Distribution Tariff Code

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

Administered by:

RSA Grid Code Secretariat
Contact: Mr. Target Mchunu
Eskom Transmission Division, System Operator
P.O Box 103, Germiston 1400
Tell: +27 (0)11 871 3076
Email: mchunut@eskom.co.za

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1. Introduction

(1) The Tariff Code sets out the objectives and rules for *retail tariff structures and connection charges for distribution retail and network services raised by Licensed Distributors*.

(2) *Distributors* shall *contract* with Customers for the payment of charges related to *distribution network and retail* services. These charges shall reflect as far as possible the cost of the different services provided, through the standard applicable tariff, standard charges and connection charges. These charges shall be provided by the *Distributor* and explained 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 retail charges:

(a) Energy charges including recovery of losses

(b) Network charges, including ancillary services

(c) Customer services charges

(d) Connection charges.

(e) Energy charges

(f) Use-of system charges / Wheeling Charges

i *Losses*

ii *Network charges, (Distribution and Embedded Transmission)*

iii *Ancillary services*

iv *Retail/Customer services charges*

(g) Subsidy related charges

(h) Connection charges.

3. Governance and communication process

(1) *Distributors* shall be required to submit any tariffs and tariff structural changes of existing tariffs for *both loads* and *embedded generators* to *NERSA* for evaluation and approval. This includes non-standard negotiated tariffs.

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

(3) *Distributors* shall submit and justify their methodology for determination of tariff structure to *NERSA* prior to approval of the tariffs.

(4) *Distributors* shall publish their approved schedule of standard tariffs.

4. Objectives

(1) The Tariff Code outlines the process for the design of the *Distribution tariffs* (structure and charges) and the connection charges methodology, which shall include the following imperatives:

(a) Adhering to the regulatory requirements for meeting *customer* expectations.

(b) *Tariffs* and *connection charges* shall provide the means to recover the regulated revenue requirement in the most cost effective way so that the *Distribution* business is financially viable and sustainable while ensuring that *customers* receive an acceptable level of service.

(c) *Tariffs* shall promote overall demand and supply side economic efficiency, and be structured to encourage sustainable, efficient and effective usage of electricity.

(d) *Tariffs* shall reflect and recover the cost of customers' current capacity and usage excluding connection costs funded by customers.

(e) *Tariffs* shall be non-discriminatory and transparent, subject to the specific tariff qualification criteria. The following principles shall apply:

i There shall be clarity to customers how these prices are determined.

ii Where cross-subsidies exist between customers, these shall be justifiable and where quantifiable, explicitly identified.

(2) Cross-subsidisation in accordance with government policy shall be permitted and facilitated.

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

(4) *Tariffs* shall reflect the purchase costs of energy, the ring-fenced cost of retail and network services.

(5) There shall be stability and predictability in *tariffs structures* in order to inform customer choices.

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

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

(8) *Connection charges* shall reflect the cost and location of the supply and ensure that new connections are not unfairly subsidised by existing customers i.e. there shall be fair allocation of cost between the customer causing the investment, and the cost included in the tariff charges

and recovered through the rate base. Subsidies may be applied to connection charges for the provision of a basic electricity service.

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

(10) Where objectives are in conflict with each other, *NERSA* will provide guidance through regulation and rules.

(11) Where *Distributors* are unable to meet all of the above objectives, they shall be required to prioritise and motivate tariffs and charges using the above objectives based on their specific economic and social circumstances.

5. 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 comprises; principles associated with the allocation of costs for *tariff* design and principles associated with *tariff* design:

5.1 Principles for the allocation and recovery of costs in tariffs

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

(2) Cost categories and charges 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) shall be ring-fenced from other non-electricity related costs.

(4) Cost pooling (aggregation and averaging of costs) into customer categories is required due to practical reasons. The cost pools shall be justifiable.

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

(6) 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.

(7) Customers that wheel shall be required to pay a fair contribution towards the use of the network, including subsidies/surcharges.

5.2 General principles for the design of tariffs

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

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

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

(4) *Tariff charges* shall be based on justifiable pooled costs.

(5) *Tariffs* shall be designed to first be cost reflective within a *tariff* category and then have the approved cross-subsidies applied. Where these are known, this information shall be made available.

