aggregation and averaging of costs) is required due to practical reasons.

(6) Costs to provide a quality of supply as determined by the *NERSA (based on NRS 048* and other *NERSA's* directives on quality of supply standards) will be recovered through tariffs and *standard connection charges.*

(7) The cost of a higher quality of supply not justified in terms of the investment criteria in the Network Code to meet specific requirements at the customer's request shall be provided at an additional dedicated cost to the customer.

4.2 Principles for design of tariffs

4.2.1 General tariff principles

(1) The *Distributor* shall make capacity available on its networks and provide open non-discriminatory access for the use of this capacity to all *South African Customers (loads)*, and *Embedded Generators*. In exchange for this service, the *Distributor* is entitled to a fair compensation through electricity tariffs.

(2) A stakeholder consultative process should be followed in the design and approval of tariffs.

(3) The structure of tariffs (the balance of fixed and variable components) should reflect the costs drivers.

(4) *Tariff charges* (including energy costs) will not be based on *customer* specific assets or services, but aggregated and averaged based on justifiable pooled costs.

(5) The components that make up a *tariff structure* will be aggregated and averaged to a lesser or greater degree depending on the tariff category being served.

(6) Tariff structures should contain pricing signals that promote energy efficiency (for example, DSM) and efficient use of network resources.

(7) *Tariffs* should be designed to first be cost reflective within a *tariff* category and then have the approved cross-subsidies applied.

(8) *Cross-subsidisation* between and within electricity tariffs shall be applied to all electricity *users* in accordance with government's policy and the *NERSA's* cross-subsidy framework. This process will be informed by *Distributors* calculating current levels of cross-subsidisation (total cost reflective tariffs versus current tariffs).

(9) All *customers* inside the borders of South Africa shall contribute to the approved electricity related subsidies, unless exempted by government policy and direction (for example, DTI's Developmental Electricity Pricing framework). These contributions shall be reflected as explicit DUoS levies for transmission-connected customers and for distribution connected customers where possible.

(10) *International end-use customers* connected to the *distribution system* will be charged standard *DUoS* / *network c*harges, including subsidies and will pay connection charges.

(11) The contribution to the government funded programmes such as cost of free basic electricity and the electrification programmes funded by government shall not be recovered through electricity *tariffs*.

(12) *Connection charges* will recover that portion of the full cost of dedicated assets and the approved standard scheduled capital contribution to shared upstream assets, not recovered by the tariff. The allocation of costs for connection charges is as per *NRS 069*.

4.2.2 Principles applicable to DUoS (unbundled distribution use-of-system) charges

(1) Unbundled *DUoS* charges will be raised where retail tariffs are not applicable. *Full service customers* will have the *DUoS* costs aggregated in their *tariffs*, which may or may not be unbundled as retail network charges depending on the tariff structure applied.

(2) *Network service customers* – customers receiving only a network service from a *Distributor* will be charged DUoS charges based on unbundled distribution costs.

(3) *Distribution–use-of-system (DUoS*) costs will be derived for all *customers* from the same cost of supply study as all other tariffs.

(4) *DUoS* charges will include the cost of upstream transmission network charges payable by the *distributor.*

(5) The charging framework for *DUoS* charges should treat loads and embedded generators on a consistent and cost-reflective basis.

(6) *Embedded generators* that make use of the distribution network to export power will pay the use-of-system charges within the applicable pricing framework for *embedded generators*.

5. Governance and communication process

(1) The *NERSA* shall be required to evaluate and approve all tariff structure applications for new tariffs or changes to existing structures. This includes non-standard negotiated tariffs.

(2) *Distributors/Service-providers* shall ensure that the consultative process is followed with stakeholders on proposed and approved changes to tariffs.

(3) *Distributors/Service providers* shall submit and justify their methodology for determination of distribution retail and network service tariffs to the *NERSA* prior to approval of the *tariffs*.

(4) *Distributors/Service-providers* shall charge only *NERSA*-approved tariffs.

(5) *Distributors/Service-providers* shall publish their approved schedule of standard tariffs.

6. Segmentation of costs for tariff design purposes

(1) For tariff design purposes, the ring fenced electricity revenue requirement of a *Distributor* shall typically be segmented into the following categories as per an accepted cost allocation methodology such as NRS 058.

(a) **Purchase costs**

These are pass-through costs as charged by *generators* and the tra*nsmission network service provider(s)* and if applicable a distribution service provider. The tariffs charged and the rules applicable to these services are separately regulated and the *Distributor/service provider* is a price-taker for these costs, These costs comprise:

i. Energy

ii. Transmission services

iii. Distribution services

(b) Distribution costs

i. Allowed annual interest and depreciation on invested capital employed to provide the existing network. The interest and depreciation cost are reflected in the revenue requirement of the utility for the regulatory period.

ii. Allowed operations and maintenance costs.

iii. Regulated return on assets.

iv. Other allowed costs (including overheads).

v. Technical and non-technical losses

(c) Retail costs

i. Allowed costs

ii. Retail margin

7. Cost reflective tariff structures

(1) Tariff structures should reflect cost drivers as far as possible. Where tariffs structures do not reflect costs, there is risk associated with mismatching of costs, tariff conversions and changes in volume forecast. The distributor/service provider shall be allowed to mitigate this risk, through appropriate tariff or claw-back mechanisms (for both under or over recovery of revenue) within the revenue requirement.

(2) The tariff charges (rates) shall be calculated based on the approved revenue requirement, volume forecast for demand and energy and customer numbers. At the end of each revenue review period, the *NERSA* may audit and verify the tariff charges (rates) calculations and results.

(3) In order to design fully cost-reflective tariff structures for a *Distributor/service provider*, electricity supply costs must be unbundled into energy purchases, network (transmission purchases and distribution costs) and retail /service components.

(4) A cost-reflective tariff structure will:

(a) Align with the purchase structure and cost of energy.

(b) Align with the transmission network purchasing structure.

(c) Reflect the provision of access to and usage of distribution networks through network charges.

(d) Include differentiation to take into account:

i. Time and /or seasonal variance.

ii. The voltage of the supply.

iii. The electrical (technical) losses associated with the applicable customer category.

iv. Power factor of the supply

v. The density of customers and geographic location of the network to which customers are connected.

vi. Load factor

vii. Load profile.

viii. Retail charges that reflect the size of the supply and the services being provided to the customer.

(5) The tariff structure ultimately used will depend on customer needs, meter capability, billing functionality and logistics, and limitations on tariff complexity. This will cause aggregation of various cost components and cost drivers in the tariff applied. Fully cost reflective tariff structures are based on unbundled costs.

