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DEPARTMENT OF MINERAL RESOURCES AND ENERGY

NO. 1747 **10 February 2022**

PUBLICATION FOR COMMENTS
ELECTRICITY PRICING POLICY OF SOUTH AFRICA, 2008

I, Gwede Samson Mantashe, the Minister of Mineral Resources and Energy, having Cabinet approval, hereby publish the Review of Electricity Pricing Policy (EPP) of South Africa, 2008, for public comments. Interested and affected parties are hereby invited to submit written representations on the Review of Electricity Pricing Policy (EPP) of South Africa. The aforesaid representations must be marked for the attention of Mr Matthews Bantsijang and hand delivered, emailed or sent by post, within 30 days of publication of this notice to the following addresses; 70 Mentjies street Private Bag x59 Sunnyside or Arcadia/0001. Email address: epp@dmre.gov.za.

GWEDE MANTASHE, MP
Minister of Mineral Resources & Energy
10/02/2022

ELECTRICITY PRICING POLICY *REVIEW*

DATE: FEBRUARY 2022

Department of Minerals Resources and Energy

GENERAL EXPLANATORY NOTE

[ ] WORDS IN BOLD TYPE IN SQUARE BRACKETS INDICATE OMISSIONS FROM EXISTING ENACTMENTS.

______ WORDS UNDERLINED WITH A SOLID LINE INDICATE INSERTIONS IN EXISTING ENACTMENTS.

ABBREVIATIONS:

[AMR:]	**[Automatic Meter Reading]**
[CFL:]	**[Compact Fluorescent Light]**
[CDM]	**[Clean Development Mechanism]**
[COS:]	**[Cost of Supply]**
[DEPP]CPA	[Developmental Electricity Pricing Programme]Central Purchasing Agency
[DME]DMRE:	Department of **[Minerals]**Mineral Resources and Energy
DPE:	Department of Public Enterprises
[DPLG:]	**[Department of Local Government]**
[DUOS]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]TUoS:	Transmission Use of System
<u>WACC</u>	<u>Weighted average cost of capital</u>
WEPS:	Wholesale Electricity Pricing System
WP:	White Paper

DEFINITIONS:

<u>Ancillary services</u>	<u>Ancillary services include inter alia; the provision of operating reserves, frequency control, generator-islanding, black-start, constrained generation and reactive energy support.</u>
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.
Capacity charge	See definition of standby charge
Central purchasing agency (CPA)	The entity assigned to fulfil the role of the Single Buyer while allowing for a transition to a competitive market with consumer choice. The CPA remains the Buyer for legacy power purchase contracts and may purchase additional capacity and energy as required to maintain system integrity in a future competitive environment.
Codes	Any Code published by NERSA, as applicable
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]**A standard procedure for deriving and allocating approved revenue from end-customers for the **[design of tariffs].**purposes of arriving at the cost-reflective unit costs. This **[does not include determining the connection charge]** may also be referred to as the Cost of service study.
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 or within the ESI to recover

	legacy costs. (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.
[Distribution network/system	**[Technology/programme to encourage customers to modify patterns of electricity usage, including timing and level of consumption. This includes conservation, interruptibility and load shifting]** An electricity network with assets operated at a nominal voltage of 132kV or less.
Distribution charges	**[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]**The grouping of the use of the distribution system (*DUoS)* charges, retail and connection charge.
Distribution use of system (DUoS) charges	**[The grouping of]** Unbundled regulated tariffs charged by the distributor to the distribution network services customers for making capacity available and for use of the distribution system.
[Distribution use of system (DUOS) charges] Distributor	[Unbundled regulated tariffs charged by the distributor to]A licensee or its appointed representative who constructs, operates and maintains the distribution network**[services customers for making capacity available and for use of the distribution system**.,**]** and as defined in the Codes.
[Distributor]Embedded TUOS charges	**[A licensee or his/her appointed representative who constructs, operates and maintains the distribution network.]** The Transmission TUOS charge raised to customers connected to a Distribution network
Electricity distribution industry (EDI)	The distribution industry connected to supply voltage not exceeding 132kV.

Electricity supply industry (ESI)	Generation, transmission **[, wholesale]** including wholesale 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 to alleviate poverty.
Flexible distribution services.	Services aimed at modifying generation injection and/or consumption patterns in reaction to an external signal (price signal or activation) in order to provide a service within the energy system. The parameters used to characterise flexibility include the amount of power modulation, the duration, the rate of change, the response time, the location etc.
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 **[Cross border]** 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]Legacy costs/contracts	**[The deliberate over-recovery of revenue, more than 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]** Costs or contracts associated with **mandatory government]** energy procurement programmes and Eskom new build programme
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.
<u>Net-billing</u>	<u>Means a credit mechanism where the customer's generation is synchronised with the grid (grid tied), and at times, there may be export of energy.</u>
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.
Prosumers	A prosumer is **[an]**a customer who both consumes and produces electricity
Quality of supply	Technical parameters that describe the electricity supplied to customers according to standard **(NRS048]** NRS 048) and any other NERSA prescribed requirements.
Retail	The function related to the supply of electricity and network services
[Traders]Resellers	Entities that are registered to purchase electricity from licensed distributors and resell it to their 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.
Return on assets (ROA)	The return on assets is the actual amount of earnings by a company in a particular year, before deducting interest cost and tax charges, expressed as a percentage of the value of the total assets of the company. Given that the value of 'total assets' always equate to that of 'total capital' this can also be referred to as 'return on total capital.
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.
Small power tariff	A tariff for customers with a supply of 100kVA or less
Standby charges	A standby charge is an annual fee charged by the utility for providing backup power for a grid-connected supply
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 <u>and rates</u> covering different aspects of <u>electricity</u> supply, <u>price signals and cross subsidies</u> 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]<u>Transmission</u>	**[The buying or selling of electricity as a commercial activity]** <u>As defined in the Codes</u>
Transmission system	Power lines and substation equipment that operate at a nominal voltage of more than 132kV <u>and as defined in the Codes</u>.
Transmission use of system (TUOS) charges	Unbundled regulated tariffs charged for the use of the transmission system.
Transparency	The explicit reflection of all composite costs that constitute a tariff, for example: energy charges, demand charges, basic charges, levies, cross-subsidies <u>(receipt and contribution)</u> 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.
<u>Wheeling charges</u>	<u>Wheeling charges are the same as network/use of system charges</u>
<u>Weighted average cost</u>	<u>The WACC is the percentage cost of debt and the percentage cost of</u>

of capital (WACC)	equity, aggregated after weighting each cost in relation to the proportion that debt capital and equity capital constitute of total capital. It is the average cost of the total capital.

1 BACKGROUND

1.1 Present Structure of the Electricity Supply Industry (ESI)

The South African ESI is **[essentially]**rapidly transitioning from the historic vertically integrated model (with Eskom generating 96% (including 5% imports) of the**[current]**requirements**[, municipalities 1%])** toward an unbundled Eskom and [others 3% (inter alia Independent Power Producers (IPP)).]an environment with independent generators supplying customers and trading independent of the utility. Meanwhile 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.][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. This approach (of cost plus return on capital or assets) functions well under most circumstances. However, when there is a major discrepancy between existing asset values used for regulatory tariff setting and new asset values the existing tariff levels would create a potential funding shortfall when new assets are introduced. South Africa found itself in the situation in the mid-2000s brought about by many years of surplus capacity, with low levels of investments and highly depreciated assets, coupled with relatively high inflation that pushed up the cost of new assets.]**

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, environmental goals <u>and establishing a</u> **[market based market-based]** <u>environment</u>. This policy document seeks to obtain a balance between several competing objectives, inter alia: affordable electricity tariffs for the low-income consumers and cost reflective electricity tariffs for all the other consumers. 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] The** introduction of **[a proper]**the EPP is not meant to solve all challenges, but to guide NERSA andLicensees for a standardised approach to electricity pricing. 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]**Too many tariff structures being used.
b. No standardised approach for tariff development for determining revenue.
c. Funding and capacity shortages and backlog of investments.
d. **[High level of fragmentation in terms of investments, sharing of facilities, services and people development.]** Non-payment of bulk electricity services.
e. **[Lack of capacity to develop appropriate tariffs.]**
f. Networks are inadequately maintained, resulting in maintenance and refurbishment backlogs giving rise to high cost of interruptions.
g. **[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.][The electrification performance for various areas varies unacceptably]**Loss of revenue due to inadequate tariffs and tariff structure.
h. Lack of Competition in the energy sector and wheeling of energy.
i. Lack of transparency for tariff cross-subsidies, funding for cross-subsidies and a lack of an appropriate framework to guide the application of subsidies in tariff structures.
j. How trading of electricity in a future wholesale and market environment will be done.
k. The recovery of costs for flexible distribution services.

1.4 [**The provision of Free Basic Electricity (FBE) is slow and inconsistentthe 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**.**]** 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 because 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 several EPP matters, was in operation between 1993 and 1995. The next WP dealt with many EPP matters and appeared in 1998. This WP became inadequate mainly because 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]** ****frameworks between Eskom and the **[municipalities]** municipal licensees.

[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.]

Several 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. Promotion of Administrative Justice Act 3, 2000

e. Eskom Conversion Act of 2001.

f. Municipal Finance Management Act, 2003.

g. National Energy Regulation Act, 2004.

h. Electricity Regulation Act, 2006.

i. Municipal Fiscal Powers and Function Act, 2007.

j. Electricity Regulation Amendment Act, 2006

k. **[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]** Consumer Protection Act

l. New Generation Regulations

m. Public Procurement Bill

n. Amendment to Schedule 2 of ERA

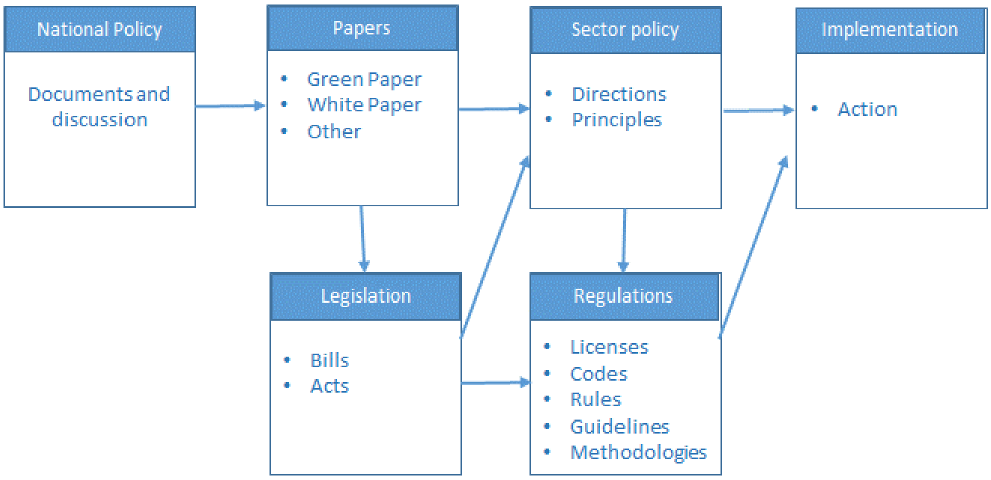
o. Court judgements

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 requirement to unbundling of Eskom, with this being a precursor to an independent system operator and the development of energy market, the electricity pricing environment is changing.

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]** direction. 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



The ESI is faced with several important changes and challenges as pointed out in this document. The emergence of viable 'partial self-generation' options which however are variable, intermitted and non-dispatchable thus requiring system/grid generation capacity to be maintained as back-up, changes the cost dynamics of the ESI in its entirety.

Failure to respond to this adequately will provide the temporary opportunity to some 'partially self-generating' consumers to avoid having to pay for their grid services and back up capacity, pushing such costs to consumers who are not 'partially self-generating'. This will ultimately and in short order make the entire ESI and grid unsustainable, to everyone's severe detriment including the original 'partial self-generating' consumers and to the entire economy of South Africa.

In addition, whereas the first version of the EPP was an excellent document, it has become evident that some of its key requirements were not implemented, possibly due to discretion allowed on such aspects and lack of monitoring on implementation. Therefore, the setting of more explicit and prescriptive requirements, the limitation of discretion regarding their application, and the introduction of monitoring and confirmation mechanisms to ensure compliance and implementation is required.

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

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.]

