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First edition reconfirmed

Interim Rationalized User Specification

NRS 058(Int):2000

COST OF SUPPLY METHODOLOGY FOR APPLICATION IN THE ELECTRICAL DISTRIBUTION INDUSTRY

Preferred requirements for applications in the Electricity Distribution Industry

N R S

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Foreword

This methodology has been prepared on behalf of the Electricity Suppliers Liaison Committee (ESLC) and has been approved by it for use by supply authorities.

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Annexes A, B, C, D and E are informative.

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Introduction

There is a need within the Electricity Distribution Industry (EDI) to regulate the prices of electricity to different categories of customer. A prerequisite for this is a standard procedure of deriving and allocating costs, which is considered to be fair and equitable and which is as broadly acceptable as possible to all stakeholders. Hence the implementation of the NRS 058 Working Group which was tasked to propose a standard Cost-of-Supply Methodology for the distribution sector of the EDI, from which tariffs are determined.

The practices set out in this methodology are intended to assist utilities in calculating the cost of a product, process or service and to provide schedules of costs for defined categories.

In the costing process the unit costs for all functions of electricity supply to customers (purchase, network and support costs) are calculated as described in NRS 058. The calculated unit costs (c/kWh, R/kVA and R/customer or percentage of costs) are applied to the customer data to determine the total allocated revenue by customer group.

The process should be viewed as being dynamic and additions/changes to the methodology could be made as technology and knowledge develops.

This methodology assumes that all relevant data is available. Subsequent parts of this methodology will suggest methods to estimate data which is not readily available. Assumptions regarding data should be recorded by the utility as evidence to a cost of supply study.

The accuracy and existance of asset registers in the industry is vital to the success of implementation of COS. Where asset registers di not exist the issue should be addressed and relevant action taken.

Key words

Profiles; Network; Ringfencing; Allocation mechanism; Modelling; Utilities; Methodology; Benchmarking.

METHODOLOGY

Cost of supply methodology for application in the Electrical Distribution Industry

Preferred requirements for applications in the Electricity Distribution Industry

1 Scope

The methodology enables the determination of the costs of supplying electrical energy at the following levels referred to in figure 1:

a) Phase 1 – direct cost of supply;

b) Phase 2 – after adjustments due to costs of non-technical losses and bad debts;

c) Phase 3 – after adjustments due to returns;

d) Phase 4 – after adjustments due to subsidies between customer categories, levies, grants and taxation;

e) Phase 5 – tariff design phase, capital contributions from developers and customers are incorporated to determine tariff levels. Reduced costs due to capital contributions are taken into account in this phase. Costs are separated into prices.

Phases 3 to 5 are included in the document in order to highlight certain costs incurred by a supplier. Being policy-driven however, they are not dealt with in great detail.

2 Normative references

Not applicable.

3 Definitions and abbreviations

In addition to the following, the definitions detailed in NRS 048-1 shall apply:

3.1 Definitions

3.1.1 allocation mechanism: Algorithm or parameters to apportion a cost to different sub-elements.

3.1.2 amortization period: Period over which a future cash flow is converted into an annuity.

3.1.3 annualized cost: A single cash flow converted into an annuity with an equal present worth.

3.1.4 average costing: Costing based upon the average input cost per unit of output.

3.1.5 benchmarks: The default technical losses at various voltage levels or profiles to be used by a utility in the absence of better information.

3.1.6 capital contributions: Cash contributions made by customers towards the capital cost of networks installed by the utility on behalf of the customer.

3.1.7 cost of services: The cost of services includes all direct costs incurred by the utility to supply electricity plus indirect costs such as profits, taxes, subsidies and abnormal costs.

3.1.8 cost vs. price: Cost is the amount of money incurred by the utility to supply a unit of goods or service. Price is the amount of cash paid by the customer to a utility for a unit of goods or service.

3.1.9 cost-of-supply methodology: A standard procedure based upon a selected philosophy that is used to derive and allocate the costs of supplying electrical energy to various customer categories.

3.1.10 customer categories: The single load profiles that best describe the customer type, for example, business, industrial, residential, electrification, night time users, agricultural.

3.1.11 customer group: The pools of customers created within the customer base consisting of customers taking supply at the same network position.

3.1.12 large/small customer: Categories of customers based on the capacity required by a customer.

3.1.13 marginal costing: Costing based upon the cost of producing an additional unit of output.

3.1.14 metered demand tariff: Tariff where a demand charge is applicable to the measured maximum demand.

3.1.15 modular process: The course of actions or proceedings consisting of standardized parts or independent units.

3.1.16 network: Electrical infrastructure over which energy is transported from source to point of consumption.

3.1.17 non-coincident approach: A network cost allocation method based on using the summated individual maximum demand requirements of customers as apposed to the maximum simultaneous demand of customers.

3.1.18 non-technical losses: Losses that arise from theft.

3.1.19 nxx: The corresponding location in the Reduced Network Diagram (RND). The replacement costs of each asset category of the RND should be determined according to the RND of the specific utility. This table is drawn up in accordance with the specified RND.

3.1.20 ringfencing: The financial separation of the electricity related costs from all other costs incurred within a utility, and the further financial separation of the generation, transmission and distribution costs within the utility.

3.1.21 rural: Networks serving clustered or scattered structures, usually of low density, not served by well-established infrastructure.

3.1.22 taxes: Any contributions required by the utility which are in addition to costs incurred directly for the provision of electrical energy and services, such as contributions to rates, shareholders dividends, return-on-investments, taxes required by the National Electricity Regulator and streetlighting, but excluding working capital and development capital used for future system reinforcement and upgrading.

3.1.23 technical losses: Losses incurred over electrical networks due to the characteristics of the physical equipment usually associated with dissipation.

3.1.24 time of use: A concept referring to the time when a specific product or service is utilized. It is applied to tariffs where the price of the product or service varies with time.

3.1.25 urban: Networks serving formally or informally built structures, usually of high density, serviced by well established infrastructure.

3.1.26 utility: An organization such as a municipality or Eskom Distribution that supplies electrical energy using its own infrastructure, to customers within its licensed area of supply.

3.1.27 weighting: A method of assigning weights to different categories for use in allocation methods. Usually aimed at expressing costs or number of customers relative to each other.

3.2 Abbreviations

3.2.1 EDI: Electricity Distribution Industry

3.2.2 NER: National Electricity Regulator

3.2.3 RDSM: Residential Demand Side Management

3.2.4 RND: Reduced Network Diagram

3.2.5 ROA: Return on assets

3.2.6 WEPS: Wholesale Electricity Pricing System

4 Guidelines

4.1 General

This section describes the scope of the cost of supply methodology and sets out the fundamental principles for the methodology. It details the relevant aspects when choosing a cost allocation method.

4.1.1 Overview

The details of a cost of supply methodology can only be understood once the role of the methodology is understood in the wider context of pricing. Before any tariffs can be determined it is necessary to calculate the costs. The role of the cost of supply methodology in the tariff design process is shown in figure 1:

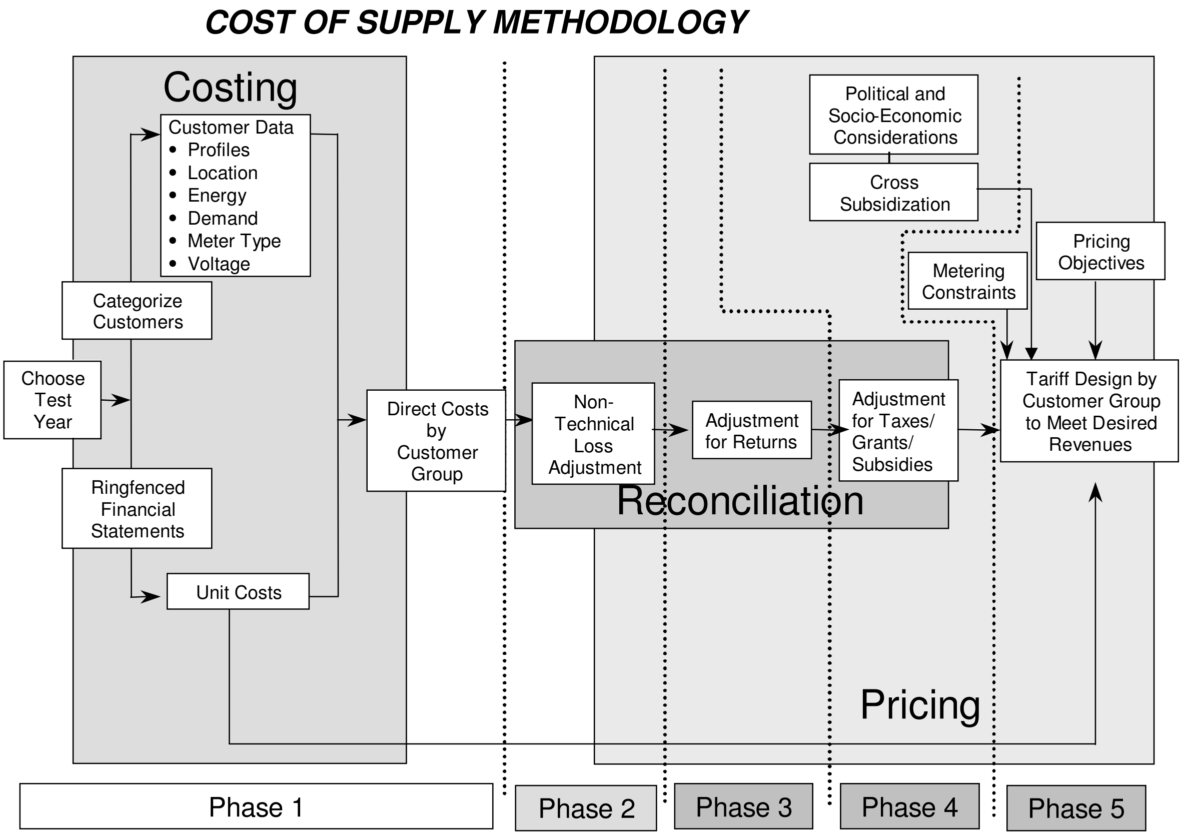


Figure 1 – Tariff design process

Figure 1 clearly indicates a costing and a pricing component. These two processes should not be confused. Costs are usually adjusted to determine prices. In the utility industry, the costs are distorted in several ways i.e. metering constraints, pricing objectives, political and socio-economic objectives. The objective of this methodology is to cover the area of costing and to address some of the issues of pricing.

Figure 1 shows the five different phases in the tariff design process. The first four phases are covered in this methodology:

a) Phase 1: The allocation of all the direct costs of electricity supply, which is the main focus of the methodology, is dealt with in this phase. All the costs identified as direct costs associated with the supply of electricity are allocated to customer categories. These costs are discussed in detail later in the document (see tables 1 to 4) (see section 4.2.7.1).

b) Phase 2: In this phase, the pure costs are adjusted to account for any costs relating to non-technical losses including theft, bad debts and revenue protection (see table 5).

c) Phase 3: In this phase, the results of phase two are adjusted to include any returns that the utility is allowed to recover (see table 6).

d) Phase 4: This phase of the methodology includes any taxes, including contributions to municipal rates fund, or levies imposed in the electricity distribution industry (see table 7) in the allocated costs.

e) Phase 5: In this phase the pricing policy of the utility is used to formulate prices from costs. Issues such as capital contribution and socio-economic subsidies are built into the costs according to the pricing policy of the utilities.

The accent of this methodology remains with the cost of supply (phases 1 and 2) although the last three phases are incorporated for completeness. This methodology does not extend to the tariff design phase and where externalities such as social or competitive subsidies and broader objectives are addressed and woven into pricing structures.

4.1.2 Purpose of the cost of supply methodology

The cost of supply methodology and the results of implementing the methodology do not prescribe that all tariffs must be cost reflective, but it allows the utility to understand which costs can be allocated to which customer categories. With such a tool in hand the following can be achieved:

a) cost reflective tariffs can be implemented within the accepted definition of cost reflectivity;

b) if cost behaviour is understood, strategies can be developed to reduce costs;

c) taxes and subsidies can be made transparent which allows policy makers a clearer view of the extent of subsidies;

d) specific market opportunities can be utilized by knowing where deviation from standard tariffs can still be profitable;

e) pricing policies can be developed to detail how tariffs should be different from costs;

f) the cost of energy and networks can be unbundled in future tariff structures; and

g) a platform for determining norms for the costs of supplying various customer categories.

The methodology is not a pricing methodology, and therefore does not attempt to prescribe how costs are translated into tariffs. It does however provide a framework for utilities to accommodate these costs in deriving tariffs. This translation requires the incorporation of political and economic factors, (such as the ability to pay, value to the customer, diffused benefits and competitive value), conversion into the tariff structure applicable to each customer group, metering constraints, and cross-subsidies.

4.1.3 Marginal cost vs. average cost approaches

The objective of the methodology is to reflect the economic cost of supply. The most common tariff structures used by utilities are based on the average cost of providing the service. The revenue requirement is based on the historical cost of providing service or the accounting cost to provide the same service. The principal weakness of the average cost approach is that the costs do not reflect the true economic cost of supply if the accounting costs are used. The costs are usually based on the historical cost of assets. This problem is overcome in this methodology by using the annualized replacement cost of assets as opposed to the historical cost. This results in a closer approximation of the true economic cost of providing the service.

Historical costs are stable until asset replacement takes effect whereafter there is a significant increase in cost which leads to unstable pricing.

One may argue that older assets should warrant a lower tariff/cost allocation. However, being older, those assets may need to be replaced (for which provision is required).

As such, it is considered fair to give equal allocation to assets irrespective of age to avoid any possible steps that might otherwise have occurred if historic costs were used. Equal allocation at annualized replacement values is adopted to provide a fair basis for comparison of asset values.

An ideal methodology is considered to:

a) be cost-reflective and transparent;

b) encourage the efficient and cost effective allocation of economic resources;

c) be fair and equitable;

d) be easy and simple to implement: it should not be unnecessarily complicated;

e) be economically sound in order to promote the continued viability of the Electricity Distribution Industry;

f) provide the foundation for stable pricing;

g) promote minimized pooling; and

h) address time variable of costs.

As some of the above principles may conflict with one another, it is necessary to compromise and determine the best balance of attributes within the methodology.

Marginal costing produces the most cost reflective and economic cost of supply methodology. Average costing on the other hand, produces a more stable methodology. A hybrid between an average and marginal costing methodology is therefore preferred.

4.1.4 Factors that influence costs

It is recognized that the physical costs of providing electrical energy to customers will vary depending on various factors i.e.:

a) the quantity of electricity used;

b) the size of the supply required;

c) periods when electricity is used;

d) the geographic location of the customer;

e) the voltage at which supply is provided;

f) the power factor; and

g) the need for redundant network capacity.

These factors prevail in varying degrees for each customer, but the costs incurred cannot always be isolated to individual customers. Hence the need for a methodology which agrees on the manner and method by which costs are determined.

4.1.5 Cost drivers

Costs should be expressed in a manner that will ultimately be applied to derive the tariffs according to an appropriate cost driver. By using the correct cost driver for each cost component, one can eliminate inappropriate pooling of costs. The 3 relevant cost drivers are c/kWh, R/kVA & R/customer. The various cost drivers are explained below.

4.1.5.1 Energy or unit-driven costs (c/kWh)

The energy or unit-related costs component of the utility consists of those costs that would vary with changes in the unit consumption of energy. This component is often time-variable.

4.1.5.2 Demand-driven costs (R/kVA)

The capacity or demand-related costs component of the utility consists of those costs that would be induced in the business as the result of customers' demands on the electrical system.

The costs that can be deemed as demand related are usually joint costs, such as network capital costs. The joint costs should be distributed amongst the customers inducing the cost, by using appropriate allocation methods.

4.1.5.3 Customer driven costs (R/customer)

Customer costs are those costs found to vary with the number of customers regardless of consumption or demand. These costs tend to be fixed and pooling of such costs should be isolated to customer groups.