8. International load customers

(1) International customers connected to a distribution network (excludes all SAPP contracts), will pay the regulated retail *tariffs* or *DUoS* charges, including all applicable subsidies as South African customers.

(2) Metering for international supplies will be installed where convenient, but adjusted for losses to the border.

(3) International customers will be required to pay connection charges that reflect all upstream investments required to provide supply, either as actual costs or a fair contribution to shared upstream networks.

(4) The financing of connection assets for international customers will be in accordance with the risk policy of each distributor.

9. Recovery of subsidies and other levies using tariff structures

(1) Subsidies on electricity tariffs shall be recovered in a number of ways, subject to approval by the *NERSA*:

(a) Embedded in a tariff (not explicit)

(b) Through a levy on a c/kWh basis

(c) Through a levy on network charges

(d) Through a levy on other fixed charges

(e) Or as a percentage applied to any of the above.

(2) Where possible the contribution to subsidies should be transparently shown.

(3) Where levies are raised to recover non-electricity-related costs (such as contribution to municipal funds); these costs may never be embedded in the regulated tariffs. *NERSA* shall approve the costs of the distributor based on the cost of supplying electricity. If a local authority/service provider wishes to raise a levy for other non-electricity related costs, this is to be done in accordance with legislation and outside of the regulated tariffs and transparently shown on the bill.

(4) Contributions to subsidies should be done in an equitable and fair way and customers should not be allowed to by-pass such contributions at the expense of other customers or the distributor. Only *NERSA* or national policy can allow for waiving of levies/reduction of rates contributing to subsidies.

(5) *NERSA's* subsidisation framework and/or national policy will provide guidance on contribution to subsidies by self-generators.

10. Non-tariff costs (excluded services costs)

(1) Excluded services are those services requested by individual that are generally excluded from the regulated rate base and may or may not be competitive, as described in the Section 8.3 of the Network code.

(2) Where excluded service is a monopoly services, such charges may be regulated.

11. Connection charges

(1) This charge is payable in addition to the tariff charges and is payable on all dedicated costs plus a fair contribution to capacity on upstream networks.

(2) Connection charges may be regulated and are excluded from the regulated asset base.

(3) The methodology used to calculate connection charges must be approved by NERSA, in line with NRS 069.

(4) In addition to the *Distributor's* costs, the *Distributor* shall be liable to the *TNSP* for any dedicated costs in the event the Transmission System require modifications in order to connect a *Distributor* customer to the *Distribution System*. If this cost is dedicated to a customer, then the transmission connection charge will be passed through to that customer.

11.1 Standard connection

(1) A *standard connection* is defined as the lowest *life-cycle* costs for a technically acceptable solution as per the investment criteria in the Network Code.

(2) All *customers* requiring a new connection or additional capacity for an existing connection shall pay a *connection charge* which may be rebated as per paragraph (6) of this section.

(3) The *connection charge* for a basic connection is a set connection fee and shall be approved by *NERSA*.

(4) A *basic standard connection* is a connection to supply a basic electricity supply to a residential customer with a pre-determined connection charge. The technical specifications, terms and conditions of a basic connection is to be defined by each *Distributor*

(5) For all standard connections that are not basic connections, connection charges will be based on dedicated network costs plus shared network costs less the capital allowance rebate in the tariff.

(6) For all connections a distributor shall provide a connection as defined in the investment section 7.2 of the Network Code and where applicable shall rebate such costs once-off by the amount of capital as allowed by the NERSA in the tariff.

(7) A *standard connection* charge covers the cost of dedicated network costs plus a contribution to shared network costs less the capital allowance rebate in the tariff.

(8) The *connection charge* may be paid by way of an upfront payment by the *customer* or if financed by the *Distributor* by way of a minimum upfront *connection fee* and a monthly *connection charge*.

(9) The connection fee is the minimum up-front contribution to the allocated connection costs of providing the required capacity. The *connection fee* is based on a minimum of 5% of the allocated costs or a set amount determined by the *Distributor*, whichever is higher.

(10) The standard connection charge will be based on costs allocated as per the methodology described in *NRS 069* where:

  (a) The *customer* pays for all dedicated costs. Dedicated costs are the cost of those assets that are unlikely to be shared in the *Distributor's* planning horizon by any other end-use customer.

  (b) *Dedicated costs* will be based on the investment to meet the *customer's* capacity requirements at the minimum technical standards, as stipulated in the Network Code.

  (c) Surplus capacity provided due to technical standards that may be shared in the near future will not be allocated as a *connection cost* to the *customer*. The cost of surplus capacity provided due to technical requirements and that will not be shared in future (for example, the provision of a 20 MVA transformer to meet a 15 MVA load), will not be pro-rated.

  (d) Dedicated assets later shared result in a refund/reduction to the initial contributor only based on capacity. Adequate records must be kept.

  (e) *Dedicated assets* for *generators* and *embedded generators* receiving a regulated tariff approved by *NERSA* and/or selling electricity to an entity regulated by *NERSA*, will at the time of commissioning be considered *shared network assets* from the *point of connection* to the *point of common coupling* and will, therefore, not incur a refund/reduction to the initial contribution made to connection costs if utilised by other *customers* at any time in the future.

(f) In addition to *dedicated costs* the *customers* shall be allocated a standard R/kVA contribution based on replacement costs, for shared upstream costs, whether new upstream investment is required or not.

(g) The costs allocated for a standard supply will be rebated by the capital allowance included in the tariff and published annually. The *capital allowance* is a standard amount recovered in the applicable tariffs towards the cost of network capital.

(h) For standard connection assets, the cost of depreciation, operations, maintenance and refurbishment cost of will be recovered through the revenue requirement, as allowed by the *NERSA.*

11.2 Premium connection

(1) A *premium connection* charge is raised where a customer contracts with the *Distributor* for additional specific requirements not justified in the investment criteria in section 7.2.4 of the Network Code as a *standard connection*.

(2) The *premium connection* charge will be based on all costs associated with providing the *premium connection* including all dedicated and upstream strengthening costs. *Premium connection charges* will not be rebated by any capital allowance.

(a) A *Premium Connection* Charge shall also be raised when dedicated connection equipment must be refurbished and the customer requirements are above that considered to be a s*tandard connection* at the time of refurbishment. Refer to Section 7.2.5 of the Network Code for the investment criteria to be used to determine what is payable as a *premium connection charge* at the time of refurbishment.