1.7 **[It is an important aspect to note that these proposals are to a very large extent largely 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.][**Plan of Electricity Pricing Policy Report

This first chapter covers the introductory part and a 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

- GENERAL PRICING PRINCIPLES
- PRICING INTERFACES
- GENERATOR PRICING
-]WHOLESALE PRICING

- Wholesale Energy [**Generators]**<u>Pricing</u>
- Transmission pricing

- INTERNATIONAL [**CROSS-BORDER]** <u>SALES</u>
- [SOUTH AFRICAN NEGOTIATED PRICING AGREEMENTS (NPAS**)**
-] DISTRIBUTION AND RETAIL PRICING
- **Error! Reference source not found.**
- [**REGULATION**
- CONCLUSION

2 BIBLIOGRAPHY]GENERAL PRICING PRINCIPLES

<u>2.1</u> 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 reasonable reflect the costs 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, considering subsidisation from sources other than the service concerned.
f. Provision may be made for the promotion of local economic development through special tariffs for categories of commercial and industrial users.
g. The economical, efficient, and effective use of resources, the recycling of waste and other appropriate environmental objectives must be encouraged.
h. The extent of subsidisation of tariffs for low income households and other categories of users should be fully disclosed.
i. 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 prudent and based on least-life cycle 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	Revenue recovery	Revenue from tariffs 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

Stakeholder	**Tariff Objectives**	**Description**
		usage of electricity.
	Cost reflective	A link between the **[price]**<u>prices</u> a user must pay <u>towards</u> 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.

<u>**2.2**</u> 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<u>, as well as to place South Africa in a favourable competitive position internationally regarding the access and price of electricity. At</u>

electricity prices that reflect prudent and efficient costs. 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. In the absence of a perfectly competitive market, the usual approach is to institute economic regulation, which is aimed at mimicking the competitive conditions to steer prices towards efficient levels. Therefore, if well implemented, economic regulation should lead to efficient prices.

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, which is also what the expected outcome would have been in the case of a perfectly competitive market.

The**[To the degree, that such]** outcome is uncertain or at risk to the investor to the certain degree, whether in the context of a perfectly competitive market of the context of economic regulation, the investor's required rate of return would increase. If such required rate of return is also uncertain or at risk, investors of capital (whether debt or equity) would be unlikely to invest at all, thus resulting in a lack of capacity to render the required product or service to the consumers.

Therefore, 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]** on capital. For reasons of practicality many economic regulators substitute 'capital' with 'assets' and given that in terms of corporate finance the value for 'total capital' is equal to that of 'assets' it makes no difference in outcome.

[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]

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[1]**[**For example a regulator may favour a steep increase in tariffs in one year or phased-in tariff increases which are phased over a number of years prior to the introduction of new assets. 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 preceding the introduction of new assets, it could result in excessive accounting profits. Whilst this may provide the opportunity for dividends which could be used for other than infrastructure [**investment purposes in the meantime , it might also imply an earlier increase in the price of electricity than strictly warranted by the cost and asset investments.]**

the chosen method, it is important that the regulated **[business]**electricity industry is able to attract reasonably priced finance in order to maintain, refurbish and grow its infrastructure and provide services reliably and 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, for example, Return on Assets (ROA) and Return on Equity (ROE), financial leverage (debt to equity) and debt service such as, interest coverage and coverage of total debt obligations).

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 (considering 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.

[**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.]In this regard, in order to assist with the application of such minimum criteria, this EPP in Appendix A sets out the requirements for key financial and credit metrics, as parameters within which economic regulation decisions must be made and against which such economic regulatory decisions would be measured.

Policy Position <u>1</u>

a) *The revenue requirement for a regulated licensee must be set at a level which covers the full cost of production, including a reasonable risk adjusted margin or return on appropriate asset values.*

b) *The regulator, after consultation with stakeholders, must adopt an asset valuation methodology that accurately reflects the replacement value of those assets such as to allow the electricity utility* ***[to obtain reasonably priced funding for investment; to meet Government defined economic growth.]****<u>be financially sustainable, meet its debt service obligations for the for the full tenor of the debt, and achieve stand-alone investment grade credit ratings;</u>*

c) *<u>This will enable the licensee to obtain reasonably priced funding for investment to facilitate the establishment of infrastructure; to meet Government defined economic growth at an efficient price of electricity; and</u>*

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

<u>2.3</u> Cost Reflectivity

All tariffs should become cost-reflective over the next <u>three</u>**[five]** years[subject to**]**, <u>except for</u> specific cross-subsidies as provided for in section **[8.23. 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.8.23.]

Policy Position 2

a)	*Electricity tariffs must reflect the efficient cost of rendering electricity services as accurately as practical;*
b)	*The average level of all the tariffs must be set to recover the approved revenue requirement;*
c)	*The tariff structures must be* ***[set]***<u>*unbundled as far as possible*</u> *to recover costs as follows:*
(i)	**[*The energy costs for a particular customer category.*]**<u>*The wholesale energy purchase price reflecting (i) the electricity generation infrastructure capacity costs for generation capacity required by the System Operator; and (ii) reflecting energy costs, with these two components reflecting the wholesale energy related purchase price;*</u>
(ii)	*The wholesale Transmission tariffs reflecting the Transmission network usage cost*
(iii)	<u>*The Distribution tariffs reflecting distribution network usage cost, and*</u>
(iv)	*Service* <u>*and administration tariffs reflecting service and administration*</u> *costs* ***[associated therewith].***

2.4 Transparency and Unbundling <u>on the bill</u>

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]**<u>ring fencing</u> 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]** on the bill 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 Position3

*The customer bill must comply with **[NRS047]** NRS 047.*

2.5 Non-Discrimination

There are currently several 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 4

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

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 to wheel power irrespective of the supplier of the power , 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].** Such access would not violate any financial, 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]** that 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 distribution and transmission assets to maximise the benefit to all users and not permit economic bypass.

Policy Position 5

a) *Fair and non-discriminatory access to and use of networks to all users of the relevant networks for all delivery of energy whether wheeling from a third-party supplier or the utility;*

b) *The full cost to operate and maintain the networks* ***[is]****shall be reflected in the****[various connection and]*** *use of system charges and, therefore, no additional charges, except for the cost of administration for wheeling of electricity (compared to directly supplied customers) will be levied****[unless the wheeling action introduces incremental costs.;]***

c) *Any incremental* ***[wheeling costs associated with a specific wheeling transaction*** *connection costs 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 legal, technical, safety and commercial requirements;

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

f) Southern African Power Pool (SAPP) rules would apply for the recovery of cost and payment of wheeling services for cross border transactions.

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/rebated to reduce consumption in **[critical]**very high demand periods, or where there are capacity constrained periods.

b. Critical peak pricing tariffs: **[TOU tariffs]** Tariffs are introduced with certain periods of very high prices when the system's reliability is threatened and lower tariffs in other periods.

c. Real-time pricing products: Rates are provided ahead of time (usually on an hourly or daily basis).

d. Short-term flexible products and services to meet supply and demand.

e. Green energy tariffs: Tariffs offered to customer to support green technologies in the energy market**[meet]**

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

Policy Position 6

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; and*
b) *NERSA needs to develop a framework that allows for quick turn-around for such tariff approvals required for short-term needs.*

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 cover two aspects namely the average national price of the entire value chain up to the point of sale to municipalities, as well as the average municipal price to each municipality's clients / consumers.

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 (all of its major sources inclusive of SOE-owned and independent/privately-owned), 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 7

NERSA, after consulting with stakeholders, should develop and publish annually a multi-year price path ***[on an annual basic.]****covering* ***[at least 310]*** *years forward.*

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 follow SADC protocols in the wheeling of power between neighbouring countries.

c. Licensed or registered generators and traders may (but are not obliged) sell electricity to: A transmission **[central purchasing agency]** or single buyer**[(e.g. Eskom)],** a licensee, a wholesale **[buyer]**or retail customer**[(e.g. RED), a retail buyer/customer],** a licensed or registered trader, or to self.

d. Wholesale electricity prices may consist of wholesale energy prices**[**, **transmission]** (determined either through a regulated wholesale tariff or on a wholesale competitive market), capacity prices, standby prices, legacy cost recovery, subsidy charges, and **[single buyer own cost**.**]**Transmission network charges.

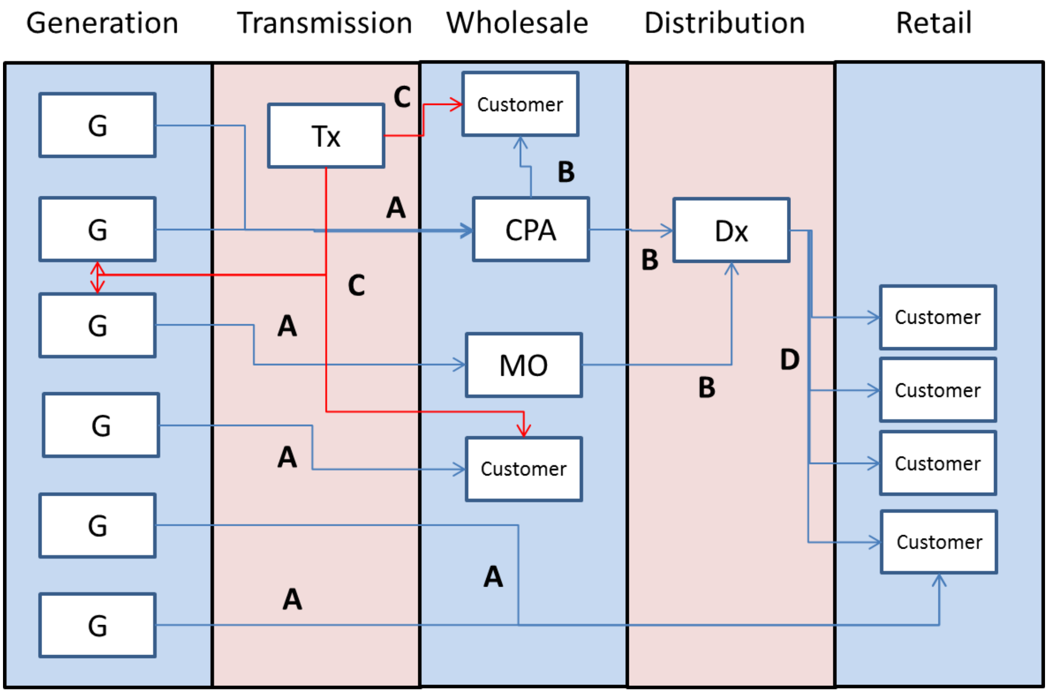
e. A competitive wholesale market is expected to be developed, comprising two key functions, specifically the Market Operator which operates the trading platforms between generators, retailers, customers and traders, takes no ownership of the energy traded; and the transmission**[Central Purchasing Agency]** that takes ownership of energy purchased through legacy contracts, and sells this energy downstream to wholesale customers.

f. Purchases by organs of state shall be subject to compliance to the New Generation Regulations.

g. Distributors, licensed traders and customers may also enter into bi-lateral or direct power purchase contacts.

h. Distributors will fulfil their regulated retail function associated with the purchase of energy from the wholesaler/market to their customers. Retail prices comprise the final regulated prices to retail customers.

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



Functions:
G: Generators (incl imports)
Tx: Transmission
CPA: Central Purchasing Agency
MO: Market Operator
Dx: Distribution

Interfaces:
A: Generator Pricing
B: Wholesale Pricing
C: Transmission Pricing
D: Distribution Pricing

4 GENERATOR PRICING

4.1.1 Applicability

This section is applicable to all licensed and registered generators (including renewable generators and co-generators) in South Africa as well as all licensed importers of electricity to South Africa **[that meet the dominant licensee threshold established**

above]. Imported electricity prices would also form part of regulated generator prices in South Africa. This is necessary as it could impact **[on affect]**<u> on he </u>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.
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.

[To the degree that operating market models and platforms have not been established or are still in the process of being established, this section will be applicable to licensees similar to the case of a deemed dominant licensee, until formal implementation of such market models and platforms and formal migration of licensees thereto.]

Policy Position <u>8</u>

a) Electricity <u>sold by</u> licensed <u>or registered</u> 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 DMRE (e.g. private generators producing electricity for own use on the same site).

