GENERAL NOTICE

NOTICE 750 OF 2008

Electricity Pricing Policy

1. The Department of Minerals and Energy, hereby invite comments on the draft Electricity Pricing Policy. All comments must be submitted to the department in writing.

2. Comments can be hand-delivery, posted, facsimiled or e-mailed to the department not later than 18 July 2008.

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ELECTRICITY PRICING POLICY

(EPP)

OF THE

SOUTH AFRICAN ELECTRICITY SUPPLY INDUSTRY

DEPARTMENT OF MINERALS AND ENERGY

31 March 2008

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ABBREVIATIONS:

AMR:	Automatic Meter Reading
CFL:	Compact Fluorescent Light
CDM	Clean Development Mechanism
COS:	Cost of Supply
DEPP:	Developmental Electricity Pricing Programme
DME:	Department of Minerals and Energy
DPE:	Department of Public Enterprises
DPLG:	Department of Local Government
DUOS:	Distribution Use of System
DSM:	Demand Side Management
DTI:	Department of Trade and Industry
EDI:	Electricity Distribution Industry
EPP:	Electricity Pricing Policy
ESI:	Electricity Supply Industry
FBE:	Free Basic Electricity
HV:	High Voltage
IEP:	Integrated Energy Planning
IPP:	Independent Power Producer
LRMC:	Long Run Marginal Cost
LGMSA:	Local Government Municipal Systems Act
LV:	Low Voltage
MV:	Medium Voltage
MSOE:	Municipal Surcharge on Electricity
NIRP:	National Integrated Resource Plan
NPA:	Negotiated Pricing Agreement
NRS:	Rationalised User Specification
NERSA:	National Energy Regulator of South Africa
PPA:	Power Purchasing Agreement
RED:	Regional Electricity Distributor
ROA:	Return on Assets
ROE:	Return on Equity
SAPP:	Southern African Power Pool
TOU:	Time of Use
TUOS:	Transmission Use of System
WEPS:	Wholesale Electricity Pricing System
WP:	White Paper

DEFINITIONS:

Avoided system cost	The cost that a utility would have incurred to meet its supply obligations if it did not buy power from another party.
Base-load demand	The regular, consistent electrical demand required at any time of the day/ night or the lowest point on the load demand curve. Alternatively, "base-load demand" means a relatively continuous level of electricity demand.

Connection charge	A charge recouped from the customer for the cost of providing new or additional capacity (irrespective of whether new investment is required or not). This is recovered in addition to the tariff charges as an up-front payment (connection fee) or as a monthly charge where the distributor finances the connection.
Cost of supply (COS) study	Standard procedure for deriving and allocating costs of supply, used for the design of tariffs. This does not include determining the connection charge.
Cost-reflectivity	The pricing method to reflect the full economic cost of supplying electricity to a customer.
Cross-subsidy (within the sector)	Over-recovery of revenue from customers in some tariff classes whether intentional (e.g. electricity levies) to balance the under-recovery of revenue from customers in other tariff classes (i.e. electricity subsidies) as calculated in the *cost of* supply study or unintentional by way of unidentified surcharges within the ESI or as a natural consequence of cost pooling. (Note definition for subsidies)
Dedicated network	Customer dedicated assets are assets created for the sole use of a customer to meet the customer's technical specifications, and are unlikely to be shared in the distributor's planning horizon by any other end-use customer.
Demand side management (DSM)	Technology/programme to encourage customers to modify patterns of electricity usage, including timing and level of consumption. This includes conservation, interruptibility and load shifting.
Distribution system	An electricity network with assets operated at a nominal voltage of 132kV or less and subsequently a *distributor* is defined as a legal entity that owns, operates or distributes electricity through a distribution system.
Distribution charges	The grouping of the use of the distribution system (*DUOS* charges) and the connection charge.
Distribution use of system (DUOS) charges	Unbundled regulated tariffs charged by the distributor to the distribution network services customers for making capacity available and for use of the distribution system.
Distributor	A licensee or his/her appointed representative who constructs, operates and maintains the distribution network.
Electricity distribution industry (EDI)	The distribution industry connected to supply voltage not exceeding 132kV.
Electricity supply industry (ESI)	Generation, transmission and distribution.
Energy charges	Charges based on the amount of energy consumed.
Free basic electricity (FBE)	The State's Free Basic Electricity initiative, which allows for a limited amount of free electricity as deemed necessary to provide basic services as determined and funded in terms of State policy in order to alleviate poverty.
Generation	The production of electricity by any means.
High voltage (HV)	Nominal voltage levels equal or greater than 44 kV up to and including 132 kV.
International customers	Customers who are situated outside the borders of the Republic of South Africa.
Least-economic cost	The lowest value of the sum of the life cycle costs to both the supplier and the customer referring to various options for the supply of electricity.
Levy	The deliberate over-recovery of revenue, in excess of the cost of supply, in order to generate funds to be used for other customers and services. Levies could be transparent and quantified, or hidden and embedded within tariffs.
Long run marginal cost	The additional cost incurred when production is increased by one unit assuming that all input costs are variable, including capital.
Long term	A period of more than five (5) years.
Losses	Technical and non-technical. (See separate definitions for technical and non-

	technical losses)
Low voltage (LV)	Nominal voltage levels up to and including 1 kV.
Medium term	A period of between one (1) and five (5) years.
Medium voltage (MV)	Nominal voltage levels greater than 1 kV and up to and including 44kV.
Municipal surcharge	A charge in excess of the municipal cost of supply that a municipality may impose on fees for a municipal service provided by or on behalf of a municipality, in terms of section 229(1)(a) of the Constitution and the Municipal Finance Management Act.
National Energy Regulator of South Africa (NERSA)	A legal entity established in terms of the National Energy Regulator Act (Act 40 of 2004) to regulate the ESI in South Africa.
Network	Electrical infrastructure needed to transport electrical energy from a source of generation to a point of consumption.
Network charges	Charges designed to recover costs (including capital, operations, maintenance and refurbishment) for the provision of network capacity required by and reserved for the customer.
Non-technical losses	Loss in revenue because of energy consumed but not paid for (unaccounted for energy), e.g. because of poor administration or theft.
Power factor	Ratio of the Root Mean Square (RMS) value of the active power (kW) to the apparent power (kVA), measured over the same integrating period.
Quality of supply	Technical parameters that describe the electricity supplied to customers according to standard (NRS048) and any other NERSA prescribed requirements.
Reseller	Entities that purchase electricity from licensed distributors and resell it to end-use customers.
Replacement cost	The cost of installing a new system in the relevant year.
Reserve margin	The percentage by which the net installed generating capacity exceeds the expected / actual peak demand during a specified period.
Short term	A period of less than one (1) year.
Single buyer	The entity that has been appointed to purchase electricity from generators on behalf of the industry.
Subsidy (from outside of the sector)	The application of funds generated from taxes, levies and other sources, outside of the electricity sector, to lower the charges to particular customer categories. (Note definition for cross-subsidies)
Standard connection / standard supply charge	The standard fee charged for a standard connection as set out in an approved schedule of fees.
Tariff	A combination of charges covering different aspects of supply, grouped into a coherent set of charges.
Tariff structure	The combination of different charges and the relationship to each other.
Technical losses	The loss of energy within the networks as a natural consequence of transporting energy because of the characteristics of the physical equipment usually associated with dissipation.
Trader	A legal entity licensed or registered to engage in the buying and selling of electricity as a commercial activity.
Trading	The buying or selling of electricity as a commercial activity.
Transmission system	Power lines and substation equipment that operate at a nominal voltage of more than 132kV.
Transmission use of	Unbundled regulated tariffs charged for the use of the transmission system.

system (TUOS) charges	
Transparency	The explicit reflection of all composite costs that constitute a tariff, for example: energy charges, demand charges, basic charges, levies, cross-subsidies and MSOE.
Wheeling	The transportation of electricity by an electricity supplier (utility) to a third party through a network not owned, controlled or leased by either party.

1 BACKGROUND

1.1 Present Structure of the Electricity Supply Industry (ESI)

The South African ESI is essentially vertically integrated with Eskom generating 96% (including 5% imports) of the current requirements, municipalities 1% and others 3% (*inter alia* Independent Power Producers (IPP)). As the only transmission licensee Eskom is responsible for all transmitted electricity. The responsibility for distribution is shared between Eskom, the municipalities and other licensed distributors. About 180 municipalities distribute 40% of electricity sales to 60% of the customer base. Although Regional Electricity Distributors (REDs) were approved in principle by Cabinet, they are not yet in operation.

The end-use of electricity in South Africa is currently divided between domestic (17.2%), agriculture (2.6%), mining (15%), industrial (37.7%), commercial (12.6%), transport (2.6%) and general (12.3%). South Africa has an installed generation capacity of approximately 40 000 MW. Most of this capacity emanates from coal fired power stations (88%), with the remainder coming from nuclear, hydro and diesel. South Africa's capacity reserve margin has fallen sharply in recent years to around 8%. This has placed considerable pressure on the industry. In response to this development new generation capacity will be added to the system to restore the reserve margin and meet new growth, and also to prepare for the replacement of older plant.

Another important feature of the current electricity industry in South Africa is the average selling price of electricity, which is one of the lowest in the world. This is partially as a result of the use of low-grade coal and partially as a result of the present pricing policy and practices.

1.2 Electricity Sector Objectives

To place the Electricity Pricing Policy (EPP) document into perspective, it is necessary to summarise the electricity sector objectives as detailed in the White Paper (WP) of 1998 as follows:

a. improved social equity by addressing the requirements of the low income;

b. enhanced efficiency and competitiveness to provide low-cost and high quality inputs to all sectors;

c. environmentally sustainable short and long-term usage of our natural resources;

d. the right of choice of electricity supplier;

e. competition in especially the generation sector;

f. open non-discriminatory access to the transmission system; and

g. private sector participation in the industry.

Furthermore, specific objectives addressed in the abovementioned document refer to ensuring that electrification targets are met; the provision of low-cost electricity; better price equality; financial viability; improved quality of service and supply (including security of supply); proper co-ordination of operation and investments and the attraction and the retention of a competent work force.

It was foreseen that the REDs would be established and that separate entities for generation and transmission would be formed. Since the WP, REDs have been approved (but not established) and the decision was taken that competition in the generation sector would not be introduced. Instead, IPPs would be encouraged through Power Purchase Agreements (PPAs) with the single buyer.

In view of the above, the State seeks to achieve an appropriate balance between meeting social equity, economic growth and environmental goals. This policy document seeks to obtain a balance between several competing objectives, *inter alia*: affordable electricity prices for the low income customers and cost reflective electricity for the industrial sector. In this regard, electricity prices should reflect efficient market signals, accurate cost of supply and concomitant price levels that would ensure financial viability of the electricity sector in its entirety.

1.3 Key Challenges for the Electricity Distribution Industry (EDI)

The EDI is currently faced with various key challenges to ensure that the above objectives are addressed properly. It goes without saying that the introduction of a proper EPP would not solve all challenges, but it may contribute to a better managed and more orderly ESI. The following contains a list of main challenges without detailed discussions and motivations to give a clearer view of the present situation and to illustrate possible benefits of an EPP:

a. Capacity shortages and backlog of investments.

b. High level of fragmentation in terms of investments, sharing of facilities, services and people development.

c. Networks are inadequately maintained, resulting in maintenance and refurbishment backlogs giving rise to high cost of interruptions.

d. Inequitable treatment of consumers, resulting in a wide range of tariffs for the same or similar groups of consumers and also unfair discrepancies between Eskom and municipalities.

e. The electrification performance for various areas varies unacceptably.

f. The provision of Free Basic Electricity (FBE) is slow and inconsistent.

With the current low reserve margin (15% is seen as normal) future approved expansions are important. The industry has embarked on a major expansion programme to meet the future demand for electricity. Many projects have already been approved, while future projects are under consideration. To date approximately 18 000 MW of new generating capacity projects have been approved for implementation over the next number of years. It is expected that the expansion drive will continue into the foreseeable future requiring major capital investment and thus severely impacting future real prices.

1.4 White Papers (WPs) and Legislation

Over the last 25 years two WPs on the energy industry were published in which both the ESI structure and EPP were addressed. The first one appeared in 1986 and became obsolete as a result of the lifting of the oil embargo; moves towards democracy; the Reconstruction and Development Programme and other developments. Before the second WP the National Electrification Forum, which incorporated a number of EPP matters, was in operation between 1993 and 1995. The next WP dealt with a large number of EPP matters and appeared in 1998. This WP became inadequate mainly as a result of new developments exerting a direct influence on EPP issues. These include capacity shortages, gaps in present policies, present challenges (e.g. REDs) and the application of different pricing policies in Eskom and the municipalities.

As a result of later developments, a proposal for an EPP was drafted by the Department of Minerals and Energy (DME) in 2004, but it was never released formally or implemented. Apparently the proposals were applicable to an EPP based on the (then proposed) multi-market model, subsequently necessitating a revision incorporating the most recent developments.

A number of legislative developments since 1996, which have a direct influence on an EPP for the electricity industry, became applicable. It is important to mention these briefly because of their relevance for EPP. They are:

a. Constitution of SA, 1996.

b. Public Finance Management Act, 1999.

c. Local Government Municipal Systems Act (LGMSA), 2000.

d. Eskom Conversion Act of 2001.

e. Municipal Finance Management Act, 2003.

f. National Energy Regulation Act, 2004.

g. Electricity Regulation Act, 2006.

h. Municipal Fiscal Powers and Function Act, 2007.

i. Electricity Regulation Amendment Act, 2007.

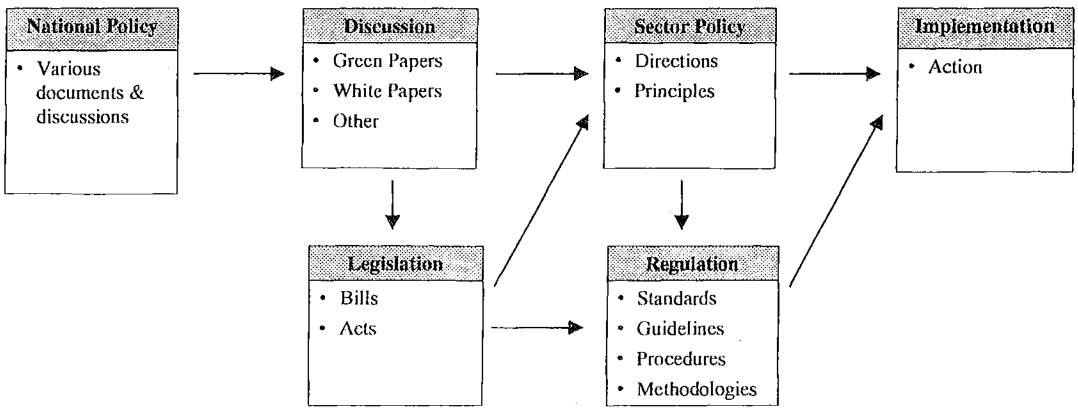
A recent relevant publication with a direct effect on EPP was authored by Adams (2004) "Allocation Methodology for Cross-subsidies in Electricity Tariffs on the Basis of a Macro-Economic Impact Study" written under the auspices of NER, now the National Energy Regulator of South Africa (NERSA). Newbury and Eberhard also completed in 2007 an independent assessment for the South African Government on the performance of the electricity sector in SA in which a number of pricing issues were raised.