4.1.6 Recovery of revenue requirement

A utility, in order to remain viable, must be given the opportunity to recover its total incurred costs of providing an electricity service to its various categories of customers. It is therefore very important for the utility to ensure that the rates it charges for electric services are sufficient to recover the total costs.

The total revenue requirement of a utility should be equal to the sum of all the costs to supply all the various customer categories and any appropriate returns.

4.1.7 Time-of-use basis for costs

Certain cost are related to the times that power or energy is required. In order to accurately reflect the time variance of some of the distribution costs and to achieve the correct pricing signal, prices should be time-variable. For generation costs, the classification of costs into time-periods is simple, as the cost is naturally differentiated between generators and from hour to hour. Generation costs should therefore be based on time-variance.

Introducing a time-variable to the distribution network cost is more difficult as there is no obvious time-differentiator. There is a need to develop an algorithm to allocate costs to different time periods in future.

4.1.8 Network cost allocation considerations

There are several factors that should be taken into account when stating the principles of a network capacity cost allocation method. In the past, network costs were allocated primarily according to the coincidence with the system peak because an awareness of the balance between these factors was ignored. This methodology focuses on striking a balance between the factors in order to optimize the allocation of network capacity costs. The criteria for selecting a network capacity cost allocation method includes, inter alia, the following:

a) cost behaviour;

b) recognition of usage;

c) recognition of diversity;

d) availability of required load data;

e) ease of implementation;

f) relative size of energy and network cost signals; and

g) variances with changes in methodology.

4.1.8.1 Cost behaviour

An important criterion for cost allocation is the extent to which the allocation method recognizes cost behaviour patterns. This criterion favours the objective of economic efficiency in that the cost will be allocated according to the correct cost driver i.e. R/kVA.

4.1.8.2 Recognition of usage

Another criterion is the extent to which the allocation method recognizes the use of the networks. This criterion can be regarded as assuring the objective of fairness or equity. If a customer makes extensive use of the networks during an off-peak period and is allocated no cost, the so-called “free rider” problem arises. The allocation method should reflect the degree of maximum potential usage of the network and contribution to excessive capacity. An improved load factor should lead to lower costs.

4.1.8.3 Recognition of diversity

Several methods allocate the cost of network assets according to the individual customer’s demand on all assets without recognizing the effect of diversity of load , especially on shared networks. This factor implies that the allocation method should allocate the cost based on the summated demand of customers on a network as opposed to the individual maximum demand of customers on the network.

4.1.8.4 Availability of required load data

This criterion is important in terms of cost and the time period required to obtain (measure and process) customer load data needed for the execution of the allocation method. It calls for the consideration of the costs and benefits involved if an allocation process requires expensive and/or extensive load measurement.

4.1.8.5 Ease of implementation

Any chosen method should be easy to implement without compromising the quality of the output and accuracy of the results. The cost allocation method should be implemented without complexities or the need for many assumptions in the absence of available data. The method should not require costly data systems.

4.1.8.6 Relative size of energy and network cost signals

The average “wires cost” of a customer is usually small compared to the energy cost. On average it is in a ratio of 25:75. The incentive to shift load due to a time variable network cost signal is therefore diluted. A time variable network cost allocation method requires complex calculations and there would be little or no response to such signals. The metering provided for many customer categories do not allow the pass through of time variable cost signals into prices. The rule should be considered that one cannot charge for what cannot be measured. It is prudent to allocate the energy cost with time variance but not the network cost.

4.1.8.7 Variances with changes in methodology

The chosen cost allocation methodology should be a good balance between the considerations discussed in this paragraph. The different methods were evaluated and the allocated cost did not change significantly with a change in methodology. The accuracy of the price signal is therefore not compromised significantly if a simple methodology with minimum data requirements is used.

4.2 Specific assumptions and principles

Before the methodology can be executed, several assumptions have to be made and certain definitions have to be laid down. In this section some of the detailed assumptions that should be made to implement a cost of supply methodology are explained. This includes the definition of customer categories, the Reduced Network Diagram, Customer Groups and the ringfencing of the costs of a utility. The ringfenced costs are shown and the appropriate cost driver for each cost component. There is also an introduction to the different allocation methods that may be used in the methodology.

4.2.1 Ringfencing

The first important prerequisite to ensure the success of the cost of supply methodology is an understanding of the cost chain involved in the supply of electricity. The activities within the EDI required to supply electricity to the end user are classified according to a few functions, i.e.:

a) production of electricity;

b) transmission of produced energy over powerlines to load centres;

c) transportation and transformation of the power over distribution networks;

d) delivering the energy to the end-users;

e) providing support services to such end-users; and

f) billing of end-users.

The cost of supply methodology is applicable to a ringfenced distribution business and allocates all costs flowing into the business and costs incurred by the business to customers. This implies that the cost of upstream functions is ringfenced and passed on to the utility in the form of a tariff.

The cost of producing electricity is also passed on to a utility in the form of a tariff. This tariff includes all costs associated with the generation of electricity. The cost of transmitting power over the transmission system is similarly passed on to utilities. The cost categories shown in tables 1 to 7 indicate the minimum level of ringfencing of costs with a utility.

4.2.2 Classification of customer categories

A customer category consists of customers who have similar patterns of usage. The profiles or patterns of use within the economic sector can vary. Provision is made to use a second level of categorization i.e. the load factor or profile of use. The cost of supply analyst may define sub-categories within a sector such as low load factor, medium load factor and high load factor. This sub division is left to the discretion of the utility.

These categories can exist across different supply voltages and at any position in the RND.

In compiling a list of customer categories, the following characteristics should be considered:

4.2.2.1 Economic sector

The economic sector is broken down as follows:

a) industrial;

b) mining;

c) distribution;

d) agricultural;

e) traction;

f) commercial; and

g) residential.

4.2.2.2 Load profiles

Customer load profiles are as follows:

a) customer-specific (for the relatively large customers) – where actual profiles are measured;

b) average profiles:

1) load factors (LF) >120 % (i.e. higher night-time demands):

   90 % to120 %,

   60 % to 90 %,

   30 % to 60 %,

   <30 %.

NOTE The load factor of a measured load profile can exceed 100 % if the maximum demand values of off-peak periods (such as night-time periods) are ignored in the calculation of load factors.

2) developing community:

   developed community,

   day time users,

   day and night time users.

4.2.3 Pooling of infrastructure: Reduced Network Diagram (RND)

The position of a customer in the network is a determining factor when calculating the cost of supply to that customer. It is unreasonable to model the entire network with all customers' requirements individually, therefore a simplified network diagram with pooled asset categories must be created.

In order to minimize cross-subsidization, it is necessary to pool costs appropriately. With networks there are two natural pooling categories – voltage level and asset type i.e. networks or transformation. In same cases asset are shared between different groups located at different positions in the RND. This could be urban and rural customers and domestic and / or non domestic customer groupings. These assets should be appertioned to the different asset groups in the RND.

The basic for apportioning the asset could be consumption or demand.

The so-called Reduced Network Diagram creates asset pools, according to voltage level and asset type. Once the reduced network is determined, the customers are positioned in the network to do cost allocation. In allocating network costs, customers taking supply at the higher voltage levels clearly do not have an impact on the capacity required at lower levels and hence should not be allocated any of these lower level network costs. This is ensured by determining unit costs for every asset in the RND and only adding the cost of the appropriate assets for a specific customer. Customers should not share in the cost of an asset if they do not utilize it. [Examples of the RNDs are shown in annex A].

A generic template for a Reduced Network Diagram with all possible asset groups is shown in annex A. This template can be used as the basis for determining the RND of any utility. The template gives the lowest level of pooling and further pooling of asset groups may take place according to the utility requirements. Several examples are shown in annex A to illustrate the RND for a few utilities of different size.

The utility should number all positions and network assets in the RND according to its specific needs. The numbering convention should be explained in a legend to enable the reader to interpret the results.

4.2.4 Electrical losses

Technical losses must be taken into account when considering the contributions to certain costs, for example, cost of purchases. The technical losses for every network component in the RND should be determined.

Some utilities may be in a position to accurately determine their technical losses. However, it is pertinent to provide benchmark levels for those instances where utilities do not have the resources to do so.

4.2.5 Customer groups

Customer groups are made up of a customer category at a specific location on the RND, receiving supply at a specified voltage. Two dimensions are added to a customer category to distinguish between customer groups i.e. a geographic location and the supply voltage. The difference between a customer category and a customer group is that customer categories can exist anywhere in the network whereas a customer group is confined to one position in the network (see annex A). The factors distinguishing customer groups from customer categories are as follows:

4.2.5.1 Geographic location

Geographic locations are defined as:

a) general (supply to both rural and urban);

b) rural, and

c) urban.

4.2.5.2 Supply voltage level

Supply voltage levels are defined as:

a) directly from the secondary busbars of a transformer, for example, 11 kV and 400 V; and

b) indirectly from a transformer, off a network, for example, 11 kV network, 400 V network.

4.2.6 Level of categorization and grouping

The level of categorization and grouping may be augmented or simplified by a particular utility. However, at minimum, the differentiation should include:

a) the supply voltage level;

b) whether the customer is supplied at the transformer or from the network; and

c) whether the customer is industrial, commercial, high consumption residential or low consumption residential.

It should be noted that the more extensive the customer categories are, the better the position of the utility will be to identify the areas of cross-subsidization. Examples are listed in annex B.

4.2.7 Cost categories

The Cost of Supply methodology separates all costs for the various customer categories into the following broad categories:

4.2.7.1 Phase 1 (see tables 1 to 4)

Phase 1 costs are:

a) contributions to costs of purchase;

b) network capital costs;

c) network operation and maintenance costs; and

d) direct support costs.

Both network capital costs and network operation and maintenance costs include any funds required for future reinforcements and working capital. The derivation of the network capital cost per asset value according to the RND is detailed in 4.2.8.

Support costs include costs associated with meter reading and billing, faults, computer facilities, finance, human resources, executive salaries, etc.

Certain costs are assigned directly to the customer category or function which exclusively imposes such a cost. The remaining costs are then assigned to the relevant cost component.

4.2.7.2 Phase 2 (see table 5)

Revenue protection and non-technical losses, and abnormal costs, for example, surcharges to recover theft losses;

4.2.7.3 Phase 3 (see table 6)

Returns.

4.2.7.4 Phase 4 (see table 7)

Taxes, subsidies and grants.

Tables 1 to 7 indicate the cost categories that should form the basis for cost aggregation. The cost of the utility should be arranged according to these categories before the allocation of costs.

Table 1 – Purchase costs

PURCHASE COSTS	Energy self generation external purchase
	Demand
	Fixed costs
	Avoided cost adjustments
	Wires charges transmission distribution fixed charges
	Rebates/discounts
NOTE The avoided cost adjustment cost should be quantified by the utility and is usually savings in purchase costs as a result of demand side management strategies. This cost will be allocated specifically to the customer category that contributes toward the saving. In the case of ripple control, for example, the cost saving of exercising the ripple control will be passed onto the domestic sector.	

Table 2 – Network capital costs

CAPITAL COSTS	Transformation TX – DX			Nxx
	Networks DX			Nxx
	Transformation DX – DX			Nxx
	Networks RX	Urban		Nxx
		Residential (Electrification)		Nxx
		Rural	Per defined network	
	Transformation LV	Urban	Per defined residential network	
			Per defined other network	
		Residential (Electrification)		Nxx
	Networks LV	Rural	Per transformer size category	
		Urban	Residential	Nxx
			Other	Nxx
		Residential (Electrification)		Nxx
NOTE 1 Nxx refers to the corresponding location in the RND.				

Table 3 – Network operation and maintenance costs

OPERATION AND MAINTENANCE	Transformation TX – DX			Nxx
	Networks DX			Nxx
	Transformation DX – DX			Nxx
	Networks RX	Urban		Nxx
		Residential (Electrification)		Nxx
		Rural	Per defined network	
	Transformation LV	Urban	Per defined residential network	
			Per defined other network	
		Residential (Electrification)		Nxx
	Networks LV	Rural	Per transformer size category	
		Urban	Residential	Nxx
			Other	Nxx
		Residential (Electrification)		Nxx
NOTE 1 Nxx refers to the corresponding location in the RND.				

Table 4 – Support cost

DIRECT SUPPORT COST	Marketing and Sales	Promotions, advertising, surveys, sponsorships, customer education and general (see below)	Per customer group
	Metering	Capital and maintenance cost of the meters and general (see below)	Per meter type
	Billing	Postage, IT and general (see below)	Per customer group
	Customer Service	Call centres and general (see below)	Per customer group
	Overheads	Only costs not included in any of the above categories will be part of this allocation plus Finance, IT, Technical records, Legal, Security, Business Planning, R&D, Human Resources	

The general costs involved for every component should include the following:

a) capital;

b) labour/salaries/wages;

c) transport;

d) materials;

e) contracts;

f) maintenance; and

g) research and development.

Table 5 – Revenue protection and abnormal cost

INDIRECT COSTS	Abnormal costs (i.e. non-technical losses, theft, non-payment)	Per applicable customer group
	Revenue Protection	Per applicable customer group

Table 6 – Returns

INDIRECT COSTS	Returns (i.e. ROA, contribution to capital , retained income)

Table 7 – Taxes, grants and subsidies

INDIRECT COSTS	Tax	
	Subsidies/Grants	Per applicable customer category

4.2.8 Annualized network capital costs and scaling of annualized network capital cost

This procedure is used to calculate the values for network capital costs (each asset category as detailed in table 2).

In this methodology, asset replacement values are used to calculate the capital costs. Replacement costs take into account technological and efficiency improvements that may occur over time. The annualization of replacement costs is done to estimate the annual capital cost of network assets. The costs of capital of the utility, inflation, lifetime and the appropriate asset replacement cost should be used in the annualization equation. An annualized cost is calculated by determining the annuity of the investment. The annuity is calculated by multiplying the annual capital recovery rate by the replacement cost.

The annualization equation is as follows:

Annualized cost = ACRR $\times$ replacement cost

$$\text{Annual capital recovery rate (ACRR)} = \frac{i}{\left\{1-(1+i)^{-n}\right\}}$$

where:

i = per unit annual interest rate; and

n = accounting lifetime of asset.

4.2.9 Cost drivers and classification

Costs should be expressed in a manner that will ultimately be applied to derive the tariffs according to an appropriate cost driver. By using the correct cost driver for each cost component, one can eliminate inappropriate pooling of costs. The various cost drivers are explained in more detail in tables 8 to 14.

Table 8 – Purchase cost classification

		c/kWh	R/kVA	R/Cust.
PURCHASE COSTS	Energy self generation external purchase	 ✓ ✓		
	Demand		✓	
	Fixed costs			✓
	Avoided cost adjustments	✓		
	Wires charges transmission distribution fixed charges		 ✓ ✓ ✓	
	Rebates/discounts	✓		
NOTE The avoided cost adjustment cost should be quantified by the utility and is usually savings in purchase costs as a result of demand side management strategies. This cost will be allocated specifically to the customer category that contributes toward the saving. In the case of ripple control, for example, the cost saving of exercising the ripple control will be passed onto the domestic sector.				

The capital provision of a utility consist of the accounting practises of a utility contributions, connetion fees, developers contribution and interest fee funding may have a distertianary impact on the capital provision in the revenue requirement of the utility capital contributions effectively reduce the overall capital pool. The benefit of a reduced capital pool will be spread across all customers by scaling the annualised replacement cost to the capital provision.

Table 9 – Network capital cost classification

					c/kWh	R/kVA	R/Cust.
CAPITAL COSTS	Transformation TX – DX			Nxx		✓	
	Networks DX			Nxx		✓	
	Transformation DX – DX			Nxx		✓	
	Networks RX	Urban		Nxx		✓	
		Residential (Electrification)		Nxx			✓
		Rural	Per defined category			✓	
	Transformation LV	Urban	Residential	Nxx			✓
			Other	Nxx		✓	
		Residential (Electrification)		Nxx			✓
		Rural	Nxx Nxx Nxx Nxx	<25 kVA <50 kVA <100 kVA >100 kVA		✓	
	Networks LV	Urban	Residential	Nxx			✓
			Other	Nxx		✓	
		Residential (Electrification)		Nxx			✓

NOTE Nxx refers to the corresponding location in the RND.