<u>4.2</u> <u>Generation</u> Tariff Structure

Pricing structures for electricity purchases from generators would reflect the underlying cost structure<u> behaviour and dynamics</u>. Alternatively, <u>or in combination where</u>

appropriate, 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 can provide certain ancillary services at a lower cost than generators. It is, therefore, essential that customers **[are]**be 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.

Pricing structures may include various incentive mechanisms on both the supplier as well as customer, applicable to aspects within such party's control. For aspects outside of the control of the supplier, the pricing structures should include the cost of hedging or insuring against such risks, or incorporate appropriate pricing adjustment mechanisms to mitigate the risk to the supplier; alternatively, the supplier's return on capital and thus price should be appropriately increased to reflect such increased risk.

Policy Position 9

a) Generating pricing structures must reflect the cost of supply of the generator or alternatively any approved PPA;
b) [Generator]The 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; and
d) Generator pricing structures must not hinder efficient and least-cost dispatch of the generating units.

4.3 Generation Tariff Level

[Electricity]Prices for electricity purchases from existing generators should be based on**[either]**the conditions either 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, efficient and prudent operator.

[Electricity]Prices for electricity purchases from new supply options should be evaluated against an appropriate reference **[This reference],** which 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 reserve margin or capacity adequacy, risk of unserved energy or load shedding, etc..

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]**To the degree that competing projects will result in the **[design]**same avoided system cost, the projects should be assessed against each other based on the discounted present value of the **[single buyer]**total life cycle cost i.e. the least cost approach, or on the least levelised cost / kWh where appropriate.

Policy Position 10

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

b) *Electricity purchases from new supply options must be evaluated and approved subject to ex ante approval of the power purchase agreements; and*

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

5 **[Renewable]**WHOLESALE PRICING

Wholesale pricing comprises wholesale energy and capacity charges, transmission charges, and the single buyer own cost charges. A detailed discussion of the wholesale energy and transmission pricing characteristics is provided in this section 5.

5.1 Wholesale Energy **[Generators]**Pricing

The wholesale market in the future will include competitive elements (with dynamic market prices as well as long- and short-term hedging contracts), physical bilateral contracts between generators and consumers, and legacy long-term PPAs.

The wholesale tariff structures should reflect a need for capacity charges raised on all customers. Generation capacity is created for purposes of capacity adequacy, system security, reserves, etc whether it is used or not at certain times and with more customers being allowed to privately purchase energy, the cost of providing this back-up needs to be covered. Otherwise, this creates cross-subsidies to those with private generation.

Initially before a fully-fledged market is in place, the proposed structure therefore needs to include an energy rate applied as a time-of-use differentiated variable c/kWh charge and an energy related capacity rate R/kW applied as a demand charge. To the degree that operating market models and platforms have not been established or are still in the process of being established the wholesale pricing will effectively be hedged back to the regulated pricing approach as discussed under section 4.1 above, until formal implementation of such market models and platforms and formal migration of licensees thereto.

[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.]

Policy Position: 11

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

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

c) *Renewable power can be traded by the single buyer, 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.*

[The DME will develop a renewable energy guideline to support the introduction of renewable energy.]

5.1.1 **[policy proposals on environmental support for electricity generators must be done by DME after consultation with DEAT and other relevant stakeholders.*]*[WHOLESALE ENERGY PRICING][Applicability]**

[This would be similar as for wholesale pricing. Please refer to section 6.1 for a detailed description in this regard.][]<u>The applicability would be to all customers eligible to participate in the wholesale energy market.</u>

5.1.2 <u>Wholesale Energy Pricing</u> Structure

Wholesale electricity pricing structures always need to encourage the efficient use of electricity. 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.]** <u>as well as standby / capacity charges applied as a demand charge.</u>

[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 underutilised (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.

The wholesale tariff structure needs to reflect the true costs in the supply chain and highlight different products and services arising from changes in the industry. Given the fixed and variable costs of generators, some stakeholders believe that generators' costs should be recovered through a combination of capacity charges (R/kVA) and energy charges (c/kWh). Against this background there is merit pointing out issues relating to between fixed and variable charges, especially at the wholesale level.

A customer’s energy demand charge may not be an accurate reflection of costs imposed on generators, considering that the customer’s peak demand and the system peak may not occur at the same time. However, given the growth in variable energy resources, the requirement for back-up capacity is not related to the demand peak, as may have been the case historically.

Where a customer’s peak demand is not strongly correlated with other customers this reduces the burden on the system from a total capacity point of view but allows that the capacity costs (incurred by the Central Purchasing Agency in ensuring back-up capacity on the network) can be dispersed among all consumers and reduces the absolute capacity required for backup. A stand-by/capacity demand charge could result in high costs for low load factor customers, which might be unpopular, but indicates the true cost of required back-up on all consumers. Refer also to section 5.3.2 for further rationale.

It will also function as an incentive on low-load-factor customers to either change their demand patterns or to install own battery or other storage or peak-shifting systems, which, if it comes at a lower cost than the system cost of establishing additional peak capacity, will imply overall net gain to the South African economy.

Policy Position 11

a) **[*Wholesale energy prices must encourage*]** *The wholesale energy price structure shall include a wholesale energy tariff which encourages the efficient use of electricity at all times and must reflect the TOU structure differentiated cost of supply/pricing signal;*

b) *The wholesale energy price structure shall also include a capacity / standby charge to signal the capital-related costs for generation capacity applied to all customers as a demand related (R/kW) charge;*

c) *The wholesale energy price structure shall include a regulated legacy recovery charge and a subsidy charge to ensure recovery of legacy costs and subsidies as approved by NERSA (to be included in the Transmission charges structure); and*

d) *The wholesale energy tariff structure must be periodically reviewed and updated by the* ***[single buyer]*** *central purchasing agency and approved by NERSA, considering its impact and implementation on customers.*

A Central Purchasing Agency (CPA) will hold the legacy PPAs (with the Renewable Energy IPP Programme as well as other IPP programmes). The CPA must sell this energy through the competitive market or the wholesale energy tariff.

A legacy deficit is likely to arise as the future competitive market prices will be less than the legacy PPA costs. This deficit may be managed through a separated recovery charge to ensure that customers exercising choice of supplier (via the competitive markets or self-supply) continue to contribute to these legacy costs. This could be levied as a demand charge or fixed charge associated with the Transmission network charges.

<u>There are inherent tariff cross-subsidies prevalent at a wholesale level between different retailers and direct customers. If these tariff cross-subsidies continue to be funded through electricity tariffs, then a mechanism will have to be developed to ensure consumers of energy are not able to avoid contribution to these charges. The recovery would be recovered through a charge raised at the Transmission network level, as either a fixed charge or a demand related charge. Revenues collected through these charges will accrue to a national subsidy fund to be managed by NERSA.</u>

5.1.3 <u>Wholesale Energy Price</u> 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]**<u>similar to</u> generator pricing structures **[(combination of capacity, energy and ancillary services),]**there **[will]**<u>should</u> be <u>minimal</u> 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.]**<u> The application of legacy charges to manage legacy PPAs could result in differences between revenue earned and costs paid to these generators.</u>

These differences should be addressed through over/under recovery mechanisms as part of the regulatory methodology for wholesale energy purchases and sales. <u>The over/under recovery mechanism should ideally be dynamic and respond timeously to changes in the legacy differences (and avoid significant cash flow issues for the Central Purchasing Agency).</u>

Policy Position 12

a) *Wholesale energy prices must* **[*cover*]**<u>*align with*</u> *the cost of wholesale purchases, including capacity, energy and ancillary services* <u>*and as far as possible provide the correct signals for different products and services at the wholesale level; and*</u>

b) **[*Wholesale energy prices must consist of the generator prices, plus the single buyer own costs*.]** *NERSA must develop* **[an]**<u>*a dynamic and timeous*</u> *over/under* *recovery mechanism to deal with mismatches between* **[*wholesale*]**<u>*legacy*</u> *energy purchases and sales.*

<u>5.2</u> 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.

c) 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<u>*costs*</u> *and structured in a way to minimise deviations from standard prices* <u>*revenues*</u>*.*

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 patterns. 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: 14

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

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

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

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

(i) The cost of supply for NPAs intended for the sale and consumption of electricity in South Africa must be defined by the electricity price forecast which will be based on the prevailing regulatory methodologies in South Africa inclusive of an appropriate risk premium.

e) DME 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.

5.3 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: 15

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 receive subsidies intended for South African customers.

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

d) International contracts will be subject to South African energy conservation legislation, regulations and rules.

5.3.1 Ancillary services and charges **[/ standby charges]**

Ancillary charges are for services supplied to the National Transmission Company by generators, distributors or end-use customers, necessary for the reliable and secure transport of power from generators to distributors and other customers. In future, there may be a significant number of parties participating in providing these services across the value chain in an ancillary service market.

Ancillary Services are as defined in the Grid Code and includes services provided by demand response and generators. Ancillary services include inter alia; the provision of operating reserves, frequency control, generator-islanding, black-start, constrained generation and reactive energy support.

Ancillary services costs include demand response, other dispatchable and non-dispatchable resources on the demand side. Ancillary Services are as defined in the Grid Code and includes services provided by demand response and generators.

The costs associated with ancillary services provided by network service providers would be recovered via network charges, and the ring-fenced cost incurred by the System Operator to operate the system would be recovered through Ancillary Services charges. Ancillary service charges should ideally be fixed charges based on capacity to ensure that all customers fairly contribute towards the costs of providing these services.

With more private generation being permitted, in addition to ancillary services, there is a need to raise standby charges for the back-up capacity required. This is dealt with further in sections 5.1.2 and 5.3.2.

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 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.

Policy Position 13

a) ***[Unless the above situation changes it would probably not be economical to unbundle the]*** *cost of ancillary services* ***[to wholesale energy customers.]****provided by Transmission network operator must form part of the Transmission network charge;*

b) *The System Operator is to ring fence its costs and the cost of operating the system which is to be recovered by ancillary service-related charges and such charges may be based on consumption and/or on capacity; and*

c) *The recovery mechanism for ancillary services should allow for the faster recovery of over-and-under expenditure relating to regulatory approved tariffs.*

5.3.2 Standby/capacity charges

A standby charge is **[a special form of ancillary charge. This charge is intended]** applicable to recover **[the cost (including generation, transmission and distribution]**capacity costs associated with providing backup power when the customer's generator is out of service. As such, the standby charge functions as an insurance premium, which enables the customer to avoid incurring the cost of own back-up capacity.

The question arises as to whether a separate standby charge should be introduced in South Africa. **[In a way the]** The standby charge components for network costs (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 capacity-related 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]** It should be noted that standby or backup generator capacity is also 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)]**However in a situation such as this there is the certainty that over a period e.g. annual cycle, such a customer who does not have own generation capacity would consume sufficient volume of electricity to cover the fixed capacity costs applicable to that customer's load factor and profile (assuming that capacity charges are recovered through volumetric tariffs).

[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 5.1.2.] [Unless the above description is no longer true 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]This situation therefore, if different for a customer who has a generator that does not produce electricity on a consistent basis and, there is no long term intention or certainty that such self-generating customer (or wheeling customer) would consume a sufficient volume of electricity to cover the fixed capacity costs applicable to that customer's load factor and profile.

For this latter type of 'self-generating' customer, it could be compared to an insurance policy with hourly premiums that only requires the normal hourly premium to be paid for the hour during which a claim is registered. Clearly that will be unacceptable – such customer will be required to pay a premium for all hours for which risk coverage is received. In contrast, the 'non-self-generating' customer with a similar frequency of load fluctuation for his switchable block-load will be paying for the coverage by virtue of his high volume of consumption, given that the 'premium' is embedded in the volumetric consumption charge.

It is thus proposed that a generation standby charge be applied to all customers at the wholesale level (and consequently carried through to retail customers) to ensure sufficient dispatchable capacity on the South African grid to meet customer demand.

Policy Position 14

a) ***[The cost of ancillary services must form part of the wholesale prices.]*** *The cost of providing generator standby services to all customers (including customers with own generators) must form part of the wholesale prices; and*

b) *The costs of system balancing shall, to a reasonable extent, be borne by those causing the imbalance. However, a balancing charge may be applied as part of ancillary services charges to cover for any shortfall.*

5.4 Transmission pricing

[TRANSMISSION PRICING] [Applicability][This would be similar as for wholesale pricing. Please refer to section 6.1 for a detailed description in this regard.]Transmission pricing is applicable to **[licensees]** licensees, registrants and customers who qualify to wheel energy through the transmission system.