1.5 Need for EPP and Related Policies

There is an urgent need not only for an EPP, but also for a new electricity (or energy) policy. Since REDs have been sanctioned in principle by Cabinet (25 October 2006) and the approval of a single buyer together with the well-publicised major challenges within the ESI, the above need has become even more urgent than before.

The EPP should provide direction and principles for the formulation of electricity prices in South Africa. The EPP should also reflect the most recent policies and legislation. The EPP should not be too detailed and should indicate broad level directions. It should also define the accountabilities/responsibilities; focus on the required outcomes and the timing aspects of the outcomes.

Figure 1: The Role of the Electricity Pricing Policy



While the EPP focuses on national strategies and priorities, the regulatory authority (NERSA) has to develop the rules, regulations, plans, standards, programmes and projects in finer detail to ensure the policy's implementation.

Policy Position: 1

a) In view of the EPP, various energy related policies must be reviewed to ensure proper integration in pursuit of a coherent macro-economic energy policy.

1.6 Interpretation of Terms of Reference and Approach

The focus in this document is on a national EPP while the rules, regulations, plans, standards, programmes and projects are detailed at a lower level. Information contained in this document was gathered by means of two questionnaires; one to main stakeholders and one to a wider spectrum of stakeholders (including the main stakeholders) and individual visits (the main stakeholders were visited twice). Individual questionnaires were prepared for National Treasury, Department of Trade and Industry (DTI) and the Competition Commission and they were visited as well.

Generally positive responses were received from the stakeholders and the other parties approached. Various internal discussions were held on different occasions. The team's proposals culminated in an initial draft report to the stakeholders and other interested parties, which was discussed at a stakeholder forum. After this discussion and further submissions by the stakeholders a Final Report was prepared.

It is an important aspect to note that these proposals are to a very large extent applicable to an industry in transition. As a result some changes could be warranted on an ongoing basis after the completion of the EPP. Proposals were formulated for an industry structure in transition to a more open market framework, which includes IPPs.

1.7 Plan of Electricity Pricing Policy Report

This first chapter covers the introductory part and a brief summary of the electricity industry and relevant historical information. The rest of the report focuses on the following aspects of EPP:

- General pricing principles
- Generation pricing (including renewables)
- Transmission pricing
- Distribution pricing
- Cross-subsidies
- Demand side management(DSM)
- Regulation
- Implementation plan
- Conclusions
- Pricing related policies

2 GENERAL PRICING PRINCIPLES

2.1 General Tariff Principles

Section 16 of the Electricity Regulation Act of 2006 states that the setting of prices, charges, tariffs and the regulation of revenues:

a. must enable an efficient licensee to recover the full cost of its licensed activities, including a reasonable margin or return;

b. must provide for or prescribe incentives for continued improvement of the technical and economic efficiency with which services are to be provided;

c. must give end users proper information regarding the costs that their consumption imposes on the licensee's business;

d. must avoid undue discrimination between customer categories; and

e. may permit the cross-subsidy of tariffs to certain categories of customers.

The Act further states that a licensee may not charge a customer any other tariff and use provisions in agreements other than those determined or approved by NERSA as part of its licensing conditions. Notwithstanding the above, NERSA may in prescribed circumstances approve a deviation from set or approved tariffs. Other principles from the LGMSA are:

a. Users of municipal services should be treated equitably in the application of tariffs.

b. The amount individual users pay for services should generally be in proportion to their use of that service.

c. Low income households must have access to at least basic services through:
   - tariffs that cover only operating and maintenance costs;
   - special tariffs or life line tariffs for low levels of use or consumption of services or for basic levels of service; or
   - any other direct or indirect method of subsidisation of tariffs for low income households.

d. Tariffs must reflect the costs reasonably associated with rendering the service, including capital, operating, maintenance, administration and replacement costs, and interest charges.

e. Tariffs must be set at levels that facilitate the financial sustainability of the service, taking into account subsidisation from sources other than the service concerned.

f. Provision may be made in appropriate circumstances for a surcharge on the tariff for a service.

g. Provision may be made for the promotion of local economic development through special tariffs for categories of commercial and industrial users.

h. The economical, efficient and effective use of resources, the recycling of waste and other appropriate environmental objectives must be encouraged.

i. The extent of subsidisation of tariffs for low income households and other categories of users should be fully disclosed.

j. A tariff policy may differentiate between different categories of users, debtors, service providers, services, service standards, geographical areas and other matters as long as such differentiation does not amount to unfair discrimination.

The above principles, together with some other tariff objectives, are summarised in the following table. The table shows that different stakeholders have different expectations of tariffs. These objectives are sometimes in conflict and trade-offs would need to be made during the process of tariff determination.

Table 1: Summary of Tariff Objectives

Stakeholder	Tariff Objectives	Description
Customer	Affordable	Price levels should assume an efficient and prudent utility, in other words prices should be based on least cost options and exclude inefficiencies.
	Non-discriminatory	Tariffs should be equitable and fair.
	Predictable and stable	Prevent price shocks and keep customers informed about future price trends.
	Transparent and unbundled	Full disclosure of cost (no hidden charges). Cost should be unbundled. Tariffs should be easy to understand and apply.
Utility	Cost-reflective	Prices should reflect the full cost (including a reasonable risk adjusted margin or return) to supply electricity and ensure that the industry is economically viable, stable and fundable in the short, medium and long term.
	Efficient use	Tariffs should promote overall demand and supply side economic efficiency, and be structured to encourage sustainable, efficient and effective usage of electricity.
	User-must-pay	A link between the price a user must pay to the cost of serving that user.
	Low cost of implementation	Implementation and transaction costs should be minimised.
State	Social support	Tariff levels and structures should accommodate social programmes.
	Environmentally responsible	The production and transport of electricity should be done in a sustainable way and be mindful of the impact on the environment.
	Sufficiency in generation capacity	Expansion through development of least cost options resources in line with national resource planning.
	State subsidies	Industry needs to achieve and maintain financial sustainability without ongoing State subsidies. This does not preclude provision for targeted subsidies such as FBE.
	Returns	Fair and equitable.

2.2 Revenue Requirement

Given the electricity supply industry's size and its predominantly commercial and industrial customer base, the industry has the potential to generate strong cash flows to sustain a financially viable industry. The need for direct State support and subsidies should, apart from funding social objectives, be minimal.

Economic theory suggests that a perfectly competitive market would produce efficient prices. The electricity industry in South Africa is currently not structured to deliver perfect competition, but this does not diminish the importance of efficient electricity prices in any way. Efficient electricity prices would lead to:

a. the optimum allocation of scarce resources including financial, human and natural resources;

b. the optimum usage of electricity;

c. the optimum usage of the different energy forms (e.g. electricity, gas, oil and coal); and

d. a financially viable industry.

In the absence of competition, regulators may select from a range of methodologies to regulate the industry. All these options have some advantages and disadvantages. Regardless of the method of regulation or price formation it is essential that an efficient and prudent licensee should be able to generate sufficient revenues that would allow it to operate as a viable concern now and in the future.

The common approach among many economic regulators in other parts of the world is to set revenues at a level which would allow the licensee to cover its full costs including a reasonable risk adjusted margin or return. This approach functions well under most circumstances. However, when there is a major discrepancy between asset values used for regulatory tariff setting and new asset values, it creates a potential funding shortfall when new assets are introduced. South Africa finds itself in this situation which has been brought about by many years of surplus capacity resulting in low levels of investments and highly depreciated assets, coupled with relatively high inflation.

This situation may be addressed in several ways through various regulatory methodologies[1]. The correct approach would depend on what is practical and consistent with the general pricing principles set out in section 2.1 Regardless of the chosen method it is important that the regulated business is able to attract reasonably priced finance in order to maintain, refurbish and grow its infrastructure and provide services at a reasonable cost.

Tariffs, therefore, need to be set at a level which would not only ensure that the utility generates sufficient revenues to cover the full costs (including a reasonable margin or return) but would also allow the utility to obtain reasonably priced funding on a forward looking basis. Rating agencies and lenders focus on a range of appraisal factors including profitability, e.g. Return on Assets (ROA) and Return on Equity (ROE), financial leverage (debt to equity) and debt service (e.g. interest coverage). It is important for the sake of financial sustainability that all these indicators move between acceptable norms and standards on a forward looking basis over the short, medium and long term. If the financial performance of the regulated entity deviates from these norms and standards investors will either be reluctant to extend credit or increase the cost of finance, ultimately resulting in higher tariffs or State support (e.g. guarantees, subsidies) or even bankruptcy in the case of private owners.

Ultimately the decision to lend money to a regulated utility is made by the financial institution and not the regulator. The regulator, therefore, has a duty to measure the projected results from its regulatory methodologies (taking into account investment cycles and other cost trends) using the same criteria that reasonable commercial lenders would employ. The regulator needs to consult with commercial lenders when assessing the financial viability of the industry on an ongoing basis.

[1] For example a regulator may favour a steep increase in tariffs in one year or phased-in tariff increases over a number of years. Both options present some challenges. In the first approach it may not be economically or politically practical to introduce a large step increase in tariffs in a short period. In the second approach, and especially if the phase-in period is over many years, it could result in excessive accounting profits which could be used for other than infrastructure investment purposes in the meantime.

Once the industry has gone through its current investment cycle (to meet growth needs, address backlogs and replacements) the asset values used for regulated tariff setting and new asset values should be more consistent. Once this position has been reached it should be sufficient for the regulator to focus on ROA (or ROE) without having to perform detailed calculations to determine the state of the utility's financial leverage and debt service.

Policy Position: 2

a) *The revenue requirement for a regulated licensee must be set at a level which will cover the full costs, including a reasonable risk adjusted margin or return using appropriate asset values.*

b) *In addition, the regulatory methodology must anticipate investment cycles and other cost trends to prevent unreasonable price volatility and shocks while ensuring financial; viability, continuity, fundability and stability over the short, medium and long term assuming an efficient and prudent operator.*

2.3 Cost Reflectivity

All tariffs should become cost-reflective over the next five years subject to specific cross-subsidies as provided for in section 9. The application of tax or levies is provided for over and above the cost reflective charges. This should be done within the current distributors and within REDs.

Policy Position: 3

a) *Electricity tariffs must reflect the efficient cost of rendering electricity services as accurately as practical.*

- *The average level of all the tariffs must be set to recover the approved revenue requirement.*
- *The tariff structures must be set to recover costs as follows:*
  - *The costs for a particular customer category from that category.*
  - *The cost of a particular cost driver by way of a associated tariff charge (i.e. network costs from demand and access charges).*

2.4 Transparency and Unbundling

Billing processes and customer invoices should communicate relevant information to customers regarding their consumption and costs. Full disclosure (transparency) and breakdown (unbundling) of all key cost drivers where practical are essential features that would empower customers to make informed consumption decisions. Accounting ringfencing of key electricity functions (e.g. generation, networks, wholesale / retail and customer services.) is the first step towards achieving accurate transparent and unbundled accounts.

In addition, the extent to which unbundling may be done at distribution level depends on the type of metering installed/available, which in turn determines what quantities could be measured and the capability of the billing system. Strategies need to be put in place so that these problems may be overcome and the maximum practical levels be shown over the next five years.

Policy Position: 4

a) The following cost components must be reflected in the bill wherever practical and applicable: Customer service, metering and billing, Time of Use (TOU) energy, Transmission Use of System, (TUOS) and Distribution Use of System (DUOS), reactive energy, cross-subsidy levies and surcharges.

2.5 Non-Discrimination

There are currently a number of obstacles, principally relating to cross-subsidies that prevent the full implementation of a non-discriminatory pricing approach.

These discriminatory practices have created a situation where similar customers are subject to significantly different tariffs without any real differences in the cost of supply. This undermines the efficient allocation of resources and prevents healthy competition within similar industries. This means that the full potential and benefits of electricity could only be extended to all customers once these discriminatory pricing practises are removed. The obstacles should, therefore, be addressed and removed.

Policy Position: 5

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

2.6 Access to and Use of Networks

Network (transmission and distribution) owners have an obligation to allow customers access to and use of their networks, provided that the customers are not in arrears in paying all the relevant charges as approved by NERSA from time to time and that such access would not violate any technical and safety requirements as set out in the relevant grid codes license conditions and tariff schedules.

The full cost to operate the networks should be reflected in the various connection and use of system charges. In other words no additional charges are needed to facilitate the wheeling of electricity between two parties unless such wheeling would result in incremental costs. Any incremental wheeling costs should be charged on a similar basis as connection charges. Southern African Power Pool (SAPP) rules would apply for the recovery of cost and payment of wheeling services for SAPP transactions.

If network constraints cause congestion and wheeling parties are affected, then NERSA has the responsibility to develop a mechanism which would allocate network capacity between interested parties. Such a mechanism needs to be fair, non-discriminatory and transparent. In addition the methodology needs to encourage the use of transmission assets to maximise the benefit to all users.

Policy Position: 6

a) Fair and non-discriminatory access to and use of networks to all users of the relevant networks.

b) The full cost to operate the networks is reflected in the various connection and use of system charges and, therefore, no additional charges for wheeling of electricity will be levied unless the wheeling action introduces incremental costs.

c) Any incremental wheeling costs associated with a specific wheeling transaction and its fair share must be recovered as a connection charge.

d) Wheeling of electricity can only be permitted if the action complies with all technical, safety and commercial requirements.

e) A methodology for transmission and distribution wheeling, including the treatment of network congestion, must be developed by NERSA.

2.7 Special Products

In addition to the standard range of pricing products, provision should also be made for the development and introduction of special products and prices. These products would typically be:

a. Curtailable and interruptible rates: Customers are paid to reduce consumption in critical periods.
b. Critical peak pricing tariffs: TOU tariffs are introduced with certain periods of very high prices when the system's reliability is threatened.
c. Real-time pricing products: Rates are provided ahead of time (usually on an hourly or daily basis).