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

(7) The charging components that make up a *tariff structure* may be bundled to a lesser or greater degree depending on the tariff category being served.

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

(9) All customers inside the borders of South Africa shall contribute to the approved electricity related subsidies, unless exempted by NERSA or government policy. These contributions shall be reflected in the DUoS charges.

(10) International end-use customers connected to the Distribution System shall be charged standard tariffs, including subsidies and shall pay connection charges.

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

(12) *Connection charges* shall recover that portion of the connection costs not recovered by tariff charges.

5.3 Segmentation of costs for tariff design purposes

(1) For tariff design purposes, the ring-fenced approved electricity revenue requirement of a *Distributor* shall typically be segmented into the following categories as per an accepted cost of supply study methodology in line with the NERSA cost of supply methodology in order to determine the cost-reflective costs per unit and to serve as the basis on which to derive the tariff charges.

(a) **Distributor Energy Purchase costs**

These are the energy costs for the Distributor based on its bulk energy purchase cost structure.

(b) **Distribution costs**

i Cost of capital i.e. the return on assets based on the allowed annual interest and depreciation on invested capital employed to provide the 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 Other allowed costs (including overheads).

iv Transmission and Distribution technical losses

v Non-technical losses

(c) **Retail costs**

i Service and administration allowed costs

ii Retail margin/return

(2) A cost of supply study needs to be done after a significant change in cost structures or at least every 5 years.

5.4 Cost reflective tariff structures

(1) Tariff structures shall reflect cost drivers as far as possible and be based on cost-of-supply study. Where tariffs structures do not reflect costs, there is risk associated with mismatching of costs, tariff conversions and changes in volume forecast. The *Distributor* 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* shall be calculated based on the approved revenue requirement, volume forecast for demand and energy and customer numbers. *NERSA* may audit and verify the tariff charges calculations and results.

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

(4) A cost-reflective tariff structure shall:

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

b) Align with the *TUoS* 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. Whether the customer is a load or a generator

ii. Time and /or seasonal variance.

iii. The transmission Zone

iv. The voltage of the supply.

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

vi. Power factor of the supply

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

viii. Load factor

ix. Load profile.

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

(5) The tariff structure ultimately used shall depend on customer needs, meter capability, billing functionality and logistics, and limitations on tariff complexity. This may cause aggregation of various cost components and cost drivers in the tariff applied.

(6) Fully cost reflective tariff structures are based on unbundled costs and contain the following charges:

a) Energy charges reflected on a TOU basis, inclusive of Distribution losses and if applicable Transmission losses

b) DUoS charges comprising:

i. Embedded TUoS charges

ii. Distribution network charges reflected per voltage, geographic location and Transmission Zone

iii. Distribution and Transmission loss factors

iv. Ancillary service charges

v. Network related subsidies

vi. Charges to disincentivise poor power factor

vii. Administration and service charges

c) The retail tariff applied may be any combination of the above, depending on the customer segment. Refer to Appendix 1 for a guideline to designing tariffs.

5.5 Principles applicable to DUoS charges

(1) In addition to the energy purchase costs and the Transmission use-of-system charges, *Distribution* related costs shall be reflected in the DUoS charges.

(2) All customers receiving a network service (including wheeling) shall pay the *DUoS charges*, irrespective of any energy trading arrangement, which may or may not be unbundled depending on the tariff structure. .

(3) *DUoS* charges shall be derived for all *customers* from a *cost of supply study* and these charges shall determine the basis for all network related charges. Cost-of-supply studies shall be undertaken using pooling which aggregates similar types of customers into significant groups.

(4) *DUoS* charges for *loads* shall include the *embedded TUoS charges* payable by the *distributor* however, no embedded TUoS charges from TNSP shall be allocated to embedded generators

(5) Where customers are in breach of the contracted network capacity, the *Distributor* shall be entitled to raise charges applicable for the exceeded capacity (NMD and/or MEC.), subject to these charges being approved by Nersa.

(6) All loads and generators connected to the *Transmission and Distribution system* shall be charged for *ancillary services* based on the total energy exported or consumed into/from the network. All *distributors* shall be required to pass on the *ancillary service charge* raised by the TNSP to its customers.

(7) The DUoS charges shall be differentiated according to the *Distributor's* voltage and topographical (rural/urban) categories determined by each distributor, based on a logical and justifiable categorisation that avoids unnecessary cross-subsidisation between customers.