Table 10 – Network operation and maintenance cost classification

					c/kWh	R/kVA	R/Cust.
OPERATION AND MAINTENANCE	Transformation TX – DX			Nxx		✓	
	Networks DX			Nxx		✓	
	Transformation DX – DX			Nxx		✓	
	Networks RX	Urban		Nxx		✓	
		Residential(Electrification)		Nxx			✓
		Rural	Nxx (0-x km)			✓	
			Nxx (x-y km)			✓	
			Nxx (y+ km)			✓	
	Transformation LV	Urban	Residential	Nxx			✓
			Other	Nxx		✓	
		Residential (Electrification)		Nxx			✓
		Rural	Nxx	<25 kVA			
			Nxx	<50 kVA		✓	
			Nxx	<100 kVA			
			Nxx	>100 kVA			
			Nxx	<25 kVA			
			Nxx	<50 kVA		✓	
			Nxx	<100 kVA			
			Nxx	>100 kVA			
			Nxx	<25 kVA			
			Nxx	<50 kVA			
			Nxx	<100 kVA		✓	
			Nxx	>100 kVA			
	Networks LV	Urban	Residential	Nxx			✓
			Other	Nxx		✓	
		Electrification		Nxx			✓
NOTE Nxx refers to the corresponding location in the RND.							

Table 11 – Support cost classification

				c/kWh	R/kVA	R/Cust	% of Revenue
DIRECT SUPPORT COST	Marketing and sales	Promotions, advertising, surveys, sponsorships, customer education and general (see below)	Per customer group			✓	
	Metering	Capital and maintenance cost of the meters and general (see below)	Per meter type			✓	
	Billing	Postage, IT and general (see below)	Per customer group			✓	
	Customer Service	Call centres and general (see below)	Per customer group			✓	
	Overheads	Only costs not included in any of the above categories will be part of this allocation plus Finance, IT, Technical records, Legal, Security, Business Planning, R&D, Human Resources		✓	or	✓	or ✓

Table 12 – Revenue protection and abnormal cost

			c/kWh	R/kVA	% of Revenue	R/Cust
INDIRECT COSTS	Abnormal costs (i.e. non-technical losses, theft, non-payment)	Per applicable customer group	✓			
	Revenue Protection	Per applicable customer group	✓	or		✓

Table 13 – Returns

			c/kWh	R/kVA	% of Revenue	R/Cust
INDIRECT COSTS	Return (i.e. ROA, contribution to capital , retained income)		✓	or	✓	

Table 14 – Taxes, grants and subsidies

			c/kWh	R/kVA	% of Revenue	R/Cust
INDIRECT COSTS	Tax		✓			
	Subsidies/Grants	Per applicable customer group	✓	or	✓	✓

4.2.10 Allocation of costs to customer groups

After the costs have been functionalized and classified, the next step of the methodology would be to allocate them to the various customer groups, based on the cost drivers (energy, demand, customer or percentages). Costs can be allocated based upon these premises:

a) energy-related costs are allocated on the basis of energy supplied to a customer plus an additional amount to cover any losses;

b) demand-related costs are allocated to a customer group on the basis of the demand imposed on the network during certain hours; and

c) customer-related costs are allocated to the customer groups based on the number of customers or the weighted number of customers.

In developing the allocation methodologies, it must be recognized that there are a variety of options available.

4.3 Cost allocation methods

4.3.1 Energy cost allocation

The energy cost component of purchases is simple to allocate because the purchase rates can simply be passed on to all lower voltage levels with an additional adjustment for losses. The losses are determined by assuming loss factors for each network component and then comparing the cumulative losses to a network position with the expected loss values for that particular network location. If the cumulative losses of the network components do not compare with the expected or theoretical losses, the loss factor of every network component should be scaled accordingly.

The share of the total cost attributable to the customer group is then calculated as follows:

a) calculate the time differentiated consumption (if required) of every customer group at each voltage level; and

b) multiply the consumption by the loss differentiated purchase rates.

The result of this allocation is a Rand value for each customer group at each voltage level representing the energy purchase cost.

Additional costs such as overheads and other energy-related costs indicated in tables 8 to 14, can be incorporated with the calculated (energy-related) unit costs. These costs can be applied to specific customers. Assume that the overhead cost for the agricultural customers is R10 million. This cost must be divided by the total energy consumption for agricultural customer to derive a unit energy-related cost for each customer in the category. This derived unit cost must be added to the unit purchase cost (as was discussed in 4.2) for each agricultural customer.

The total energy-related cost for each agricultural customer can now be determined by multiplying the unit energy-related cost (including the additional energy-related costs) with the total consumption of the customer.

4.3.2 Demand cost allocation

The demand cost allocation method will be used for all costs that are classified as being demand-driven. This includes the network capital cost, the operations and maintenance cost of some networks, demand purchase cost and the wires component of the purchase cost (if applicable). As stated in 4.1.8, there are several objectives to be considered before deciding on a specific allocation method. Many different methods can be used to allocate the cost of networks that are used simultaneously by many customers.

There is no single, exact solution to this complex problem. Consequently methods have been derived that produce results that are considered "fair and just" and not "unduly discriminatory" in the regulatory sense of those terms.

Although many methods have been developed for the allocation of "jointly-used facilities" costs, four methods were considered in the design of the cost supply of methodology. They are:

a) single non-coincident peak method;

b) average and excess method;

c) excess threshold; and

d) demand weighting method.

The excess threshold and demand-weighting methods give a more rigorous analysis of time-based cost of supply and require detailed load profiles and complex calculations which are not readily available or practical in the South African EDI.

These methods were included in an attempt to obtain a demand cost allocation method that reflects the time variable of cost. The methods require detailed load profile data and often necessitates various assumptions to keep data within manageable proportions. Based upon the considerations detailed in 4.1.8 and the analysis detailed in annex C, the Average and Excess Method was adopted as the most appropriate method.

The Average and Excess Method is used to allocate the cost of each asset category in the RND to each applicable customer group. If a customer group uses a specific asset that customer group is included in the allocation of the cost of the asset group. The cost of the 132 kV assets, for example, will be determined based on the demand imposed by each customer group on the 132 kV network and the cost of these assets.

The allocation of a share of the network capital to a specific customer group is then calculated as follows:

a) calculate the proportion of each asset category in the RND that should be allocated to each customer group;

b) summate all cost portions for all applicable assets per customer group; and

c) the total cost is divided by the sum of the customer groups' undiversified maximum demands to calculate a R/kVA cost.

4.3.3 Customer costs allocation

The number of customers or weighted number of customers is the basis for the customer allocation factors.

The total cost of a function is divided by either the number of customers or the weighted number of customers triggering such a cost component. The number of large customers, for example, is used to divide the cost of meter reading for large customers amongst large customers.

The customer service cost, for example is divided by the weighted customer numbers to determine the unit cost per customer. The principle is that one large customer is equivalent to several small customers. Therefore, a bigger proportion of the cost is allocated to the large customer. An example is shown in annex E.

4.4 Methodology overview

There are 4 major activities to be performed in the cost of supply methodology, i.e.:

a) define customer categories, profile classes and the reduced network diagram;

b) separate the components of income and expenditure of a utility according to cost categories as defined in 4.2.7;

c) classify all the identified costs as being energy, demand or customer-related; and

d) develop allocation factors and allocate the costs.

After all the costs are allocated, the calculated unit costs are applied to the customer data to determine the total revenue recovered by the unit costs. If the allocated cost and the revenue requirement are not equal because of load profile assumptions or any other uncertainties, the unit costs are adjusted to balance costs with revenue requirements. After the reconciliation exercise, relevant tariffs can be developed (see figure 2).

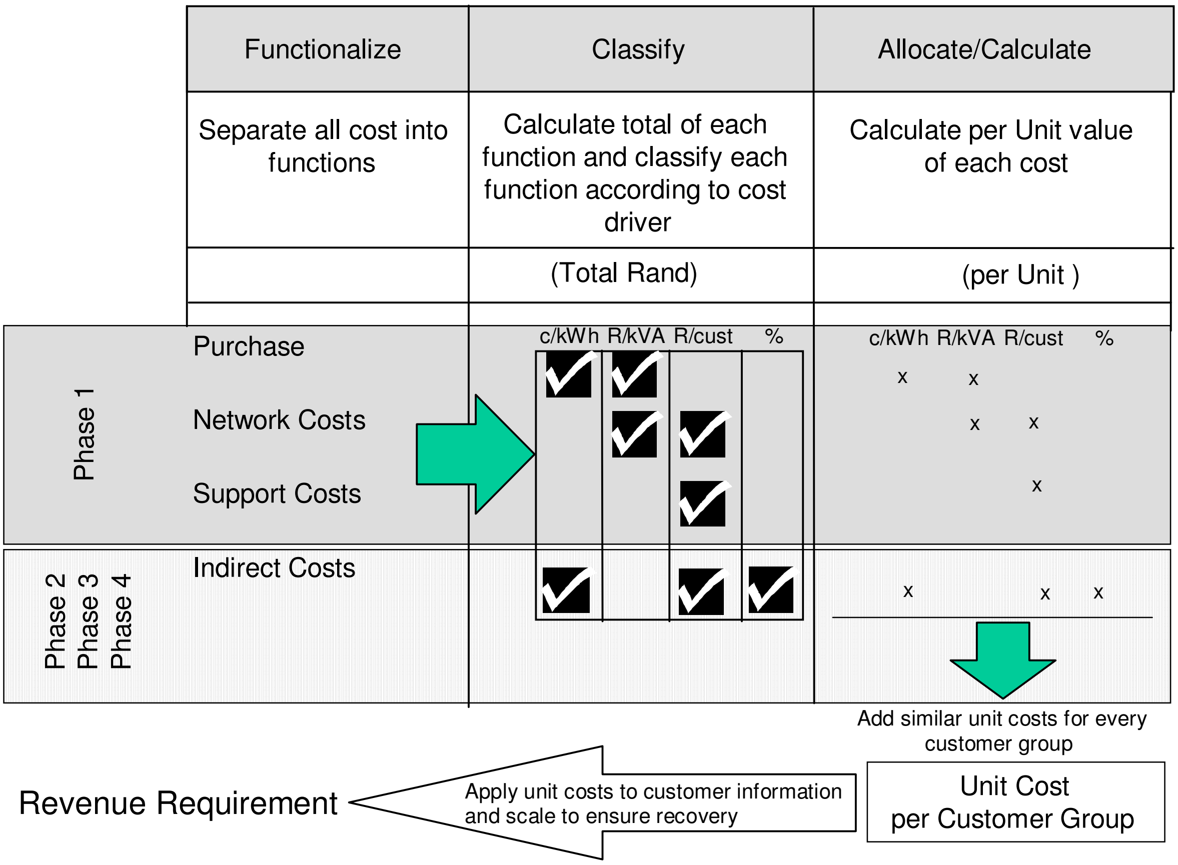


Figure 2 – Overview of the cost of supply methodology

4.4.1 Separation of costs

Separation of costs is the process of identifying the functions in a utility and ringfencing the expenses attributable to those functions.

4.4.1.1 Purchase costs

Purchase costs are those costs associated with wholesale purchases. The cost associated with the delivery of purchased electricity over the bulk transmission system is also part of the purchase function.

4.4.1.2 Network costs

The network cost function encompasses the distribution and reticulation systems that connect the customer to the transmission system.

The network capital and operation and maintenance functions are subdivided according to voltage and asset type.

The following list gives examples of costs that can be identified as network costs:

a) land and land rights;

b) structures and improvements;

c) station equipment;

d) storage battery equipment;

e) poles, towers and fixtures;

f) overhead conductors;

g) cables; and

h) line transformers.

These detailed costs must be grouped into two overall categories that will be used in the allocation process. The functions used in the cost of supply methodology are:

a) circuits; and

b) transformation.

All costs associated with a circuit are combined with the cost of the circuit, for example, land and rights, line bay, circuit-breakers, towers, etc. All the costs associated with transformation should be added together as transformation costs.

The costs are separated according to the asset groups indicated in the RND of the utility. The total capital cost of the utility is apportioned to each asset, based on the annualized replacement cost of each asset group in the RND.

4.4.1.3 Direct support costs

The support function includes the investment and expenses associated with marketing and sales, meter reading, billing, and customer service. This cost component also includes corporate overhead costs that are allocated to a utility.

4.4.1.4 Indirect costs

This function includes costs that are not directly incurred to supply electricity, but form an important part of a utility's cost. It includes the cost of revenue protection, bad debts, returns and contributions to rates funds, abnormal costs, taxes, grants and subsidies.

4.4.2 Classification of costs

Once the system investment and expenses have been identified and separated the next step is to classify the cost components based upon the cost drivers, for example, energy, demand or customers. The costs that vary with the peak usage (i.e., the kVA demand imposed by the customer) are classified as demand costs. Costs that vary with the energy (i.e., total energy consumption or kWh) are called energy costs, whereas the costs that are directly related to the number of customers served are called customer costs. The classification is illustrated in tables 8 to 14.

4.4.3 Allocation of costs

After the costs have been separated/identified and classified, the next step is to allocate the cost to the various voltage levels and customer groups based on the cost causation factors (energy, demand or customer). Once the customer groups to be used in the cost allocation study have been designated and the aggregated profiles at all voltage levels in the Reduced Network Diagram (RND) calculated, the unit costs can be calculated and allocated to customers based upon these premises:

a) demand-related costs are allocated to each customer group on the basis of demand imposed on the network following the Average and Excess method;

b) energy-related costs are allocated on the basis of energy supplied to a customer plus an addition for losses; and

c) allocation of the customer-related costs to the customer groups is based on the number of customers or the weighted number of customers in a group.

4.5 Procedure

The model can logically be broken up into four modules as shown in figure 3. The Network Module, Cost Module, and the Consolidation Module.

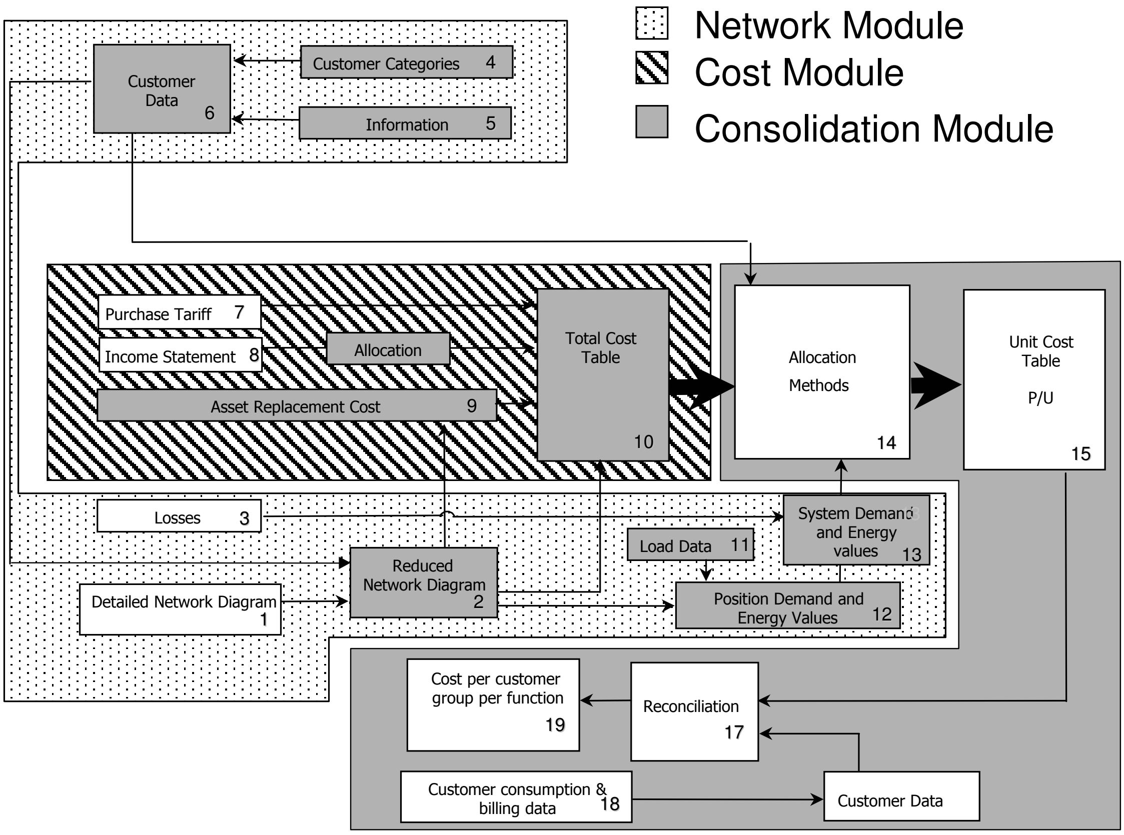


Figure 3 – The cost of supply procedure

4.5.1 Network module (Phase 1)

Input	Detailed Network Diagram and losses per network component
Output	Reduced Network Diagram with losses per asset category

4.5.1.1 The position of a customer in the network is a determining factor when calculating the cost of supply to that customer. It is unreasonable to model the entire network with all customers/categories individually therefore a simplified network diagram with pooled assets must be created. This will be called the Reduced Network Diagram (RND) (see annex A).