These products, in conjunction with enabling technologies, could significantly increase the penetration of demand response programmes and products.

Policy Position: 7

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

2.8 Long Term Price Outlook

Given that customers have long term planning requirements there is wide support for the publication of a long term price outlook. The price forecast should include a reasonable period of not less than 10 years. The outlook should be updated on a frequent basis to signal the overall expected trend in electricity prices. Ideally the forecast should show the contribution of generation, transmission and distribution to the forecast price level for some representative notional customers. These forecasts should be treated as indicative and will not be binding on any of the players.

Policy Position: 8

a) NERSA, in collaboration with licensees, should develop and publish indicative price levels on an annual basis.

3 PRICING INTERFACES

The EPP has been developed without a specific industry structure in mind. This would ensure that the policy recommendations and positions remain valid under several industry scenarios. However, some basic assumptions had to be made regarding the key functions and pricing interfaces in the industry. If needed these assumptions could be developed in more detail through separate policies over time. The assumptions are briefly discussed and illustrated below.

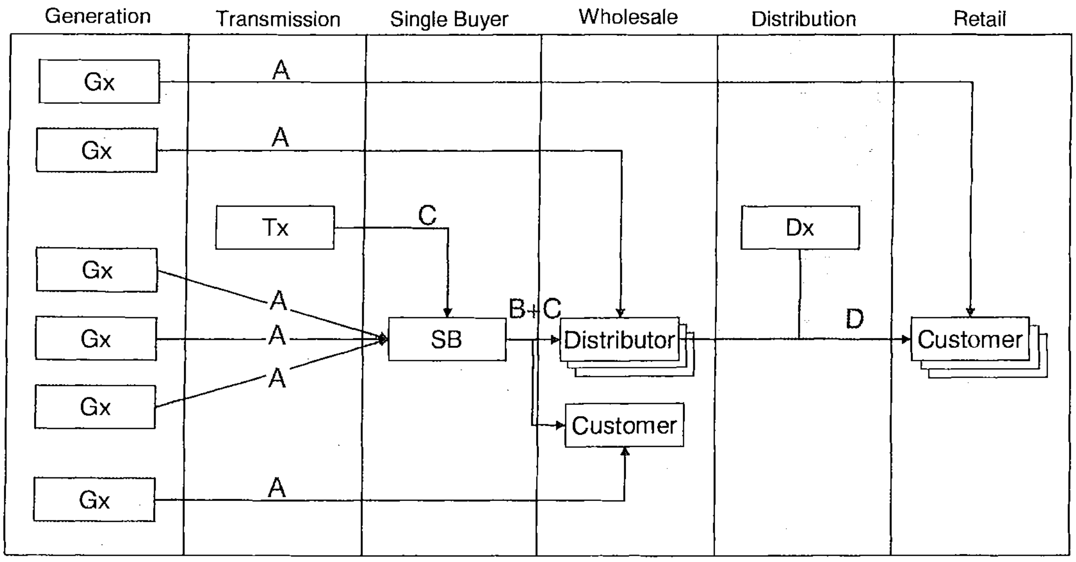
a. Generators may be owned by: Eskom, municipalities, independent power producers and private persons / entities.
b. South Africa may import and export electricity to and from other African countries and would facilitate in the wheeling of power between neighbouring countries.

c. Licensed generators and traders may (but are not obliged to) sell electricity to: A single buyer (e.g. Eskom)[2], a wholesale buyer/customer (e.g. RED), a retail buyer/customer or to self.

d. Wholesale electricity prices consist of wholesale energy prices, transmission prices and single buyer own cost.

e. Retail prices comprise the final prices to customers.

Figure 2: Basic Diagram to illustrate the key Functions and Pricing Interfaces



Functions

Gx: Generation (incl trading of imports)
SB: Single Buyer (buys electricity on behalf of industry)
Tx: Transmission
Dx: Distribution (REDs, Munics, Eskom)

Pricing Interfaces

A: Generator Pricing
B: Wholesale Energy Pricing
C: Transmission Pricing
B+C: Wholesale Pricing
D: Distribution Pricing

4 GENERATOR PRICING

4.1 Applicability

This section is applicable to all licensed generators (including renewable generators and co-generators) in South Africa as well as all licensed importers of electricity to South Africa. Imported electricity prices would also form part of regulated generator prices in South Africa. This is necessary as it could impact on the security of supply and price levels for local customers.

International wheeled energy (energy transported via South Africa to facilitate a transaction between SAPP members) does not form part of wholesale energy prices in South Africa. NERSA may develop criteria to exclude certain generators and import options from the EPP requirements, for example:

a. Transactions that originate and terminate outside the borders of South Africa fall outside the scope of this policy.

[2] Note: The definition of a single buyer is currently underway and falls outside the scope of the EPP.

b. Private generators producing electricity for their own use and where the electricity is not conveyed over any public networks would fall outside the scope of this policy.

Policy Position: 9

a) Electricity from both licensed generators in South Africa and from all approved importers of electricity to South Africa must fall within the scope of the EPP.

b) NERSA may apply certain exclusions in terms of predetermined criteria as prescribed by DME (e.g. private generators producing electricity for own use on the same site).

4.2 Tariff Structure

Pricing structures for electricity purchases from generators would reflect the underlying cost structure. Alternatively the pricing structure would reflect the contractual commitments and agreements between the buyer and seller.

In addition to the sale of energy and capacity some generators also provide ancillary services to ensure that the quality of electricity falls within acceptable standards. Ancillary services include *inter alia*; the provision of operating reserves, frequency control, generator-islanding, constrained generation and reactive energy support. Without these services, customers will experience unacceptable poor quality of supply including very frequent interruptions, frequency drifts and voltage fluctuations. This approach creates the opportunity for a generator that provides ancillary services to earn more revenue than one not providing such services.

It is important to note that some customers are able to provide certain ancillary services at a lower cost than generators. It is, therefore, essential that customers are given the opportunity to sell these ancillary services to the market.

Pricing structures for generators usually consist of a combination of capacity, energy and ancillary services charges. These charges may be TOU differentiated to encourage availability and production during certain periods. Tariff structures should not impede on the least cost dispatch of the different generating sets and supply options.

Policy Position: 10

a) Generating pricing structures must reflect the cost of supply of the generator or alternatively any approved PPA.

b) Generator pricing structure can consist of the following: Capacity, energy and ancillary service charges.

c) Customers, who are able, must be given the opportunity to sell ancillary services to the market on a fair and non-discriminatory basis.

d) Generator pricing structures must not hinder efficient and least cost dispatch of the generating units.

4.3 Tariff Level

Electricity purchases from existing generators should be based on either the conditions set out in the PPA or be based on a regulatory methodology that would produce satisfactory financial performance over the short, medium and long term assuming a competent and prudent operator.

Electricity purchases from new supply options should be evaluated against an appropriate reference. This reference is defined as the avoided system costs. The determination of avoided cost considers factors such as discount rate, duration, capital costs, fixed and variable operating costs, TOU, location, voltage level and specific risk factors.

Competing projects should be assessed using the same criteria. The criteria should be: fair, non-discriminatory and transparent. This aspect is expected to be addressed in the design of the single buyer.

Policy Position: 11

a) *The price paid for electricity generated in South Africa or imported to South Africa must be based on either the appropriate and approved regulatory method or on conditions set out in the approved PPA.*

b) *Electricity purchases from new supply options must be evaluated and approved against the appropriate avoided system cost.*

c) *NERSA may approve a framework to expedite the determination and approval of prices from supply options (e.g. short term purchases).*

4.4 Renewable Energy Generators

The impact of climate change and the role of fossil fuels have received considerable attention over the past few years. It is expected that the focus on cleaner energy will intensify in future. The introduction of a Clean Development Mechanism (CDM) has brought tangible financial benefits to renewable energy supply options. Renewable energy suppliers can already access this support through the official channels which have been created for this purpose. In addition, renewable energy projects could access various other overseas support mechanisms, including grants and soft loans.

Several stakeholders have enquired about the introduction of a mechanism to support the development of local renewable energy projects to achieve the State's renewable energy targets. Renewable energy projects can already qualify for special tax dispensation provisions. Furthermore, the State is active in developing a renewable support mechanism to improve the viability of renewable energy projects. Moreover, a voluntary green tariff category in support of renewable energy options could be introduced to further stimulate the demand for renewable energy.

The introduction of these measures should be appropriately reflected in terms of the principles of transparent and unbundled prices. The DME should facilitate the discussions in this regard to develop an official position.

Policy Position: 12

a) *Preferably, renewable generators will compete with non-renewables in terms of price taking into account all forms of support (for example grants, soft loads, CDM, feed-in tariffs, green tariff and tax incentive).*

b) *Alternatively, in the case where renewable support mechanisms are insufficient and State targets for renewables are thus not reached, renewables could be introduced at a price premium relative to non-renewables, subject to approval by NERSA.*

c) Renewable power can be traded by the single buyer, licensees or customers. Renewable power can be sold at a special price or the cost can be pooled with energy cost and form part of the charges to all customers.

d) Develop a renewable energy guideline to support the introduction of renewable energy.

e) Any policy proposals on environmental support for electricity generators must be done by DME in consultation with National Treasury and other key stakeholders.

5 WHOLESALE ENERGY PRICING

5.1 Applicability

This would be similar as for wholesale pricing. Please refer to section 7.1 for a detailed description in this regard.

5.2 Tariff Structure

Wholesale electricity pricing structures need to encourage the efficient use of electricity at all times. Wholesale electricity sales should be based on TOU energy prices to promote the efficient use of electricity. Some stakeholders may question why the wholesale energy price is energy based only. Given the fixed and variable costs of generators, these stakeholders believe that generators' costs should be recovered through a combination of capacity charges (R/kVA) and energy charges (c/kWh). Against this background it may merit pointing out some of the differences between fixed and variable charges, especially at the wholesale level.

A customer energy demand charge may not necessarily be an accurate reflection of costs imposed on generation considering that the customer's peak demand and the system peak may not occur at the same time. Furthermore, unlike nearby network capacity, generation capacity can easily be diverted for use by other customers. This reduces the chance of under utilised (or stranded) capacity and eliminates the need for demand based charges in favour of TOU energy based charges at the generation level. Moreover, a demand charge at the generation level would result in unfairly high prices for low load factor customers. This outcome is neither desirable nor cost reflective.

The definition of TOU needs to reflect the cost of supply for different combinations of generation categories (base, mid merit and peak) which would be used to meet the integrated system demand.

The demand and supply dynamics in an integrated electricity system change constantly. It is, therefore, necessary to periodically review, and if necessary, update the TOU definition for the purpose of wholesale energy pricing to keep pace with the latest developments.

Policy Position: 13

a) Wholesale energy prices must encourage the efficient use of electricity at all times and must reflect the TOU structure differentiated cost of supply.

b) The wholesale energy price structure must be periodically reviewed and updated by the single buyer and approved by NERSA.

5.3 Tariff Level

Wholesale sales should cover the total cost of wholesale purchases and services. Given that the wholesale energy pricing structure (energy only) will be different from generator pricing structures (combination of capacity, energy and ancillary services), there will be differences between the revenue earned for the selling of wholesale energy and the cost paid to purchase the electricity from generators. Depending on the demand and energy situation these variances could be very significant. These differences should be addressed through over/under recovery mechanisms as part of the regulatory methodology for wholesale energy purchases and sales.

Policy Position: 14

a) *Wholesale energy prices must cover the cost of wholesale purchases, including capacity, energy and ancillary services.*

b) *Wholesale energy prices must consist of the generator prices, plus the single buyer own costs.*

c) *NERSA must develop an over/under recovery mechanism to deal with mismatches between wholesale energy purchases and sales.*

5.4 Negotiated Pricing Agreements (NPAs)

NPAs refer to any price agreement that may deviate from approved standard tariff levels, structures, service fees, network standards and capital contributions. There are several examples of NPAs currently existing in the industry, including: Commodity linked agreements, fixed price agreements, Developmental Electricity Pricing Programme (DEPP) agreements and waiving of capital contribution by municipalities for some developments.

NPAs have served and could potentially serve as a valuable instrument to support projects that require price certainty over many years. NPAs are permitted, but should be limited and structured in a way to minimise deviations from standard prices.

One concern relating to NPA contracts is that its price could deviate considerably from the prevailing WEPS over time. This may result in inefficient price signals, thus distorting consumption patters. In addition it may create a significant surplus or a shortfall for the licensee.

A commodity linked electricity price is another form of NPA. The embedded derivative implications flowing from commodity based agreements are potentially significant and should be hedged outside of the ESI.

All existing NPAs should be honoured until the end of contract and the customers would then purchase electricity either at standard tariffs or a newly negotiated NPA based on the latest framework.

NPAs need to be evaluated against the appropriate price projections on a discounted basis over the life of the project. Factors that should be taken into consideration include period, TOU, location, voltage level and risks.

All NPAs (including commodity based transactions) should be approved by NERSA. In addition, all national NPAs would be subject to approved wholesale subsidies and levies.

Policy Position: 15

a) *NPAs are permitted, but must be structured in a way so as to minimise price distortions.*

b) *Commodity price risk exposure must be hedged outside of the ESI.*

c) *Existing NPAs will be honoured until the end of contract.*

d) The evaluation of NPAs at inception must be based on the cost of supply (excluding cross-subsidies) on a discounted cash flow basis over the period of the agreement.

- *The cost of supply for NPAs intended for the sale and consumption of electricity in South Africa must be defined by the electricity price forecast which will be based on the prevailing regulatory methodologies in South Africa inclusive of an appropriate risk premium.*
- *The cost of supply for NPAs intended for the export of electricity from South Africa must be evaluated against the avoided cost of supply inclusive of an appropriate risk premium.*

e) DME must develop a transparent NPA application and approval process to ensure adequate evaluation and consultation with key stakeholders, including National Treasury.

f) DME must update the NPA pricing framework setting out the evaluation criteria. NERSA will approve and monitor NPAs in accordance with the framework.

g) All applications must be treated in accordance with the approved processes and frameworks and be approved by NERSA.

h) NERSA must approve as soon as possible a forward price curve and avoided cost estimates for NPA evaluation purposes for a period of at least 10 years.

5.5 International Sales

There is currently no formal framework in place to guide the pricing of international sales. Part of this framework should be that international customers connected to the transmission system should not pay or receive subsidies intended for South African customers. This of course excludes cross-subsidies based on cost averaging, which is an inevitable outcome from the way tariffs are calculated.

Furthermore, local customers should not subsidise the export of electricity. The method of evaluation to determine whether international customers receive a subsidy is the appropriate avoided costs.