(8) Where the customer is both an *embedded generator* and a *load*, the customer shall not be double charged DUoS network charges for the same portion of the network.

(9) The cost of electrical losses shall be based on representative technical studies and recovered as a function of the appropriate loss factors for the relevant voltage level and the distributor's cost of energy purchases on a time-of-use basis.

a) The *distributor* shall be responsible for all *Distribution and Transmission* losses flowing through its system and shall recover these costs from all load and generator customers connected to its system.

b) The *loss factors* shall be differentiated according to the *distributor's* voltage and geographic categories or if applicable the Transmission Zone determined by the TNSP.

5.5.1. Principles applicable to DUoS (unbundled distribution use-of-system) charges for embedded generators

(1) *Embedded generators,* including those that wheel, that make use of the distribution network to export power shall pay the Distribution generator use-of-system charges.

(2) The following *DUoS charges* may be applicable to generators:

a) *DUoS* network charge for generators based on the annual *maximum export capacity*.

b) An *ancillary service charge* to cover the costs of providing ancillary services.

c) *Administration and service charge* to cover the cost of providing a customer service and all administrative transactions.

d) Losses charge, where embedded generators shall pay or be compensated for the losses caused on the Distribution System based on the amount of energy produced, the voltage and the time that the energy was produced. The following formula may be applied to calculate charge for losses:

Losses charge = wholesale/purchase energy rate in peak, standard and off-peak periods x (Distribution loss factor x if applicable*Transmission loss factor-1)

e) Where embedded generators reduce losses, the losses charge may be negative.

5.5.2. Principles applicable to DUoS (unbundled distribution use-of-system) charges for loads

(1) The following *DUoS charges* may be applicable to *loads*:

a) The *DUOS* network charge for loads to be based the annual *notified maximum demand* (NMD) and /or the monthly *maximum demand*.

b) *An ancillary service charge* to cover the costs of providing ancillary service.

c) *Administration and service charge* to cover the cost of providing a customer service and all administrative transactions.

d) *Losses charge* - where the following formula may be applied to calculate the **losses charge** to be added to the energy charge to recover the cost of losses.

Losses charge = (Wholesale purchase energy rate for peak, standard and off-peak periods) x (Distribution voltage loss factor + if applicable Transmission loss factor-1)

e) Network related subsidies (received or paid).

f) Charges for poor power factor.

6. International customers

(1) For regulated retail tariffs:

a) Cross-border loads or utilities connected to a *distribution* network primarily for the export of electricity from South Africa shall be treated the same as domestic loads and shall pay the same regulated retail *tariffs*, including all applicable subsidies as South African customers.

b) Cross-border generators or utilities connected primarily for the import of electricity to South Africa shall be treated the same as local generators and shall pay the same regulated retail tariffs as South African generators.

(2) *SAPP* contracts shall be managed in accordance with the *SAPP* rules. *SAPP* wheeling provided on behalf of *SAPP* Operating members shall be charged as per the *SAPP r*ules.

(3) Metering for international supplies shall be installed at agreed locations.

(4) For connection charges:

a) International load customers shall be required to pay *deep connection charges* for all *dedicated, shared* and *upstream* investments required to provide supply.

(5) International generator customers that sell electricity through a South African regulated programme shall be required to pay connection charges that reflect all dedicated and shared investments required to provide supply. Generator customers involved in international bilateral trade shall pay a deep connection charge i.e. dedicated, shared and upstream investments.

7. Recovery of subsidies and other levies

(1) Subsidies on electricity tariffs may 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 shall be made available.

(3) Where levies are raised to recover non-electricity-related costs (such as contribution to municipal funds); these costs shall not 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 intends to raise a levy for other non-electricity related costs, this shall be done in accordance with applicable legislation, separate from regulated tariffs and transparently shown on the bill.

(4) Contributions to subsidies shall be done in an equitable and fair way. Customers shall not be allowed to by-pass such contributions at the expense of other customers or the distributor. Only *NERSA* or national policy may permit the waiving of levies/reduction of rates contributing to subsidies. Subsidies payable shall therefore avoid undue discrimination between customer categories.

(5) All load customers, including those wheeling energy, shall be required to contribute to network-related subsidies

(6) *Embedded generators* shall not be required to contribute to subsidies.