5.4.1 Transmission Tariff Structure and Connection Charges

To encourage cost reflective pricing **[it is recommended that] transmission charges must be unbundled. These charges would typically consist of]** to reflect Transmission Use of System **[Charges (TUOS), line loss charges**,**]**(TUoS) costs, cost of losses, administration and service **[charges]**costs and where applicable connection costs. These charges will apply to generators and loads but may be different.

The charges will comprise:

- connection charges **[If needed special;]**
- use of system charges based on annual capacity and transmission zones (in R/kVA or R/kW);
- ancillary service charges (in R/kVA or R/kW or c/kWh);
- line losses (in c/kWh);
- service and administration charges in R/POD or R/account);
- charge for the recovery of national subsidies and/or other legacy costs (in R/kVA or c/kWh); and
- if required additional charges may be introduced to better reflect the cost of supply, such as **[reliability charges]** reactive energy charges**[and,]** congestion charges, etc.

Connection charges need to be fair and must be calculated in accordance with **[a policy to be developed. The basic features of such a policy]** the principles and rules set out in the relevant sections in the Code. The connection charges principles should **[include]**be aligned to the following:

a. **[The licensee should clearly and transparently define the**] The basis on which connection charges **[would be]**are calculated by the licensee should be clear and transparent

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.]**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]**are shared. This is to prevent “second comers / free riders” from benefiting once the “first user” has paid for the system.

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

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

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

More specific policy guidance is provided in respect of charges to generators (refer to section 5.4.3) as well as the geographic differentiation of transmission charges (refer to section 6.5).

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 3: Transmission Cost Allocation between different Generators and between different Customers]

Policy Position: 17

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

b) ***[Connection charges must be fair and calculated in accordance to a standard to be approved by NERSA.]****The transmission tariff structure must reflect the overall cost of supply and could consist of a combination of capacity, energy loss factors, ancillary services and* ***[fixed]****service and administration charges, etc;*

c) *Connection charges must be fair and calculated in accordance the Code;*

d) *No customer connecting to the Transmission system shall be permitted to avoid contribution to approved cross-subsidies or legacy costs unless allowed by NERSA; and*

e) *The calculation of charges for the unbundled services should be in line with the principles set out in the Codes to ensure fairness and transparency in the way transmission charges are calculated.*

5.4.2 Transmission 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:

- **[an]**the approved **[grid code]** Codes;
- an approved cross-subsidy framework; and
- **[other]**regulatory rules and other regulatory requirements.

Policy Position 15

a) *The transmission tariffs need to be set at a level that must allow the licensee to earn its approved revenue requirement; and*

b) *Tariff levels must be determined in accordance with approved standards, codes, frameworks and other regulatory requirements.*

5.4.3 Transmission Investment for New Capacity, Refurbishment and Maintenance

The Transmission network service provider's revenue determination should be set at a level that provides adequate recovery to meet its investment obligations in terms of the Transmission Development Plan, refurbishment and maintenance.

Policy Position 16

a) *Transmission must undertake the required analyses to determine the extent of investment and resources required to provide new capacity, refurbishment and maintenance;*

b) *NERSA must give due cognisance to requests for funding to be recovered in tariffs to provide for the above requirement.*

5.4.4 Transmission Charges to Generators and Customers **[Loads]**

[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] Electricity is characterised by significant transport (transmission and distribution) costs. The location of generation relative to the location of consumption within an electricity grid influence the costs of supplying customers. The costs of electricity transmission fall into two categories:

- **Infrastructure and operating costs:** Infrastructure costs include power lines, cables, transformers, and other equipment. Operating costs include the cost of building and maintaining these assets.

- **Short-Run Marginal Costs:**
  - **Losses costs:** The transportation of electricity along transmission lines results in electrical energy losses. This lost energy must be replaced, at a cost, by increasing total generation output.
  - **Constraint costs:** When transmission capacity is not available to accommodate power flows, instead of transporting power from one area to another, expensive generators that would not be dispatched in an uncongested system have to be dispatched to ensure supply exactly equals demand in all areas.

The mechanisms used to allocate these transport costs to generators can materially affect the value of a generator and the value of its output. The mechanism can also affect generators' locational decisions. Signalling electricity transport costs to generators **[share in the cost of transmission or not. Consequently]** through energy and/or infrastructure prices can give them an incentive to make an efficient trade-off between all the factors that vary by location. For example:

- The choice where to locate wind farms entails a trade-off between regional variation in wind speeds and the costs they **[hold the view that it does not add any value to first allocate some]impose on the transmission [costs to the]**system.
- The choice where to locate gas-fired generators **[if, in turn, the generators increase their energy]** entails a trade-off between regional variation in gas and electricity transmission system costs.
- The signals conveyed to investors through the charges **[to offset the additional costs. They conclude]**that**[all transmission costs should]recover the costs of infrastructure, constraints and losses, therefore[be recovered directly from the customer through]** provide a means of ensuring that generation investors make a least cost trade-off between their own generation costs and the transmission costs that their presence imposes on the system, and hence promotes economic efficiency.

[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]<u>A reasoning</u> that<u> only</u> consumers should pay **[directly]**for **[all]**<u>Transmission</u> costs based on the assumption that **[it is]**only<u> load</u> customers**[who]** need the transmission network**[and should pay for it. This**], is of course not**[the case because the]**<u>correct. The</u> location of a generator <u>also</u> has a **[similar] influence** on the cost of transmission**[** as**]**<u>, similar to </u>the location of the **[customer. In fact, if]**<u> load. This</u> 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] will**<u> be driven by access to the grid, access to fuel and renewable energy sources.</u>

<u>Due to the reasons often linked to</u> fuel cost, economies of scale and **[other reasons]**<u>others,</u> generators are rarely located in the near vicinity of their customers<u>, but closer to or in areas where it is cost effective to produce power. This implies that the Transmission Company should build network to transmit the generated power to areas where it is required.</u>

<u>The costs of operating and maintaining the network as well as the portion of capital costs not recovered directly from the generators (that is, socialised) will need to be recovered based on accepted principles. Without locational signals, the cost of socialising means that all pay the same and generators causing the costs are not exposed to the correct pricing signal, as they may choose to locations that are more suitable for themselves and less suitable for the Transmission Company or country. Therefore, the costs should equally be allocated to the generators and include locational signals.</u>

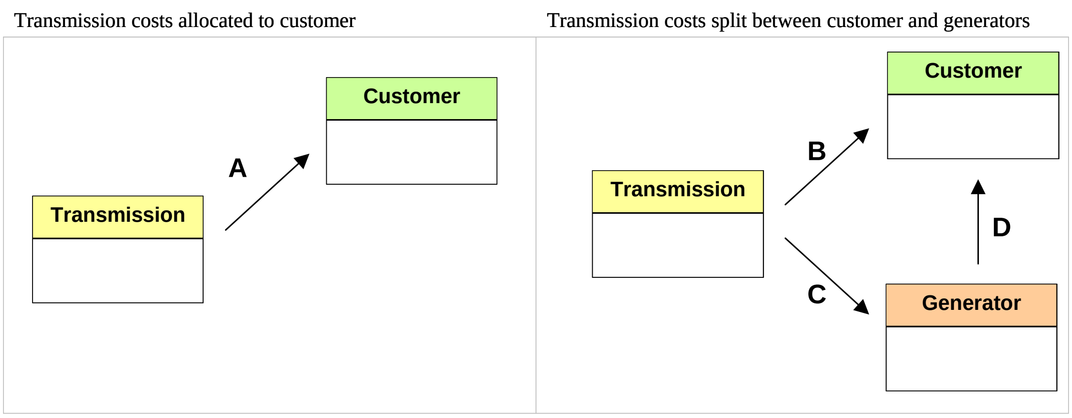
The implications, if customer **[load]** customers pay for all transmission costs, are that:

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 between energy and demand charges. **[The reason for this is that all generator costs (including any]**For generators selling energy to the wholesaler, the transmission **[costs)]**network charges are **[converted into TOU]**a pass-through and added to the energy charges as described under wholesale energy pricing (see section**[5.1.2)]**5.1.2). If generators do not pay transmission network charges all the transmission costs will be recovered from load customers through demand (kVA) charges. In other words, whether generators pay for transmission costs or not affect whether load customers pay for transmission through a combination of energy or demand charges or through demand charges only. 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.

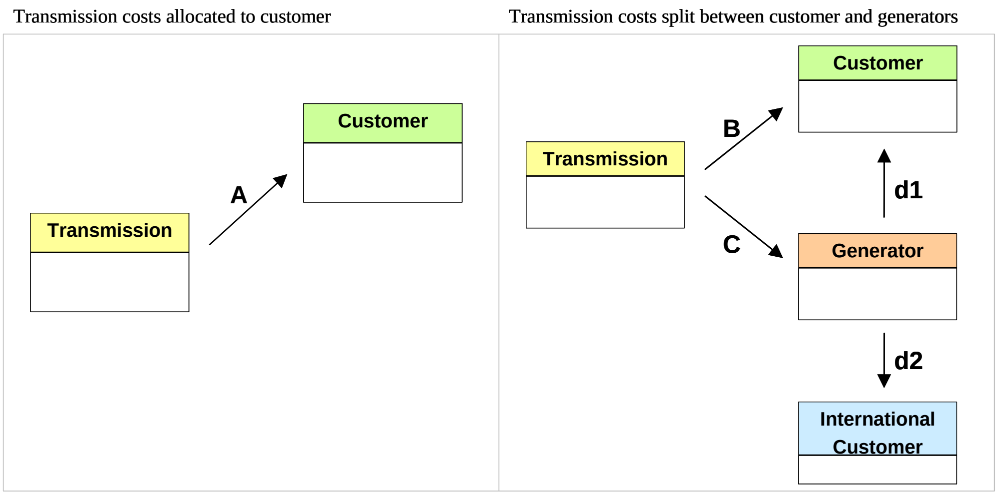
Figure4: Illustration of Cost Split between Customers and Generators



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

The deviation from cost-reflective tariffs and the 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 [**5**]**See Figure [5 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 [**5.**]**Figure [5. 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 [5: 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 if 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 Position17

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

b) *<u>The transmission tariff structure will be based on a zonal pricing methodology;</u>*

c) *Transmission losses costs will be allocated directly to loads <u>and generators</u>;*

d) *Transmission service and other costs must be allocated rationally between loads and generators and must reflect the cost to provide the service<u>; and</u>*

e) *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.*

5.4.5 <u>Transmission Charges</u> Geographic Differentiation

[Transmission network access and losses]<u> The TUoS</u> charges **[to customers]** for both generators and loads are**[currently differentiated into four]**<u>based on</u> zones. The <u>zones loads are based</u> geographic **[differentiation of transmission network charges has been] and** 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.

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]** <u>for</u> **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]**<u>considers both geographical location and electrical proximity of the</u> 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**.**]**<u>to loads. These are explained as follows</u>:

[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 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.] [Figure 6: Transmission Cost Allocation between different Generators and between different Customers]

a) Load Zones

The TUoS tariffs for loads are based on a concentric-pricing approach. The charge is geographically differentiated in four zones based on the distance of the location of the load from Johannesburg, measured in kilometres. This differentiation methodology is arbitrary and results in non-cost-reflective charges.

It is generally argued in the industry that the different approaches for determining charges for generators and loads create artificial arbitrage opportunities and economic discrepancies that are difficult to explain. It is recommended that the approaches be harmonised in the medium to longer term.

b) Generator Zones

TUoS tariffs for generators are derived from load-flow simulations on the Transmission system as it is planned to be in operation. Generation units are dispatched in proportion to their installed capacity to match peak demand. The cost of the Transmission asset is allocated to generators based on the proportional installed capacity and contributions to power flows for the different Transmission assets. The current charging methodology only recognises peak security as a driver of Transmission charging.

The integration of renewable generation brings fundamental challenges in Transmission planning and charging. The current Transmission pricing methodology does not appropriately reflect the costs imposed by different types of generators (in particular, renewable generators) on the electricity Transmission network.

The charging methodology only recognises peak security as a driver of network usage and assumes that all types of generation within an area of the network (a generation charging zone) contribute equally to network use. In doing so, it overlooks the fact that some generators use the Transmission system more during the peak hours and some less. Under the current methodology, all types of generators are assumed to provide peak security. The additional advantage will be to dampen fluctuations that would otherwise be observed.