Policy Position: 16

a) NERSA must develop and implement a framework for the pricing of international sales contracts.

b) International customers connected to the transmission system must not pay or receive subsidies intended for South African customers.

c) South African customers must not subsidise the export of electricity.

5.6 Ancillary charges / standby charges

Currently the cost of providing all ancillary services are already embedded in the generation charges. However, it is in theory possible to unbundle the cost of these services, but very few countries have actually unbundled these costs to their customers. There are several reasons for this, including:

a. It is unclear what the cost driver is for ancillary services from a customer perspective. The current cost drivers such as energy (kWhs) and capacity (kW) are not suitable to accurately reflect the ancillary cost imposed by a customer. Because there are no obvious ancillary cost drivers, it is debatable whether these costs should be unbundled and what value would be added if it is unbundled.

b. Ancillary service costs are generally relatively low compared to the overall cost of generation, transmission and distribution (less than 5% of total turnover). This is probably another reason why most countries have not unbundled these services.

Unless the above situation changes it would probably not be economical to unbundle the cost of ancillary services to wholesale energy customers.

A standby charge is a special form of ancillary charge. This charge is intended to recover the cost (including generation, transmission and distribution costs) associated with providing backup power when the customer's generator is out of service. The question arises as to whether a separate standby charge should be introduced in South Africa.

In a way the standby charge components for transmission and distribution have already been introduced by way of network access charges which apply for at least 12 months or for as long as a standby is required. Hence, the remaining question is whether a separate standby charge should be introduced to recover the cost of generation (capacity, operating reserves and frequency control). If introduced, it could have a significant influence on the development of self generation projects.

There is little doubt that any form of backup service will cost real money to provide. However, it should be noted that standby or backup generator capacity is constantly provided to customers who do not have self generators. For example the industry needs to carry sufficient plant and operating reserves to meet the needs of a customer with large switchable block-loads. These customers are currently allowed to switch their loads in or out without notice and without incurring standby charges. This situation is no different to a customer who switches a self generator in and out without any notice (provided that the generator is not larger than the biggest switchable block-load).

Given the above it would seem unfair and discriminatory to introduce a standby charge for a customer with self generation without introducing a similar charge to all other customers. The introduction of a generator standby charge on any or all customers would also be inconsistent with the conclusion that a capacity based charge for wholesale energy pricing is inappropriate, contained in the discussion under section 5.2.

Unless the above description is no longer valid it would not be appropriate to unbundle the cost of generator standby services. It would also be unfair to introduce a standby charge only to customers with self generation.

Policy Position: 17

a) The cost of ancillary services must form part of the wholesale energy prices.

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

6 TRANSMISSION PRICING

6.1 Applicability

This would be similar as for wholesale pricing. Please refer to section 7.1 for a detailed description in this regard.

6.2 Tariff Structure

To encourage cost reflective pricing it is recommended that transmission charges be unbundled. These charges would typically consist of Transmission Use of System Charges (TUOS), line loss charges, service charges and where applicable connection charges. If needed special service charges may be introduced to better reflect the cost of supply, such as reliability charges, reactive energy charges and congestion charges.

Connection charges need to be fair and be calculated in accordance with a policy to be developed. The basic features of such a policy should include:

a. The licensee should clearly and transparently define the basis on which connection charges would be calculated.

b. Customers should not pay twice for the same infrastructure.

c. No amendments to the connection agreement unless such changes are mutually agreed. Furthermore, the cost of the refurbishment of connection assets should be covered through a new set of connection charges, to be raised at the time, unless these assets have become integrated into the system to the extent that they can no longer be viewed as premium.

d. There needs to be a fair and transparent reimbursement mechanism in the connection charge policy to deal equitably with network assets that were deemed dedicated, but later become shared. This is to prevent "second comers / free riders" from benefiting once the "first user" has paid for the system.

e. Although customers would pay for the assets, the network company will own and maintain the assets.

f. The connection charge policy should clearly address all the obligations, including the calculation of charges and the making of payments (who must do what, where, when and how).

g. The contracting parties should also have a clear understanding of funding and payment for the repair, refurbishment or even replacement of connection assets.

The calculation of charges for the unbundled services should be based on approved regulatory methodologies. This will ensure fairness and transparency in the way transmission charges are calculated. More specific policy guidance is provided in respect of charges to generators (refer to section 6.4) as well as the geographic differentiation of transmission charges (refer to section 6.5).

Policy Position: 18

a) Transmission tariffs must be unbundled (e.g. charges for: TUOS, line losses, customer services and connection) to reflect more accurately the cost of supply.

b) Connection charges must be fair and calculated in accordance to a standard to be approved by NERSA.

c) The transmission tariff structure must reflect the cost of supply and could consist of a combination of capacity, energy loss factors and fixed charges.

6.3 Tariff Levels

The transmission tariffs need to be set at a level that would allow the licensee to meet his approved revenue requirement.

Tariff levels should be determined in accordance with:

a. an approved grid code;

b. an approved cross-subsidy framework; and

c. other regulatory requirements.

Policy Position: 19

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

6.4 Charges to Generators and Customers

In some parts of the world the generators are also responsible for contributing towards the use of the transmission network. However, this practise is not universal and this raises the question whether generators should carry any cost for the use of the transmission network.

Many tariff designers would argue that the customer ends up paying for all the transmission costs anyway whether the generators share in the cost of transmission or not. Consequently, they hold the view that it does not add any value to first allocate some transmission costs to the generators if, in turn, the generators increase their energy charges to offset the additional costs. They conclude that all transmission costs should, therefore, be recovered directly from the customer through transmission charges.

The main advantage of the above approach is that it keeps transmission tariffs simple. This is an important consideration especially at distribution level, but at the transmission level the benefits of simple tariffs may be offset by the distortions of tariffs that are too simple and not cost reflective. Another small benefit is that it keeps generator prices "clean" of any transmission costs and, therefore, facilitates the benchmarking of generation costs. On closer inspection, however, the approach deviates from cost reflective principles and introduces unintended distortions.

The argument that consumers should pay directly for all costs is based on the assumption that it is only customers who need the transmission network and should pay for it. This is of course not the case because the location of a generator has a similar influence on the cost of transmission as the location of the customer. In fact, if generator location did not impact on transmission networks there would be no need for transmission networks because a generator would position itself next to the customer. But because of fuel cost, economies of scale and other reasons, generators are rarely located in the near vicinity of their customers.

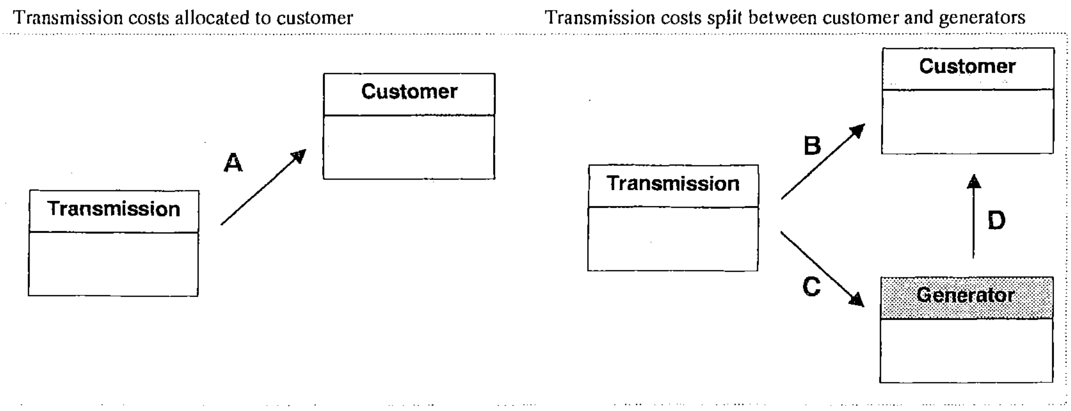
Few would argue that generators do not impact on the cost of transmission, but some may indeed argue that the generators do not pay because the customer ultimately pays for all the costs. The implications, if customers pay for all transmission costs, are that:

a. The approach deviates from the principle that the user-must-pay. In this instance, as described above, the generator is also a user of the transmission system and should, therefore, pay according to this principle.

b. Whether the generator pays or does not pay causes a considerable shift in energy and demand charges. The reason for this is that all generator costs (including any transmission costs) are converted into TOU energy charges as described under wholesale energy pricing (see section 5.2). If generators do not pay transmission network charges all the transmission costs will be recovered from customers through demand (kVA) charges. In other words, whether generators pay for transmission costs or not affect whether customers pay for transmission through a combination of energy or demand charges or only through demand charges. This would in turn have a significant impact on the cost of customers at lower load factors.

The above concepts are demonstrated in the following figure.

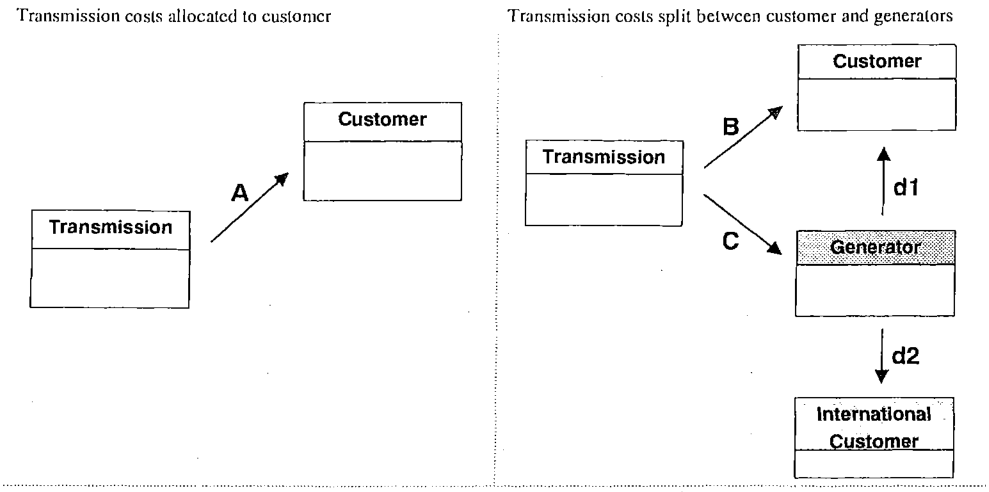
Figure 3: Illustration of Cost Split between Customers and Generators



Note:
A = B + C
A, B & C (kVA charges)
D (energy charge)

The deviation from cost reflective tariffs (user-pay principle) if generators do not pay for the use of the transmission network becomes more obvious when some of the electricity produced in the country is exported. See Figure 4 for a simple illustration. This may lead to a situation where local customers subsidise international customers for the use of the transmission networks. This is illustrated by the fact that A > B + d1 in Figure 4. This is not a desirable outcome and should be avoided given that the volume of international trade in SAPP is expected to increase over time.

Figure 4: Illustration of Cost Split between Customers (local and international) and Generators



Comments:
A = B + C
C = d1 + d2
B + d1 < A
A, B & C (kVA charges)
d1 & d2 (energy charge)

The above cost split could be applied to the following transmission services, including TUOS charges service charges and other charges that are relevant. Transmission losses are quite dynamic and respond to changes in system characteristics. It is not practical to frequently change transmission loss allocation to generators to take these movements into account. These dynamics are best optimised at a central level using real time dispatch programmes. Consequently, it could be argued that all losses should be charged directly to the loads only, thereby not impacting on real time dispatch decisions.

The allocation of transmission costs could impact on the competitiveness of generators. This should not present a problem as long as the cost allocation is fair and reflective of the costs. This may become a problem when countries that trade electricity follow different approaches to the allocation of transmission costs to generators. Therefore, an important point to keep in mind is to ensure that there is consistency between SAPP members in the way they treat the allocation of transmission costs to generators.

Policy Position: 20

a) *Transmission network costs must be apportioned 50/50 between generators and customers to more accurately reflect the cost of supply.*

b) *Transmission losses costs will be allocated directly to loads.*

c) *Transmission service and other costs must be allocated rationally between loads and generators and must reflect the cost to provide the service.*

d) *The apportionment between generators and customers must be reviewed from time to time to ensure compliance with regional approaches in order not to disadvantage South African based generators.*

6.5 Geographic Differentiation

Transmission network access and losses charges to customers are currently differentiated into four zones. The geographic differentiation of transmission network charges has been the subject of debate over several years. There are essentially three approaches:

a. It may remain as it is at present (four zones).

b. It could be treated according to the so-called postage stamp method where there is no geographic differentiation.

c. The transmission zones could be re-defined based on some methodology.

One of the key challenges in dealing with geographic differentiation of transmission charges is that the level of differentiation may change significantly (if not radically) depending on the pattern of future power generation development. This raises concerns around transmission network geographic price predictability, stability and fairness.

In keeping with the objective to move towards more cost reflective tariffs, NERSA may define new and more cost reflective transmission zones on which transmission infrastructure and losses charges would be based. However, any change should be measured against the full range of tariff principles including price stability and the cost of implementation and administration.

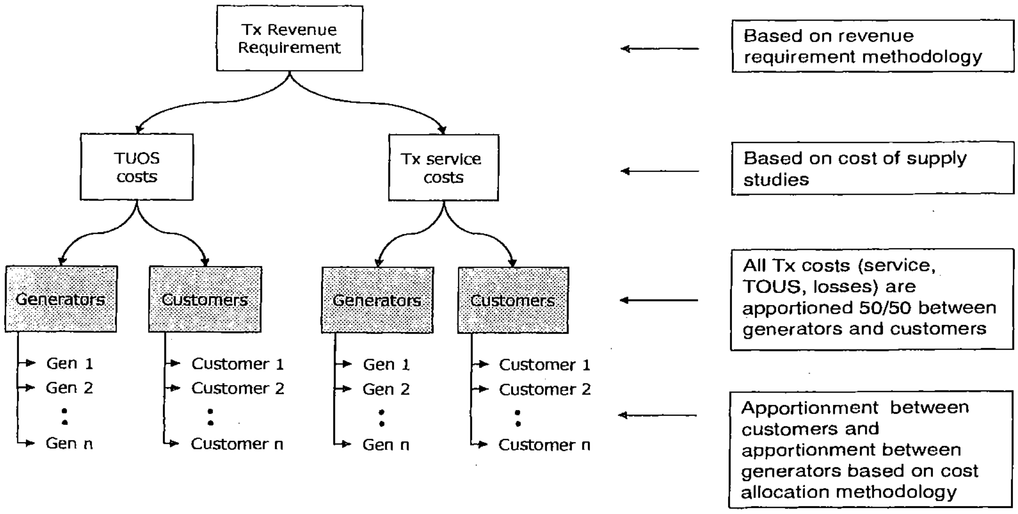
The allocation of transmission costs between different generators is usually based on a methodology that best balances the various tariff principles and objectives. On the one hand a "postage stamp" method will levy the same charge to all generators regardless of their position. This approach is simple and stable, but is not cost reflective.