8. Excluded services

(1) Excluded services are those services requested by customers or other parties requiring work to be done that are generally excluded from the regulated tariff base and may or may not be competitive, as described in the Section 7.3 of the Network code.

(2) A connection charge shall be raised for any excluded services works done by the *Distributor*, including *monopoly works* on a *self-build/developer* project.

9. Connection charges

9.7. Connection charging principles

The following principles are applicable to the determination and recovery of connection charges for the different types of connections and customers. The connection charging methodology is applicable to all connecting customers, first connecting customers and customers connecting thereafter (late-comers) and aims to:

(1) Encourage sharing of assets

• The connection charging rules shall encourage customers to share connection sites and assets, as this promotes efficiencies in the provision of assets and encourages cost sharing between users;

(2) Ensure clarity and transparency in the application of the rules

- Charges and allocation methods shall be based on clear and transparent rules that avoid arbitrariness and limit administrative overheads;

(3) Ensure equitable treatment between all connecting customers

- The Distributor shall not discriminate between any customers connecting onto its Distribution System. Equitable treatment between all connecting customers requires that customers connecting to the same part of the network and sharing connection assets should each be charged an amount that is representative of their usage of the connection assets;

(4) Ensure that customers do not receive windfall profits

- Customers whose connection costs are recovered through a regulated tariff, for example the IPPs under the government procurement programme, shall not receive windfall profits through refunds;

(5) Ensure that there are no free-riders

- All customers requesting a connection to the network shall pay for the assets related to the connection. The cost for connection shall not be borne by the first connected customer only;

(6) Ensure that there are no barriers to entry

- Connection charges shall, as far as possible, avoid creating barriers to entry and shall ensure non-discriminatory access to the network.

(7) Clearly identifiable assets

- Connection costs should be based on assets that are clearly identifiable in accordance with the definitions in this Code.

(8) Investment decision and cost allocation

- The investment decision is based on the network code.
- The cost allocation for customers is based on the minimum technical standard.
- In cases where the Distributor deviates from the minimum technical standard the customer shall only pay for the minimum technical standard.

(9) NERSA may request data and assess a Distributor's application of connection charges, to ensure compliance with the Codes and pricing principles. Customers may also raise a formal dispute with NERSA if a Distributor is applying connection charges incorrectly or unequally between similar customers.

(10) Assets funded by connection charges are excluded from the regulated asset base.

(11) The methodology used to calculate connection charges for loads must be, in line with NRS 069 or any other approved NERSA document.

(12) For all connections a Distributor shall provide a connection as defined in the investment section 7.2 of the Network Code, which shall determine whether the connection be classified as a standard connection or a premium connection or both.

(13) In addition to the Distributor's costs, the Distributor shall be liable to the TNSP for any connection charge raised by the TNSP as specified in section 0.9.7.

9.7. Connection charge approach

(1) Connection assets are assets associated with the Connection Works which are installed to enable the transfer of maximum capacity required by the customer, to or from, as appropriate, the Distribution and/or Transmission system. These assets comprise dedicated assets, shared assets and upstream assets.

(2) The connection charge/tariff boundary is used to determine the level and extent to which connection costs are allocated to a single customer, a group of customers and/or to the tariff base through tariff charges. This connection boundary depends on whether a shallow, shallowish or deep connection charge methodology is applied.

(3) A shallow connection charge approach is where only dedicated connection assets are allocated to a connection charge. A shallowish connection charge approach is one where dedicated and pro-rated shared costs are allocated. A deep connection charge approach is one where full dedicated, shared and upstream assets costs are allocated in the connection charge.

(4) Each Distributor shall be transparent about its connection charge approach and methodology

(5) The connection charge shall differ depending on whether a connection is standard or premium or catered for in the Distributor's revenue requirement or not..