Policy Position18

a) *The current transmission geographic differentials for customers l must remain until they are updated by an approved redefinition of geographic differentials;*

b) *The transmission licence holder, **[DME]**DMRE 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; and*

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

5.4.6 Transmission Charges for International **[Cross Border]** 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, connection charges and principles should apply to international customers connected to the transmission system.

Policy Position 19

a) *International SAPP operating members connected to the transmission network will pay the regulated transmission tariffs.*

b) *International Use of system charges will be the regulated Transmission charges determined in accordance with this Section 5.4;*

c) *Cross border customers will be required to pay connection charges in accordance with the Code and connection charge policy. Where there are deviations that are warranted, they should be approved by NERSA;*

d) *Import will be treated as a generators and export as a load for tariff purposes; and*

e) *The financing of connection assets for international***[***cross-border***]** *customers will be in accordance with the* ***[connection charge policy]****Codes and where there are deviations that are warranted, they should be approved by NERSA.*

f) *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.*

6 WHOLESALE PRICING

6.1 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 electricity traders 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.

7 INTERNATIONAL **[CROSS-BORDER]** 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. The relevant licences granted by NERSA will enable cross-border trade. All cross border trades will be in terms of the South African Grid code and Distribution codes in the first instance and Southern African Power Pool (SAPP) rules or any other African Power Pool (as the case may be in future) in the second instance

[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]. Cross borders customers must not pay or receive subsidies intended for South African customers.

Policy Position20

a) ***[NERSA must develop and implement a framework for the pricing of international sales contracts]*** *Cross border customers must not receive subsidies intended for South African customers;*

b) ***[International customers connected to the transmission system must not receive subsidies intended for South African customers]***. *South African customers must not subsidise the export of electricity; and*

c) *International contracts will be subject to South African energy conservation and load curtailment legislation, regulations and/ or rules.*

[SOUTH AFRICAN NEGOTIATED PRICING AGREEMENTS (NPAS)][NPAs may be applied to South African customers and cross-border customers. All cross-border agreements are negotiated and are therefore in their nature NPAs. These agreements will be in terms of the principles provided for in paragraph.] [NPAs are

not necessarily designed not to obtain a reduced electricity price but to obtain long term price certainty. NPAs are permitted and refer to any price agreement that may deviate from approved standard tariff levels and structures whether it applies over a short term or a multi-year period. NPAs are required to address country competitiveness to ensure the sustainability and growth of industry in South Africa through electricity price certainty. NPAs can be for both established industries, both operational and idle capacity, and new investments in industry in the country. NPAs can also be for established or new industry located cross border to ensure the sustainability and growth of industry in SADC.][NPAs should focus on sectors that are energy-intensive (electricity usage) and sustaining them makes the most benefit to the stability of the ESI; in that having such an industry helps dilute the electricity costs for the rest of the customer base (high load factor) and assists the System Operator with managing the power system (interruptability and demand response). NPAs may also incorporate and reflect that the true net system cost to supply a particular customer might be less than what the normal tariff products would be able to reflect.]

[should be structured in a way to minimise deviations from standard prices and must take cognisance of the long-term viability of both the ESI and the specific sector. NPAs at inception must not be below the true cost of supply to such customers and should include an appropriate risk premium. NPAs may have fixed increases to provide escalation certainty and should then include an appropriate real adjustment to mitigate against the risk of the costs and the price diverging over time. NPAs may grant reprieve on subsidies, levies and taxes.][Any NPA (incentive price) is approved in the country's interest, as such, for the sustainability of the ESI any revenue shortfall or excess to the licensee can be recovered through the applicable regulatory process. A commodity and currency linked electricity price is permitted, however where appropriate, hedging mechanisms should be put in place with parties outside of the ESI.]

Policy Position 21

h) DMRE must provide NPA framework/s and updates as appropriate and NERSA will approve and monitor NPAs in accordance with these framework/s;

i) *Revenue shortfall or excess to the licensee resulting from NPAs can be recovered through the applicable regulatory process through approved subsidies as provided for under Section 8.23, or through external funding provided to the licensee;*

j) *The above framework will have to prescribe how this will be funded and if through tariffs, which Licensee will be responsible for managing the funding, whether at wholesale or retail level;*

k) *Existing NPAs will be honoured until the end of contract;*

l) *South African customers will not cross-subsidise cross border NPAs; and.*

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

8 **[DME in consultation with NERSA must determine qualification criteria for wholesale traders and NERSA determine implementation guidelines] [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 5.4.]** DISTRIBUTION <u>AND RETAIL</u> PRICING

[The]<u>Distribution Pricing includes components of both retail and network services. For some customers, distributors would act as the retailer for the purchase of power and for others, they may purchase directly from the wholesaler, the market or through wheeling. For both scenarios, distributors would be providing network services and some form of administration.</u>

<u>However, the</u> 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]**<u>is disjointed with no clear framework on tariff structures, resulting is a multitude</u> in **[many respects these are too vague]**<u> retail tariff variants. Bundled tariffs make it difficult</u> to **[really assist the industry]**<u> separate out the different services being provided</u> and to **[move forward]**<u>transparently show cross-subsidies. Tariffs between Eskom and other distributors are also regulated differently by NERSA.</u> Therefore, **[the**

proposed EPP would give specific] NERSA must develop a framework aligned to the principles set out in this policy document, to which licensees must be required to comply.

Policy Position 22

NERSA shall develop a national tariff framework to guide how tariffs are structured while recognising need for innovation in development and the approval of updates to tariff structures.

8.1 Tariff Level and Structure

This first section will address the key principle for distribution pricing, namely that tariffs **[would]**should be designed from cost reflective principles and are in support of cost reflectivity and transparency. Cost-reflectivity includes the tariff level and the tariff structure. Provision **[is]**can, however, made for deviations from cost and these are covered under the **[sections]**section on cross-subsidies**[and Demand Side Management DSM / energy efficiency]**in Section 8.23.

The tariff level is that revenue sufficient for a Licensee to recover its costs plus a fair return, whereas the structure is where the allowed revenue is broken up into different types of charges and recovered through these charges.

For all Distributor's their costs should be based on an appropriate methodology that treats all Distributors the same and should not be based on historic benchmarks, but a uniform regulatory method that fairly considers an acceptable level for returns on assets. A cost-of supply (COS) study should not be used to justify costs, but to allocate costs based on approved revenue.

Policy Position23

a) *Tariff levels shall recover the NERSA allowable revenues / revenue requirements per financial year;*

b) *Tariff structures shall reflect the NERSA allowed revenues in terms of the cost structure and components of the allowable revenues determined in terms of the principles set out in the EPP; and*

c) *NERSA shall develop a consistent regulatory method for the approval of revenues for all Distributors*

8.2 Cost of Supply Studies

[The industry's Cost]A cost of**[Supply (COS]**supply (CoS) methodology **[and some models]**(also referred to **[calculate these]**as a Cost-to-serve study[2]) is needed to understand costs**[have existed]**for **[more than ten years. It has nevertheless only been applied by a few utilities, thus leaving the extent of]** tariff design purposes and cross-subsidies**[largely unknown]**, not to justify costs. .

Policy Position 24

a) *Electricity distributors shall* **[undertake COS]***provide CoS studies* **[at least every five years, but at least when significant licensee]***to propose new tariffs, special pricing and products or tariff structure changes* **[occur, such as in customer base]***to the NERSA and submit an updated CoS study at least every 5 years the NERSA to inform on the current customer base (all customer categories), relationships between cost components and sales volumes***[This;]**

b) *CoS studies' models and approaches are to be based on a cost causation principle;*

[2] This is to differentiate between justification of costs such as done to determine approved revenue versus a cost allocation exercise which allocates the approved revenue.

c) *CoS studies must be done according to the approved NERSA standard and revenue approval methodology to reflect changing costs of sales and customer behaviour* **[The]** *informed by data based cost* **[of service]***allocation assumptions; and*

d) *The CoS study's' report and costing methodology used to arrive at the unit costs to derive tariffs must accompany (or precede) applications to the regulator for changes to retail tariff structures including the associated approved of wholesale/purchase tariffs.*

8.3 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 24

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

8.4 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.**[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**.**][Distribution Losses / Bad debt**

Policy Position 25

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

8.5 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.] Customer Categories

Each **[different type of]** customer/customer category has a different load profile, demand and[] load factor and consequently the energy and network costs differ. However, as it is not possible to have tariffs for each customer, therefore, there is a need to pool costs based on customer categories, including both loads and generators. For this reason, costs and 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]**category.

Policy Position 25

*a) The number of **[consumer]**customer categories for**[tariff]**costing, tariffing, special pricing and products purposes should be justifiable to NERSA based on cost drivers and the entire customer base including end-users, generator, wheeling, trading and customers considering the following:*
*(ii) consumption and/or generation patterns e.g. usage **[in different times]** or export, , load factor and **[average]**time-of-use consumption or export;*
*(iii)**[type of supply]** **type**, size, demand e.g. notified maximum demand (including export demand)1 phase or 3 phase, capacity level, overhead or underground**,[urban versus farms]**high/low density, multiple connection points), load or generator;*
*(iv) type of metering**[**(conventional**]**, for example, post-paid or pre-payment, **[kWh, demand, TOU;) and]** SMART metering or remote metering ;*
*(v) position on the network **[(not geographic location),]**, density of supply, transmission zone, voltage of the supply and the system from which the supply is taken;*
(vi) use of customer service channels and type of account management made available to the customer;
(vii) Contribution to network losses; and
(viii) Provision of energy storage;

b) *A new category* **[*must*]**<u>*can*</u> *be created where costs* <u>*or nature of supply justifiably*</u> *differ***[*by at least 10% between a group of customers and another based on the above criteria*]**<u>*from existing categories; and*</u>

c) *Sub-categories could also be created* **[*where only one or more*]**<u>*when there is justifiable differentiation of*</u> *components of costs.*

<u>8.6</u> Cost **[Reflective Tariff]** <u>Drivers and</u> Components <u>in CoS Studies</u>

[In addressing cost-reflective tariffs the first issue relates to what] The cost components <u>and cost drivers that </u>should**[ideally]**be included <u>in cost of supply studies must be identified</u> to reflect the <u>allocation of their</u> costs accurately.

Policy Position 26

NERSA must see within **[five]**<u>*three*</u> *years* **[that cost reflective tariffs]** <u>*CoS information*</u> *shall* <u>*be unbundled to*</u> *reflect* **[all]**<u>*where appropriate/practical the approved revenue requirement into l*</u> *the following cost components as far as possible:*

a) *Energy* <u>*purchase cost based on the energy purchase price structure;*</u>

b) <u>*Transmission network charges reflecting the Transmission purchase tariff structure;*</u>

c) <u>*Cost of Distribution and Transmission losses per transmission zone and voltage of supply*</u>

d) <u>*Cost of Distribution network services per voltage of supply;*</u>

e) <u>*Retail*</u> *costs* <u>*per supply size, types of services rendered and metering; and*</u>

f) <u>*The COS study should*</u> *in*[**]**<u>*the results provide a view of the subsidies compared to the existing tariffs.*</u>

<u>8.7</u> <u>Cost-reflective Tariff Structures</u>

<u>A cost reflective tariff structure is one that reflects the costs as closely as possible. For distributors, this cost starts with their purchase costs for energy and transmission network services, and the Eskom Distribution charges, and for municipal licensees their own distribution cost.</u>

The EPP should guide the industry on recovery of fixed costs through fixed charges. Tariffs that currently recover fixed costs through a variable charge impose a revenue risk on the Distributor and increases tariffs to all its customers. The correct separation and structuring of network, retail, and energy costs in the tariff charges provides the correct economic signals and payback period for alternative energy decisions by comparing the energy cost of the utility versus the energy cost of the alternative.

If tariffs are not correctly structured, to reflect fixed and variable costs:

- a reduction in sales and volumes will result in lower bills by not only in the energy value, but also in the network value; and
- this is not equitable or fair on those who, for example, are not able to afford alternative energy sources.

This loss in revenue when the bill is reduced must still be recovered, as network costs will remain for capex, continued maintenance and operations, even when there is reduced consumption. These costs would still have to be recovered thorough tariff, resulting in increases to tariff charges. Therefore, if the electricity industry does not to restructure existing distribution tariffs to meet a changing ESI environment, all customers will be negatively affected. Customers who opt for alternative sources of energy should also equitably face the cost for their backup energy supply from Distributors; otherwise, unintended tariff subsidies would result.