On the other hand the "power flow" method would determine a specific charge for each generator depending on that generator's use of the transmission network. In other words, a generator that uses more of the network will pay more and vice versa. This approach is more cost reflective but also more complex. NERSA would need to investigate the different options and decide on the most appropriate method.

It should be kept in mind that when consideration is given as to where to build a new generator, that all costs (on a life cycle basis) need to be considered in order to decide on the best economic solution. This includes all new network costs. Once the investment decision is made, those costs become sunk costs and deciding how to recover the costs from various industry players does not change the decision where to position the power station. In other words sunk costs do not influence future decision-making.

The different transmission costs (services) and their relation to the transmission revenue requirement and the cost recovery from generators and customers are summarised in the following figure.

Figure 5: Transmission Cost Allocation between different Generators and between different Customers



Policy Position: 21

a) *The current transmission geographic differentials for customers must remain until it is succeed by an approved redefinition of geographic differentials.*

b) *The transmission licence holder, DME and NERSA must evaluate the redefinition of geographic differentials for customers assessing the price stability, comparing the current generation mix with that foreseen in the next 10 years.*

c) *The transmission license holder, DME and NERSA must investigate different options and adopt the most appropriate method for allocating costs between generators.*

6.6 Transmission Charges for International Transactions

South Africa is an active participant in SAPP development and trading. To prevent any cross-subsidisation between South African and SAPP customers, it is important that the same transmission tariffs and principles should apply to international customers connected to the transmission system.

Policy Position: 22

a) *International customers connected to the transmission network will pay the regulated transmission tariffs.*

b) *International customers will be required to pay connection charges in accordance with the connection charge policy.*

c) *The financing of connection assets for international customers will be in accordance with the connection charge policy.*

d) *Any wheeling by SAPP members through the Transmission network in South Africa must result in a payment to the transmission licensee for the wheeling service provided. The payment will be in accordance with SAPP rules for wheeling charges and will be recovered from SAPP members the approved trading entity.*

7 WHOLESALE PRICING

7.1 Applicability

Wholesale pricing is applicable to licensees who qualify to purchase electricity at the wholesale level. DME in consultation with NERSA should periodically revise and announce the qualification criteria for wholesale energy purchases.

Access to wholesale electricity prices should be available to all licensed wholesale purchasers on a fair and non-discriminatory basis.

Electricity exported from South Africa would be subject to NERSA pricing principles. This is necessary as it could impact on the security of supply and price levels for local customers.

Policy Position: 23

a) *Wholesale energy and transmission prices must be available on a fair and non-discriminatory basis to all qualifying wholesale purchasers.*

b) *DME in consultation with NERSA must determine qualification criteria for wholesale purchasers and implementation guidelines subject to cross-subsidy stipulations in this EPP document.*

7.2 Tariff Characteristics

Wholesale pricing consists of the wholesale energy charges, plus the transmission charges, plus the single buyer own cost charges. A detailed discussion of the wholesale energy and transmission pricing characteristics is provided in sections 5 and 6.

8 DISTRIBUTION PRICING

The pricing of electricity in the distribution sector has been the subject of extensive debate over the past decade. The current Electricity Act and WP provide guidance, but in many respects these are too vague to really assist the industry to move forward. Therefore, the proposed EPP would give specific policy statements without stating how it should be implemented.

This first section will address the key principle for distribution pricing, namely that tariffs would be cost reflective and are in support of cost reflectivity. Provision is, however, made for deviations from cost and these are covered under the sections on cross-subsidies and Demand Side Management (DSM) / energy efficiency.

8.1 Cost of Supply Studies

The industry's Cost of Supply (COS) methodology and some models to calculate these costs have existed now for more than ten years. It has nevertheless only been applied by a few utilities, thus leaving the extent of cross-subsidies largely unknown.

Policy Position: 24

a) *Electricity distributors shall undertake COS studies at least every five years, but at least when significant licensee structure changes occur, such as in customer base, relationships between cost components and sales volumes. This must be done according to the approved NERSA standard to reflect changing costs and customer behaviour.*

8.2 Refurbishment / Maintenance backlog

The distribution industry has largely neglected its obligations to undertake appropriate maintenance and refurbishment of infrastructure. This has caused an outstanding backlog which needs to be addressed going into the future.

Policy Position: 25

a) Licensees must undertake the required analyses to determine the extent of backlog of maintenance / refurbishment and put strategies in place to catch up.

b) NERSA must give due cognisance to requests for additional funds to provide for capital and operating expenditure, including staff to manage such projects and undertake the required work.

c) The above must be done with due cognisance where proper ringfencing is not done and much of the needed funds are removed in a non-transparent fashion from the electricity sector.

8.3 Distribution Losses / Bad debt

Non-technical losses and bad debt have become a massive problem with a very significant impact on electricity sales, maximum demand and viability of many licensees. The question is whether such high non-technical losses and subsequent bad debt could be considered to be a legitimate cost which should be recognised as part of efficient electricity supply costs, and how it should be treated.

Policy Position: 26

a) NERSA must develop acceptable standards for non-technical losses and provision for bad debt.

b) Such standards should not be applied on the whole of any licensee but to any significant identifiable area within the licensee's purview.

c) The component of non-technical losses and bad debt which exceeds the approved standard must be considered unacceptable and be removed from the approved revenue base that would otherwise impact on the return of owners.

8.4 Customer Categories

Each different type of customer has a different load profile and thus load factor and consequently the energy and network costs differ. For this reason tariffs need to be differentiated by the type of usage profile and by type of customer. Such differentiation should be applied when the cost of any cost category differs significantly from another application.

Policy Position: 27

a) COS studies and thus tariffs shall be differentiated for different customer categories and these shall reflect the cost differences based on:

- *consumption patterns e.g. usage in different times load factor and average consumption;*
- *type of supply (1 phase or 3 phase, capacity level, overhead or underground, urban versus farms, multiple connection points);*
- *type of metering (conventional or pre-payment, kWh, demand, TOU;) and*
- *position on the network (not geographic location), voltage of the supply and the system from which the supply is taken.*

b) *A new category must be created where costs differ by at least 10% between a group of customers and another based on the above criteria.*

c) *Sub-categories could also be created where only one or more components of costs differ significantly.*

8.5 Cost-Reflective Tariff Components

In addressing cost-reflective tariffs the first issue relates to what cost components should ideally be included to reflect the costs accurately.

Policy Position: 28

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

- *Energy costs in c/kWh: The energy cost from the bulk supplier or other sources differentiated by:*
    - *the bulk supplier TOU periods;*
    - *or, with non-TOU metering, the relevant portion of the various TOU costs; and*
    - *plus the losses on the relevant transmission and distribution networks.*
- *Network demand charges in R/kVA/period covering:*
    - *the contribution to the transmission network costs by the relevant loads; and*
    - *plus the variable (shared component) of the DUOS costs.*
- *Network capacity charges in R/kVA/month or R/Amp/month based on annual capacity: (the fixed or dedicated component) of the DUOS costs;*
- *Customer service charges in R/cust/month: covering the costs of providing the services to serve the customer including, billing, revenue collection, marketing and customer claims;*
- *Point of supply costs R/POS/month: covering the costs associated providing each connection customer from the point of common coupling and metering; and*
- *Cost of poor power factor: Charges may be levied to reflect the avoided costs for the distributor if it had to restore the power factor to the optimum level.*

8.6 Tariff Simplification

In situations where simple metering is applied or billing systems are constrained the various cost components could well be simplified in a fewer number of components. This should be done in a way to reflect the full cost of supply as for the group of customers that would be charged at the simplified rates.

Policy Position: 29

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

8.7 Seasonality

There is a marked difference in the amount of usage during the high demand (winter) season versus the low demand (summer) season nationally and, therefore, the costs also differ accordingly. For this reason all tariffs should be differentiated by season to accurately reflect the full cost difference as is reflected in the wholesale energy charges and not by the local / customer specific seasonality.

Policy Position: 30

a) *All licensees shall differentiate their energy charges by season in line with wholesale energy prices with a view to addressing the seasonal cost differences.*

8.8 Tariff Structure and Level

In some utilities in the world the application of tariffs, both in structure and levels, are based on LRMC. In South Africa the tariff levels do not recover the revenue requirement associated with LRMC. Against this background the tariff levels and structures should be as set out below.

Policy Position: 31

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

8.9 Cost-Reflective Versus Pricing Signal

Customers respond to the signal provided by the electricity prices. The question arises: should the tariff be modified from the COS with the objective of creating a specific signal to customers to achieve a specific objective?

Policy Position: 32

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

8.10 Time of Use Tariffs

The load profiles of customers differ significantly. The application of tariffs with only one energy rate result in large cross-subsidies and, therefore, customers do not have the opportunity to respond by using less power at more expensive times. Eskom introduced TOU tariffs more than 15 years ago. Since then the majority of Eskom's large customer sales are at TOU. This is not the case with municipalities where only a very small percentage of sales in the municipalities are at TOU. For this reason the application of TOU tariffs to all customers in the industry should be promoted actively.

Policy Position: 33

a) *Tariffs must include TOU energy rates as follows:*

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

8.11 Time of Use Tariff Structures

The structure of TOU tariffs is very important to signal long term pricing signals, but provision should also be made to cater for emergency signals where possible.

Policy Position: 34

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

8.12 Distribution Geographic Price Differentials

All municipalities now apply one set of tariffs within the relevant area of jurisdiction of the municipality.

Policy Position: 35

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

Eskom does not apply any distribution geographic differentiation in its national tariffs. This means that there is major cross-subsidisation between customers in the various parts of South Africa. This also creates a significant obstacle for restructuring the EDI.

Policy Position: 36

a) *Eskom shall apply pooling of costs and base its tariffs on the proposed RED boundaries.*

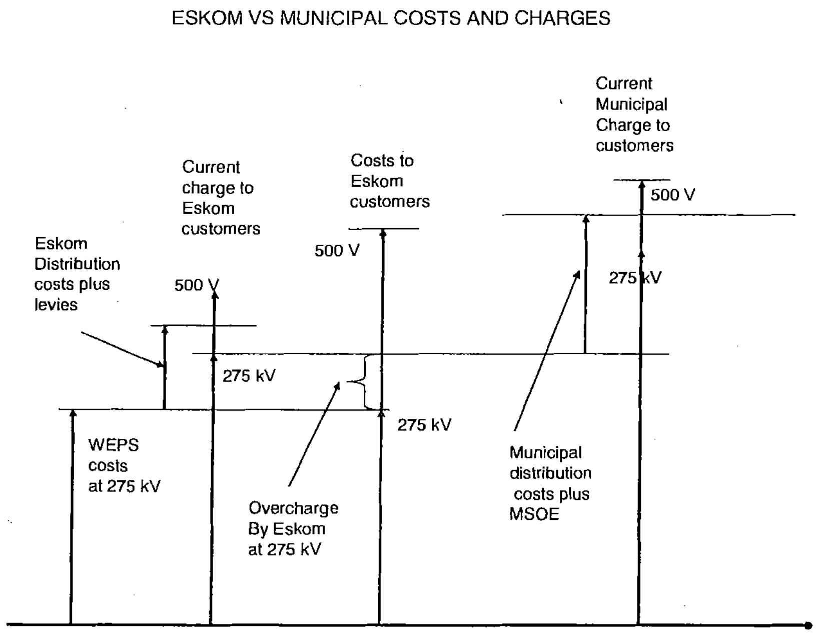
8.13 Voltage and Position Differentiation

Most utilities currently apply tariff differentials based on the supply voltage. The problem associated with the current practice is as follows:

a. The level of the differentials is in general smaller than the actual cost differences.
b. The differential is applied as either a percentage discount to the low voltage (LV) or a percentage surcharge on the high voltage (HV) tariff and the same percentage is applicable to the demand and energy rates.
c. The differentials are applied to the supply voltage only without reflecting the system voltage. Costs differ significantly for supplies directly from the LV side of a substation and that of a customer taking a supply from deep in the LV network, although both are supplied from the same voltage.

Eskom's current voltage differentials are not cost reflective, resulting in an overcharge of the large municipalities and other customers at higher voltages which in turn leads to an overcharge of the municipality's customers. This means that a similar customer supplied by Eskom versus one supplied within the municipality's area could pay a very different price which is not cost based. In terms of a directive from the Competition Commission, this practice could possibly be a contravention of the law. This dilemma is illustrated in the figure below.

Figure 6: Eskom Voltage Differentials Problem



Policy Position: 37

a) Voltage and supply position differentials must be applied in tariffs within a licensed distributor as follows:

- *based on the supply and system voltage;*
- *based on the cost differences from the cost of supply study;*
- *to be applied as different energy & demand / capacity charges not as a percentage on all charge; and*
- *NERSA must drive a plan for phased increases in tariffs at lower voltages and decrease of tariffs at higher voltages.*

8.14 Domestic (Residential) Tariffs

Domestic customers present significant challenges for utilities because of their large numbers and the many different types of domestic customers with diverse needs. Utilities should start charging cost-reflective tariffs for domestic customers, but also cater for cross-subsidisation of some customers. The detailed provisions for low income customers are discussed in the cross-subsidy section.

Policy Position: 38

a) Domestic tariffs to become more cost-reflective, offering a suite of supply options with progressive capacity-differentiated tariffs and connection fees:

- *At the one end a single energy rate tariff with no basic charge, limited to 20 Amps and nominal connection charge (details under section on cross-subsidies);*

- *At the next level a tariff with a basic charge, customer service charge, capacity charge and energy charge with cost-reflective connection charges; and*
- *At the final level TOU tariffs must be instituted on the same basis as above, but with TOU energy rates.*

8.15 Rationalising Electricity Tariffs

NERSA, together with the industry, should develop a national set of tariff structures for the industry. All utilities need to then adapt their tariffs in terms of the approved national structure. The tariff levels would remain different for each utility to match the local circumstances.

Policy Position: 39

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

8.16 TOU Tariffs and Low Income Customers

It has been suggested that low income domestic customers should not be exposed to TOU tariffs. This would be unwise. Although the cost of Automatic Meter Reading (AMR) systems for domestic customers is still expensive, prices are decreasing and when considering the load management and loss management features of these systems, their life cycle costs are already less than many of the current metering and load control options being applied in the industry. For this reason it is foreseen that AMR systems could be applied in low income areas and in such cases, TOU tariff could be made available. For the low income customers such tariffs could well have the same features as the life line tariff with some capacity limitation, no fixed charges and a low connection fee.