(6) Figure 1 demonstrates the boundaries describing shallow, shallowish and deep (at the time of connection):

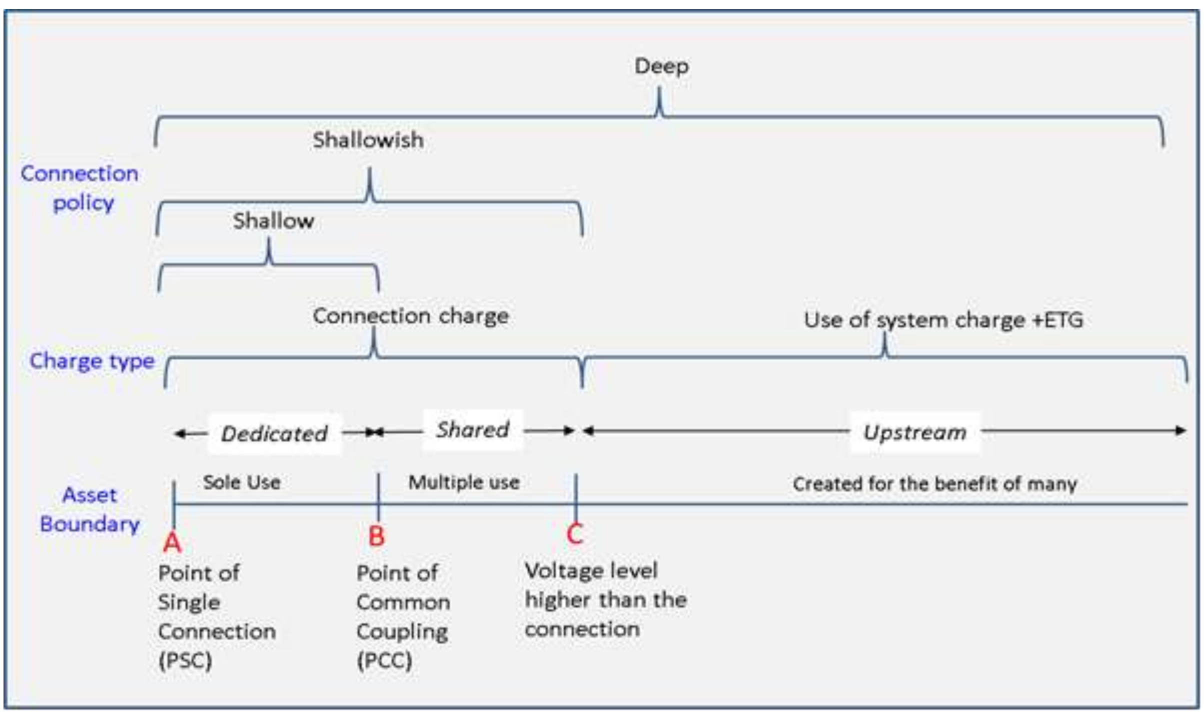


Figure 1: Connection charging boundaries

Table 1 provides the definitions of the connection boundaries and the applicable charging principle, as illustrated in Figure 1.

Table 1: Asset definitions, boundaries and cost allocation

Asset	**Asset boundary**	**Definition**	**Cost determination**	**Charge type**
Dedicated assets - Sole use assets	Between points “A” & “B”	Assets which are used for the purposes of connecting an individual user to the network. Assets which are used exclusively by the individual user and not shared by other customers. Assets which do not deliver system wide net benefits. The capacity installed is the minimum least-cost standard technology that would be installed to provide the customer’s MEC/NMD. Refer also to Section 7.2.4 in the Distribution Network Code	Must be recovered directly from specific customer. Individual customer to pay full connection costs.	Connection Charge
Shared Assets – Multiple use assets	Between points “B” & “C”	These assets may be exclusively used by the identified user group, or they could be shared with the rate base. Refer also to Section 7.2.4 in the Distribution Network Code	Could be recovered directly from an identifiable group of customers or could be split on a pro-rata basis based on % utilisation of installed capacity and remaining costs to be recovered from all customers. Point C point shall depend on whether the customers is an embedded generator or a load and between tariff classes.	Connection Charge

Upstream Assets	Beyond Point “C”	Assets used for the benefit of many customers and that cannot be directly allocated to one or an identified group of customers. Assets which deliver system wide net benefits and are based on least life-cycle economic cost (Refer to section 7.2.3 in the Distribution Network Code)	Will be recovered from all customers. An early termination guarantee will be raised.	Use of system Charges + Early Termination Guarantee(ETG)