4.5.1.2 All the components not present in a specific distributor are omitted from the RND template to arrive at the specific RND for the distributor. All the assets of the distributor are categorized into the relevant category of the RND.

4.5.1.3 The losses for every asset component of the RND should be determined based on the losses of the network components that are pooled together to create an asset category in the RND. The losses will be adjusted once the energy sales at every network position are determined and added with addition for losses to arrive at the purchase volume. The weighted average loss over all the individual asset components should equal the total losses for the system.

4.5.2 Customer module

Input	Customer Categories, RND, Information on Customers, billing information, meter types, demand, location, voltage
Output	POD Data Table containing all information relating to a POD

4.5.2.1 The customer categories should be defined according to the parameters prescribed in the methodology. The definition of customer categories is at the discretion of a distributor but should be concise enough to avoid cross subsidization between different users.

4.5.2.2 Determine representative load profiles (one year) for each customer category by using load research techniques or sampling several profiles to determine the average profile. The process of determining these profiles is at the discretion of the utility executing the COS study. The representative load profiles are then used to calculate maximum demand and the time-of-use energy ratios for customers where these are not measured.

4.5.2.3 Gather customer information i.e. the number of points of delivery per defined customer category, consumption per point of delivery or customer group (in the case of small customers), maximum demand per point of delivery or customer group, voltage per point of delivery and metering types per point of delivery or customer group.

4.5.2.4 Determine the position of each point of delivery or customer group in the RND.

4.5.3 Cost module

Input	Purchase tariff, income statement, asset register, RND, Cost Tables
Output	Table with total costs

4.5.3.1 Identify the purchase tariff/s of a distributor. The purchase tariff can include several charges such as service charges, energy charges, demand charges, wire charges etc. The purchase costs should be identified, calculated and indicated in the total cost table.

4.5.3.2 Ringfence the detailed costs of the utility according to the template for costs shown in tables 1 to 7 and determine the cost driver for each cost component in accordance with tables 8 to 14.

4.5.3.3 Determine the annualized replacement cost of the assets in the case of network capital costs and the income statement expenditure in the case of other costs and complete the total cost table. For some support costs such as billing it might be necessary to separate the cost for different categories. These costs can be allocated to the different customer categories based on the weighting procedure discussed in the document (see the example in annex D).

4.5.3.4 The total cost table is compiled according to the defined cost categories of the methodology.

4.5.4 Network module (Phase 2)

Input	Non-Coincident Maximum Demand (NCMD) and sales per customer and losses per RND asset component.
Output	NCMD for customer categories at all voltage levels and sales expressed at every network level.

4.5.4.1 The allocation of costs is done according to the characteristics of a consumer in terms of energy or demand and according to the position of a customer in the network. In order to do the allocation, as described later, the demands at each level in the network have to be calculated. To be able to calculate these demands, each customer should have a measured or estimated non-coincident maximum demand.

4.5.4.2 Determine the combined NCMD and sales of all customers in the same category at the same position in the RND (this is referred to as a customer group). Determine the position NCMD and sales at each network position in the RND by adding the customer group demands and sales.

4.5.4.3 Determine the position profile at each network position in the RND by adding all the customer group profiles and the individual profiles at each network position (see figure 3).

4.5.5 Consolidation module

Input	Total cost table with all costs, system demands, number of customers
Output	Unit costs for all functions and aggregated costs per customer group

4.5.5.1 The purpose of the consolidation module is to convert the total costs in the total cost table to unit costs. A unit cost will be calculated for each cost component in tables 1 to 7.

The unit cost calculation or allocation methods are described in 4.3 and annex F. The unit costs can be c/kWh, R/kVA, R/customer or % of revenue of customer grouping. Tables 8 to 14 show the appropriate allocation method to be used for each cost component. The unit costs are compiled into the unit cost table that contain the per unit cost values for all the functions at every network position in the RND.

The allocation of ***energy purchase costs*** is done by adjusting the energy purchase rates (c/kWh) for losses and calculating the loss adjusted energy purchase cost at every network level.

The total annual ***purchase demand cost*** is calculated and added to the total cost table in 4.5.3.4. This cost should be converted to R/kVA unit costs by using the Average & Excess Allocation Method. The result would be a unit cost representing the portion of the purchase cost.

The allocation of the ***fixed purchase costs*** is done by dividing the total cost by the number of customers.

The total annual ***transmission or distribution wires charges*** are converted to unit rates by using the Average & Excess Allocation Method. This results in R/kVA wires charges at every network position in the RND.

Rebates or discounts are passed onto all customers as a reduced c/kWh rate or to specific customers as a c/kWh discount if the rebate or discount is attributable to that specific customer group or category.

The ***network capital costs*** are allocated according to the Average and Excess allocation method.

The network operations and maintenance costs for each asset group of the RND are also allocated according to the Average & Excess Allocation Method. This cost is allocated exactly like network capital costs. The operations and maintenance cost portions (per asset group) are added to the unit cost table.

The ***direct support costs*** are allocated according to the number of customers imposing a cost or the weighted number of customers in the case where a cost is shared by different groups of customers. The overhead cost is allocated by dividing the total cost component by the amount of energy sold.

Example: The billing cost can be split between large and small customers. The total cost of the large customer billing function is divided by the total number of large customers. The result is a R/customer value that will be applicable to all voltage levels where large customers are connected.

The ***indirect support costs*** are allocated according to the utility's policy and are not prescribed in this methodology. Tables 12 to 14 indicate which drivers are regarded as acceptable for the allocation of these indirect costs. The return of the utility can be allocated as a c/kWh, a R/kVA or % of revenue to the different customer groups. The allocation of these costs is done after all the direct costs have been allocated in phases 2 to 5 of the methodology. The unit cost table contains all the direct costs to supply the customer groups.

4.5.5.2 Once all the unit costs have been determined, all c/kWh, R/kVA and R/customer unit costs are added for every voltage level for every customer category to determine the summarized unit cost table as shown in table 15. The table indicates a c/kWh charge at every network position that includes all the direct supply costs i.e. energy purchase costs, avoided cost adjustments, rebates or discounts and overheads. The R/kVA charges include the network capital component and the operation and maintenance component. The separate R/Customer column in the table hold the unit rate for network capital cost where the capital cost is allocated as a R/customer cost such as residential networks.

The R/Customer columns on the right of the table reflect the summarized customer cost per customer category at every network position. Most customer categories can exist at any network position. The cost is therefore expressed at every network level.

Table 15 – Summarized unit cost table

Customer Categories

			c/kWh*	R/kVA	R/Cust	R/Customer					
DISTRIBUTION			**Per defined time period**		**Network Capital Cost**	Cat.1	Cat.2	…	…	…	Cat.n
	Transformation	Nxx	✓	✓	-	(✓)	(✓)	(✓)	(✓)	(✓)	(✓)
	Circuits	Nxx	✓	✓	-	(✓)	(✓)	(✓)	(✓)	(✓)	(✓)
			c/kWh*	**R/kVA**	**R/Cust**	**R/Customer**					
RETICULATION			**Per defined time period**		**Network Capital Cost**	Cat.1	Cat.2	…	…	…	Cat.n
	Transformation	**Urban** – Nxx	✓	✓	-	(✓)	(✓)	(✓)	(✓)	(✓)	(✓)
		Rural – Nxx	✓	✓	-	(✓)	(✓)	(✓)	(✓)	(✓)	(✓)
	Circuits	**Urban** – Nxx	✓	✓	-	(✓)	(✓)	(✓)	(✓)	(✓)	(✓)
		Rural – Nxx	✓	✓	✓	(✓)	(✓)	(✓)	(✓)	(✓)	(✓)
		Rural – Nxx	✓	✓	✓	(✓)	(✓)	(✓)	(✓)	(✓)	(✓)
		Rural – Nxx	✓	✓	✓	(✓)	(✓)	(✓)	(✓)	(✓)	(✓)
			c/kWh*	**R/kVA**	**R/Cust**	**R/Customer**					
			Per defined time period		**Network Capital Cost**	Cat.1	Cat.2	…	…	…..	Cat.n
LOW VOLTAGE	Transformation	**Urban Residential** Nxx	✓	-	✓	(✓)	(✓)	(✓)	(✓)	(✓)	(✓)
		Urban Other Nxx	✓	✓	-	(✓)	(✓)	(✓)	(✓)	(✓)	(✓)
		Residential Electrification Nxx	✓	-	✓	(✓)	(✓)	(✓)	(✓)	(✓)	(✓)
		Rural Network Nxx	✓	✓	-	(✓)	(✓)	(✓)	(✓)	(✓)	(✓)
		Rural Network Nxx+1	✓	✓	-	(✓)	(✓)	(✓)	(✓)	(✓)	(✓)
	Circuits	**Urban Residential** Nxx	✓	-	✓	(✓)	(✓)	(✓)	(✓)	(✓)	(✓)
		Urban Other Nxx	✓	✓	-	(✓)	(✓)	(✓)	(✓)	(✓)	(✓)
		Residential Electrification Nxx	✓	-	✓	(✓)	(✓)	(✓)	(✓)	(✓)	(✓)

4.5.5.3 Due to the metering technology and standards prescribed per customer category, it is not possible to make the calculated unit rates of the unit cost table applicable to all customers and to base tariffs on these unit costs. In the case of the energy charges where the purchase rates might be time-of-use rates, it cannot be passed on to customers. In this case the time-of-use energy rates should be converted to a single energy rate.

The conversion of unit rates should be minimized and, where possible, expressed in the original c/kWh, R/kVA and R/cust forms.

Typical tariff simplifications include:

From:	To:
Time differentiated R/kVA	Single R/kVA
Time differentiated R/kVA	Time differentiated c/kWh
Time differentiated R/kVA	Single c/kWh
Time differentiated c/kWh	Single c/kWh
per customer cost	Single c/kWh

The conversion of the rates falls outside of the scope of this methodology and is therefore not explained in detail.

4.5.5.4 The indirect unit costs should be added to the appropriate customer groups or categories as part of the reconciliation. This includes all the costs that are deemed to be part of phases 2, 3 and 4. Example: The unit cost for abnormal costs such as non-technical losses is added to the category where the non-technical losses occur. All the indirect costs are added to the converted unit rates.

4.5.5.5 The unit rates including indirect costs are applied to the customer data to determine the total allocated cost per customer group. The total allocated cost should be equal to the revenue requirement of the utility.

4.6 Data and data assumptions – Information requirements

The rates that are designed from the cost of supply methodology are likely to remain in effect for an indeterminate period into the future. Consequently, the methodology should be conducted using the most current actual or projected cost and sales information for a pre-selected year.

The data required includes but is not limited to:

a) balance sheet;

b) asset records;

c) operating expense information;

d) system network diagrams;

e) purchase tariffs;

f) network expansion or replacement plan;

g) load flows; and

h) load profiles.

5 Conclusion

This cost-of-supply methodology document is intended to provide the South African Electricity Distribution Industry with a common base from which costs of supply may be determined.

This document is a first draft and is the result of many months of deliberation. It should be borne in mind that even the final document is not intended to be mandatory for all suppliers, but, like all standards, one which parties may in essence decide to or not to adopt.

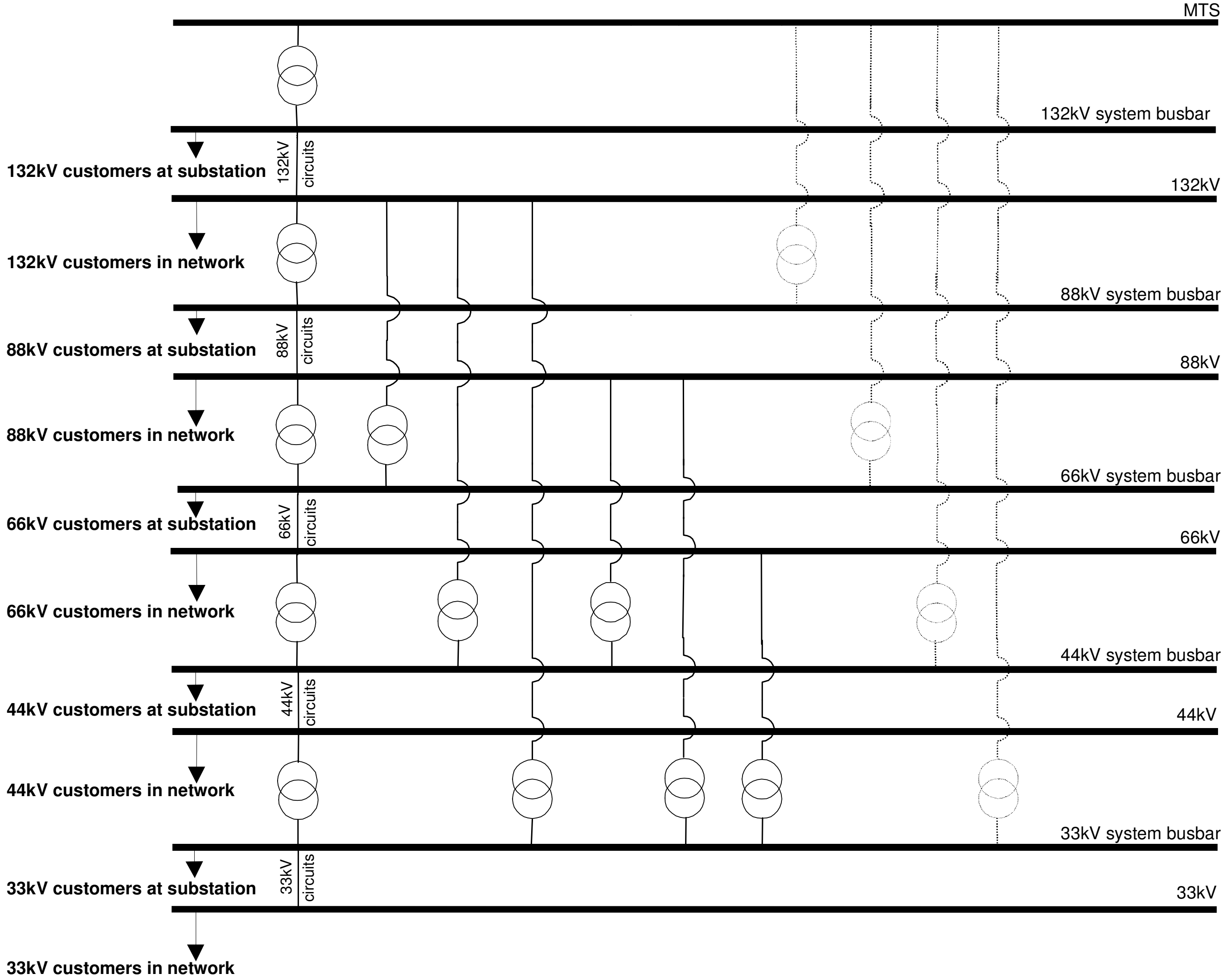
This does not, however, exclude the possibility of the National Electricity Regulator ruling that all suppliers will be required at some time to implement the methodology; and from specifying more stringent parameters where the methodology remains flexible.