Policy Position: 40

a) With the availability of AMR systems for domestic customers, the option of a TOU life line tariff with no fixed charges must be researched by NERSA to offer more cost saving opportunities for low income customers.

8.17 Treatment of Network Capital Contributions

There are various situations in the industry where the cost of new networks and even the expansion of existing networks are not funded by the utility, but by other sources such as:

a. Through the connection cost. This is typically the service connection or in many cases the incremental costs.

b. The State electrification fund grant towards the cost of establishing networks to supply new customers and maintain low connection fees.

c. By way of capital contributions. Typically this is the contribution to cover the full cost of any existing or future infrastructure that would be used.

d. In many cases developers would establish and fund infrastructure and then hand them over to the utility at no compensation.

e. A utility often receives assets from another entity without any debt or equity associated therewith.

The issue at stake is whether a utility should be allowed to apply depreciation and earn a return on these assets which are funded by the customers outside of the tariff. If this is allowed, it would mean that customers would have to pay twice for the same network assets. The principle thus is when the upgrade or refurbishment of these assets are due, the required funds could either be obtained from existing profits or debt for which customers would then eventually need to pay.

Policy Position: 41

a) *Any assets which are not financed by the distributor, but from sources such as: State grants, customer capital contributions and connection fees, developer networks handed to the utilities and networks transferred to new utilities debt free, shall be excluded from the asset base for the purpose of determining depreciation and return on assets and in the same way these costs be excluded from COS studies.*

b) *The provision for the replacement of these assets when it becomes due shall form part of the Licensee's revenue requirements as set out in 2.2*

c) *These assets would, however, be included for provisions relating to all operating expenses.*

A wide range of practices used to be applied to recover a contribution from new customers / developers towards the cost of infrastructure being used for the new supplies. An industry standard (NRS 069 – Industry Standard for Recovery of Capital Costs for Distribution Network Assets) based on replacement cost was established and is currently applied by a number of utilities. However, it is not applied very widely and the calculation of the relevant rates is not regulated.

Policy Position: 42

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

8.18 Public Lighting

Many municipalities consider public lighting to be part of the electricity supply service and as such, expenses have to be covered by electricity customers. Public lighting is, however, a municipal service which is a consumer of electricity and not part of electricity supply. This is a service to the community, not to the electricity customer. The type of lighting and replacement of lights are subjects affected by the voters of the municipality and subject to issues of aesthetics, road safety and public safety. These matters do not form part of electricity supply and are very different to the criteria for determining expenditure on electricity networks. Worldwide systems of public lighting are considered part of municipal services and are thus paid by these authorities. The only exceptions are some developing countries where proper functioning municipal services have not been established. It is important to understand that it is not proposed that municipalities should now charge the tax payers more, but rather that the cost of public lighting should be shown separately and be charged separately to the municipality. The municipality may in turn recover this money from the Municipal Surcharge on Electricity (MSOE) or any other source.

Policy Position: 43

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

8.19 Quality of Supply: n-1

Most utilities in the country traditionally applied the practice to provide supplies > 10 MVA or supplied at any voltage higher than LV, based on the formula of "n-1".

a. During the past few years Eskom started to slip back to provide "n" only and whenever customers asked for "n-1," Eskom insisted that it be treated as a premium supply and the customer should pay the capital costs and operating costs associated with the additional equipment to provide "n-1".
b. Municipalities also reverted to "n" in many cases, because the income they derived should have been used to fund the "-1" component which was abrogated.

In view of the socio / economic implications of having very long outages for such large supplies, it is recommended that all supplies > 10 MVA or supplied at any voltage higher than LV, be based on the principle of "n-1".

Policy Position: 44

a) *The network standard shall be set to ensure that the cost of redundancy of distribution networks matches the socio / economic implications of power outages and willingness to pay to avoid such disruptions. Charges for all customers shall thus be based on the standard applied at each level in the network.*

8.20 Customer Service Quality

NERSA currently regulates the quality of service to customers. It should be noted that the general customer service provided to customers in the industry is not on an acceptable level. Internationally the only way in which service provision has been improved, was through the application of a self-regulating system involving penalties paid by the utilities to customers for inferior service.

Policy Position: 45

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

8.21 Resellers Charges

There are extensive debates on the functions and financial viability of resellers. The key issues relate to the charges of resellers, their responsibilities and whether customers should have the choice to take a supply from the reseller or the licensed electricity utility in the area. It is recognised that the non-cost reflective nature of the tariffs of licensees are part of the reseller's problem. The EPP proposes how this should be addressed which should then alleviate the problem. Real choice would address this issue. However, in practice choice is severely limited and thus the EPP proposes that:

Policy Position: 46

a) *Non-licensed resellers of electricity shall provide the electricity at terms, tariffs and services not less favourably than that provided by the licensed distributor in the area.*

b) *NERSA shall provide guidelines to resellers regarding resale principles.*

9 CROSS-SUBSIDIES

There are a host of cross-subsidies in the ESI. Some of these are inherent to the nature of the ESI and tariff-making, but some others exist specifically to subsidise a particular group of customers. There have been extensive debates about these cross-subsidies and what should be done in this respect.

9.1 Cross-Subsidy / MSOE

The EPP makes very clear and gives specific recommendations about how customers should be charged in general. The cost should reflect tariffs within pre-determined, homogeneous, customer categories. This section then provides for a few very specific cross-subsidies which should be/ continue to be applied in the ESI.

Policy Position: 47

a) *The application of only specifically approved cross-subsidies, subsidies, levies and surcharges must be instituted in the ESI to address certain socio / political / environment needs.*

b) *Cross-subsidies should have a minimal impact on price of electricity to consumers in the productive sector of the economy.*

9.2 Transparency of Cross-Subsidies / MSOE

One of the disadvantages of applying non-transparent cross-subsidies is that customers often forget about these and very soon more subsidies are demanded. The negative impacts of these cross-subsidies are not always considered in normal decision-making.

Policy Position: 48

a) *All levies, subsidies and cross-subsidies shall be made transparent, while moving towards cost-reflective and transparent tariffs in the ESI.*

b) *Licensees are required to establish and publicise the average level of cross-subsidy between customer categories.*

9.3 Future Electrification Capital Subsidies

Sales to low income consumers enjoy special treatment under special circumstances. Linked to this aspect is the high expenditure on electrification assets with an estimated total figure of 70% electrification. For the rural areas this figure is marginally in excess of 50%.

The current State electrification capital fund has already achieved significant success in increasing the rate of electrification drastically without burdening electricity customers too heavily. The electrification fund should be continued as a fiscal grant to target the subsidisation of the electrification capital to ensure that the industry achieve the electrification targets set by National Government.

Policy Position: 49

a) *The subsidisation of capital cost to connect new electrification (neglected communities) customers will be the main mechanism for National Government funded from the budget to achieve the required rate of electrification at affordable price levels.*

b) *As refurbishment / upgrade of these networks are required, consideration should be to include provision for such in the State mechanism.*

9.4 Past Electrification Capital Debt

During 2007 the State started providing grants to fund a major portion of electrification capital costs in South Africa. Prior to this, Eskom and many municipalities funded this capital through their own means and even subsequently municipalities invested significant amounts because of the shortfall in money provided by the State based on the lower priority given to municipal connections relative to the Eskom connection.

This past electrification debt is significant. This debt should be transferred to the REDs. If this cost is pooled for domestic customers only, it would entail very high charges for domestic customers. This matter may be addressed in various ways. National Treasury has indicated that it would not contribute any support. The preliminary EDI Holdings financial modelling indicates that all REDs would be able to carry the existing debts and provide for future capital requirements without raising tariffs above current average levels in each RED. The following thus seems to be the most attractive proposal to address this issue:

Ringfence this debt and create a levy applied to all customers in the RED to repay this debt over a period of say five years. This is in line with what Eskom has done with its past electrification debt. This practice could even be applied by current licensees. If this strategy has a serious impact on the viability of some REDs, a national strategy should be considered.

Policy Position: 50

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

9.5 Low Income Customer Tariff Subsidisation

The provision of cross-subsidies for low income domestic customers is a foregone conclusion and it is expected that this would be a requirement at least for the next ten years. The following mechanisms will all contribute towards achieving this objective:

a. the State subsidy towards the network capital cost;

b. charging of a low connection fee;

c. charging an appropriate tariff structure that allows for maximum subsidisation at low consumption levels with gradually reducing cross-subsidies as the consumption level increases; and

d. the granting of FBE.

It is not practical for most licensees to determine who low income customers are. For practical purposes, licensees have been using low consumption levels and low installed capacity as the key criteria to approximate low income. In view of the above the following is proposed:

Policy Position: 51

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

- *a single energy rate tariff;*
- *with no fixed charge;*
- *limited in capacity to 20 Amps;*
- *supplied with pre-payment / AMR; and*
- *nominal connection fee.*

9.6 Life Line Tariff Level

The determination of the tariff level for the low income customers is the subject of intense political debate. Many municipalities are using this as a tool to win votes, sometimes neglecting important State objectives. There is thus merit in having one life line tariff level with the same conditions associated. This should not necessarily be enforced onto utilities, but could be developed in a high level of detail and be made available with a strong support for all utilities that apply this tariff level. When consumption levels exceed 350 kWh per month it is usually associated with the use of a complete stove and even a geyser. This is then considered not to be a low income household any longer. The life line tariff should thus break even with the cost of supplying a 20 Amp customer at 350 kWh/month.

Policy Position: 52

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

9.7 Life Line Customer Subsidy Impact

Even though Eskom established during the mid 1990s an electrification fund and later the State established such a fund financed through the fiscus, significant amounts of capital were also spent by electricity utilities to fund electrification. This was either:

a. Before such funds were established.

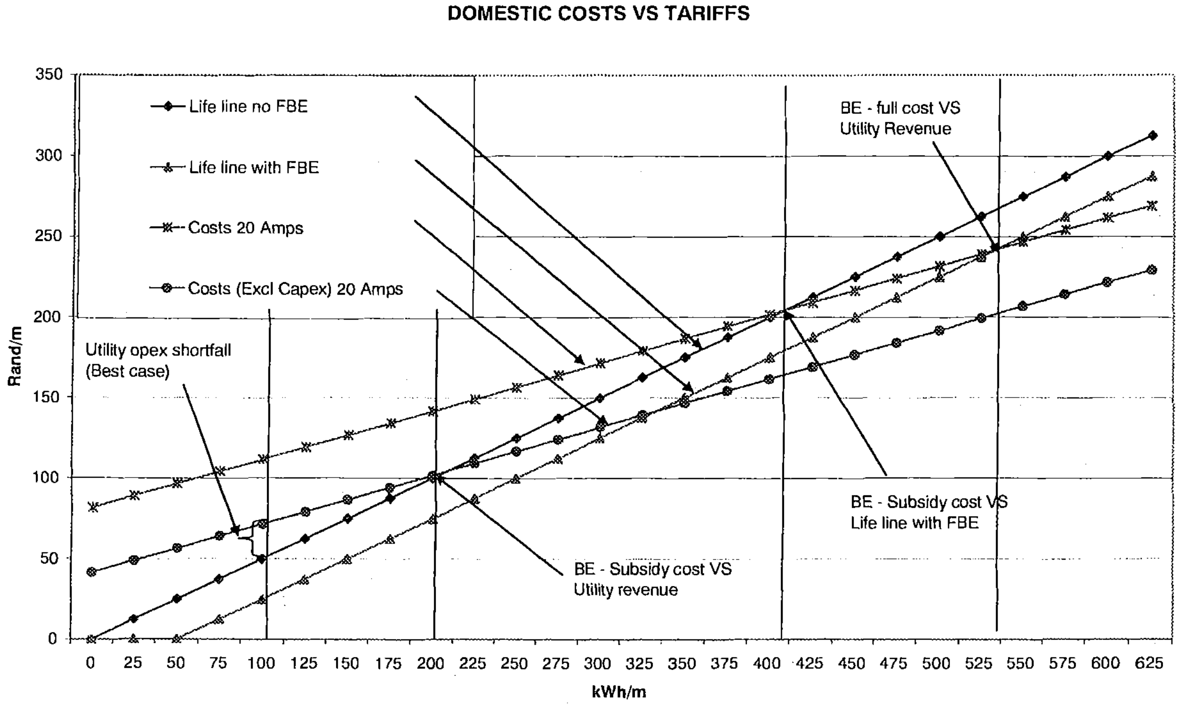
b. The funds provided did not cover all costs. In many cases utilities applied very high standards which led to costs exceeding the fund grant received and in other cases the remoteness of supplies required much more money.

c. In many cases the funds did not match the political requirements in a particular area.

d. Municipalities also claim that in many cases Eskom was given preferential treatment and thus they had to provide significant amounts of their own funds, whereas Eskom benefited from the electrification fund.

The impact on utilities of the proposed subsidy tariffs are shown in the figure below for the cases with/without capital subsidy and with/without FBE. It shows that even with a capital subsidy and FBE revenue coming from the equitable share to the distributor, there is still a shortfall.

Figure 7: Domestic Costs versus Revenue



It is, therefore, important to formulate policy to determine how these matters should be addressed.

Policy Position: 53

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

9.8 Free Basic Electricity (FBE)

The application of FBE is proceeding well and is reaching the target market, but there are certain application problems that need to be continually monitored to ensure that they are applied correctly and are addressing the needs of the low income.

Policy Position: 54

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

9.9 State Tariffs

When State usage is subsidised, this practice distorts the ESI and the economy. It is essential that the standard tariffs are charged to ensure that the full cost of providing electricity to the State is known and also to ensure that the appropriate pricing signals are provided to ensure efficient use.

Policy Position: 55

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

9.10 Tariffs on Farms

Electricity tariffs are not necessarily defined by the purpose for which the electricity is used, such as for agricultural or domestic purposes, but rather by cost. To supply electricity to farms is very expensive because of the long distances involved and thus the low utilisation of the network. Over the years utilities have differentiated their tariffs for these customers, but called them either rural tariffs or agricultural tariffs. It really refers to supplies to farms where typically the most economic option would be to supply one or two customers from each transformer. Detailed definitions have been set in NRS 069 which clearly defines the border between the networks to farms and other supplies.

The provision of a subsidised electricity infrastructure for customers on farms, mostly for agricultural purposes, but also for the workers on farms, has been ongoing over the past 30 years. Enough studies have been done to prove that the application of cost-reflective tariffs for farms would have a serious socio / economic impact on the country. Some provision, therefore, needs to be made to ensure that the tariff levels do not increase too much.