(b) The cost of maintenance and operation of the *premium connection* shall be recovered from the regulated revenue requirement, unless specifically contracted otherwise between the *Distributor* and the *customer*.

12. Financing of charges for excluded services and connection charges

(1) Excluded services are those services requested by an individual, which are generally excluded from the regulated tariff charges, that is, funded directly by the individual requesting the service and include construction of dedicated assets. Refer to section 7 of the Network Code for details as to what costs are recovered through regulated tariff charge.

(2) Charges associated with providing excluded services and connections may be financed by the *Distributor*, to be recovered as a monthly charge over a maximum period of 25 years at a *NERSA* approved interest rate but never to exceed the expected life of the associated asset. The *Distributor* has the right to decide whether to finance connection charges or nor.

(3) Where financing is provided, a *Distributor* will be allowed to add a reasonable rate of return on the financing cost as allowed by the NERSA to be recovered directly from the customer on the capital employed by the *Distributor* in providing the excluded service/connection asset.

(4) Where financing is provided appropriate guarantees must be supplied by the customer to cover risk associated with early termination.

  (a) Where charges are not financed and where irrecoverable costs exceed the charge (usually where dismantling costs are high), the difference between the amount paid upfront and the irrecoverable costs must also be provided by a guarantee and the value of the recovered assets will be credited to the customer.

  (b) Any claim against the guarantee is subject to the costs in question being actually incurred.

Appendix 1 –Guideline to designing tariffs

(This appendix is a guideline for tariff design. Each distributor shall publish its own methodologies once approved by the NERSA).

The following sets out a high level overview of tariff design and proposed tariff structures.

1) BUILDING BLOCKS OF TARIFF DESIGN

Unbundling costs is essential to determine the charging parameters to be used to recover those costs and ultimately form the tariff structure. The following are the building blocks of tariff design:

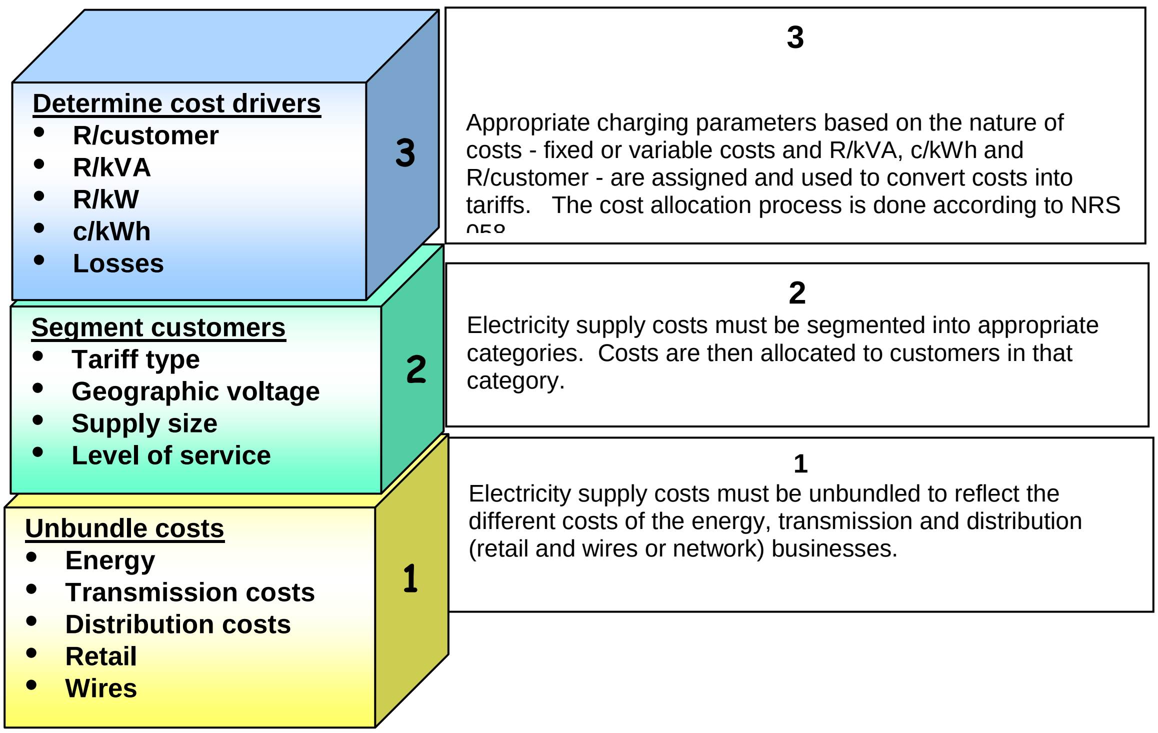


Diagram 1 - Tariff design building blocks

1.1 Step 1 - Unbundle costs

In order to calculate pure cost-reflective tariffs, electricity supply costs must be unbundled to reflect the costs of the retail, supply and wires (network) businesses. These costs are then further unbundled into costs that are either fixed or variable.

NRS 058 should be used to unbundle and allocate costs in the detail required for the determination of cost-reflective tariffs.

*It is important to differentiate **COST and COST DRIVERS** from **CHARGING PARAMETERS or RATES.** The cost refers to the cost of the distribution business and the charging parameters are how these costs are recovered per appropriate unit from the customer within a tariff. For example, the network costs are expressed as the total cost allocated divided by the demand (kVA) to give a R/kVA per unit cost. This cost may or may not be charged differently, e.g. for a smaller customer this cost could be recovered as a c/kWh rate component. The ideal is always to try and recover costs through charges that reflect the nature of the cost.*

Unbundling the costs into their appropriate drivers assists in determining the charging parameters in the retail tariffs to be used to recover those costs. The first decision to be made in the allocation of costs is to decide what the nature of the cost is, whether it is fixed or variable, as this determines how these costs are allocated on a per unit basis and what the ultimate structure of the tariff is. The following table gives a high-level overview of the different components of unbundled costs and whether these costs can be considered fixed or variable:

Table 1 - Unbundling of costs as per revenue requirment

	Fixed costs	**Variable costs**
Energy costs		
- Energy purchases (reactive and active energy)		X
Transmission		
- Reliability services		**X**
- Network	**X**	
- Transmission losses		**X**
Distribution business		
- Network capital	X	
- Losses		X
- O & M	X	X
- Overheads	X	X
- Return and taxes	X	X
Retail business		
- Service and administration	X	
- Return and taxes	X	
Bad debts		**X**

The shaded area represents pass-through costs that are the purchase costs for a *distributor*. How these costs are recovered from customers by the *distributor* is part of the tariff design process. For a retailer, the distribution network costs will also be a pass-through cost.