Further discussions and comments are expected and invited from the industry, in order to enhance the document; and to ensure a reasonable and fair methodology which ultimately, can stand as the accepted national standard.

Annex A
(informative)

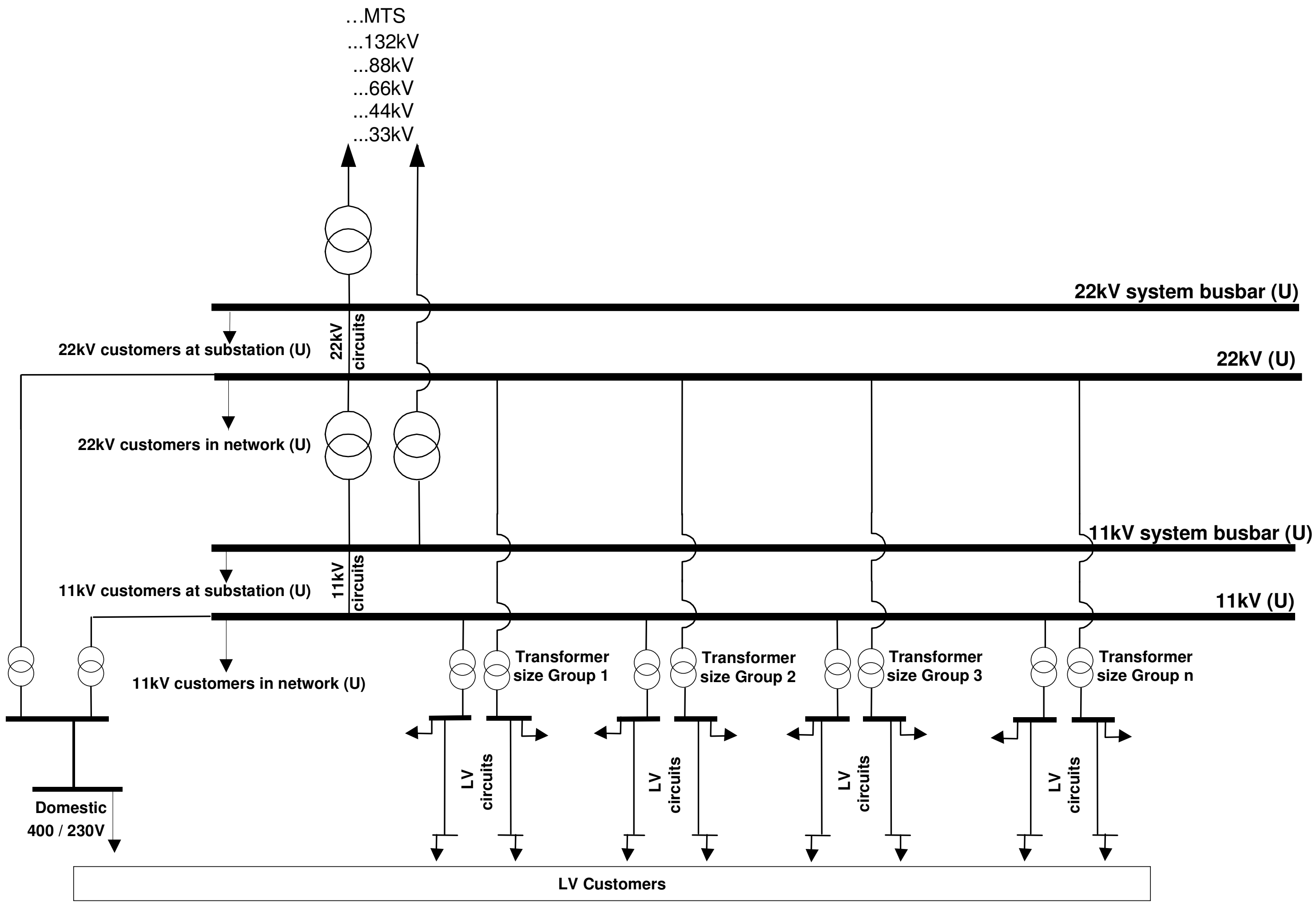
Reduced Network Diagram

A.1 Sub-transmission Networks



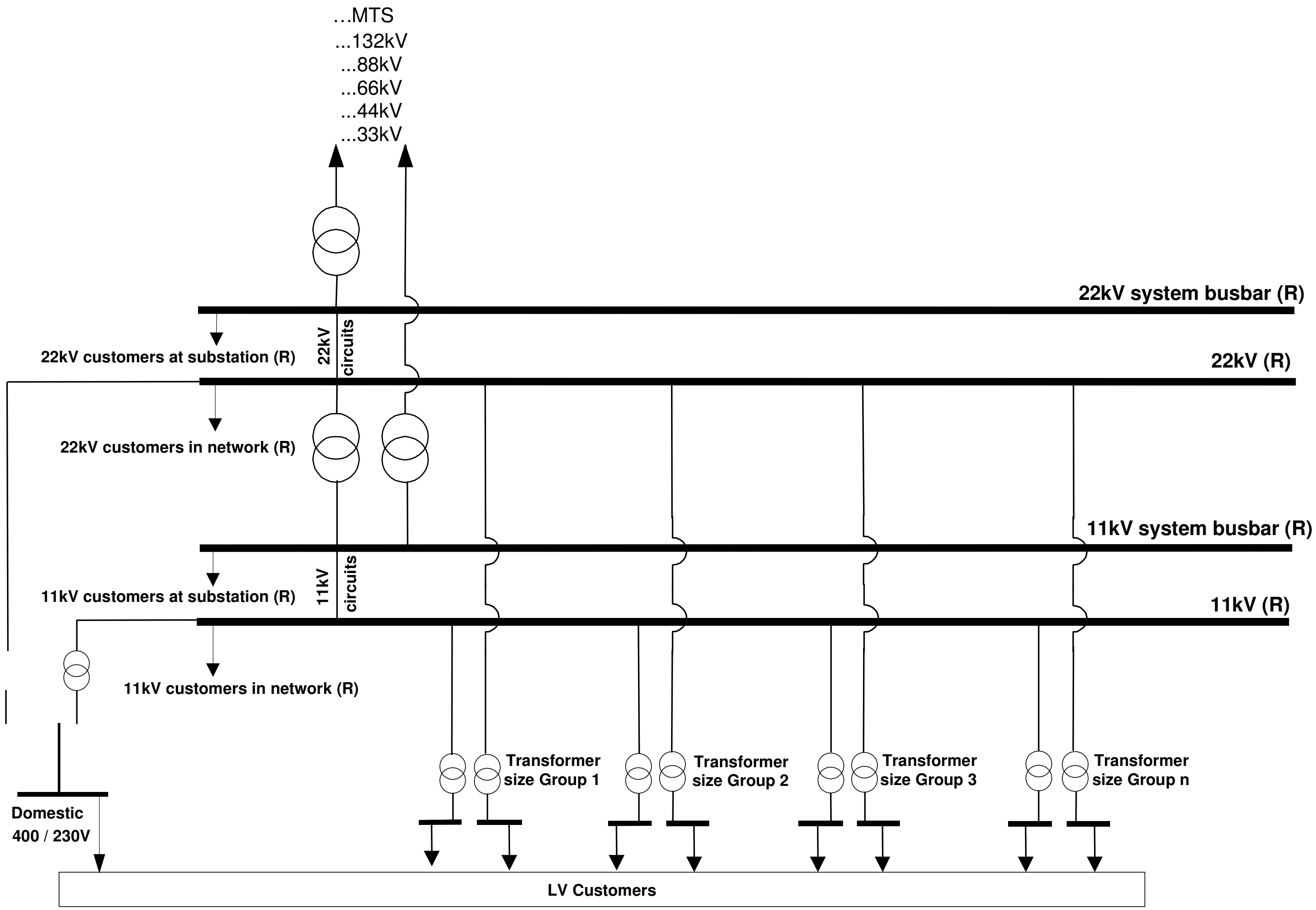
Annex A
(continued)

A.2 Urban Reticulation Networks

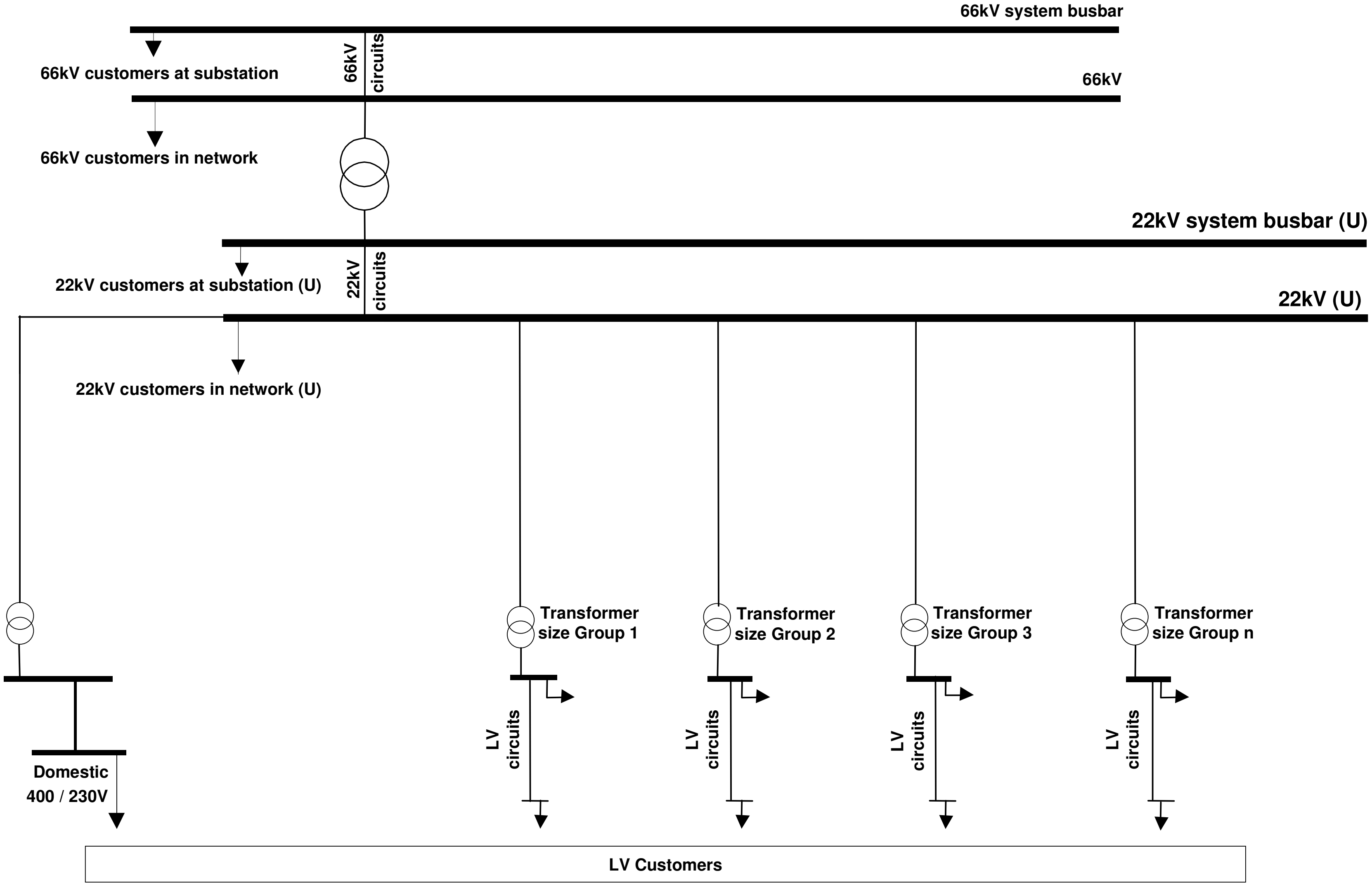


Annex A
(continued)

A.3 Rural Reticulation Networks

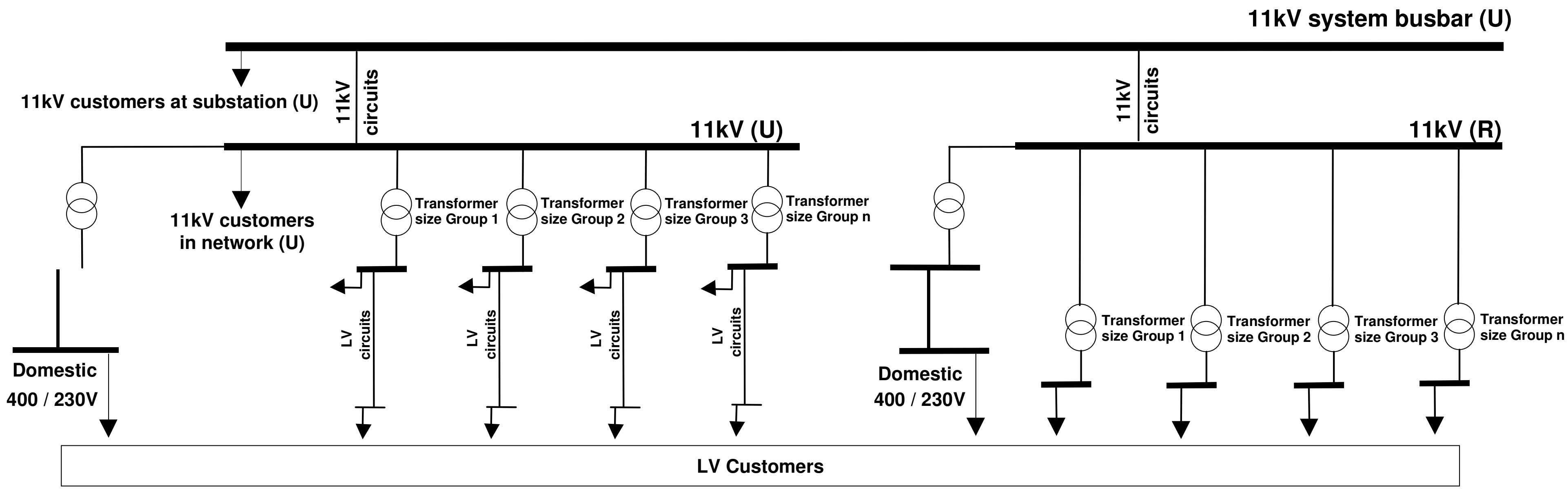


A.4 Template for a small re-distributor feeding urban customers taking supply at 66 kV



Annex A
(concluded)

A.5 Template for small re-distributor feeding urban and rural customers taking supply at 11 kV



Annex B
(informative)

Customer categories

Sector	Characteristics	Criteria Load Factor	Customer Category
Industrial	Daytime (1) Night time (2) All day (3) High LF (4) Low LF (5)	< 60 % > 120 %[a] > 70 % & < 90 % > 90 % < 40 %	21 22 23 24 25
Agricultural	Daytime (1) Night time (2) All day (3) High LF (4) Low LF (5)	< 60 % > 120 %[a] > 70 % & < 90 % > 90 % < 40 %	11 12 13 14 15
Traction			70
Domestic	High Consumption (1) Low consumption (2)	> 300 kWh < 300 kWh	91 92
Streetlighting		All night	93
Bulk	Daytime (1) Night time (2) All day (3) High LF (4) Low LF(5)	< 60 % > 120 %[a] > 70 % & < 90 % > 90 % < 40 %	41 42 43 44 45
Commercial	Daytime (1) Night time (2) All day (3) High LF (4) Low LF (5)	< 60 % > 120 %[a] > 70 % & < 90 % > 90 % < 40 %	61 62 63 64 65
Individually Profiled Customers			

[a] The billing load factor of a measured load profile can exceed the scientific load factor. The billing load factor is defined in the same way as the scientific load factor.

$$\text{LF} = \frac{\text{Energy}}{\text{Maximum Demand} \times \text{hours}}$$

For customers using the bulk of their energy in off-peak periods (22:00 to 06:00) the actual maximum demand will occur in off-peak periods. The billing load factor is calculated by using the maximum demand measured in the peak time period (from 6:00 to 22:00). The maximum demand in the peak periods will be low and result in a load factor greater than 1.