One of the biggest problems related to tariffs for farms is the refurbishment costs. Many of the lines were previously funded through an Eskom cross-subsidy on tariffs and in many cases lines were erected by the farmers themselves to keep costs low. Now that these circuits are due for refurbishment, the costs are proving to be very high. If these costs are included in tariff calculations, tariff levels would probably have to increase by more than 100%. Rather than continuing with the practice of having a system of un-transparent cross-subsidy to these customers with the ongoing fear that costs would increase drastically, the following is proposed:

Policy Position: 56

a) *Cost of supply studies must be undertaken featuring pooling strategies which separate significant groups of customers that differ significantly from other customers. One such category which must be treated separately relates to supplies on farms.*

b) *The current cross-subsidy mechanism for supplies on farms must be continued for the time being and the impact shall be shown as a transparent levy in electricity bills where practical.*

c) *DME must undertake a study to consider the introduction of alternative subsidy / cross-subsidy mechanisms to address the challenges relating to farm network replacements. The following option should be considered:*

The establishment of a farms' network refurbishment fund either be financed through:

- *State allocation managed by the Department of Local Government or the Department of Agriculture and Land Affairs.*
- *A RED electricity levy applied at the RED level and it thus managed by the RED.*
- *A national electricity levy applied at the wholesale level and thus managed by DME / agent of DME.*

9.11 Municipal Surcharge on Electricity (MSOE)

Currently a significant amount of electricity revenue is used by many municipalities to subsidise other municipal services. This is done by way of a transparent so-called "surplus," but also by way of various un-transparent methods such as: provision of streetlights, overstated administrative charges, unfair surcharges on materials handling and understated internal usage charges Until municipalities have completely ringfenced their activities, overstated charges to electricity departments will probably continue.

The MSOE will be regulated through norms and standards for electricity surcharges (as and when introduced) as provided for in the Municipal Fiscal Powers and Functions Act. When regulations on electricity surcharges are introduced, the regulation of the "base tariff" will be the responsibility of NERSA (which will be exclusive of the electricity surcharge) and the Minister of Finance / National Treasury will be responsible for the regulation of the MSOE.

Some municipalities have already introduced a transparent MSOE without phasing out the existing hidden surpluses. This is totally against the intention of the legislation to regulate the application of the MSOE. Furthermore it is also uncertain as to whether these municipalities have ringfenced their activities in order to quantify the hidden surpluses.

Policy Position: 57

a) Under no circumstances shall the new MSOE be introduced in addition to the current non-transparent / un-ringfenced surpluses.

b) The electricity service by municipalities should be ringfenced properly before the introduction of the proposed new MSOE.

c) NERSA shall regulate the electricity prices excluding the transparent MSOE.

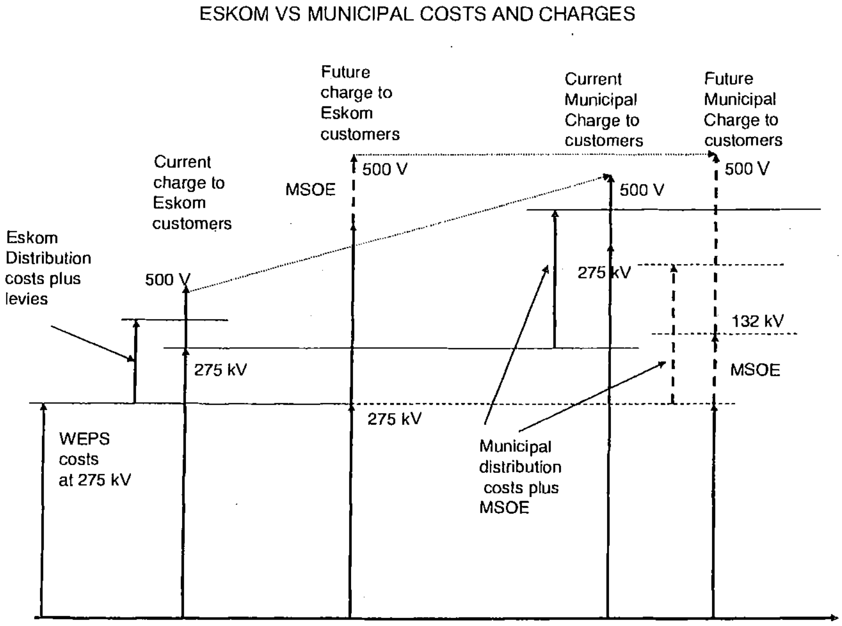
Many of Eskom's large customers are overcharged and they cross-subsidise other customers, specifically at lower voltages. The new Municipal Fiscal and Powers Act provides for the application of a MSOE on electricity customers of Eskom who fall within the area of jurisdiction of the LG. It is strongly recommended that these large customers mostly supplied at high voltage, many of them competing in export markets, should not be exposed to MSOE without first rectifying the current tariff overcharging.

Policy Position: 58

a) The phasing in of MSOE on non-municipal electricity customers who are currently being overcharged, should be matched by the phasing out of current overcharging of these customers as a result of existing cross-subsidies so as to avoid any unfair overcharging / MSOE burden on these customers.

The challenges facing the ESI in respect of the MSOE together with the problem of the non-cost reflective Eskom voltage differentials are illustrated in the figure below.

Figure 8: Future Treatment of MSOE and cost reflective Eskom Charges



Municipalities apply the rule of cutting off or not selling pre-payment electricity as a measure also to recover municipal rates revenue. In areas where this is not done the rates payment levels are very low. In a REDs scenario municipalities would face a situation of a serious non-payment of rates and, therefore, provision needs to be made to prevent this eventuality.

9.12 Viability Assistance

With the forming of REDs it is possible that some of the REDs would not be viable initially at least without raising tariff levels excessively. Significant amounts of capital and operating costs would be required to catch up on some of the maintenance, refurbishment and expansion backlogs. In the case of Eskom, significant amounts of capital are required to fund the massive generation expansion. As the owners of the public entities, new capital should be funded by the owners through a combination of debt and equity. The State should thus forfeit the receipt of any dividends for some time and may even need to inject some capital into the entities. As with any other private entity, the State should in time receive a return on its investment.

Policy Position: 59

a) *The State, as the owner of public entities, must consider forfeiting dividend payments and even MSOE and must make equity investments, if needed, to assist electricity utilities to retain their tariffs at economic levels while incurring capital expenditure for the expansion and refurbishment of existing networks to ensure appropriate gearing ratios and business indicators.*

10 DEMAND SIDE MANAGEMENT / ENERGY EFFICIENCY

Current electricity usage behaviour is based on many distortions. These have caused usage behaviour that is increasing costs significantly and causing immense environmental damage. Some of the key distortions are as follows:

a. The very low electricity prices in general.

b. The substantial subsidies to domestic customers.

c. The mindset that an all electricity home is the only option.

d. The political agenda that all should receive the same.

e. Massive electricity non-payment and theft.

Some of the undesirable patterns of behaviour caused by the distortions are as follows:

a. There is a general wastage of electricity by all groups of customers.

b. There is almost no recovery of waste energy for electricity generation or re-use in plants.

c. Space heating and cooking are done with electricity rather than with alternatives, causing 400% more pollution.

d. The scrapping of options such as clean, de-smoked, coal projects.

e. Conversion from coal stoves / water heaters / space heaters to electricity rather than clean coal.

f. Use of electricity for water heating without any solar support.

g. Swimming pools using electricity for water heating, rather than solar installations.

h. Building of factories, businesses, shops and houses with very little consideration for efficiency and the environment.

i. RDP houses being built as energy drains, e.g. not facing north, no big windows to the north for good light and heat and corrugated iron roofs without any ceilings or added insulation.

j. Practice of handing out two plate electrical stoves and electrical space heaters.

This section addresses the key policies which need to be applied to ensure that energy is used in the most effective way considering the broader environmental and economic impact and that loads are used in the most appropriate time of the day and year.

10.1 Pricing Signal

Questions about the relationship between tariffs being driven by cost reflectivity versus being a pricing signal are raised regularly. It is recognised internationally that cost reflective tariffs, as reflected by LRMC representing the true economic cost, are the best price signal. Whenever deviations from cost are applied as a measure to achieve a specific objective the economic signal would be distorted which could in turn lead to inefficient allocation of resources in the economy.

Policy Position: 60

a) *Cost reflective tariff levels and structures as discussed in the EPP shall be the first main driver of DSM and efficient use in the ESI. For this reason unbundled cost reflective charges must be charged to customers.*

b) *This is to be applied as one of the NERSA tariff evaluation criteria.*

10.2 Utility DSM / Energy Efficiency Revenue Impact

The application of DSM and energy efficiency measures in the ESI is a reality in terms of various objectives. It is a fact that when utilities implement energy efficiency and DSM, these would cost them money to do so and they would lose revenue which could thus affect their viability. This would, however, save utilities some purchase costs and significantly influence network infrastructure upgrades.

NERSA needs to take cognisance of all these factors in determining the revenue requirement and thus future price increases of utilities.

Policy Position: 61

a) *NERSA must include the impact of DSM and energy efficiency on increased implementation cost, reduced revenue and reduced network capital expenditure in determining its utility revenue requirement. As with all other costs and revenues, licensees will have to submit the detailed DSM and energy efficiency programmes with the cost and revenues implications as part of their annual price increase proposals.*

b) *These implications must also be ringfenced and be reported on annually by licensees.*

10.3 Domestic DSM and AMR

The domestic sector, which contributes more than 35% of the total system peak demand, presents very significant DSM and energy efficiency opportunities. Very little is, however, done to achieve this. The following factors have caused this state of affairs:

a. Heavily subsidised rates.

b. Very few tariffs with capacity limitation.

c. Almost no tariffs with TOU pricing signal.

d. No emergency pricing signal or systems.

e. Very high non-payment and theft in many areas.

Certain practices and the required support systems are applied in other parts of the world with substantial success. The application of AMR for domestic customers, linked with sophisticated AMR and DSM and utility control systems on an integrated basis, should receive serious consideration in South Africa.

Policy Position: 62

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

These measures will facilitate the following behaviour:

a. Load shift from high demand periods to low demand periods.

b. Reduced consumption because of high prices by:

- Energy efficiency measures.
- Efficient behaviour.
- Energy switching to alternative energy forms.

c. Reductions during emergencies.

d. Reduced losses and increased service.

10.4 Emergency Measures for Capacity / Energy Shortages

The capacity shortage situation in the country is a serious threat to the economy. Provision should be made to ensure that this is rapidly eliminated and prevented. Such provision should cover issues to be considered by the utilities and customers. Action taken in this respect in Brazil had the desired impact and in fact exceeded expectations.

During times of serious power shortages two new types of costs start to play a role:

a. When serious shortages are being experienced the cost for customers to run their own back-up generation plant.

b. During interruptions the cost of unserved energy reflects the impact on the economy of such shortages.

These costs should thus be used in setting penalty / pricing signals during these times and not be based on some arbitrary charges. This would ensure that those customers who do not save according to the targets would feel the same financial impact than those customers whose supplies are interrupted because of their actions.

Policy Position: 63

a) The industry must apply emergency measures to avoid the interruption of groups of customers because of shortage of supply.

b) Power rationing and similar measures must be applied to obtain mandatory reductions in power usage to such level to match supply and demand with the following provisions:

- *Penalties in price and/or interruption must be applied to those who do not reach their targets.*
- *Those who do not reach the targets must be charged at the variable cost of a diesel fired open cycle gas turbine.*
- *To limit the economic impact of ongoing industrial load reductions more dynamic price options, such as a TOU tariff with a super peak rate during times when interruptions are effected, should be offered at the COE applicable to rationing quantities not saved.*
- *Mechanisms to encourage economic growth in line with system availability must be incorporated*

c) NERSA must investigate a mechanism to link charges payable by customers to the quality of supply in cases where it moves outside of the accepted norms and standards, e.g. Capacity Charge = MW x MD Charge x (Actual supplied/Max Target hours)

d) NERSA must ensure that ongoing power interruptions because of capacity / energy shortages feature in the performance management systems of licensees and its management.

10.5 DSM / Energy efficiency funding

The application of DSM and energy efficiency strategies has gained momentum with the recent power shortages in South Africa. Eskom has been managing the DSM / Energy efficiency fund, which is funded from a portion of the Eskom budget. The Minister of Finance recently announced the application of a 2 c/kWh levy on non-renewable generation in South Africa. It is unclear for which purpose the funds would be used. The need for money to fund various DSM / Energy efficient and renewable energy sources in South Africa is extensive and urgent and this includes *inter alia* the following:

a. Smart meters for domestic customers over 500 kWh/m.

b. Energy efficient lighting programmes.

c. Installation of solar water heaters.

d. Various other demand side management projects.

e. Mechanism to make renewable energy sources competitive with non-renewables.

f. Assisting with energy switching away from electricity.

Policy Position: 64

a) All levies / funds collected from electricity customers must be grouped as one.

b) This is to be quantified accurately and be shown as a transparent levy on electricity sales.

c) The funds generated shall be managed on an integrated basis under one independent body to be appointed by the Minister of DME.

d) The funds shall be applied and be prioritised on a least total cost basis.

e) All parties in the ESI shall be treated fairly and independently based on the measure to which the application meets the qualification criteria.

11 REGULATION

DME determines the EPP to be applied in the ESI and NERSA (appointed by the Minister of Minerals and Energy) is tasked with establishing these or to establish the rules, regulations, plans, programmes and projects in finer detail. In terms of the Electricity Regulation Act of 2006 NERSA is *inter alia* responsible for the consideration and issuing of licenses for all operating functions (locally and internationally), regulation of prices and tariffs and mediation of disputes. Based on the objectives of the Electricity Regulation Act of 2006, it is necessary to accentuate the following with regard to the efficient execution of the EPP:

a. Orderly coordination of licensing, system of appeals and public hearings are important aspects in the regulation process.

b. Timescales in respect of submissions and feedback of information to various parties are essential to ensure cooperation in all respects.

c. The nature of regulation should be established. The tougher the attitude of the regulatory personnel, the more difficult co-operation could become. A balanced approach is necessary.

d. A justification for and acceptance of all aspects of regulation are required because the level of tariffs is argued in many instances.

e. A case has to be made for *ex post* and *ex ante* regulations because they could affect the magnitude of the adjustments.

f. The acceptance of a fair return on capital employed is necessary. Returns in line with the risks involved should be the aim and should include full costs as well as a reasonable margin. Please also see the application of this concept under section 2.2.

g. Co-operation between generation, transmission, distribution and other divisions of the market participants are necessary to ensure achievable goals for the various divisions.

h. The formulation of the primary objectives of stakeholders aligned with ensuring a balance between the required capital investments (adequate capacity) and utilisation levels is attained.

i. Economic and technical efficiency is necessary to minimise prices and maximise both supply and service quality.

j. Competition as far as possible and justified is required.
k. Price discrimination should be justified.
l. Harmony in the ESI is necessary.
m. Disputes and complaints should be addressed promptly.