1.1.1 Energy purchases and transmission network charges pass- through costs

The shaded area in the above table represents the purchase costs for a *distributor*. How these costs are recovered from customers by the *distributor* is part of the tariff design process. For a retailer, the distribution network costs will also be a purchase cost.

Currently the energy purchase cost is based on the WEPS energy rates, seasons and time periods. A *distributor* will contract with *generation* for the volume of energy required per season and time period. The *distributor* is at risk when there are volume changes and/or profile changes, if purchases and end-use tariffs are based on different structures to the purchase structure. There may be a hedge in place to mitigate volume changes or changes in profile. This energy cost is included in the revenue requirement based on the forecast consumption. When a competitive generation market exists, the contracting for energy will be based on the market.

For transmission costs, the *distributor* will be required to reserve the capacity required from the transmission system for the coming year and will contract with the *Transmission network provider* for this reserved capacity. This reserve capacity is the diversified demand of the distributor's customers at the MTS level. This will be paid for through a fixed network charge to *Transmission*, with penalties payable if the reserve capacity is exceeded (refer to Transmission Network Grid code). The *distributor* is again exposed to volume risk if the reserve capacities are incorrect and can impact the transmission network charges. Reliability services will be charged on a consumption basis.

1.1.2 Distribution costs

The distribution costs are made up of the regulated revenue requirement for the distribution business and in addition to energy purchase costs comprise the following:

1.1.3 Distribution network costs

These costs are *distributor*'s allowed costs associated with capital (interest and depreciation) including refurbishment costs, operations and maintenance, return and taxes for all standard supplies for the costs of all 132 kV and lower networks.

1.1.4 Energy losses – for both distribution and transmission losses

Electrical losses occur as a result of transporting electricity from the source (the generator) to the load (the customer). This means that more electricity is generated at the source than is supplied to the customer. The generator will expect to be paid for the energy produced, but the customer is only charged for the energy sold. This difference results in a cost to the *distributor* for the "lost" energy, which needs to be charged for, and is referred to as electrical losses. The *distributor* is responsible for all electrical losses flowing through its system.

The cost of electrical losses is unbundled and recovered as a function of (a) the appropriate loss factors for the relevant voltage level and (b) the *distributor's* cost of energy purchases on a time-of-use basis.

In calculating the cost of these losses for distribution customers, both the transmission and distribution loss factors have to be considered and will be charged at the purchase energy rates as follows.

Charge for total losses

$= \sum\{\text{Delivered energy}_t \times (\text{distribution loss factor} \times \text{transmission loss factor} - 1) \times P_t\}$

Where:

t = the appropriate peak, standard or off-peak time period and

P_t= Purchase energy price for each PSO time periods.

Transmission loss factors are geographically differentiated whereas the distribution loss factors might be differentiated differently (by voltage or by geographical location).

1.1.5 Reactive energy costs

These costs associated with the provision of reactive energy.

1.1.6 Transmission charges

The cost charged by the transmission service provider to transport energy from the source to the *distributor.*

1.1.7 Retail costs

The costs associated with the retail business including allowed return as included in the revenue requirement.

1.1.8 Bad debts

These are as included in the revenue requirement.

1.2 Step 2 – Segment customers

Segmentation should always be based on underlying cost drivers and not discriminate on the economic sector of customer being served. The latter has historically been used, but is not a significant driver of any cost in the electricity distribution business.

Segmentation of costs should be done as described in NRS 058 and demonstrated in the next diagram:

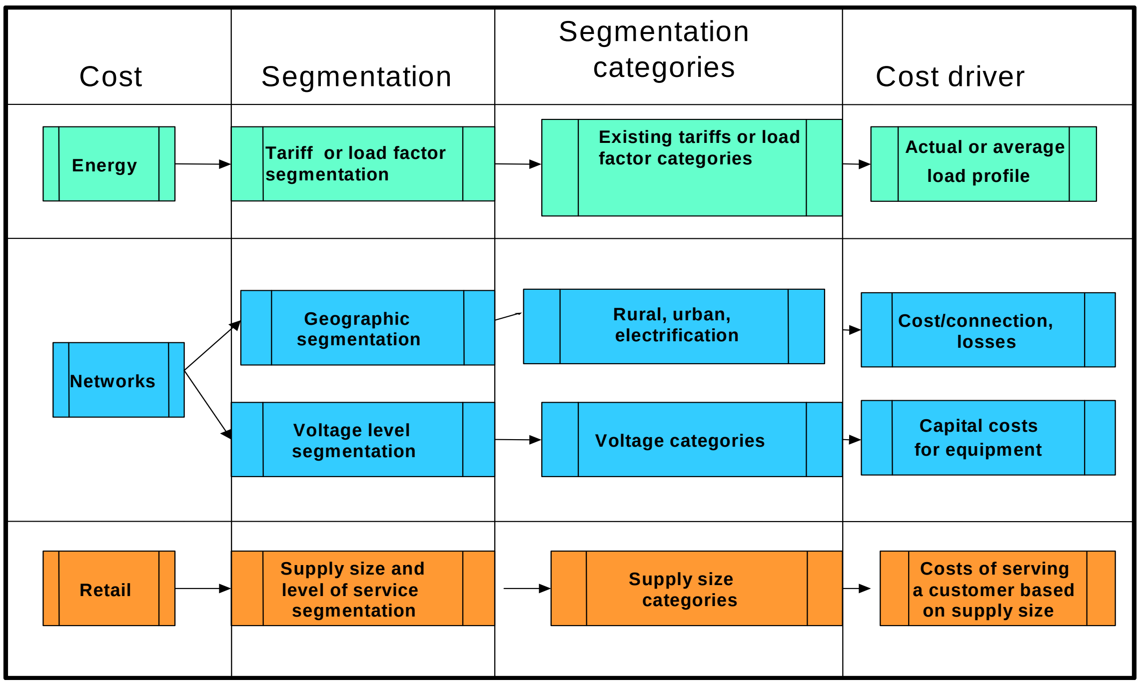


Diagram 2 - Segmentation

1.2.1 Tariff or load factor segmentation (energy costs)

Customers may be allocated to their existing tariff types or, alternatively, load factor categories could be used to segment customers for the purposes of allocating energy costs. The load factor becomes a proxy for the load profile.

Smaller customers can be also segmented into economic sectors, e.g. residential, commercial and agricultural, as these could be closely linked with load factor or existing tariffs.