Annex C
(informative)

Evaluation of Demand Allocation Methods

C.1 Introduction

This report contains an evaluation of different cost allocation methods used for allocating demand related costs. The methods that will be discussed in this report are the Single Non-Coincident Peak Demand Allocation Method, the Average and Excess Allocation Method, the Excess Threshold Method and the Demand Weighting Allocation Method.

The purpose of the report is to compare all methods, which are generally accepted in the international electricity utility environment[1], to the Demand Weighting cost allocation method. The report is based on Eskom data. The issues that will be investigated are:

a) the cost implications of the methods with regard to the location of the customer, load factor, demand peaks and customer category;

b) the sensitivity of the different methods with regards to fluctuations in network costs; and

c) an evaluation of these methods according to the objectives of pricing.

The basics of the cost allocation methods that were investigated in this report will be explained in brief. All the methods were implemented by Eskom and the results shown in this report. The report is based on the actual Eskom data and a Reduced Network Diagram shown in Annex D.

C.2 The methods

C.2.1 Single Non-coincident Peak (NCP) Demand Allocation Method

The NCP Method attempts to give recognition to the maximum demand placed upon a system during the year by all customers. This method is based on the theory that facilities are sized to meet these maximum demands. Therefore the network costs are allocated in accordance with each customers' contribution to the sum of the maximum demands of all customers' imposed on the facilities.

The demand ratio of a customer group under this method is computed as follows:

$$\text{Customer Demand Ratio} = \frac{\text{Cust. Group NCP Metered Demand} + \text{Demand Losses}}{\text{Distribution System NCP Demand}}$$

[1] *Electricity Utility Cost Allocation Manual*, National Association of Regulatory Utility Commissioners, Washington DC, 1992.

Annex C
(continued)

C.2.2 Average and Excess Allocation Method

Contrary to the previous method which assigns costs based entirely on peak demand responsibility, the Average and Excess Method divides distribution costs into two parts, for allocation purposes, on both demand and energy based on the system load factor[2]. As such, the Average and Excess method emphasizes or recognizes the extent of the use of capacity resulting in allocation of an increasing proportion of capacity costs to a customer group as its load factor increases.

The average and excess allocation method is expressed algebraically as follows:

$$D = L \times \frac{A}{B} + (1 - L) \times \frac{C}{E}$$

where:

D is the customer group's demand responsibility ratio;

L is the system's annual load factor;

A is the customer group's energy requirements;

B is the total system energy requirements;

C is the customer group's excess demand; and

E is the sum of all customer groups' excess demand.

C.2.3 Excess Threshold Method

The Excess Threshold Method allocates the demand-related charges to defined periods according to the demand of a customer in excess of a specified threshold demand for each time period. A suitable threshold demand level needs to result in time periods that are the same or within the peak and standard periods of Eskoms Time-of-Use tariffs.

The customer demand ratio under this method can be calculated as follows:

$$\text{Demand ratio} = \frac{\text{Demand in excess of the specified threshold demand for each time period}}{\text{Summated Demand in excess of the specified threshold demand for all periods}}$$

C.2.4 Demand Weighting Allocation Method

The Demand Weighting Allocation Method estimates allocated cost by examining each customer group's contribution to system demand in each defined time-period. Time-periods in which large differences in demand-profile are most likely to occur, are the Eskom time-of-use periods (peak, standard and off-peak). The resulting charges are allocated to these applicable time periods.

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[2] The system load factor is the ratio of the average load over a designated period to the peak demand occuring in that period.

Annex C
(continued)

The method recognizes the undiversified maximum demand placed on a system during the year by customers. This method is based on the theory that networks are sized to meet the maximum demands of customers, during any time period. The costs of the facilities are allocated in accordance with each customer's contribution to the sum of the undiversified maximum demands of all customers imposed on the network, in all time periods.

The demand ratios in each defined period are calculated by using the following formula:

$$\text{Demand ratio in period} = \frac{\text{Max. Demand in Period}}{\text{Sum of Max. Demands in all time periods}}$$

C.3 Structural and economical analysis

The results of the report show all methods relative to the Demand Weighting Method. This method was chosen as reference due to the fact that it requires the most intensive calculations and data.

In this paragraph, the economic implications of a change from the Demand Weighting Allocation Method towards one of the other three cost allocation methods will be discussed. Overall, no significant incentives would be provided for any individual customer to reconnect elsewhere in the network with the cost allocation being done with any of the other methods. However on the aggregate level of customer groups, shifts in network charges would occur. These would mostly concern changes within a customer segment, but overall the domestic customer category would have to bear a larger proportion of the total shared network costs with any of the other methods compared to the Demand Weighting Method.

C.3.1 Total costs per network position

The network positions are indicated on the Reduced Network Diagram of annex D. If one considers the impact of the other methods on the allocated cost per network position, the most penalized customers would be the urban domestic customers and the electrification customers. These customers would experience a 0,2 % to 1 % increase in the proportion of network costs carried, with the electrification customer group being most affected. For any of the urban domestic and electrification customers the increases would be largest in the event that the single non-coincidental peak method was implemented.

In general, it can be seen that the changes in allocated cost proportions will be largest when the Single Non-Coincident Peak Demand Method was implemented. However, overall these changes would not exceed 1,1 %, and therefore a change of method would not bring about a significant incentive towards reconnection at another position in the network.

Furthermore, the three methods do show differences relative to the Demand Weighting Method for the positions in the rural network. As shown in figure 1, the whole rural network would see very small increases in proportions with the Single Non-Coincident Peak Demand Method. On the contrary, with the Average and Excess Method, the positions downstream from the distribution substation (P11,P12,P13,P14 & P16,P17,P18,P19 & P21,P22,P23,P24) would benefit whereas the connections placed at higher voltage at this substation (P10,P15 and P20) would carry a larger proportion of the costs. The inverse situation appears for the Excess Threshold Method: the customers connected at the Distribution substation would experience a decrease in their proportion of network costs carried, whereas the customers connected downstream from this substation would experience increases.

Annex C
(continued)

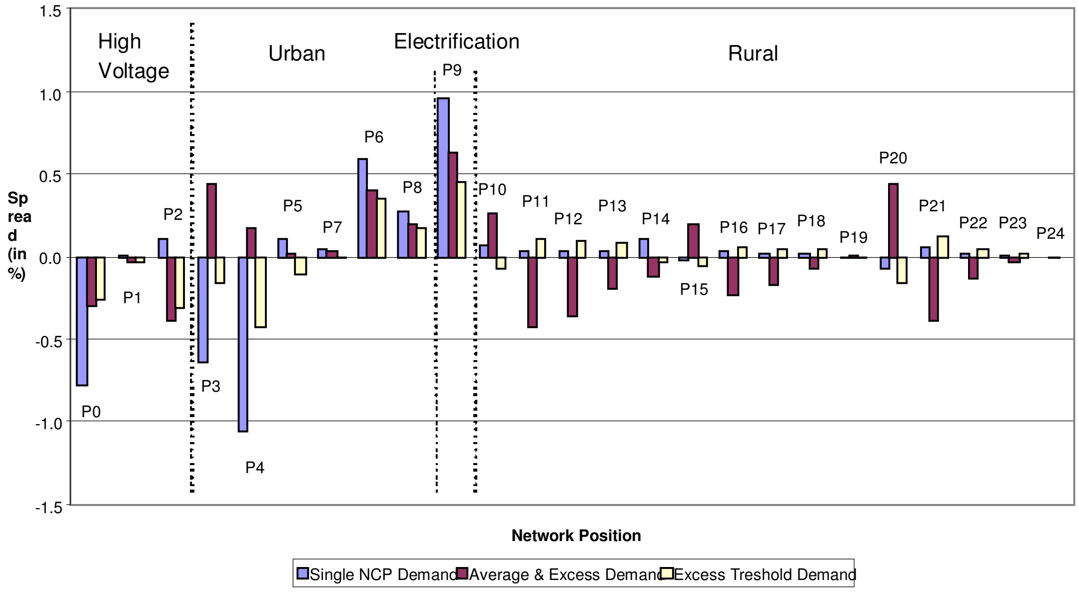

Figure C.1 – Spreads per Customer Group as compared to the current Eskom Method

C.3.2 Total cost share per Customer Group

In terms of customer grouping the changes are generally consistent for the three methods, but they differ significantly from the Demand Weighting Method (see below). The spreads are widest in the industrial customer segment: Industrial All Day and Industrial Day customers would face the largest allocation of network cost with the other methods, whereas Industrial High Load Factor customers would carry on average 13 % less of the network costs than they do with the Demand Weighting Method. Industrial Night customers would see a reduction in network costs of approximately 4 % when changing to any of the alternative three methodologies.

Bulk Supply Day customers would carry 6,5 % to 7 % less of the network cost, whereas the Bulk All Day customer category would see an increase of approximately 8 %. In the Commercial segment, Commercial Day and High Load Factor customers would benefit from a change, while their gains would be more or less offset by the higher charges the All Day customers would have to pay.

In general it can be observed that very large shifts in network costs would occur from Industrial All Day tariffs and the Industrial Day tariff to the High Load Factor and Night time customer tariff groups, as well as the Bulk Day and Commercial Day tariff groups. The Industrial and Bulk Supply groups, and to a lesser extent the Commercial customer group, are affected by this phenomenon.

Annex C
(continued)

What is especially worth noting however, is that in general - as presented in table C.1 – the Industrial and Bulk Supply categories would bear a lower proportion of the total network costs with the Single Non-Coincident Peak Demand Method. This would be mainly offset by the increased proportion carried by the domestic category.

In the Average and Excess demand methodology, the agricultural and traction categories would mainly benefit, whereas this proportion of the costs would be taken over by domestic, industrial and commercial customer categories.

Finally, with the Excess Threshold Method, the burden on the domestic customer category would be least significant. The flows in terms of proportion of total shared costs between customer categories would be smallest in this methodology.

Table C.1 – Spreads (in %) from the Demand Weighting Method, grouped per customer segment

1	2	3	4
	Single NCP	**Average and excess**	**Excess threshold**
Industrial	–2,3	0,8	–0,6
Agricultural	0,2	–2,2	0,6
Commercial	0,8	0,7	–0,6
Bulk	–0,7	0,2	0,2
Domestic	1,9	1,3	1,0
Traction	0,2	–0,7	–0,6

C.4 Objectivity analysis

In this paragraph, the cost allocation methods will be valued according to objectives of pricing.

C.4.1 Cost reflectiveness

All methods allocate the costs of the assets to the respective customers based on their location in the network, demand and customer profile. This enables a user to determine the effective cost of supply of different customer groups. Therefore, tariffs that will be constructed according to this cost allocation can be regarded as cost reflective.

With regard to the issue of spreading costs, the Demand Weighting Allocation Method spreads the costs more than other methods and this results in cross subsidies. This is especially the case between different customer groups, for instance Industrial High LF customers are carrying a larger portion of the network cost in favour of Industrial All Day.

C.4.2 Economic efficiency

All methods, except the Single Non-Coincident Peak Demand Method, encourage customers to shift their electricity usage to standard or off-peak periods. This philosophy finds its extreme in the Excess Threshold Method.

Annex C
(continued)

C.4.3 Fair, equitable and transparent

This objective deals with the fair, equitable and transparent recovery of the different cost components of the electricity supply. All methods, except the Demand Weighting Allocation Method, allocate the cost on a fair basis with regards to the demand, location and profile of a customer. As already stated, the Demand Weighing Allocation Method has huge cross subsidies across different customer groups. This cannot be considered as fair for the customer groups which are penalized by this practice.

C.4.4 Simplicity

The Single Non-Coincident Peak Demand Method is the most simple method because the only information you need is the customer demand in the different positions and the loss percentages along the network. Data for individual customers such as municipal or co-operative systems is usually readily available by delivery point. The calculation is also very straightforward.

The Average and Excess Allocation Method is more difficult to implement. As the formula of this method shows, a lot of information is needed or needs to be derived. The method is not based on load profiles and can be implemented with existing billing information of customers. There would be very little uncertainty in the application of this method as the information is available in general.

The Excess Threshold Method can be considered as complex because of its extensive need for information, computational complexity and seasonal character. When implementing this method, the following difficulties should be taken into account:

a) gathering of information: the method requires representative load profiles, with half-hourly intervals; for a weekday, a Saturday and a Sunday; for Summer and Winter;[3]

b) a “fair” division of the demand costs between summer and winter;

c) the determination of suitable thresholds may be decreed or varied depending on what is considered as “fair” to the different customer groups; and

d) how can a suitable (simple) tariff structure be found that reflects the seasonal character of the cost allocation of this method.

The Demand Weighting Allocation Method requires only a representative load profile with half-hourly intervals, apart from the costs of the assets. This can pose significant uncertainty as these profiles are usually unavailable. The definition of time-of-use periods is a problem as this cannot be based on arbitrary decisions. The cost can be allocated per hour with this method and grouped into time periods. The complexity of such an approach is not acceptable.

C.5 Conclusion

This report summarized the results of an evaluation and comparison of four different cost allocation methods for the supply of electricity. The two main issues covered in this report were the economic implications of the different models and a valuation of them with regard to pricing objectives.

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[3] Note that the current study was done with load profiles, with half-hourly intervals, of a maximum demand day because the recommended information was not available.

Annex C
(concluded)

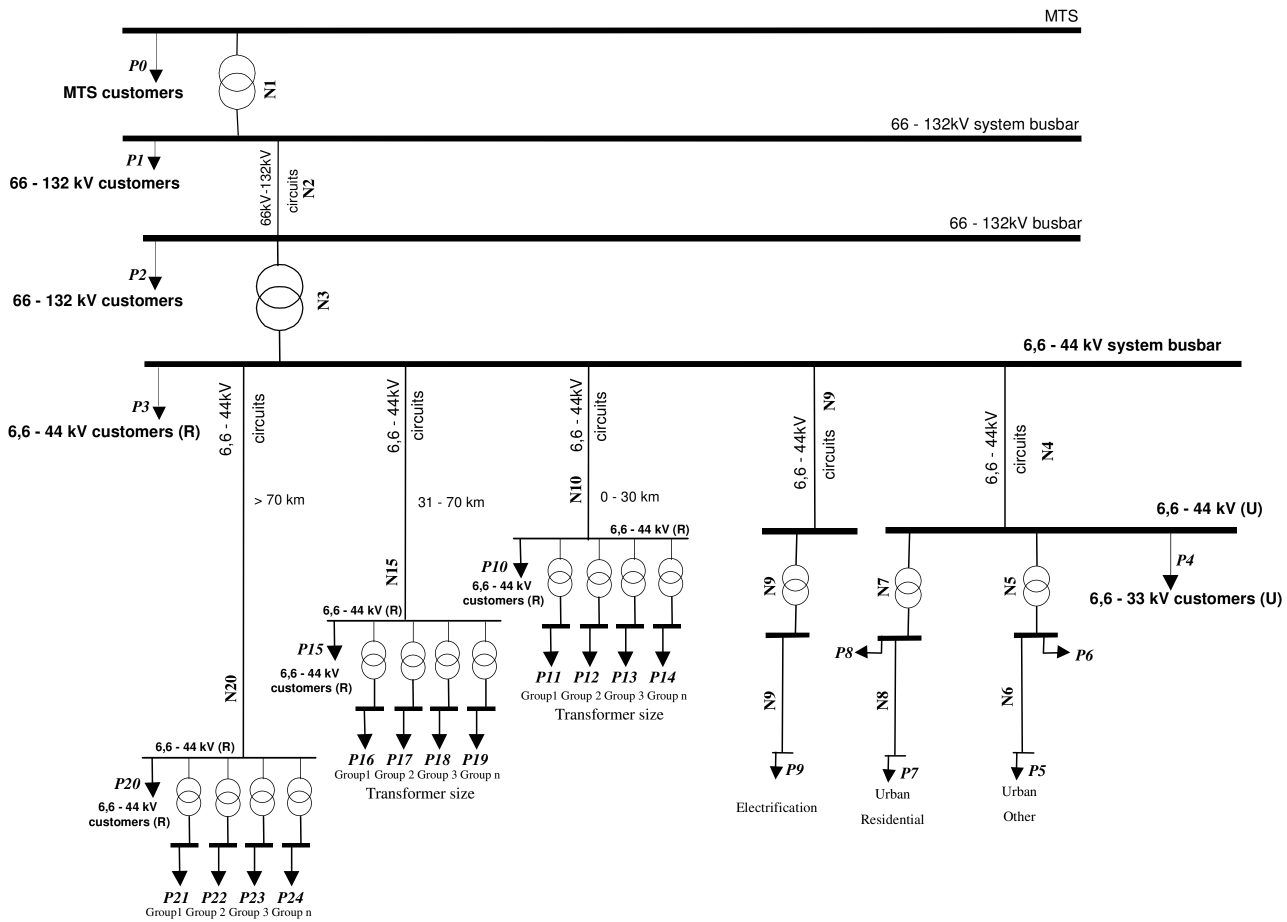
Considering the economic implications of a change towards one of the allocation methods, no significant incentives would be provided for any individual customer to reconnect elsewhere in the network. However, on the aggregate level of customer groups, meaningful shifts in network charges would occur.