For some customer categories, for ease of customer understanding, the various cost components can be simplified for some tariffs to a fewer number of charges (more bundled), but should reflect the full cost of supply for the group of customers charged through at the simplified tariffs.

Policy Position 27

The charges reflecting the unbundled costs, should be structured as far as possible to include:

a) *Energy costs in c/kWh and generation capacity charge reflecting the purchase cost structure;*

b) *Transmission network charges reflecting the Transmission purchase price structure;*

c) *Distribution network charges in R/kVA based on maximum demand per billing period* **[*covering;;*]**

d) **[*Network capacity*]** *Distribution network charges in R***[/]***KVA or R/kW/ month or R/Amp/ month based on annual capacity;*

e) ***[Customer service charges in R/cust/months;]*** *Customer service charges in R/customer or /Point of* **[*supply costs R/POS/month; and*]** *delivery (POD) / day/months based on the size of the supply;*

f) **[***Cost of***]** *Administrative charges in R/POD/or month/day;*

g) *Charges for poor power factor,*

h) **[As a result of metering and]** A *TOU energy net-billing* **[constraints]** *rates for prosumers,*

i) *Charges for the cost of losses; and*

j) *For ease of customer understanding, tariffs for some customer categories will not reflect all the above cost components. The applicable charges* **[must]** *whether unbundled or bundled must however cover the full cost of all the above cost components, except where approved cross-subsidies are applied*

[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.][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: 28

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

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: 29**]Rationalising Electricity Tariff Structures in the EDI

NERSA, together with the industry, should develop for the EDI, a national guideline to standardise tariff structures. This would facilitate for all Distributors, the tariff design process, transparency, and ease of understanding by all stakeholders. Distributors will need to adapt their tariffs in compliance to the national guideline. The tariff levels may remain different for each utility to match their local circumstances, demographics and costs.

Policy Position 28

NERSA shall provide a framework to guide the standardisation of existing electricity Distributors' tariff structures amongst all licensees, based on the policy positions set out in this EPP.

8.9 Changes to Tariff structures

Structural changes will be required when cost drivers, customer segmentation and pricing signals need to be more reflective of the Distributors' customers' needs and business requirements. Delayed changes to existing tariff structures may result in energy consumption inefficiencies, purchase cost under-recovery, Distributor volume risks and create unintended cross-subsidies. Customers need to receive the correct signals in a timeous manner in order to address these electricity distribution issues. At a minimum, structural changes to tariffs should be done based on a cost-of-supply study and may include pricing signals.

Policy Position 29

a) *Tariff structure and levels shall be aligned with the results from the updated COS studies* **[in which the resultant income]***and will* **[equal]***reflect the associated revenue requirement;*

b) *NERSA may approve changes to tariff structures where tariffs are combined or rationalised, using existing tariff revenue without a COS study; and.*

c) *NERSA shall timeously evaluate all submitted structural changes and provide reasons for decisions with guidance.*

8.10 Distribution use-of-system (DUoS)/Network Charges

The distribution network costs are the costs of a Distributor associated with capital (regulated return on assets and depreciation) for new and refurbishing of existing infrastructure, maintenance and operations and for flexible service provided. Use of system charges can also be used for raising of subsidies and other charges that may not be avoided.

DUoS charges are unbundled network related charges that reflect these distribution costs, plus any contribution to network-related subsidies and are as follows:

- Distribution network costs – split into fixed and variable components.
- Ancillary service cost – pass-through cost from the System Operator in Transmission and distribution related service cost.
- Embedded Transmission network charges – pass-through cost from Transmission.
- Administration and service costs related to the provision of a network service.
- Subsidy charges – network related subsidies that should not be avoided.

Network tariffs need to be reformed to move away from variable based charges (e.g. c/kWh) to tariff structures that had better reflect the fixed costs and the demand users of the Distribution network impose on the network. This is an appropriate mechanism to compensate Distributors for providing the network and required capacity e.g. ensure that customers with PV their own generation also face the same cost of the network as other customers.

Without a distribution network, energy generated cannot be delivered. The Distribution network business is just as important as the generation of electricity because network assets; wires, poles and transformers are needed to transport the energy from the generator to the consumer and to accommodate bi-directional flow of energy where the customer is both a consumer (load) and a generator.

Distributors are required to pay TUoS charges to reimburse the Transmission network operator for use of the transmission system. Similarly, Distributors will need to recover this transmission cost through an embedded TUoS charge. Consequently, the Distribution network charges comprise the DUoS and the embedded TUoS charges.

Policy Position 30

a) *DUoS charges shall be raised for both generators and loads;*

b) *DUoS and embedded TUoS charges shall be the basis for all network-related charges and shall be based on cost causation related to capacity used, the voltage, Transmission zone, losses and whether a supply is classified as urban or rural based on an updated cost-of-supply study;*

c) *DUoS and embedded TUoS charges for loads shall recover the cost of managing and operating the Distributor's network, providing flexible services, distribution losses, TUoS costs (including ancillary services), retail costs and where applicable, the*

NERSA approved contribution to subsidies for all users of the Distribution network, both local and cross-border;

d) *DUoS charges for generators shall recover the cost of managing and operating the Distribution network, Distribution losses, ancillary services and retail costs;*

e) *Unbundled DUoS charges will comprise at a minimum a fixed network capacity charge based on reserved capacity for loads and generators. Other charges may include a variable network demand charge based on monthly maximum demand or consumption for loads;*

f) *The above shall also apply to all small power tariffs except for subsidised lifeline tariffs;*

g) *NERSA shall pursue the phasing-in of cost reflectivity for distribution network charges' structures within the next 5 years; and*

h) *NERSA shall develop a national DUoS charges framework to prescribe the requirements set out above.*

8.11 DUoS Charges for Wheeling

In compliance with the Electricity Regulation Act and the transmission and distribution licences, Licensees must provide non-discriminatory access to the grid. Therefore, access and the DUoS and TUOS charges for the delivery of energy are, therefore, independent of the supplier of the energy or the buyer of the energy. Where energy is wheeled through a bilateral arrangement/contract, the charges for the delivery of the energy will be the same charges as for customers buying their energy from the licensees, plus and associated administrative costs.

Policy Position 31

a) *A generator wheeling energy will pay the standard generator DUoS charges as applicable;*

b) *A load buying wheeled energy will pay the standard load DUoS and TUoS charges as applicable;*

c) *No wheeling customer will be subsidised by a non-wheeling customer;*

d) *A wheeling customer will have to pay the administration costs involved in a wheeling transaction; and*

e) *A wheeling customer will not be allowed to avoid contribution to approved cross subsidies.*

8.12 Retail Charges

Retail charges recover the cost of administration (meter reading, billing), energy trading, wheeling transactions and customer service (including support, queries, applications, quotation and call centres).

Policy Position 32

a) *Retail charges shall be based on appropriate segmentation linked to the level of administration required the type and the level of service provided to the customer;*

b) *Except for lifeline tariffs all tariffs will pay cost-reflective (level and structure) retail charges;*

c) *For any additional services or transactions required on the bill an additional administration charge will be raised; and*

d) *Additional retail charges may be applicable for additional value-added services.*

8.13 Crediting for Energy Exported into The Network (Net-Energy Billing Tariffs)

Load customers generating some electricity may choose to export this energy into the Distribution network and receive a credit for the exported energy.

In this context, net-energy billing is a mechanism applied when the customer's generation is synchronised with the grid (grid-tied), some energy is exported, and a credit is provided on this exported energy. The utility or another party does not purchase this energy; the energy still belongs to the customer using the grid as a bank. Depending on legislation, this customer may be required to be registered or apply for a generation licence.

The benefits of using the network despite customer having their own generation include:

- The grid is a virtual battery, that is, it can temporarily store excess energy and can accommodate more storage than a battery.
- The customer can benefit from a net-billing tariff, which is a debit and credit process for energy consumed and produced at the same point of supply and not a netting of import consumption kWh and export production kWh.
- If net billing is combined with storage, the customer can benefit by reducing higher peak power charges. Storage could include hot water and batteries (including electric cars).
- The grid provides ancillary services that the customer would otherwise have to provide such as supplemental and back-up power and a fault level.
- The customer can also provide ancillary services to the grid provider and the System Operator, that is, remote control over the generation and/or storage, for which the customer can be compensated.

With grid-tied and net-energy-billing tariffs, it is important that appropriate charges are raised for the use of the network and the services being provided and that these charges are not raised as volumetric c/kWh charges as far as possible. If tariffs do not reflect cost causation, this means that customers with own generation could end up being subsidised by customers without by reducing their contribution to covering network and retail costs, while shifting those costs onto utility customers who do not have own generation.

At a minimum, TOU tariffs should be mandatory to ensure fair payment and compensation in the various time-of-use periods. Tariffs that reflect costs in different time periods, including net billing, will encourage storage, the reduction of peak demand and result in a reduction of costs for the utility and the customer.

Policy Position 33

a) *Net-energy billing will be allowed, subject to any licensing or registration required by law and in compliance with NERSA rules;*
b) *The net-energy billing customer will be required to be at a minimum on a time-of-use tariff;*
c) *The net-energy billing customer will be required to pay the relevant DUoS and TUoS charges for the use of the Distribution grid associated with consumption;*
d) *The net-energy billing customer will be required to pay the relevant DUoS or TUoS charges for the use of the grid associated with export of energy;*
e) *A credit rate for energy exported into the Distribution grid will be given based on avoided purchase cost;*
f) *DUoS, embedded TUoS, and retail charges will always be payable and will not be credited against the value of energy exported into the Distribution grid;*
g) *This compensation will be done on a time-of-use basis for the value of the energy exported;*
h) *An additional retail charge will be raised to cover the incremental cost associated with the additional billing transaction ;and*
i) *NERSA shall establish a framework for the raising of net-energy billing rates and approve such rates.*

8.14 Cost-Reflective Versus Pricing Signal

Customers respond to the signal provided **[by the]** through electricity prices. **[The question arises: should the tariff be modified from the COS with]**

Tariffs have the objective of creating a specific signal to customers to achieve **[a specific objective?]** specific objectives. Tariffs are not solely about cost causation and price signalling, but also cater for other objectives like capacity to supply.

[Policy Position: 30] [*Cost*]In addition to being cost-reflective, the price signals in tariffs **[]**should meet a range of objectives, which may include:

i. manage generation capacity and related cost recovery;
ii. meet the System Operator's requirements to optimise the operation of the power system;
iii. provide the right economic signals that promotes economic efficiency;
iv. incentivise investment for the benefit of both the customers and licensee; and
v. improve financial sustainability by increasing efficiencies in operating costs

Policy Position 34

a) The pricing signal to be provided to customers must reflect costs and other objectives to ensure operational and financial sustainability, and
b) Any additional pricing signals over and above ***[the costs]****recovering the costs and ensuring operational and financial sustainability must be motivated specifically and be approved by NERSA.*

8.15 **[Time of Use Tariffs]** Retail Energy Charges

The load profiles of customers differ significantly**[The]** and therefore, the application of tariffs with single energy charges does not reflect the system usage or the wholesale tariff and this may result in uneconomic use of the system and, result in increased costs and under-recovery of revenue. In addition if customers only **[one]**pay an average single energy rate**[result in large]**, but rely on the system for peak power, this would result in these customers being cross**[subsidies and, therefore, customers do not have]** subsidised by customers that use electricity more effectively. TOU signals also provide customers with the opportunity to **[save if they do]** respond **[by using less power at more expensive times. Eskom introduced TOU tariffs].**

The changing electricity environment is becoming more **[than 15 years ago. Since then the majority of Eskom's large customer sales are at TOU. This is]** important for customers to have time-of-use signals as the installation of PV reduces consumption, but not **[the case with municipalities where only a very small percentage of sales in the municipalities are at TOU.]** necessarily peak demand.

For **[this reason]** these reasons the application of TOU tariffs to all customers in the industry, except for the lifeline tariffs and, where practical should be **[promoted]** actively promoted.