For larger customers, categorisation according to economic sector is not appropriate, as energy costs are driven more by customer needs and the impact the customer has on the load profile and cost pooling. Load factor is a more appropriate mechanism.

Where there are existing tariffs and new tariffs have to be developed, similar tariffs between entities that serve similar customers could also be combined to form a tariff category.

1.2.2 Geographic segmentation (network costs)

Geographic segmentation is used for the purposes of allocating network costs. Where a customer's point of supply is situated has an impact on the cost of supplying the customer. The geographic segmentation of costs should be based on the methodology set out in NRS 058. The categories prescribed in NRS 058 are rural, urban and electrification.

A. Urban (high density)/rural (low density)/electrification

Depending on the amount of high-density, low-density and electrification customers, a *distributor* may decide to allocate its points of supply to these categories if there are clear and distinct differences in network costs between these categories.

This is to ensure that costs are allocated correctly to avoid cross-subsidies such as those between rural and urban supplies.

Urban usually refers to supplies in proclaimed urban areas or supplies at voltages greater than 22 kV. Rural is broadly defined as supplies in areas where large-scale agricultural activity takes place and electrification areas are those that are part of the electrification programme and are ringfenced as such. NRS 069 gives more detail on how rural and urban areas may be determined.

B. Distance from source and losses

The geographic position of a supply point has an impact on electrical losses: the further the point of supply is from the source of the supply, the higher the losses. As losses are a cost to the business, they should be allocated to customer categories based on the amount of losses determined. Losses over urban and rural networks will be different and therefore different loss factors are associated with the geographic position. Voltage also has an impact on losses and this is discussed in the next section.

1.2.3 Voltage level segmentation

Network costs differ depending on the voltage level of the supply. The lower the voltage of the supply, the more electrical losses there are and the more network assets are needed to supply customers. Supplies at higher voltage levels therefore cost less to supply than supplies at lower voltage levels in absolute terms.

Voltage level categories should be determined on clear and reasonable cost differences as far as possible. Loss factors are represented at geographic and voltage levels.

1.2.4 Supply size and level of service segmentation

Customers are to be segmented according to supply size and level of service delivered. This segmentation is related to retail or customer service related costs only.

No differentiation of other costs is made on this basis. In other words, energy and network costs are payable on the same c/kWh or R/kVA basis, irrespective of the type of customer being served.

1.3 Step 3 – Determine cost drivers

There are a number of ways of converting the costs that have been unbundled and segmented into more understandable and measurable units, such as kVA or kWh. In order to determine what the unit should be, the most appropriate cost driver for a particular cost needs to be established. The following are the most common cost drivers:

Table 2 – Common cost drivers

- **R/customer/month or R/customer/day charge - *typically for customer service and administration costs.***
- **R/kVA - *typically for network costs.***
- **R/kW - *typically for network or some energy related costs.***
- **c/kWh - *typically for energy costs, return and taxes.***
- **c/kvarh - *reactive energy costs.***
- **R/Amp - *to recover energy or network costs.***
- **Energy loss factors *for energy loss costs.***

The cost driver should be based on the nature of the cost, i.e. what influences the cost. This cost driver also becomes the appropriate unit to be used to determine the cost per unit. The following table gives an overview of the fixed and variable costs for a *distributor* and how they may be allocated to the different cost drivers and ultimately the rate components: There are other options that are possible, depending on how costs are interpreted.

Table 3 - Allocation of costs to relevant cost drivers

Cost Driver / Cost	R/ customer	c/kWh	R/kVA R/A	c/kvarh	R/kW
Energy costs					
- Purchases		**X**		**X**	**X**
Transmission costs					
- Network			**X**		
- Reliability services		**X**	**X**		
- Losses		**X**			
Distribution network costs					
- Capital			**X**	**X**	
- O & M			**X**		
- Overheads			**X**		
- Losses		**X**			
- Return and taxes			**X**		
Retail costs					
- Service and administration	**X**				
- Return and taxes		**X**			
Bad debts		**X**	**X**		

2) TARIFF STRUCTURES AND DETERMINATION OF RATES

A cost reflective tariff structure has all cost components reflected separately and charged according to the appropriate cost driver per appropriate rate unit.

The sophistication of the customer's need and the cost of the meter capabilities become the deciding factor to depart tariffs structures from the real cost drivers. The following table shows units that could be used, depending on the customer segment, to recover costs and determine cost-reflective tariffs.

Table 4 - Matrix of potential rate units to be used to recover cost

	R/ customer	c/kWh	c/kvarh	R/kVA R/Amp	R/kW	% of energy
Energy						
- Purchases	X	X	X	X	X	
Transmission						
- Network	X	X		X	X	
- Reliability services		X		X		X
- Losses						X
Distribution network						
- Capital	X	X	X	X	X	
- O & M	X	X		X	X	
- Overheads	X	X		X	X	
- Losses	X					X
- Return & taxes	X	X		X	X	
Retail						
3) - Service & admin.	X					
4) - Return & taxes	X	X				
Bad debts		X				

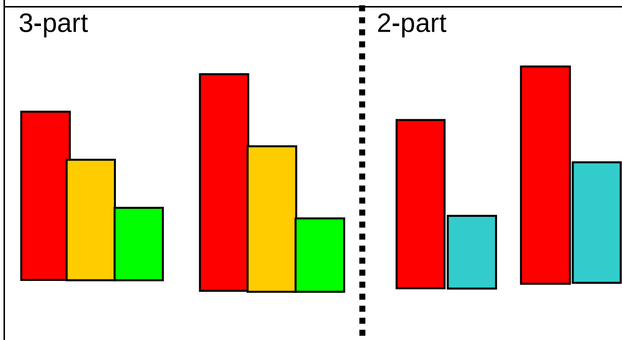
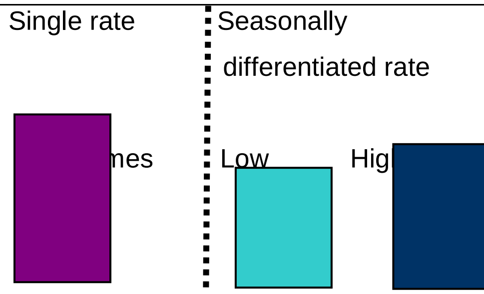
Each rate component is discussed in further detail below.

4.1 c/kWh charges

Energy related c/kWh charges recover mainly energy costs, retail return and taxes, but depending on the tariff structure used may also recover other costs as indicated in Table 1. Energy charges also typically encompass non-technical losses.