With regard to the pricing objectives, it is remarkable that the Demand Weighted Allocation Method has huge cross subsidies across different customer groups, and therefore fails to meet the objectives of cost reflectiveness and a fair cost allocation.

The Average and Excess Method adheres to the pricing objectives and is the best available Method to apply within the information constraints of the EDI. The method can be regarded as cost reflective as it allocates costs to customers based on the average use of the network AND excessive use of network capacity. This method does not lead to "free-rider" customers that only use in off-peak network capacity periods. All other methods would allocate little if any costs to customers that only use the network capacity in off-peak periods. It is therefore proposed that this method is implemented as the demand cost allocation method.

Annex D
(informative)

Reduced Network Diagram (Template for Eskom according to current voltage groupings)



Annex E
(informative)

Weighted Customer Number example

The following example illustrates how the weighting factors can be used to allocate costs to different customer categories.

Apportionment of Customer Service Cost to Customer Groups		
	Total	
Total Cost of Customer Service	R 1 000 000	1

Customer Groups to share cost									
	Small	Small	Small	Small	Medium	Large	Very large	Total	
	Electrification	Residential	Rural	Other	>100 kVA to 1 MVA	> 1 MVA to 100 MVA	> 100 MVA		
Number of customers	1,710,402	361,735	142,738	25,315	6,636	2,278	64	2,249,168	2
Weight	1	6	24	24	270	270	270		3
Weighted number	1,710,402	2,170,410	3,425,712	607,560	1,791,720	615,060	17,280	10,338,144	4
%	16,5	21,0	33,0	5,8	17,3	5,9	0,2	100,0	5
Total R'000	R 165 000	R 210 000	R 330 000	R 58 000	R 173 000	R 59 000	R 2 000	R 1 000 000	6
R/Annum	R 0,10	R 0,58	R 2,32	R 2,32	R 26,11	R 26,11	R 26,11		7

1 Budgeted cost for Customer Service.

2 Number of customers in each customer service category.

3 Weighting factor. The principle of equivalent customers is used to calculate the weighting factors. Example: One industrial customer is equivalent to 270 small prepayment customers in terms of customer service cost.

4 Weighted customer numbers. Note 2 * Note 3.

5 Percentage of the cost to be allocated to the different customer categories. Based on the Weighted number of customers of Note 5.

6 Total customer service cost per category.

7 R/customer per annum. Note 6 / Note 2.

Annex F
(informative)

Case Study for Average and Excess Method of allocating network costs

This study demonstrates the Average and Excess Method for allocating the network costs for a specific example network. The network costs are based on 2000 replacement costs.

F.1 Information gathering

F.1.1 Reduced Network Diagram (RND)

The entire network of a distributor can be diminished into the following RND.

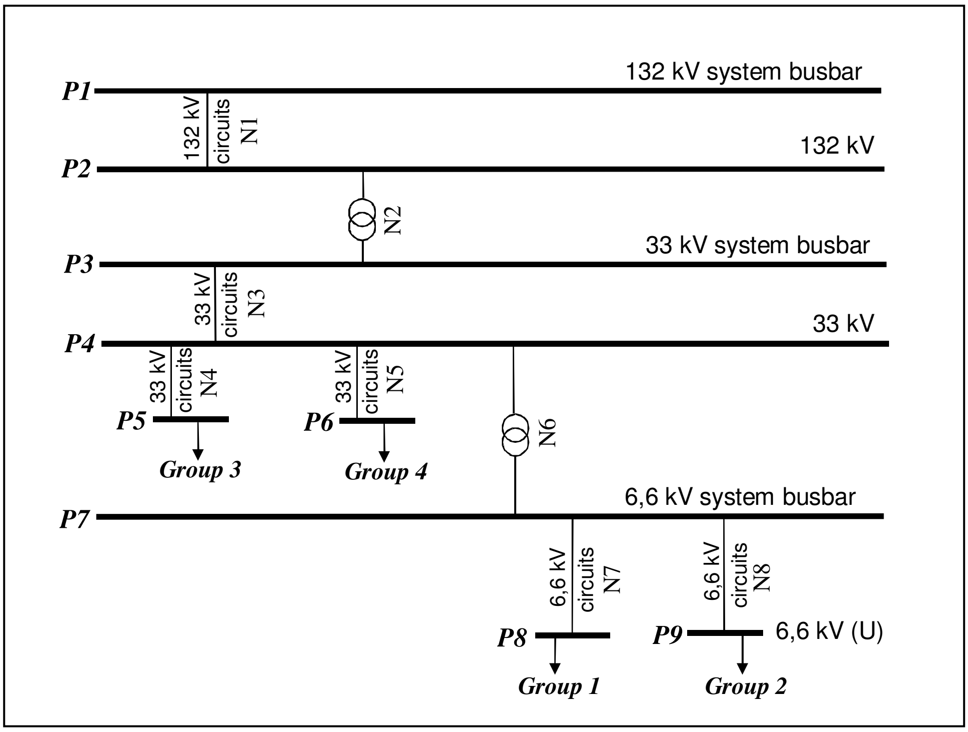


Figure F.1 – The RND indicating the loads of each Customer Group, the network and the location of the loads. P1 to P8 indicate different positions in the RND

F.1.2 Load requirements and billing information

The maximum demand (MD) for the last year, and the total annual consumption for each individual load can be obtained from the last 12 month's bills. The power factor (pf) at the time of maximum demand needs to be estimated if no actual values are available or if insufficient metering data exists to calculate the pf. Where the MD for customers are not measured the average load factor of a representative profile can be used to determine the after diversity MD.

Annex F
(continued)

The dates when the highest MDs for the last year occurred, and the sum of the last 12 month's consumption are tabled below:

Load	Date of highest MD (last 12 months)	Power factor	Maximum demand (kVA)	Annual energy consumption (kWh)
Group 1	2 July 1999	0,886	12 429	86 998 208
Group 2	1 February 1999	0,573	468	499 979
Group 3	24 December 1999	0,824	113 855	589 618 327
Group 4	2 July 1999	0,886	14 813	103 685 289

F.1.3 Losses

The losses in every network component should be determined or estimated. The default loss scaling factors in this example were taken as 1,005, i.e. 0,5 % losses. If the loss factors of all the network components are applied, it should balance to the total losses in the distributor.

F.2 Calculating the costs

F.2.1 Network capital cost

A Network Cost table, similar to table 2 of the document, can be compiled according to the methodology. The assets involved can be referred to in figure 1. The assets with their associated replacement costs and annuity are tabled below.

Asset group	Replacement cost	Lifetime (years)	Interest rate	Annualized replacement cost
(N1) 132 kV circuits	R 7,916,800	35	15,5 %	R 1,235,071,51
(N2) 132 kV/33 kV transformation	R20,078,876	35	15,5 %	R 3,132,433,27
(N3) 33 kV circuits	R 6,200,000	25	15,5 %	R 987,926,19
(N4) 33 kV circuits	R 966,676	35	15,5 %	R 150,807,65
(N5) 33 kV circuits	R 202,500	25	15,5 %	R 32,266,94
(N6) 33 kV/6,6 kV transformation	R 6,929,706	35	15,5 %	R 1,081,078,52
(N7) 6,6 kV circuits	R 1,215,000	25	15,5 %	R 193,601,66
(N8) 6,6 kV circuits	R 285,000	25	15,5 %	R 45,412,74

F.2.2 Operating and maintenance cost

The Operating and Maintenance (O&M) costs are calculated according to the asset value. The total O&M budget is apportioned to the assets. This is described in paragraph 4.4 and shown in table 3 of the document.

Annex F
(continued)

Asset group	Replacement cost (p)	Total % of replacement cost (r) = (p)/(q)	Total annualized O&M cost = (r) × (p)
(N1) 132 kV circuits	R 7,916,800	0,095 %	R 7,484
(N2) 132 kV/33 kV transformation	R 20,078,876	0,425 %	R 85,348
(N3) 33 kV circuits	R 6,200,000	0,121 %	R 7,493
(N4) 33 kV circuits	R 966,676	0,095 %	R 914
(N5) 33 kV circuits	R 202,500	0,497 %	R 1,007
(N6) 33 kV/6,6 kV transformation	R 6,929,706	0,154 %	R 10,642
(N7) 6,6 kV circuits	R 1,215,000	0,095 %	R 1,149
(N8) 6,6 kV circuits	R 285,000	0,095 %	R 269
Total	R 43,794,558 (q)		R 114,305

F.3 Allocating the Network costs to each load

F.3.1 Network Capital cost

From the RND, determine which assets are utilized by which load.

Asset Group	Annualized replacement cost	Annualized O&M cost	Total annualized cost	Load
(N1) 132 kV circuits	R 1,235,071,51	R 7,484	R 1,242,555,37	Group 1 Group 2 Group 3 Group 4
(N2) 132 kV/33 kV transformation	R 3,132,433,27	R 85,348	R 3,217,781,50	Group 1 Group 2 Group 3 Group 4
(N3) 33 kV circuits	R 987,926,19	R 7,493	R 995,418,83	Group 1 Group 2 Group 3 Group 4
(N4) 33 kV circuits	R 150,807,65	R 914	R 151,721,46	Group 3
(N5) 33 kV circuits	R 32,266,94	R 1,007	R 33,274,17	Group 4
(N6) 33 kV/6,6 kV transformation	R 1,081,078,52	R 10,642	R 1,091,720,18	Group 1 Group 2
(N7) 6,6 kV circuits	R 193,601,66	R 1,149	R 194,750,22	Group 1
(N8) 6,6 kV circuits	R 45,412,74	R 269	R 45,682,15	Group 2

Annex F
(continued)

F.3.2 Draw up a table for each of the above asset groups (N1 to N8)

Draw up a table for each of the above asset groups (N1 to N8) containing the following: (an example is shown below)

a) load utilizing the asset group;

b) annualized cost of the asset group;

c) loss factor of the asset;

d) power factor of each load at the time of Maximum demand; and

e) System Coincident Peak demand for the asset group.

The system coincident peak demand value of each asset group is the maximum demand imposed on the asset group at any time. If the System Coincident Peak (CPD) values for each asset group is available it can be entered, if not, it will be calculated.

F.3.2.1 Calculate upstream Demand and Energy values for each asset group by taking losses into account

Calculate the demand and energy values for each load in the tables for upstream assets, by taking the loss factors into account. Each load that uses an upstream asset group is represented in the table of that asset group. For example, all low voltage loads that make use of high voltage assets will be represented in the table with an adjustment for losses. Make use of the RND for assistance. Start with the downstream loads and work upwards.

For example, for load Group 1 the demand and energy at the load is 12 429 kVA and 86 998 208 kWh respectively. To allow for losses, the demand and energy of Group 1 at each network position is calculated as follows:

From the RND it is clear that Group 1 makes use of assets (N7), (N6), (N3), (N2) and (N1).

a) at position 7 (P7) with 0,5 % losses in (N7):

1) 12 429 kVA × 1,005 = 12 491 kVA; and

2) 86 998 208 kWh × 1,005 = 87 433 199 kWh

b) at position 4 (P4) with 0,5 % losses in (N6):

1) 12 491 kVA × 1,005 = 12 554 kVA; and

87 433 199 kWh × 1,005 = 87 870 365 kWh

c) at position 3 (P3) with 0,5 % losses in (N3):

1) 12 554 kVA × 1,005 = 12 616 kVA; and

2) 87 870 365 kWh × 1,005 = 88 309 717 kWh

Annex F
(continued)

d) at position 2 (P2) with 0,5 % losses in (N2):

1) 12 616 kVA × 1,005 = 12 679 kVA; and
2) 88 309 717 kWh × 1,005 = 88 751 266 kWh

e) at position 1 (P1) with 0,5 % losses in (N1):

1) 12 679 kVA × 1,005 = 12 743 kVA; and
2) 88 751 266 kWh × 1,005 = 89 195 022 kWh

Complete the tables below for each load at each network position.

Load	**Non-coincident peak demand** (kVA)	**Annual consumption** (kWh)
Group 1	12 429	86 998 208
Group 2	468	499 979
Group 3	113 855	589 618 327
Group 4	14 813	103 685 289

Asset Group	**Customer**	**Non-coincident peak demand** (kVA)	**Annual consumption** (kWh)	**Power factor**
(N8)	**Group 2**	470	502 478	0,573
System coincident peak demand				
System excess				
Losses in (N8)			0,5%	
Total annualized cost of asset			R 45 682,15	

Asset group	**Customer**	**Non-coincident peak demand** (kVA)	**Annual consumption** (kWh)	**Power factor**
(N7)	**Group 1**	12 491	87 433 199	0,886
System coincident peak demand				
System excess				
Losses in (N7)			0,5 %	
Total annualized cost of asset			R 194 750,22	

Annex F
(continued)

Asset group	Customer	Non-coincident peak demand (kVA)	Annual consumption (kWh)	Power factor
(N6)	Group 1	12 554	87 870 365	0,886
	Group 2	473	504 991	0,573
	Total	13 026	88 375 356	
System coincident peak demand				
System excess				
Losses in (N6)			0,5 %	
Total annualized cost of asset			R 1 091 720,18	

Asset group	Customer	Non-coincident peak demand (kVA)	Annual consumption (kWh)	Power factor
(N4)	Group 3	113 855	589 618 327	0,824
System coincident peak demand				
System excess				
Losses in (N4)			0,5 %	
Total annualized cost of asset			R 151 721,46	

Asset group	Customer	Non-coincident peak demand (kVA)	Annual consumption (kWh)	Power factor
(N5)	Group 4	14 887	104 203 715	0,886
System coincident peak demand				
System excess				
Losses in (N5)			0,5 %	
Total annualized cost of asset			R 33,274.17	

Asset group	Customer	Non-coincident peak demand (kVA)	Annual consumption (kWh)	Power factor
(N3)	Group 1 Group 2 Group 3 Group 4	12 616 475 114 424 14 962	88 309 717 507 516 592 566 419 104 724 734	0,886 0,573 0,824 0,886
	Total	142 477	786 108 385	
System coincident peak demand				
System excess				
Losses in (N3)			0,5 %	
Total annualized cost of asset			R 995 418.83	

Annex F
(continued)

Asset group	**Customer**	**Non-coincident peak demand** (kVA)	**Annual consumption** (kWh)	**Power factor**
(N2)	**Group 1** **Group 2** **Group 3** **Group 4**	12 679 477 114 996 15 036	88 751 266 510 053 595 529 251 105 248 358	0,886 0,573 0,824 0,886
	Total	143 190	790 038 927	
System coincident peak (CPD)				
System excess				
Losses in (N2)			0,5 %	
Total annualized cost of asset			R 3,217,781.50	

Asset group	Customer	Non-coincident peak demand (kVA)	Annual consumption (kWh)	Power factor
(N1)	**Group 1** **Group 2** **Group 3** **Group 4**	12 743 480 115 571 15 111	89 195 022 512 604 598 506 897 105 774 599	0,886 0,573 0,824 0,886
	Total	143 906	793 989 122	
System coincident peak (CPD)				
System excess				
Losses in (N1)			0,5 %	
Total annualized cost of asset			R 1,242,555.37	

Annex F
(continued)

F.3.2.2 Expand the tables for each Asset group and applicable loads with the following fields: Average Demand, Excess Demand, Excess Demand %, Load Factor, Bary Coincident Factor, Coincident Peak Demand, Allocated Excess Demand, Total Demand, Total Allocation and Total Cost Portion.