The above requirements imply that the acts of the Regulator should demonstrate *inter alia* the following attributes: Openness, transparency, aptness, informative, timeliness, efficiency, customer focus, fairness and equity, independence, honesty and integrity.

In the EPP implementation plan, which is defined in section 12, reference is made to several additional duties to be allocated to NERSA. This is likely to increase the work load of NERSA, which according to current indications, is already inappropriately staffed. There is consequently an urgent need for the appointment of suitably qualified staff with the necessary experience.

A committee that could make valuable contributions should consist of *inter alia* of representatives of DME, all other Public Service Departments related to electricity affairs, NERSA, Eskom, municipalities (to be replaced by REDs), pricing, customers, trade unions and outside consultants with expertise in pricing, technical, financial, legal and related disciplines.

Policy Position: 65

a) In view of the increasing workload expected at NERSA and the urgency to execute the EPP it is strongly recommended that a committee of experts be established to assist and advise regarding the implementation of the EPP. Inter alia the staffing requirements and other resource constraints of NERSA should be addressed.

12 IMPLEMENTATION PLAN

Table 2 below summarises the implementation plan for the EPP. It shows the main task description, responsible party and completion period for every policy position. There are a total 65 policy positions with most of the workload being shared by DME and NERSA. It must be highlighted that National Treasury also carry some responsibilities, especially in the areas of subsidies and funding support.

Table 2: EPP Implementation Plan

Policy	Task Description	Responsibility For Development And Oversight	Completion Period
1	Review various electricity policies to ensure coherent macro-economic energy policies.	DME	3 years. Ongoing thereafter.
2	Review and update Revenue Requirement methodology.	NERSA	Immediate implementation. Review every three years.
3	Tariffs to become cost reflective.	NERSA	5 years.
4	Achieve appropriate transparency and unbundling.	NERSA	3 years. Monitor thereafter.
5	Reach tariff non-discrimination.	NERSA	3 years. Monitor thereafter.
6	Allow full access to and use of networks and develop wheeling methodology.	NERSA	2 years.
7	Develop and approve special products and prices.	Licensees to develop, NERSA to approve.	Immediate. Ad hoc review and approval.
8	Develop and publish indicative long term price outlook.	NERSA with support from licensees.	1 year. Annually thereafter.
9	Generator Applicability: Apply policy. Develop any exclusion criteria.	DME to develop criteria, NERSA apply.	1 year. As required thereafter.

Policy	Task Description	Responsibility For Development And Oversight	Completion Period
10	Generator tariff structure: Apply policy.	NERSA	Immediate and ongoing.
11	Generator tariff level: Apply policy.	NERSA	Immediate and ongoing.
12	Develop renewable energy guideline and funding support mechanisms. Apply policy statements.	DME (with NERSA, National Treasury and other stakeholders) to develop guideline and mechanisms. NERSA to apply.	1 year. Update as required thereafter.
13	Wholesale energy tariff structure.	Licensees to implement, NERSA to approve.	Immediate with periodic review of tariff structure.
14	Wholesale energy tariff level.	Licensees to implement, NERSA to approve. NERSA to develop over/under recovery mechanism.	Immediate. Develop and implement over/under recovery mechanism in 2 years.
15	Negotiated Pricing Agreements.	DME to develop application and approval process. NERSA to update NPA framework. NERSA to determine cost estimates.	Process within 2 years. Update NPA framework in 2 years. Determine cost estimates within 1 year and annually thereafter.
16	International sales: Develop framework and implement policy.	NERSA to develop framework and implement policy.	Develop framework within 1 year. Immediate policy implementation.
17	Ancillary services and standby charges.	Licensees to implement and NERSA to oversee.	Immediate and ongoing.
18	Transmission tariff structure and connection policy development.	Licensees to implement tariff structure and develop connection policy and NERSA approve and oversee.	Develop policy within 2 years. Immediate and ongoing for tariff structure.
19	Transmission tariff levels.	Licensees to implement and NERSA approve and oversee.	Immediate and ongoing.
20	Charges to generators and customers.	Licensees to implement and NERSA approve and oversee.	Implementation within 1 year and ongoing thereafter.
21	Geographic differentiation	NERSA to evaluate geographic differentiation for customers and generators.	Generation -1 year. Customers – 3 years
22	Transmission charges for international customers.	Licensees to implement and NERSA approve and oversee.	Implementation within 1 year and ongoing thereafter.
23	Determine qualification criteria for wholesale purchases.	DME in consultation with NERSA.	1 year.
24	Distribution pricing: Cost of supply studies.	NERSA to develop and update COS standard. Licensed distributors to comply with standards.	Licensed distributors to comply within 2 years.
25	Refurbishment / maintenance backlog.	Licensees to implement and NERSA approve and oversee.	5 years.
26	NERSA to develop standards for non-technical losses and provision for bad debt.	NERSA	2 years.
27	Distribution customer categories.	Licensed distributors to comply with policy position and NERSA to ensure compliance.	5 years.
28	Distribution tariff components.	Licensed distributors to comply with policy position and NERSA to ensure compliance.	5 years.
29	Distribution tariff simplification.	Licensees to implement and NERSA approve and oversee.	3 years.
30	Distribution seasonality.	Licensees to implement and NERSA approve and oversee.	3 years.
31	Distribution tariff structure and level.	Licensees to implement and NERSA approve and oversee.	3 years.

Policy	Task Description	Responsibility For Development And Oversight	Completion Period
32	Cost-reflective versus pricing signal.	Licensees to apply and NERSA approve and oversee.	3 years.
33	Distribution TOU tariffs.	Licensees to apply and NERSA approve and oversee.	5 years.
34	Distribution TOU tariff structure.	Licensees to apply and NERSA approve and oversee.	5 years.
35	Distribution geographic price differentials.	Licensees to apply and NERSA approve and oversee.	5 years.
36	Eskom shall apply pooling of costs and base its tariffs on the proposed RED boundaries.	Eskom to implement and NERSA approve and oversee.	3 years.
37	A tariff plan for phased increases in tariffs at lower voltages and decrease of tariffs at higher voltages.	NERSA in consultation with distribution licensees.	5 years.
38	Domestic tariffs to become more cost reflective.	Licensees to apply and NERSA approve and oversee.	5 years.
39	Rationalise existing electricity distribution tariffs into a set of electricity tariff structures for the EDI.	NERSA in consultation with EDI. Holdings and other stakeholders.	3 years.
40	Investigate TOU life line tariffs.	NERSA	3 years.
41	Treatment of distribution network capital contributions.	Licensees to apply and NERSA approve and oversee.	Immediate and ongoing.
42	Develop standard for the determination of distribution capital contributions.	NERSA in consultation with EDI Holdings and other stakeholders.	2 years.
43	Public lighting.	Licensees to apply and NERSA approve and oversee.	Phase in over 2 years.
44	Distribution design standard.	Licensees to apply.	Immediate and ongoing.
45	Develop and implement an effective mechanism to ensure that quality customer services are provided by distributors.	NERSA in consultation with EDI Holdings and other stakeholders.	3 years.
46	Reseller charges.	Non-licensed re-sellers to implement and NERSA to ensure compliance.	1 year.
47	Cross-subsidy / MSOE.	Licensees to apply and NERSA approve and oversee.	2 years.
48	Achieve transparency of cross-subsidy / MSOE	Licensees to apply and NERSA approve and oversee.	2 years.
49	Future electrification capital subsidies.	DME in consultation with National Treasury.	2 years.
50	Ringfencing of and mechanism for past electrification capital debt.	Licensees to apply and NERSA approve and oversee.	2 years.
51	Low income customer tariff subsidisation.	Licensees to apply and NERSA approve and oversee.	To be phased in over 5 years.
52	Life line tariff level.	Licensees to apply and NERSA approve and oversee.	1 year.
53	Life line customer subsidy impact.	Licensees to apply and NERSA approve and oversee.	2 years.
54	Free basic electricity.	Licensees to apply and NERSA in consultation with DPLG to approve and oversee.	2 years.
55	State tariffs.	Licensees to apply and NERSA approve and oversee.	3 years.
56	Perform COS studies and investigate alternative subsidy mechanisms to address the challenges relating to farm network replacements.	Licensees to perform COS studies and DME investigate alternative mechanisms.	All within 2 years.

Policy	Task Description	Responsibility For Development And Oversight	Completion Period
57	Implementation of MSOE.	Licensees to apply and NERSA approve and oversee.	2 years.
58	Concurrent phasing in of MSOE and cost reflective tariffs for non-municipal customers.	Licensees to apply and NERSA approve and oversee.	3 years.
59	Consider viability assistance.	DME in consultation with National Treasury, DPLG and other stakeholders.	2 years.
60	DSM price signals.	Licensees to apply and NERSA approve and oversee.	5 years.
61	Cost of DSM.	Licensees to apply and NERSA approve and oversee.	2 years.
62	Implementation and funding of domestic DSM and AMR.	Licensees to apply and NERSA approve and oversee implementation. DME in consultation with National Treasury to investigate funding options.	3 years.
63	Implementation and approval of emergency measures.	Licensees to apply and NERSA approve and oversee.	1 year.
64	DSM and energy efficiency funding.	DME in consultation with National Treasury and other stakeholders.	2 years.
65	Establish a committee of experts to assist and advise regarding the implementation of the EPP.	DME	Immediate.

13 CONCLUSIONS

At this point in time it is essential that the proposed EPP should receive the highest possible priority. The ESI is faced with a number of important challenges as pointed out in this report. Although there are perhaps other burning issues to be addressed at this stage, the finalisation and implementation of the proposed EPP would make a very important contribution to the state of the industry. The EPP involves *inter alia* aspects of generation, transmission, distribution, cross-subsidies, DSM and regulatory matters.

South Africa needs to make substantial investments in the generation, transmission and distribution industries to meet the growing demand of an expanding economy. In addition it is recognised that certain infrastructure backlogs also need to be addressed to maintain and improve quality of supply and service delivery. Furthermore, it is anticipated that independent power producers and renewable energy projects will play a more prominent role in South Africa's future energy mix.

It is against this backdrop that it is important that the industry moves towards tariff levels that will sustain a viable industry. In addition, the EPP highlights the importance of non-discriminatory pricing practices as well as the need to promote pricing transparency and the unbundling of tariffs. These are essential requirements to attract investments and to unlock efficiencies.

The EPP has been formulated using a number of key assumptions and pricing interfaces, namely; generator prices, wholesale energy prices, transmission prices and distribution prices. The tariff structure at the wholesale level will consist of generation energy charges and transmission charges.

The EDI should apply cost reflective tariffs for properly defined customer categories within a short period of time. This has to be applied as per the proposed REDs boundaries. The tariffs need to be set according to the results from the COS studies which must be undertaken periodically and all possible type of costs should be shown transparently.

The underlying approach in the development of the various policy positions is to promote economic efficiency while providing scope for the introduction of approved and transparent subsidies and support mechanisms. To this effect the EPP defines a specific set of cross-subsidies which should remain in the ESI. These are clearly defined with the transparent mechanisms of how each should be treated to ensure that the needs of various customer categories are addressed and that proper decisions are made.

The need to increase the utilisation of the generation, transmission and distribution infrastructure and natural resources in the country should be addressed with the application of appropriate pricing strategies. These include the provision of pricing strategies to ensure the provision of DSM, energy efficiency, rationing and other strategies funded from a range of sources to mobilise resources optimally.

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15 ANNEXURE 1: ELECTRICITY PRICING RELATED POLICIES

No electricity pricing policy can operate in a vacuum and it should always be seen in terms of broader industry policies. There are various gaps in the present electricity supply policies. Many old policies need to be modified because of some National Government direction changes and because of new challenges facing the ESI. This section highlights some of the key policies that need to be formulated and be approved as soon as possible. If these are not addressed, some of the EPPs would not have the basis they require.

15.1 Single Buyer

- Where should it be housed? (Within or outside Eskom?)
- Should all PPAs be with the single buyer, or may bilaterals exist?
- How would the single buyer market function?
- How would the conflict be addressed when Eskom is the single buyer, purchasing from itself and competing IPPs?
- Who is eligible to buy from it?
- Are there minimum/maximum requirements?
- What about self-generation?
- What about the wheeling of power?
- What about current non-Eskom generators?
- How should it support renewable generation?
- Would distributors have to apply for future energy supply from the single buyer?
- Should new loads within the distributor be approved without availability being provided by the single buyer?
- Can a customer / licensee in SA import electricity, and if so, under what terms and regulations?

15.2 Rights / Obligation to supply

- Do licensed distributors have the obligation to supply electricity to customers within their areas of supply?
- Can municipalities cede their obligation to supply electricity in their areas of jurisdiction to a relevant, licensed electricity utility, which would then have an obligation to supply customers within its areas of supply?
- Do licensed distributors have the sole right to provide distribution networks in their area of supply?
- Since customers have the obligation to pay for the electricity services provided to them, should their supply be disconnected in the case of non-payment or illegal use?

15.3 Choice for Customers

- Should customers be given the choice to select the supplier of their energy and customer services?

- Should key customers be given the choice to select the supplier of their energy and customer services and what would the qualification criteria be?
- Would some plan for the phasing in of choice be developed?
- Should customers, collectively per site, who fall within complexes and or commercial / industrial centres, have the right to purchase their power from the owner of the complex / his agent or the licensed distributor?
- Would supplies such as traction and bulk water supply industries which are of national strategic importance qualify for a choice of energy supplier even if they consume more than 100 GWh from different points of supply?

15.4 National Integrated Resource Plan (NIRP)

- Should the single buyer be the custodian of the NIRP plan?
- Should not only one NIRP plan involving all key stakeholders be developed jointly to develop one NIRP plan for South Africa?

15.5 DSM / Energy Efficiency Programme

- Who is the best custodian of the DSM / energy efficiency fund to assist with the financing of DSM and energy efficiency projects in the ESI?
- Is Eskom able to act as impartial agent in managing the DSM / energy efficiency funds, considering its vested interest and own interest?
- What strategies should be put in place to ensure the fast-roll out of solar water heaters?
- What should be done to ensure that energy efficiency / DSM be solved with integrated solutions ensuring that optimal results are achieved with the available funds?
- Would rules be developed of best / worst practice in terms of energy generation and how would these be enforced?
- What should be done to ensure the rapid roll-out of energy efficient lighting and the recovery of old CFLs?
- Who would drive the development and implementation of appliance labelling and building efficiency grading?