The recovery of costs on a c/kWh basis can be done as follows:

Table 5 - c/kWh structures

On a TOU. c/kWh basis	**Single rate c/kWh**
3-part 2-part  Low High Low High	Single rate Seasonally differentiated rate 
Three-part energy rate reflecting peak, standard and off-peak energy costs, or for smaller customers a simpler two-part tariff – peak and off-peak rates.	Energy rate can be the same, irrespective of time and season, or can be seasonally differentiated, with rates in the high demand season being much higher than rates in the low demand season.
Based on the purchase energy rate differentials. For three-part tariffs these are seen as a pass-through cost plus other non-energy costs. For a two-part tariff, the peak and standard periods could be combined.	Calculated as the average cost for the customer segmentation load profile over the period of a year (total cost/consumption).
Could have non-energy related costs added to all the c/kWh energy rates to cover other costs (e.g. network costs). Any adders will be distributed in a manner that must preserve the DSM signal, e.g. if added only to peak, incentivises the *distributor* to sell more in peak to recover the network costs.	Could have c/kWh adders to the rate to cover non-energy costs (e.g. network costs), depending on the tariff structure used.

4.2 R/kW charges to recover active energy charges

The recovery of active energy costs through demand related rate components (R/kVA or more correctly R/kW) is typically used in non-TOU tariffs as a DSM pricing signal, i.e. allows for the recovery of peak energy costs. More expensive energy purchase costs can be recovered through demand measured in peak and standard energy periods. This ensures a signal to manage demand to the benefit of the customer and to the country where a TOU tariff is not used.

It is possible that in the future the energy purchase rate may reflect a capacity charge based on R/kVA to recover generation fixed or peak costs. If this is the case, then a R/kVA charge would be appropriate to recover these energy purchase costs.

4.3 Energy loss factors

The cost of losses is recovered by applying pre-determined loss factors as a percentage of usage on all active energy related costs (c/kWh or R/kW) at different voltage levels and at different geographic positions. For simplicity, this factor may be bundled into the energy rates at the low voltage level for smaller customers.

4.4 Distribution network charges

Network charges and distribution use of system charges are cost-reflective rate mechanisms that recover costs of a network business. In order to have tariffs that are cost-reflective, it is necessary to have rate components that allow the recovery of costs in an unbundled way. The introduction of network charges is therefore essential to achieve this objective of cost reflectivity.

Network charges are to be derived from the network costs allocated to each customer category and recover both distribution and transmission purchased network costs, as approved in the revenue requirement. These costs may be recovered separately or bundled into the distribution network charge.

It is important to remember that although capital costs may be based on replacement costs, they are always scaled to the costs as allowed by the NER to be recovered through the rate base, i.e. through tariffs and tariff increases. These costs always exclude connection charges or any excluded services revenue.

The following prescribed how network charges are to be calculated.

Table 6 - Calculation of network charges

Transmission purchases	The cost of purchasing transmission services
Capital	Capital is made up of the annualised cost of finance charges and depreciation for approved investment
+O & M	Operations and maintenance costs as budgeted for
+Overheads	Engineering overheads
+Return	The rate of return allowed
+Tax	The tax payable
Total_1	**The sum of all costs equals the revenue requirement for the wires business**
- Connection charges	Sum of all connection charges
Total_2	**Costs less connection charge**
Network charges	***Total_2 divided by the relevant demand/consumption = the network charge***

Network charges must reflect the reserved capacity and the capacity used. Network charges will not reflect the location of a supply. The cost associated with the location of the supply will be recovered through connection charges.

4.5 Demand used to calculate the network charge

Network charges are to be based on the allowed cost per kVA (excluding connection charges). The kVA used to determine the charge may be based on the annual notified demand or the actual demand.

Using the annual notified demand gives a fixed charge and using the actual maximum demand in a month gives a variable charge. For smaller customers where the demand is not measured, the demand can be determined by assuming a load factor.

Where customers in a particular category have a very similar load profile, such as residential customers, the diversified load can be used to determine a fixed charge per customer. In NRS 069 typical ADMDs of different residential customer categories are given.

4.6 Network rate components

The network charge is a function of the cost divided by the demand. In order to mitigate any volume risk (if demand changes), the ideal would be to charge a customer a fixed charge each month. This approach, however, has consequences and the following should be considered:

- However cost-reflective it may be considered, it can be punitive to a customer with a poor load factor.
- It completely exposes the *distributor* to a volumetric risk if the annual demand is allowed to change after the rates are calculated.
- Basing a network charge on an annual demand creates a weaker signal with regard to DSM and real-time management of demand.
- It does not show that the *distributor* can select to allocate some costs as variable in the medium term, i.e. O & M, return and taxes.
- It also does not show that some costs may be time-differentiated.

In order to address these issues the distribution network charge structure should be divided into a fixed and a variable charge as follows:

4.7 Fixed network charge

The costs recovered through a fixed charge should include transmission purchases and all distribution capital related costs and should reflect the capacity required/reserved by a customer in the short term. As network capital (depreciation and finance costs) are largely fixed and do not vary (at least in the short term) according to the amount of demand used or not, this cost should be recovered through a fixed network charge. The mechanism to recover this may be through:

- a R/kVA or R/kW charge.
- A R/Amp charge.
- R/customer charge
- A c/kWh charge.

For supplies where demand is measured, the R/kVA or RkW charge is calculated as follows:

[Total allocated distribution fixed cost + Transmission purchase cost] ÷ Utilised capacity in all time periods

The above charge will be voltage-differentiated and have the appropriate loss factors applied to the rate calculated.

For smaller customers this charge may be converted to a R/customer charge as follows:

[Total fixed cost + Transmission purchases allocated to the customer segment] ÷ Sum of highest maximum demands determined for the customer segment x ADMD or average demand per customer.

For smaller customers this charge may also be converted to a R/Amp charge as follows:

[Total fixed cost + Transmission purchases allocated to the customer segment] ÷ Sum of Amps allocated to the customer segment

For single energy rate tariffs

Total allocated network costs (including transmission costs) for the customer segment ÷ Total kWh consumption of the customer segment

In order to mitigate the risk of volume changes once a demand is reserved, customers should not be allowed to decrease this capacity for a period of a year, i.e. an annual reserved capacity. Increases in capacity are also a risk, but generally there is a lead time associated with upgrades, which should catered for in the forecast.

This can be called a network access charge as it recovers the cost associated with providing a customer access at any time to the demand reserved through a notified maximum demand. This charge should be levied in all time periods. If the charge is only levied in peak periods, for example, customers who use significant demand in off-peak periods end up making no or very little contribution to the shared cost of the network providing their NMD, i.e. they will get a free ride.