In order to calculate the coincident demands from the non-coincident values, one need to make use of the Bary coincident factors used commonly to express the coincince of demand as a function of load factor. If the load factor is known, one can determine the coincidence from the Bary graph. The graph is shown in annex G.

Load	**Non-coincident peak demand**	**Annual** (kWh)
Group 1	12 429	86 998 208
Group 2	468	499 979
Group 3	113 855	589 618 327
Group 4	14 813	103 685 289

Annex F
(continued)

Asset Group	Customer	Non-coincident peak demand (kVA)	Annual consumption (kWh)	Power factor	Average demand (kVA)	Excess demand (kVA)	Excess demand (%)	Load factor	Bary coincident factor	Coincident peak demand (kVA)	Allocated excess demand (kVA)	Total demand (kVA)	Total allocation (%)	Total cost portion (Rand)
(N8)	**Group 2**	470	502 478	0,573										

System coincident peak demand	
System excess	
Losses in (N8)	0,5 %
Total annualized cost of asset	R 45,682,15

Asset Group	Customer	Non-coincident peak demand (kVA)	Annual consumption (kWh)	Power factor	Average demand (kVA)	Excess demand (kVA)	Excess demand (%)	Load factor	Bary coincident factor	Coincident peak demand (kVA)	Allocated excess demand (kVA)	Total demand (kVA)	Total allocation (%)	Total cost portion (Rand)
(N7)	**Group 1**	12 491	87 433 199	0,886										

System coincident peak demand	
System excess	
Losses in (N7)	0,5 %
Total annualized cost of asset	R 194,750,22

Asset Group	Customer	Non-coincident peak demand (kVA)	Annual consumption (kWh)	Power factor	Average demand (kVA)	Excess demand (kVA)	Excess demand (%)	Load factor	Bary coincident factor	Coincident peak demand (kVA)	Allocated excess demand (kVA)	Total demand (kVA)	Total allocation (%)	Total cost portion (Rand)
(N6)	**Group 1** **Group 2**	12 554 473	87 433 199 502 478	0,886 0,573										
	Total	13 026	87 935 678											

System coincident peak demand	
System excess	
Losses in (N6)	0,5 %
Total annualized cost of asset	R 1,091,720,18

Annex F
(continued)

Asset Group	Customer	Non-coincident peak demand (kVA)	Annual consumption (kWh)	Power factor	Average demand (kVA)	Excess demand (kVA)	Excess demand (%)	Load factor	Bary coincident factor	Coincident peak demand (kVA)	Allocated excess demand (kVA)	Total demand (kVA)	Total allocation (%)	Total cost portion (Rand)
(N4)	**Group 3**	113 855	589 618 327	0,824										
System coincident peak demand														
System excess														
Losses in (N4)			0,5 %											
Total annualized cost of asset			R 151,721,46											

Asset Group	Customer	Non-coincident peak demand (kVA)	Annual consumption (kWh)	Power factor	Average demand (kVA)	Excess demand (kVA)	Excess demand (%)	Load factor	Bary coincident factor	Coincident peak demand (kVA)	Allocated excess demand (kVA)	Total demand (kVA)	Total allocation (%)	Total cost portion (Rand)
(N5)	**Group 4**	14 887	104 203 715	0,886										
System coincident peak demand														
System excess														
Losses in (N5)			0,5 %											
Total annualized cost of asset			R 33,274,17											

Asset Group	Customer	Non-coincident peak demand (kVA)	Annual consumption (kWh)	Power factor	Average demand (kVA)	Excess demand (kVA)	Excess demand (%)	Load factor	Bary coincident factor	Coincident peak demand (kVA)	Allocated excess demand (kVA)	Total demand (kVA)	Total allocation (%)	Total cost portion (Rand)
(N3)	**Group 1** **Group 2** **Group 3** **Group 4**	12 616 475 114 424 14 962	87 870 365 504 991 592 566 419 104 724 734	0,886 0,573 0,824 0,886										
	Total	142 477	785 666 508											
System coincident peak demand														
System excess														
Losses in (N3)			0,5 %											
Total annualized cost of asset			R 995,418,83											

Annex F
(continued)

Asset Group	Customer	Non-coincident peak demand (kVA)	Annual consumption (kWh)	Power factor	Average demand (kVA)	Excess demand (kVA)	Excess demand (%)	Load factor	Bary coincident factor	Coincident peak demand (kVA)	Allocated excess demand (kVA)	Total demand (kVA)	Total allocation (%)	Total cost portion (Rand)
(N2)	**Group 1** **Group 2** **Group 3** **Group 4**	12 679 477 114 996 15 036	88 309 717 507 516 595 529 251 105 248 358	0,886 0,573 0,824 0,886										
	Total	143 190	789 594 841											

System coincident peak (CPD)	
System excess	
Losses in (N2)	0,5 %
Total annualized cost of asset	R 3,217,781,50

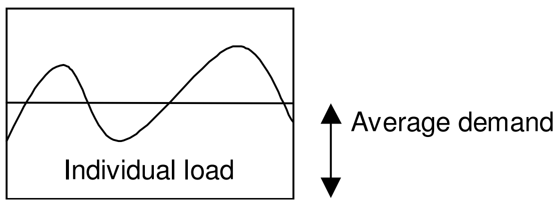
Asset Group	Customer	Non-coincident peak demand (kVA)	Annual consumption (kWh)	Power factor	Average demand (kVA)	Excess demand (kVA)	Excess demand (%)	Load factor	Bary coincident factor	Coincident peak demand (kVA)	Allocated excess demand (kVA)	Total demand (kVA)	Total allocation (%)	Total cost portion (Rand)
(N1)	**Group 1** **Group 2** **Group 3** **Group 4**	12 743 480 115 571 15 111	88 751 266 510 053 598 506 897 105 774 599	0,886 0,573 0,824 0,886										
	Total	143 906	793 542 815											

System coincident peak (CPD)	
System excess	
Losses in (N1)	0,5 %
Total annualized cost of asset	R 1,242,555,37

Annex F
(continued)

F.3.3 Calculate the Average and Excess demands for each load in each asset group

F.3.3.1 Calculate the Average demands



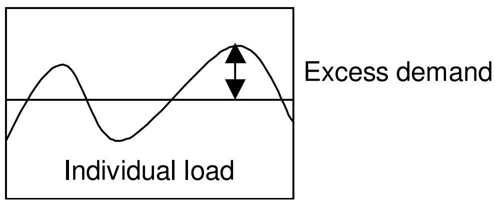
Calculate the average annual demand for each load in each asset group table of 3.2, by using the following formula:

Average demand = Annual consumption ÷ 8760 hours per annum ÷ power factor (pf)

As an example, the Average demand for Group 1 in table (N1) is calculated as follows:

Average demand	=	88 751 266 kWh ÷ 8760 hours per year ÷ 0,886 pf
	=	11 435 kVA

F.3.3.2 Calculate the Excess demands



Calculate the excess demand for each load in each asset group table of 3.2, by using the following formula:

Excess demand = Non-coincident Peak demand – Average demand

As an example, the Excess demand for Group 1 in table (N1) is calculated as follows:

Excess demand	=	12 743 kVA – 11 435 kVA
	=	1 308 kVA

F.3.3.3 Calculate the % Excess demand of each load in terms of the Total Excess demand

Calculate the % Excess demand for each load in each asset group table of 3.2, by using the following formula:

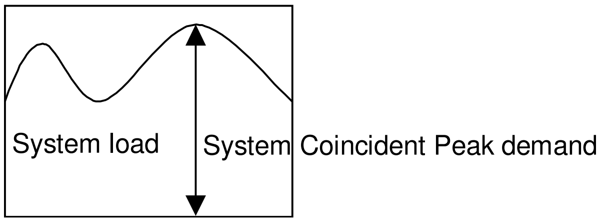
ED (Load 1) ÷ Sum of EDs for all loads × 100 = %ED for Load 1
ED (Load 2) ÷ Sum of EDs for all loads × 100 = %ED for Load 2
ED (Load n) ÷ Sum of EDs for all loads × 100 = %ED for Load n

ED = Excess demand

Annex F
(continued)

F.3.3.4 Determine the System Coincident Peak demand at each location (position)/asset group in the network

NOTE The system refer to the total summated load of all downstream load profiles.

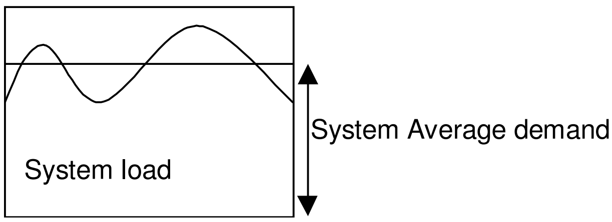


If the System Coincident Peak demand values are not available, calculate the Coincident Peak demand for each load by using the Bary load/coincident factor graph. A copy of the Bary load/coincident factor curve is attached hereto. The non-coincident load is multiplied with the Bary coincident factor to determine the coincident load.

In order to do this, the load factor for each load needs to be calculated.

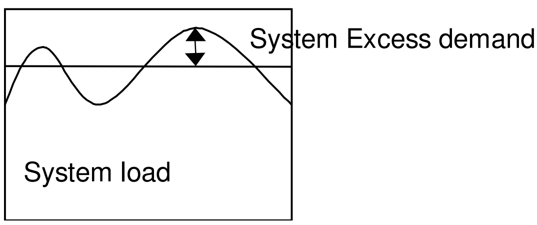
The system Coincident Peak demand equals the sum of the individual Coincident Peak demands.

F.3.3.5 Determine the System Average demands



Calculate the system average demand for each of the defined systems by summating the Average Demands for each individual load constituting the load of the system.

F.3.3.6 Determine the System Excess demands



Calculate the System Excess demand for each asset group (represented in each table). The System Excess can be calculated as follows:

System Excess demand = System Coincident Peak – System Average demand

or

System Excess demand = System Coincident Peak – System kWh ÷ 8760 hrs ÷ System pf

Annex F
(continued)

F.3.3.7 Determine the Allocated Excess demands

Calculate the Allocated Excess demands for each asset group and for each load as follows:

Allocated Excess demand (Load 1) = %Excess demand for load 1 × System Excess demand
Allocated Excess demand (Load 2) = %Excess demand for load 2 × System Excess demand
Allocated Excess demand (Load n) = %Excess demand for load n × System Excess demand

The sum of all the Allocated Excess demands must equal the System Excess demand.

F.3.3.8 Calculate the Total demand for each load

The total demand of each load is equal to the sum of the Average demand and the Allocated Excess demand of each load.

The sum of the total demands of each load should be equal to the System Coincident Peak demand.

F.3.3.9 Calculate the % allocation of each load in terms of the Total System Coincident Peak demand

Total demand (Load 1) ÷ Total System Coincident Peak demand × 100 = %Allocation for Load 1
Total demand (Load 2) ÷ Total System Coincident Peak demand × 100 = %Allocation for Load 2
Total demand (Load n) ÷ Total System Coincident Peak demand × 100 = %Allocation for Load n

F.3.3.10 Calculate the Cost Portion of each Load in terms of the Allocation % of the

Allocate the total annualized costs to each of the loads according to the allocated % calculated in 3.3.9

If the above procedure is followed, the tables under 3.2 can be completed.3.4 Calculation of the Annual Allocated cost, the Monthly Allocated cost and the Monthly cost per kVA

In order to calculate the Total Allocated Annual cost, simply summate the Total Cost Portion (TCP) of each asset for each load from the table in 3.2. For example:

Total cost for Group 1 = TCP(N7) + TCP(N6) for Group 1 + TCP(N3) for Group 1
+ TCP(N2) for Group 1 + TCP(N1) for Group 1
= R 194 750 + R 1 072 565 + R 96 610 + R 312 302 + R 120 596
= R 1 796 823

The total allocated monthly costs are calculated as 1/12 of the total allocated annual cost values.

The monthly cost is calculated by dividing the total allocated monthly cost by the reserved Capacity.

Create a table to calculate the monthly costs.

Annex F
(concluded)

Load	**Total allocated** Annual cost	**Total allocated** Monthly cost	**Maximum notified demand** kVA	**Monthly cost** R/kVA
Group 1 – 6,6 kV	R 1 794 681	R 149 557	R 12 429	R 12,03
Group 2 – 6,6 kV	R 77 563	R 6 464	R 468	R 13,81
Group 3 – 33 kV	R 4 439 405	R 369 950	R 113 854	R 3,25
Group 4 – 33 kV	R 661 255	R 55 105	R 14 813	R 3,72

Calculate the monthly cost per kVA by dividing the total allocated monthly cost value by the size of the reserved capacity. In the case of TP1a the reserved capacity was taken as 12 429 kVA.

The total allocated monthly cost for each customer group is as follows:

a) Group 1 R149 557 per month, or R12,03 per kVA per month;

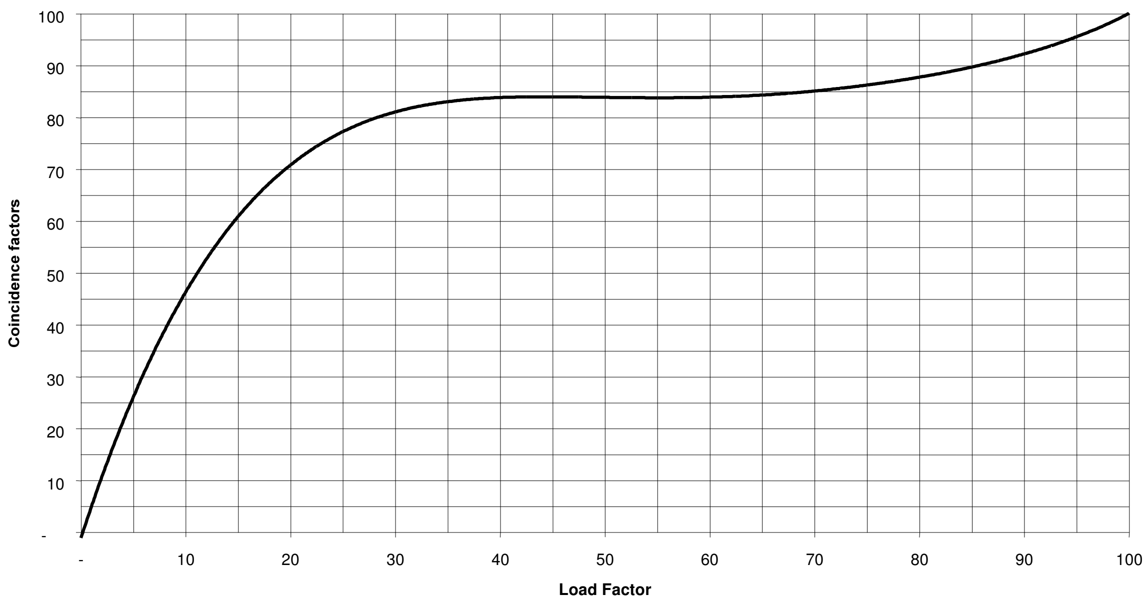
b) Group 2 R 6 464 per month, or R13,81 per kVA per month;

c) Group 3 R369 950 per month, or R 3,25 per kVA per month; and

d) Group 4 R 55 105 per month, or R 3,72 per kVA per month.

Annex G
(informative)

Bary coincidence factors



This graph is used to determine the simultaneous or co-incident demand for customers where only the non-coincident demand is measured or estimated. It is used in the Average & Excess methodology