Policy Position 35

Tariffs must include TOU energy rates as follows: *a) that reflect the energy purchase price;* *b) be applicable to all customers supplied at MV or above within two years;* *c) be applicable to all customers with three-phase connection or above 100 kVA within five years; or* *d) be applicable to all cases where the metering provides such features within five years, and*

be applicable to **all [other]customers [where it is warranted][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 32

TOU tariff energy charges must be differentiated by: • *All the components as reflected by the WEPS.* • *In addition an approved super peak rate to reflect the short terms costs could be applied during*

emergencies in which case customers need to be informed in advance.**][**Distribution Geographic Price Differentials

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

Policy Position 33

*e) 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-subsidization between customers in the various parts of South Africa. This also creates a significant obstacle for restructuring the EDI***]** *have grid-tied embedded generation.*

Policy Position 34

8.16 *Licensees shall apply pooling of costs per consumer category to achieve reasonable tariff.*] 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:]** due to the difference in costs and losses at the different supply voltages. However, these tariff differentials are not necessarily cost-reflective resulting in subsidies from one voltage level to the next. The following highlights some of the issues identified:

a. The level of the differentials **[is in general]**between supply voltages in tariffs is generally 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.]The differentials are[**

applied to the supply voltage]only **[without reflecting the system voltage]**applied to the supply voltage and do not reflect the point on the network where the supply is connected. Costs differ significantly for supplies directly <u>connected</u> from the <u>lower voltage</u> side of a substation and that of a customer taking a supply from deep <u>within</u> in **[the LV]**<u>a</u> network<u> (length of line considerations),</u> although both**[are]**<u>could be</u> supplied **[from]**<u>at</u> the same <u>supply</u> voltage.

c. **[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 7: Eskom Voltage Differentials Problem]**<u>To reflect supply voltage differentials, whether connected directly to a substation or deep within the network requires a very complex cost-of supply study and would create more voltage categories that may complicate the COS study and increase the number of resulting tariff structures. This may encourage customers to request a direct connection to substations and this may not necessarily be economical for the Distributor or other customers. This would result in uneconomic by-pass where customers would seek to own connection assets and avoid paying lower voltage network charges that include costs for shared network assets, or duplication of distribution networks..</u>

Policy Position 5

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

a) based on the <u>justifiable</u> supply <u>voltages, per customer</u> and **[*system voltage*]** *<u>customer grouping</u>;*

b) based on the cost <u>and losses</u> differences from the cost of supply study;

c) to be applied **[*as different energy & demand / capacity*]***<u>to tariff</u> charges* **[*not as a percentage on all charge*]***<u>as applicable;</u> and* *d) NERSA must drive a plan for phased increases in tariffs at lower voltages and a commensurate decrease of tariffs at higher voltages where voltage differentials do not reflect costs.*

8.17 Domestic (Residential) Tariffs

[Domestic customers present significant challenges for utilities because of their] There is a large [numbers and the many different types**]** number of domestic **[customers with diverse needs. Utilities]** (residential) tariffs and tariff structure being used in the EDI and these need to be rationalised through a NERSA framework.

Distributors should **[start charging]**charge cost-reflective tariffs for domestic customers, **[but]**through common structures, while also **[**c**ater]**catering for cross-subsidisation of some customers through lifeline tariffs. The detailed provisions for low-income customers are discussed in the cross-subsidy section.

Inclining block rate tariffs and tariffs that do not reflect cost-causation in an unbundled way should be removed unless they are used to provide cross-subsidies. Inclining block rate tariffs for higher consumption residential tariffs are not appropriate as they provide no TOU signal do not reflect unbundled costs (energy, network and retail) accurately and this may lead to an incorrect signal to customers when deciding on sources of alternate energy sources. Inclining block rate tariffs are not necessarily linked to the cost of additional consumption and, do not reflect the additional demand imposed. The tiers in inclining block tariffs may be arbitrarily set, and there is little evidence of any customer response to inclining block tariffs.

Policy Position 36

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

a) At the one end a lifeline inclining block-rate tariff or a single energy rate tariff with no basic charge, **[*limited*]***up to 60 Amps single-phase and* **[*nominal*]***connection* **[*charge (details under section on cross-subsidies)*]***charges aligned to the DMRE suite of supply options guidelines;*

b) At the next level a tariff **[*which could*]***to contain unbundled tariff charges to reflect* **[*a basic charge*]***network charges based on capacity, a customer service charge,* **[*capacity charge*]***and an energy charge with cost-reflective connection charges; and*

c) At the final level TOU tariffs must be instituted on the same basis as above, but with TOU energy rates for all three-phase connection (subject to smart metering roll-out).

[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 37

8.18 *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***.** Treatment of [**Network Capital Contributions]** Connection Charges

[There are various situations in the industry where the cost of new networks and even the expansion of existing networks are not]Funding of capital costs for the provision of capacity is funded **[by the utility, but by]**either through tariffs or from other sources such as:

a. **[Through the connection cost. This is typically the service connection or in many cases the incremental costs.]** By way of connection charges as a contribution to the cost of any existing or future infrastructure that would be used, that is not recovered through tariff charges.

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**.**]**In many cases developers <u>or customers</u> would establish and fund infrastructure and then hand them over to the utility at no compensation.

<u>Connection charges need to be fair and must be calculated in accordance with the principles and rules set out in the relevant sections in the Distribution Code. The connection charges principles should be aligned to the following:</u>

b. <u>The basis on which connection charges are calculated by the licensee should be clear and transparent</u>

c. <u>Customers should not pay twice for the same infrastructure.</u>

d. <u>There needs to be a fair and transparent reimbursement mechanism in the connection charge policy to deal equitably with network assets that are shared. This is to prevent “second comers / free riders” from benefiting once the “first user” has paid for the system.</u>

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

[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]**funded from**[existing profits]**<u>approved revenue</u> or debt<u>, which in turn would need to be recovered through tariffs</u> for which <u>all</u> customers would then eventually need to pay.

<u>A wide range of practices used to be applied to recover a connection charge from customers towards the cost of infrastructure being used for the new capacity. An industry standard (NRS 069 –Guidelines for Distribution connection charges for loads) was</u>

established to standardise the methodology for how connection charges for loads are calculated in South Africa and its application is a Grid Code requirement.

The Distribution Code also provides guidance with regards to the connection charge policies that should be applied to recover capital costs from customers

Policy Position 36

a) *Any assets which are not financed by the distributor, but from sources such as: State grants,* **[*customer capital contributions*]***connection charges and connection fees,* **[*developer networks*]***self-build infrastructure 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*]*2.2;*

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

d) *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 several utilities. However, it is not applied very widely, and the calculation of the relevant rates is not regulated.*

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

8.19 Public Lighting

Many municipalities consider public lighting to be part of the electricity supply service and as such, expenses must 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 taxpayers 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 such as rates.

Policy Position 37

a) Public lighting, including streetlights, high mast lights, parking area lights and traffic lights are considered as consumers of electricity and are not part of electricity supply;

b) The associated charges must cover capital and operating costs associated with: energy, electricity network, dedicated lighting networks and lighting services;

c) Such services may be provided by electricity utilities, but such costs must be charged to the appropriate owner, in most cases the municipality; and

d) The municipality can in turn fund such service from the MSOE.

8.20 Refurbishment and Maintenance

[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.] There is a significant challenge in the distribution industry related to the backlog of appropriate maintenance and refurbishment of infrastructure. This needs to be addressed so that the asset is able to maintain a reasonable level of service quality for its customers..

Policy Position 38

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 be recovered in tariffs to provide for capital for refurbishment of standard assets and all operating expenditure, including staff to manage such projects and undertake the required work;*

c) *The above must be done with due cognisance with proper ring-fencing* **[***is not done and much of the needed funds are removed in a non-transparent fashion from the electricity sector***]***to ensure that the needed funds not from the electricity sector is used to fund other sectors; and*

d) *The refurbishment of premium assets will be funded outside the tariffs in accordance with the Distribution Code.*

8.21 Distribution Losses and 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 a legitimate cost which should be recognised as part of efficient electricity supply costs, and how it should be treated.

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

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.*

Distribution losses comprise both technical and non-technical losses. Non-technical losses and bad debt are a problem with a very significant impact on electricity sales, maximum demand and viability of many licensees. In addition, the ability to enforce payment has become politicised and exceedingly difficult resulting in significant under-recovery of revenue by Licensees. The question is whether such high non-technical losses and subsequent bad debt could be considered a legitimate cost to be recognised as part of efficient electricity supply costs, and how it should be treated.

Losses will increase as more customers are added to the network and, IPP connections in low load areas are increasing losses. A NERSA methodology must accommodate this changing environment.

Policy Position 39

d) *<u>NERSA must</u>* **[*acceptable standards for non-technical losses and provision for bad debt*]** *<u>develop a methodology to quantify and establish technical, non-technical losses and provision for bad debt; and.</u>*

e) *The component of technical, non-technical losses and bad debt that 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*]** *<u>affect all customer electricity tariffs.</u>*

<u>8.22</u> <u>Traders</u> **[Reseller]** <u>Charges</u>

[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:]

Resellers are registered parties that purchase electricity from a licensee for resale to tenants or homeowners. A reseller must comply with Schedule 2 of the Electricity Regulation Act, regarding the raising of tariff charges. NERSA has a guideline related to resellers, which must be updated to reflect current legislation.

One area that is not clear is the monitoring of compliance by resellers to the Act and ERA and the settling of disputes. Licensee can mediate, but do not have any regulatory or legal powers in terms of ERA to instruct resellers to be compliant, other than disconnection.

Policy Position 40

a) *Non-licensed traders of electricity shall provide the electricity at terms, tariffs and services* **[*not less favourably than that provided by the licensed distributor in the area*]** *in compliance to Schedule 2 of ERA;*

b) *NERSA shall provide* **[*guidelines to resellers regarding resale principles*]***rules to licensees and resellers regarding electricity resale pricing principles; and*

c) *The Licensee shall mediate disputes relating to electricity resale and if there is no resolution, NERSA shall be the final arbiter and such conditions must be included into the Licensee's electricity supply agreement with the reseller.*

8.23 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.]The implementation of FBE must be done in accordance with the DMRE Electricity Basic Services Support Tariff (Free Basic Electricity) policy. The application of the FBE needs to be continually monitored to ensure it is applied correctly to ensure implementation addresses the needs of the targeted customers.

FBE is meant to be funded through the equitable share allocation to Local Government and not through the revenue requirement of the Licensee.

Policy Position 41

*Where***[** ***LG*****]** *Local Government wish to apply free electricity in excess of the amount provided for the equitable share to more customers or for more kWhs, this shall be funded outside of electricity income***[***by municipal revenue and not from electricity income***.]**

8.24 Electricity Tariffs for Organs of State

[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.]When organs of the state are supplied with electricity, standard NERSA approved tariffs charges should be applied. There should be no preferential tariffs as this practice would under-recover revenue and create subsidies. The full cost of providing electricity to organs of state should be charged to ensure that the appropriate pricing signals are provided to ensure efficient use.

Policy Position 42

a) **[*There shall*]** ***No special electricity tariffs or terms shall be permitted for organs of state*** **[*the State*]***or State funded institutions including schools and clinics / hospitals; and.*

b) *Organs of state* **[*These*]***shall be required to budget and pay for the full cost of electricity services* **[*anticipated in the financial year in question. Any subsidies must be procured through inter-governmental transfers*]** *based on NERSA approved tariffs.*

9.18 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 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 41

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

9.19 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 42

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

9.20 Trader 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 43

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

e) NERSA shall provide guidelines to resellers regarding resale principles.

9. CROSS-SUBSIDIES

8.25 Cross-Subsidies

[There are a host of cross-subsidies in the ESI. Some of these whenever] Cross-subsidies in electricity tariffs exist, where customers either pay more or less than either pay more or less than the cost of supply. These are inherent **[to the nature of the ESI and tariff-making, but some others exist]**due to cost pooling, tariff-design, to address affordability by those paying the subsidies and, to specifically subsidise a particular group of customers or sustainable electricity supply investments.

There **[have been]** are extensive debates **[about these]**in the industry on tariff cross-subsidies, how they should be funded, who should pay and who should receive and what should be done in this respect? This is relevant due to the changing nature of the ESI, where customers can have own generation and avoid contributing to subsidies increasing the burden on the remaining customers.