A *distributor* also faces a risk in its purchases from Transmission with regard to the reserve capacity. Transmission is required in terms of the Transmission Grid Code to charge for capacity as reserved by its customers for a full calendar year. This charge is payable for demand in all periods.

4.8 Variable network charge

This is a charge that recovers some network costs through a variable R/kVA or c/kWh charge. It can be called a network demand charge as it recovers costs associated with the demand or usage of the network. This charge may be based on TOU periods to provide some DSM (network and energy) signals. The above rates may be voltage-differentiated and loss factors will be charged to recover differences in cost at different voltage levels and geographic positions.

The rates are calculated as follows:

For supplies where demand is measured the R/kVA charge is calculated as follows: **Total allocated distribution variable cost ÷ Sum of all highest monthly demands in a chargeable period over a year** The above charge will be voltage-differentiated and have the appropriate loss factors applied to the rate calculated. For smaller customers this charge may be converted to a c/kWh customer charge as follows: **Total allocated variable network costs ÷ Total kWh consumption of the customer segment**

The following table gives a summary of the various rate options that can be used to recover network costs:

Table 7 - Potential network charge rate components

Network demand charge (NDC)	Network access charge (NAC)	Voltage differential
Where demand is measured, charged as a R/kVA on monthly demand	Charged as a R/kVA based on the utilised capacity (highest of NMD or actual (in all periods) over a rolling 12 months)	Different charges for each voltage level
Where demand is not measured, may be charged as c/kWh in peak and standard periods	For smaller customers, converted to a: R/customer charge based on the standard size of the supply, or May even be a c/kWh rate bundled with the energy rate	Averaged and included in the energy rates and/or network charges

4.9 Service and administration charges

Customer service and administration costs are costs associated with billing, the meter cost, meter reading and customer service. These costs are allocated to customers mainly based on their size category as this is the cost driver (the bigger the customer, the more expensive the meter, the service etc.).

The allocated costs are divided amongst the accounts or points of delivery for that size category that receives this level of service to calculate this charge.

These can be charged as:
R/customer/month or R/customer day - based on supply size or NMD.

4.10 Transmission charges

Transmission charges may be separately shown or bundled into the rate components used. Where they are separately shown, the charge reflected should be the embedded TUOS charge applicable to customers supplied from a distribution network. This charge is based on the diversified demand required by a *distributor* from the MTS.

The ideal structure would be to separate the transmission network and reliability charges from the distribution network charges, as is reflected in WEPS and the TUOS charges for those tariffs that have voltage and loss factor differentiated network charges.

For smaller customers, these charges are to be averaged and included in the energy rates.

4.11 Reactive energy charge

It is very difficult to quantify the costs associated with providing reactive energy. In most cases only a signal can be provided to ensure that customers manage their power factor correctly, such as reactive energy charges or charging for demand costs on a R/kVA basis and not R/kW. If, however, the cost of providing reactive energy is unbundled from the other reliability service costs, it may be charged as a c/kVArh charge.

4.12 DUOS charges

Distribution use of system charges (UOS) are unbundled rates like network charges that recover costs associated with a customer's use of the network business. Network charges in retail tariffs may be structured exactly like the DUOS charges or may be bundled in one way or another into retail tariff components. The DUOS charges are the source of the network charge components in the retail tariff structures i.e. retail network charges are determined from the DUOS network charges.

The DUOS charges and retail rates are determined in exactly the same way through the tariff design process, where DUOS charges reflect the network costs in a fully unbundled way and where retail structures may have bundled costs It is recommended that retail network charges for larger customers should be aligned with the DUOS charges so that all customers (both retail and wholesale) utilising the same network will have charges that are directly comparable for customers of the same size. This is not a priority for smaller customers as these customers will not be contestable for a considerable time and complex tariff structure would be inappropriate.

The DUOS charges are the cost to the retailer for using the wires company's network capacity and can either be passed to the end customer, thereby minimising the risk of the retailer or can be packaged differently depending on the pricing objectives that the retailer want to achieve.

The DUOS charges are made up of:

- Distribution network charge
- Charges for energy losses – for both Distribution and Transmission losses
- Reactive energy charges
- Customer service charges
- Levies to recover subsidies (rate rebalancing levy and distribution network levy)
- Embedded TOUS charge

Refer to the NER's document "NER Guidelines on Distribution Use of System (DUOS) Charges" for the more detailed explanation and application of DUOS charges"

4.13 Summary of cost recovery through rate components

The following table gives a breakdown of the costs and rate components used to reflect the costs in the tariff. This allocation matrix forms the basis for the tariff structure.

Table 8 - Rate components

	Energy costs	Admin costs	Customer service costs	Network capital costs	Network O & M costs	Network overheads	Energy losses or geographic differentiation
R/customer/day based on std sizes	✕	✔	✔	✕	✕	✕	✕
Single c/kWh	✔	✕	✕	✕	✔	✔	✔
TOU c/kWh	✔	✕	✕	✕	✔	✔	✔
TOU seasonal c/kWh	✔	✕	✕	✕	✔	✔	✔
Seasonal c/kWh	✔	✕	✕	✕	✔	✔	✔
R/kVA – annual utilised capacity	✕	✕	✕	✔	✕	✔	✕
R/kVA – monthly capacity (could include TOU signals)	✕	✕	✕	✕	✔	✔	✕

4.14 Determination of a tariff structure for each tariff type

For more energy-intensive users of electricity, tariff structures tend to be more complex, while for customers such as domestic customers, tariff structures are simpler. It is assumed in all cases that subsidies are recovered through c/kWh charges for tariffs that pay the subsidies and are allocated to the network charges for the subsidised tariffs.

The supply sizes given in the tables below are examples of what could be optimal sizes to be used to minimise the trading risk and to reduce conversions between tariffs leading to windfall benefits. These structures could be applicable to rural or urban supplies. The differential between the two should be the level of the tariff rates.