9.7. Standard connection

1) A standard connection is defined as the assets and investment required to meet the least life-cycle costs for a technically acceptable solution as per the investment criteria in the Network Code.
2) The following will apply to the standard connection charge for loads as per the methodology described in NRS 069 or other approved NERSA document.
   a) the costs associated with the dedicated assets,
   b) the costs associated with the shared assets (pro-rated) based on actual or replacement costs (where actual costs are not known), plus
   c) a contribution associated with the upstream assets based on actual or replacement costs (where actual costs are not known) whether new upstream investment is required or not,
   d) less, if applicable any capital allowance rebate in the tariff.
3) The following shall apply to the standard connection charge for *embedded generators*
   a) The *standard connection charge* for *embedded generators* shall cover the costs associated with the dedicated and shared connection assets.
   b) The *Distributor* shall be entitled to raise a connection charge for upstream assets, subject to the *Distributor’s* connection charge approach. .
   c) less, if applicable any capital allowance rebate in the tariff.
4) *Dedicated assets* costs shall be based on the investment required to meet the customer’s capacity requirements at the least-life cycle cost to meet minimum technical standards, as stipulated in the Network Code. The cost of surplus capacity provided due to least-cost technical standards (for example, the provision of a 20 MVA transformer to meet a 15 MVA load), is not likely to be shared and shall be allocated 100% to the customer.
5) *Shared and upstream asset* costs shall be based on the investment required to meet least-life cycle economic cost investment required and this may result in surplus capacity being installed. Surplus capacity provided due to technical standards and that may be shared in the near future shall not be allocated as a connection cost to the customer.

6) For *standard connection assets* funded through a *standard connection charge*, the cost of decommissioning operations, maintenance and refurbishment cost shall be recovered through the use-of-system charges, as allowed by *NERSA.*

9.7. 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* shall be based on all costs associated with providing the *premium connection* including all dedicated, shared and upstream *premium connection costs*. *Premium connection charges* shall not be rebated by any capital allowance.
   a) A p*remium connection charge* shall also be raised when *dedicated assets* have to be refurbished and the customer requirements are above that considered to be a s*tandard connection* at the time of refurbishment.

   b) Where the *premium connection* came about without any identifiable assets, the cost of refurbishment shall be pro-rated between the *Distributor* and the *customer* in the same ratio that the original investment was incurred. As an example: In the event of the *customer* specifying a non-standard conductor type, at premium cost to the standard, one cannot argue that the entire conductor is a premium asset; only the additional cost over and above what the *Distributor* would have provided. Upon refurbishment, the entire conductor needs refurbishment and therefore the costs have to be pro-rated.

   c) The investment criteria to be used to determine what is payable as a *premium connection charge* at the time of refurbishment is stipulated in section 7.2.5 of the Network Code.

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

9.7. Transmission connection

1) For *Transmission Standard connection* investments for the benefit of a Distributor's customer base in general and not for a specific customer or a group of customers of a *Distributor* shall form part of the *TNSP's* rate base with the exception of feeder/line bays.
2) *Transmission Standard connection* investments for the benefits of a single customer of a Distributor or identified group of customers of a *Distributor* shall be allocatable and attract a *Transmission connection charge* (including shared costs) and any applicable Transmission guarantees.
3) *Transmission Premium connection* investments for the benefit of a single customer of a *Distributor* or identified group of customers of a Distributor shall attract *connection charges* for all assets

above the standard connection requirement where it does not satisfy the *least-life cycle economic cost investment criteria.*

9.7. Payment of connection assets

1) The *connection charge* shall be payable in full and in advance of energising the connection assets. Where a connection is to be commissioned or constructed in phases, payments shall correspond to agreed phases or key milestones, with full payment details to be set out in the connection quotations and customer agreements.
2) Refunds due to later sharing:
   a) For *loads and embedded generators* that have not been selected through a government IPP procurement programme, *dedicated assets* previously funded through a *connection charge* that are later shared, shall result in a refund/reduction to the initial contributor. The refund value shall be the pro-rata contribution payable by the subsequent customers of the now shared asset. The refund shall apply for a period of 10 years from the initial connection. Adequate records must be kept.
3) Refunds shall not be given to *embedded generators* that are selected through a government IPP procurement programme and where the asset has been fully funded and it is later shared. For subsequent customers a pro-rata share of the shared asset shall be raised, this shall however not be refunded to the IPP but would be paid to the *Distributor* and be treated as part of its revenue. If such a refund causes the *Distributor* to earn revenue in addition to that approved by *NERSA*, this over-recovery shall be adjusted in subsequent year's revenue requirement.
4) Should - the customer wish to bring forward the connection date, *connection charges* shall will be based on the following principles:
   a) The customer shall be required to pay for all actual *dedicated, shared and upstream assets* i.e. will fund the total cost of the project.
   b) A refund may apply in cases where a new load customer makes use of the connection assets funded by the first customer. Refer to 2 (a) above regarding refunds for IPPs.
5) Refunds shall be calculated using the PV of the outstanding annuity value of the connection charged, pro-rated on capacity.
6) . The refund shall be calculated according to the following formula:

$$Refund = \frac{PMT\,(1-((1+r)^{-N}))}{r} \times S$$

Where
r = monthly compounded interest rate

$$r = (1+i)^{1/12} - 1$$

i = prime interest rate when subsequent customer connects
N = remainder of loan period
S = pro-rata ration on a per MW basis

$$S = \frac{Z}{W}$$

Z = MEC/MIC of connecting customer

W = Total installed capacity

PMT = monthly repayment/monthly annuity value

$$PMT = ICC \times \frac{r}{(1-(1+r))^{-n}}$$

ICC = initial connection charge
n = loan recovery period = life of the asset

9.7. Guarantees

1) For any connection assets funded by the *Distributor* i.e. not allocated to a customer in the connection charges, an appropriate guarantee/financial instrument shall be provided by the customer to cover the risk associated with early termination.
2) Where there are upstream *Transmission connection assets* not allocated to a customer, the *TNSP* may raise an *early termination guarantee*, which shall be passed onto the customer.
3) For loads, a guarantee shall cover the capital allowance or any portion of (pro-rated) costs funded by the Distributor to cover in the event of early termination.
4) For embedded generators, the guarantee/financial instrument in the event of early termination shall be 25% of the pro-rated (allocatable) share of the upstream connection costs.

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:

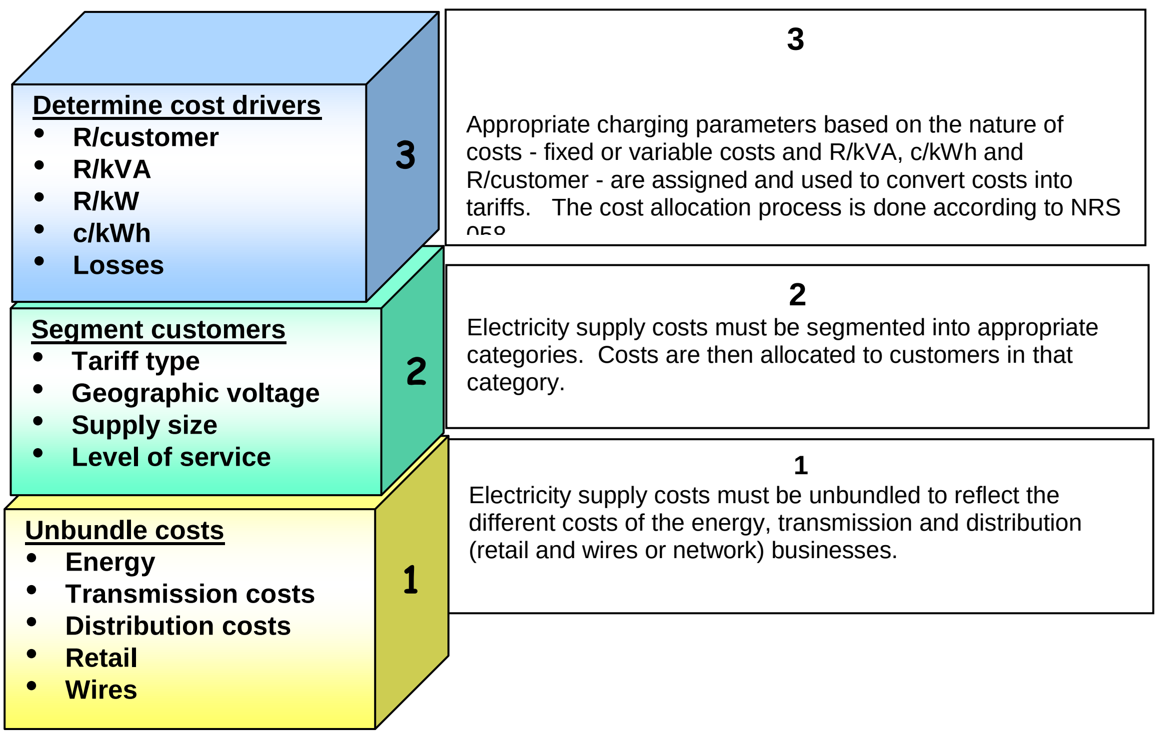


Diagram 1 - Tariff design building blocks

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:

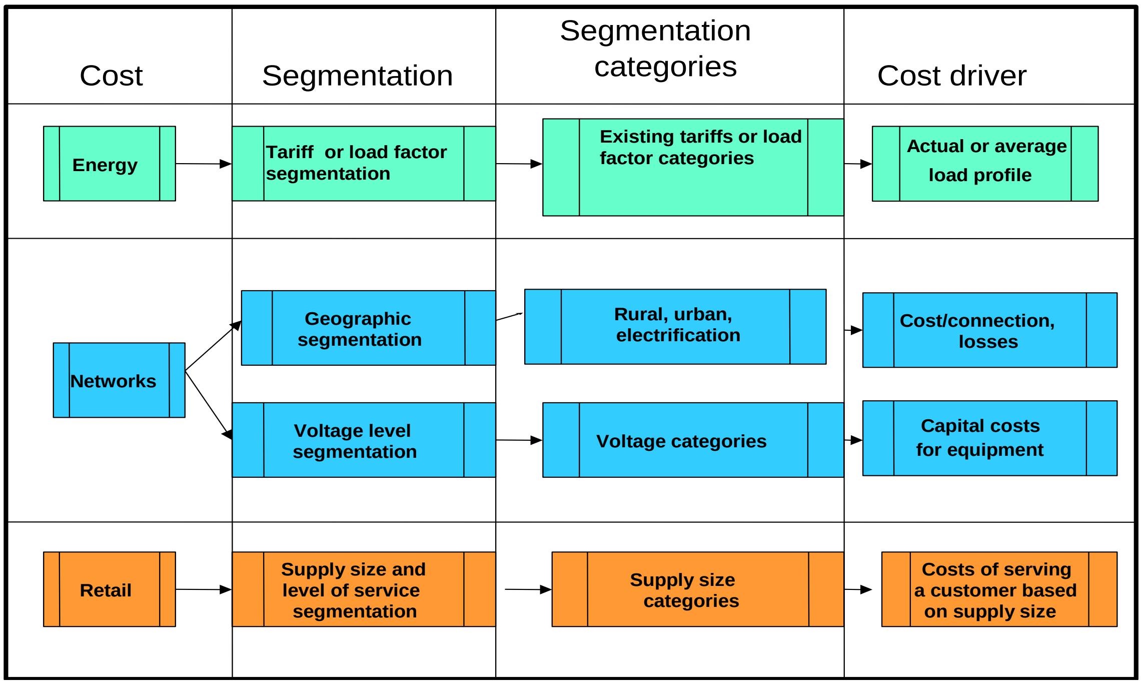


Diagram 2 - Segmentation

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				

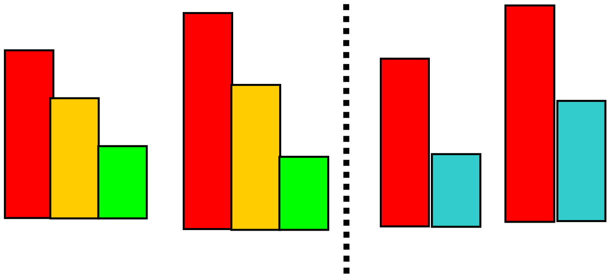
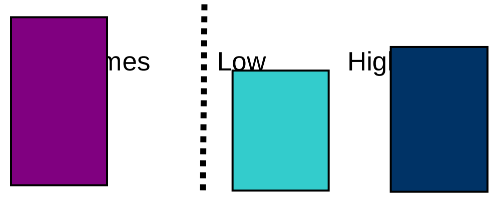
Each rate component is discussed in further detail below.

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 <u>consistent</u> and <u>very low</u>. 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.