Affordability is an argument made by both those receiving the subsidies and those paying the subsidies. Removal of the tariff cross-subsidies would result in sharp tariff increases to recipients. On the opposite increased contribution to cross subsidies motivates requests for exemption from subsidy payments or defection to own generation or alternative energy sources. This will result in higher tariff subsidy payments from the contributing customers (wheeling and load) that remain unless cross-subsidy funding is located outside the tariff base.

[**Cross-Subsidy**] **[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.]**All customers that use the Licensee’s network for fairness and equity should not avoid an equivalent contribution to subsidies otherwise this would lead to undue discrimination. Generators may be excluded from contributing to cross subsidies to avoid double cross subsidy payments by customers receiving their energy. Therefore, all customers on the network should contribute at an equivalent and fixed rate to subsidies relative to their network demand.

The application of cross-subsidies is not uniform in the electricity industry, there is no national framework guiding the application of tariff related subsidies and, there is a lack of transparency as to the level of subsidies received and contributed by the different Licensees' customers.

Policy Position 43

a) *NERSA***[*DoE*]** *shall develop* **[*together with NERSA*]** *a national subsidy framework to guide the application of tariff subsidies which should seek to balance the subsidy's impact on the price and affordability of electricity to recipients and contributors;*

b) *The application of only specifically approved cross-subsidies* **[*subsidies, levies and surcharges*]** ***must be instituted in the ESI to address certain socio*****[*/ political /*]-** *economic and environment needs as provided for by National legislation and regulations;*

c) ***[Cross-subsidies should have a minimal impact on price of electricity to consumers in the productive sector of the economy]*****[*All levies, subsidies and cross-subsidies*]***All cross-subsidies in electricity tariffs shall be made transparent, while moving towards cost-reflective and transparent tariffs in the ESI;*

d) *Any levies and surcharges raised by Municipalities need to be treated as per Policy Position 44;*

e) *No load customer shall be allowed to avoid contribution to subsidies unless approved otherwise by NERSA;*

f) *Generators may be excluded from subsidy contribution so long as this avoids double-counting subsidy contributions for the loads they serve;*

g) *A subsidy paid for by Distributors in their energy purchases is a pass-through to their end-customers;*

h) Removal of subsidies from a Distributor's tariff base will be subject to prior implementation of transparent and justifiable tariff subsidy charges and the availability of alternative cross subsidy funding through the DMRE national subsidy framework;

i) NERSA approval will be required to give effect to the removal of tariff cross subsidies and the adjusted tariff rates thereof;

j) <u>Tariff charges to recover remaining tariff cross subsidies should be ideally structured as fixed charges;</u>

k) <u>Tariff cross-subsidies that are a contribution to a wider electricity consumer base than a single Distributor may be implemented at the wholesale level; and</u>

l) Licensees are required to establish and publicise the average level of cross-subsidy between **[*customer*]**<u>*tariff*</u> *categories* <u>*(receipt and contributions).*</u>

9.21 Transparency of Cross-Subsidies

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.

9.22 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 46

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

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

9.23 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 47

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.

9.24 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

the granting of FBE. 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 48

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 ;and*
- *nominal connection fee.*

9.25 Lifeline 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 lifeline 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 lifeline tariff should thus break even with the cost of supplying a 20 Amp customer at 350 kWh/month.

Policy Position 49

The level of the lifeline 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.

9.26 Free Basic Electricity/Lifeline 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.

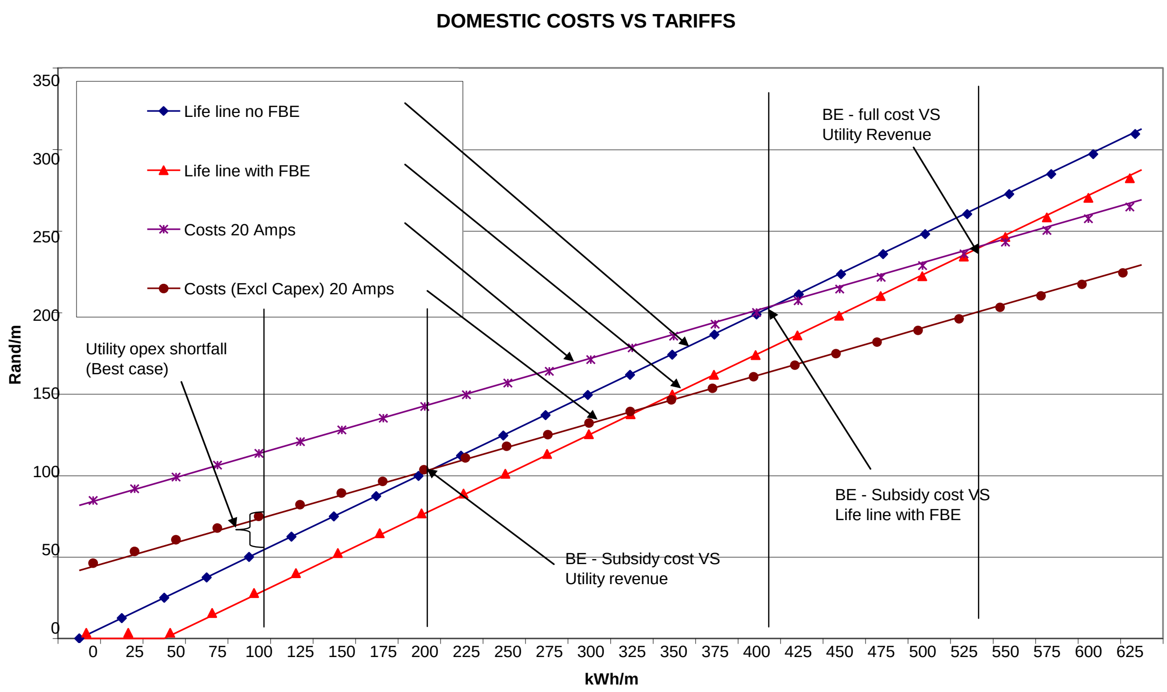
b. The funds provided did not cover all costs. In many cases utilities applied very high standards which led to costs exceeding the fund grant received and in other cases the remoteness of supplies required much more money.

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 8: Domestic Costs versus Revenue



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

Policy Position50

The shortfall in revenue between the lifeline 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.

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: 51LGs wish to apply free electricity more than 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.

9.27 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 to ensure that the appropriate pricing signals are provided to ensure efficient use.

:

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.

9.28 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 53

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

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

c) **[*DME must undertake a study to consider the introduction of alternative subsidy / cross-subsidy mechanisms to address the challenges relating to farm network replacements.***

- ***A RED electricity levy applied at the RED level and it thus managed by the RED.]***

[A national electricity levy applied at the wholesale level and thus managed by DME / agent of DME.]9.11]

8.24 Municipal Surcharge **[on]**<u>On</u> 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, understated internal usage charges, etc. Until municipalities have completely ring-fenced 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.

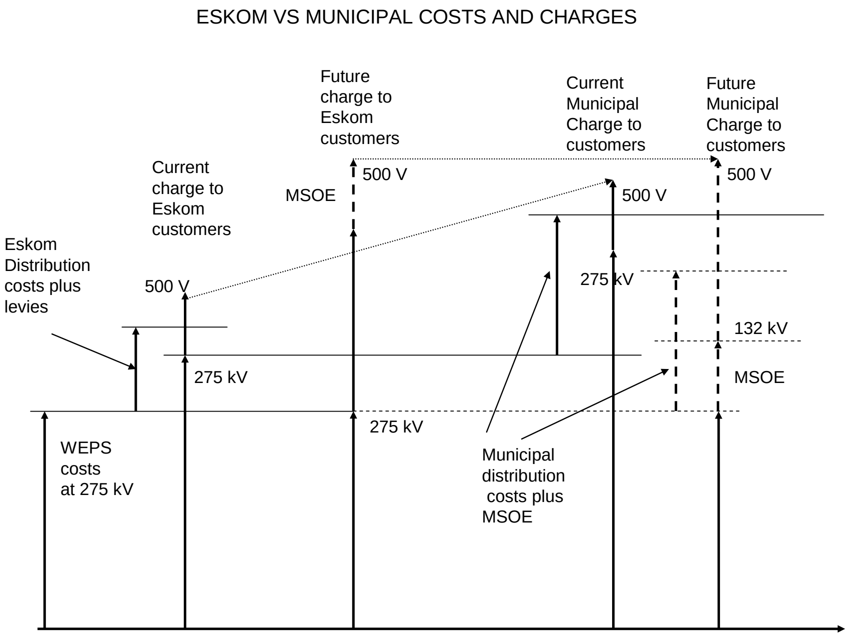
Some municipalities have already introduced a transparent MSOE without phasing out the existing hidden surpluses. This is totally against the intention of the legislation to regulate the application of the MSOE. Furthermore it is also uncertain as to whether these municipalities have ring-fenced their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

Policy Position 44

a) *Under no circumstances shall the new MSOE be introduced in addition to the current non-transparent / un-[]<u>ring-fenced</u> surpluses.*

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

Figure 9: 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.]**

[9.12Viability Assistance

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

10 DEMAND SIDE FLEXIBLE SERVICES **[MANAGEMENT / ENERGY EFFICIENCY]**

Demand side flexible services and products are needed to optimally mange the system and grid. These can be used to reduce demand, capacity constraints and even energy requirements. Some examples of such products and services to incentivise investment in the space are:

- Voltage support for local, regional and national needs
- Unbalance support
- Constraint management
- Energy storage
- Support for planned and unplanned outages
- Phased balancing
- Tariff products
- Demand response mechanisms

Policy Position 45

a) *NERSA must consider the impact and the effectiveness of demand and supply side flexible options in determining revenue requirements of licensees.*

b) *These demand and supply side flexible options must also be ring-fenced and be reported on per revenue review period to demonstrate the costs and the benefit by licensees.*

c) *The regulator must decide on the amount of funds to be allocated to demand and supply side flexible options based on requests made by the licensee.*

d) *The funds shall be applied and prioritised on a reliability and security of supply and/or least cost per saved MVA/MW 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 as prescribed by the Codes.*

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.

10.18 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 58

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.

10.19 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.

10.20 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

Policy Position 59

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.

10.21 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 60

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

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

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

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

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

10.22 DSM / Energy efficiency funding

The regulator may allow a licensee to recover DSM and energy efficiency costs from the tariff. The regulator needs to ensure that projects proposed by the licensee make the necessary saving.

Policy Position: 61

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

a. **[REGULATION][DME] DMRE determines the EPP to be applied in the ESI and NERSA is tasked with establishing these or to establish the rules, regulations, planscodes, 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, 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:] [The required amendments to the Acts to enable an unbundled industry.**

b. **Appropriate frameworks, rules and codes to be in place by NERSA to guide the industry.**

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

d. **Timescales Appropriate timescales in respect of submissions and feedback of information to various parties are essential to ensure cooperation in all respects.**

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

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

g. **A case has to be made for *ex post* and *ex ante* regulations because they could affect the magnitude of the adjustments. NERSA should timeously provide reasons for decisions for all submissions to the NERSA.**

h. **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 2.22.2.**

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

j. **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.**

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

l. **Competition as far as possible and justified is required.**

m. **Price discrimination should be justified.**

n. **Harmony Standardisation where applicable in the ESI is necessary.**

Disputes and complaints should be addressed promptly and NERSA to establish an escalation and dispute process in consultation with all stakeholders.][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.]

11 [CONCLUSIONS]

12 CONCLUSION

It is essential that the proposed EPP should receive the highest possible priority. The ESI is faced with a number of important changes and challenges as pointed out in this **[report]** document. 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 wholesale, generation, transmission, distribution, cross-subsidies, **[DSM]** flexible services to meet supply and demand, 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]** Independent power producers and renewable energy projects will play a more prominent role in South Africa's future energy mix.

It is this backdrop that necessitates that the industry moves towards tariff levels and structures that will ensure sustainable and viable industry. In addition, the EPP highlights the importance of non-discriminatory pricing practices as well as the need to promote pricing standardisation, 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, wholesale prices, generator prices, wholesale prices, transmission prices and distribution prices and that the Regulations supports what is contained in the EPP.

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 as transparently as possible.

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]** acknowledged the need for cross-subsidies**[**which should remain**]**, but that this needs to be done in [**the ESI. These are clearly defined]** terms of a separate national subsidy framework 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, managing the system 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]**flexible services, energy efficiency**, [** rationing**]** and other strategies funded from a range of sources to mobilise resources optimally.

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