The following main categories of tariff structures recommended are:

- Time of use (TOU) tariff for large supplies (e.g. > 500 kVA)
- TOU tariff for medium-sized supplies (e.g. 25 kVA to 500 kVA)
- TOU tariff for residential, see residential
- Non-TOU demand-based tariffs
- Tariff for large supplies (e.g. > 500 kVA)
- Tariff for medium-sized supplies (e.g. 25 kVA to 500 kVA)
- Residential:
- Lifeline tariff (for low users of electricity)
- Tariff for medium to high users
- TOU tariff for residential
- Non-TOU small (non-residential) supplies
- Metered supply
- Non-metered supply

Table 9 - Recommended tariff structures for TOU tariffs

	TOU tariff for large supplies (e.g. > 500 kVA)	**TOU tariff for medium-sized supplies (e.g. 25 kVA to 500 kVA)**	**TOU tariff for residential See residential**
Retail charges	Based on capacity	Based on size	
Administration charges	R/point of delivery/day	R/point of delivery/day	
Service charges	R/account/day	R/account/day	
Energy charges	Includes only energy costs	Includes energy and variable network costs (network demand charge)	
	• Peak, standard and off-peak TOU c/kWh rates expressed at the highest voltage level • Seasonally and hourly differentiated ✪#	• Peak, standard and off-peak TOU c/kWh rates expressed at the highest voltage level • Seasonally and hourly differentiated ✪#	
Reactive energy charges	c/kvarh	c/kvarh	
Transmission network charges			
Transmission network charge	R/kVA ✪ - based on utilised capacity in all periods	R/kVA ✪ - based on utilised capacity in all periods	
Transmission reliability services charge	Separate c/kWh charge #	Separate c/kWh charge #	
Distribution network charges			
Network access charge	R/kVA charged on utilised capacity*	R/kVA charged on utilised capacity*	
Network demand charge	R/kVA - based on actual demand in peak and standard periods*	c/kWh – charged in peak and standard periods*	
Levies	Separate c/kWh charge	Separate c/kWh charge	

*** - Voltage differentiated**

 # - Distribution loss factor applicable

✪ - Transmission zonal surcharges and loss factors applicable

Table 10 - Recommended tariff structures for non-TOU demand-based tariffs

	Tariff for large supplies (e.g. > 500 kVA)	**Tariff for medium-sized supplies (e.g. 25 kVA to 500 kVA)**
Retail charges	Based on size	Based on size
Administration charges	R/point of delivery/day	R/point of delivery/day
Service charges	R/account/day	R/account/day
Energy charges	Includes c/kWh energy costs and R/kW peak energy costs	Includes c/kWh energy costs and R/kW peak energy costs and variable network costs (network demand charge)
	• Seasonally differentiated expressed at the highest voltage category ✪#	• Seasonally differentiated expressed at the highest voltage category ✪#
Reactive energy charges	c/kvarh	c/kvarh
Transmission network charges		
Transmission network charge	R/kVA ✪ - based on utilised capacity in all periods	R/kVA ✪ - based on utilised capacity in all periods
Transmission reliability services charge	Separate c/kWh charge #	Separate c/kWh charge #
Distribution network charges		
Network access charge	R/kVA charged on utilised capacity*	R/kVA charged on utilised capacity*
Network demand charge	R/kVA - based on actual demand in peak and standard periods*	c/kWh – charged in peak and standard periods*
Levies	Separate c/kWh charge	Separate c/kWh charge

✪ - Transmission zonal surcharges and loss factors applicable

*** - Voltage differentiated**

 # - Loss factor applicable

Note

If rural tariffs are introduced it is possible that they will receive subsidies

Table 11 - Recommended tariff structures for residential

	Lifeline tariff (for low users of electricity)	**Tariff for medium to high users**	**TOU tariff for residential**
Retail charges	Not size-differentiated	Not size-differentiated	Not size-differentiated
Administration charges	Included in energy rate	Included in service charge	Included in service charge
Service charges	Included in energy rate	R/point of delivery/day	R/point of delivery/day
Energy charges	Includes all costs	Includes energy, transmission and variable distribution network costs (network demand charge)	Includes energy, transmission and variable distribution network costs (network demand charge)
	• Charges differentiated based on the supply size (Amp) • Tariff more expensive for higher supply sizes • Rates receive a subsidy	One single rate or rate seasonally differentiated expressed at the low voltage level	• Peak and off-peak TOU c/kWh rates expressed at the low voltage level • Seasonally and hourly differentiated
Reactive energy charges	N/A	N/A	N/A
Transmission network charges			
Transmission network charge	Included in energy rate	Included in network access charge	Included in network access charge
Transmission reliability services charge	Included in energy rate	Included in energy rate	Included in energy rate
Distribution network charges			Included in energy rate equally in all time periods
Network access charge	Included in energy rate	R/customer/day – based on supply size (kVA or Amp)	R/customer/day – based on supply size (kVA or Amp)
Network demand charge	Included in energy rate	Included in energy rate	Included in energy rate – charged in peak and standard periods only*#
Levies	NA	Included in energy rate	Included in energy rate
Subsidies	Included in energy rate		

Note: No voltage or loss differentiation as charges are averaged at the low voltage level and rates include these costs.

Table 12 - Recommended tariff structures for non-TOU small (non-residential) supplies

	Metered supply	**Non-metered supply**
Retail charges	Not size-differentiated	Not size-differentiated
Administration charges	Included in service charge	Included in service charge
Service charges	R/point of delivery/day	R/point of delivery/day
Energy charges	Includes energy, transmission and variable distribution network costs (network demand charge)	Includes energy, transmission and variable distribution network costs (network demand charge)
	One single rate or rate seasonally differentiated expressed at the low voltage level	One single rate or rate seasonally differentiated expressed at the low voltage level x fixed level of consumption
Reactive energy charges	N/A	N/A
Transmission network charges		
Transmission network charge	Included in network access charge	Included in energy rate
Transmission reliability services charge	Included in energy rate	Included in energy rate
Distribution network charges		
Network access charge	R/customer/day – based on supply size (kVA or Amp)	Included in energy rate
Network demand charge	Included in energy rate	Included in energy rate

Note: Tariffs for non-metered supplies (such as street lighting) should only be used where the level of consumption is consistent and very low. The cost of metering and doing meter reading for such supplies does not warrant a metered supply. Non-metered supplies are not suitable for supplies where the consumption is high and/or inconsistent. No signal is provided for true cost and this encourages wastage and provides no incentive to manage the amount of electricity used.

For public lighting tariffs, the tariff should only recover the costs associated with providing an electricity supply and not recover costs associated with the public lighting infrastructure (globes, fittings etc). The infrastructure costs should be recovered in terms of a maintenance contract that should be a competitive service. All costs associated with the provision of public lighting should be explicitly charged for and recovered from the local authority. It is not supported that these costs are recovered through inherent electricity subsidies as this does not provide a cost reflective signal (to manage these costs) nor does it take into account the different requirements each local authority within a *distributor* might have.