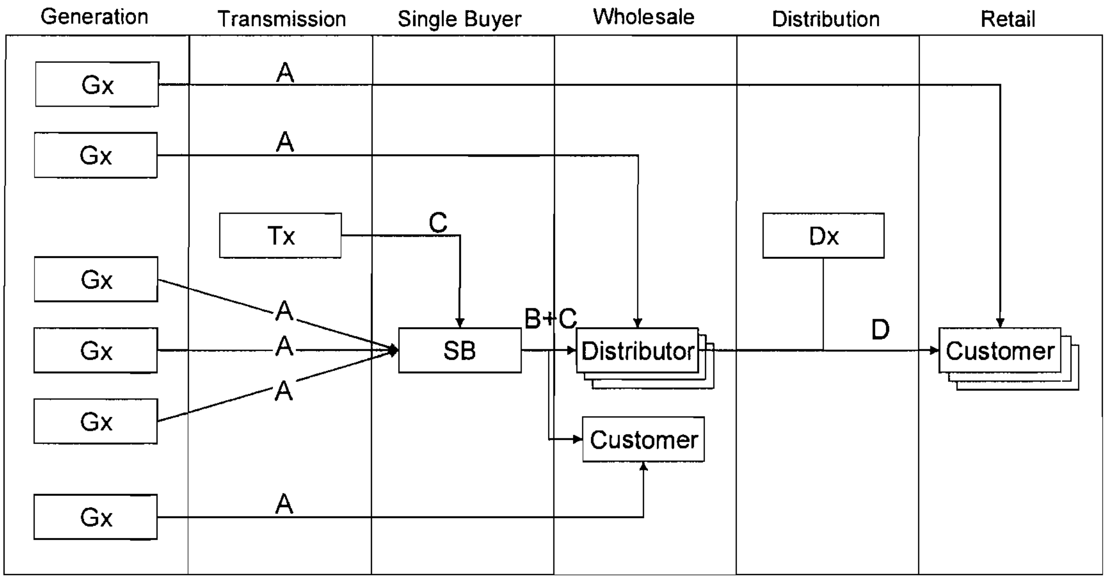
Figure 2: Basic Diagram to illustrate the key Functions and Pricing Interfaces



Functions

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

Pricing Interfaces

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

4 GENERATOR PRICING

4.1 Applicability

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

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

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

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

Policy Position: 8

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

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

4.2 Tariff Structure

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

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

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

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

Policy Position: 9

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

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

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

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

4.3 Tariff Level

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

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

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

Policy Position: 10

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

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

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

4.4 Renewable Energy Generators

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

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

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

Policy Position: 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.*

d) *The DME will develop a renewable energy guideline to support the introduction of renewable energy.*

e) *Any policy proposals on environmental support for electricity generators must be done by DME after consultation with DEAT and other relevant stakeholdesrs.*

5 WHOLESALE ENERGY PRICING

5.1 Applicability

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

5.2 Tariff Structure

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

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

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

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

Policy Position: 12

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

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

5.3 Tariff Level

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

Policy Position: 13

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

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

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

5.4 Negotiated Pricing Agreements (NPAs)

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

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

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

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

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

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

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

Policy Position: 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.

- *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.

5.5 International Sales

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

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

Policy Position: 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.

5.6 Ancillary charges / standby charges

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

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

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

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

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

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

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

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

Unless the above description is no longer 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.

Policy Position: 16

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

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

6 TRANSMISSION PRICING

6.1 Applicability

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

6.2 Tariff Structure

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

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

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

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

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

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

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

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

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

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

Policy Position: 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.

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

6.3 Tariff Levels

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

Tariff levels should be determined in accordance with:

a. an approved grid code;

b. an approved cross-subsidy framework; and

c. other regulatory requirements.

Policy Position: 18

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

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

6.4 Charges to Generators and Customers

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

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

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

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

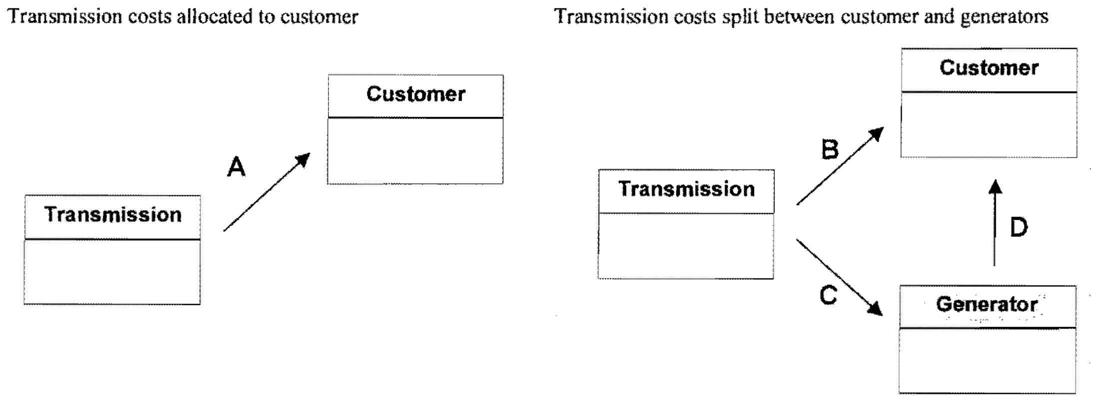
Few would argue that generators do not impact on the cost of transmission, but some may indeed argue that the generators do not pay because the customer ultimately pays for all the costs. The implications, if customers pay for all transmission costs, are that:

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

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

The above concepts are demonstrated in the following figure.

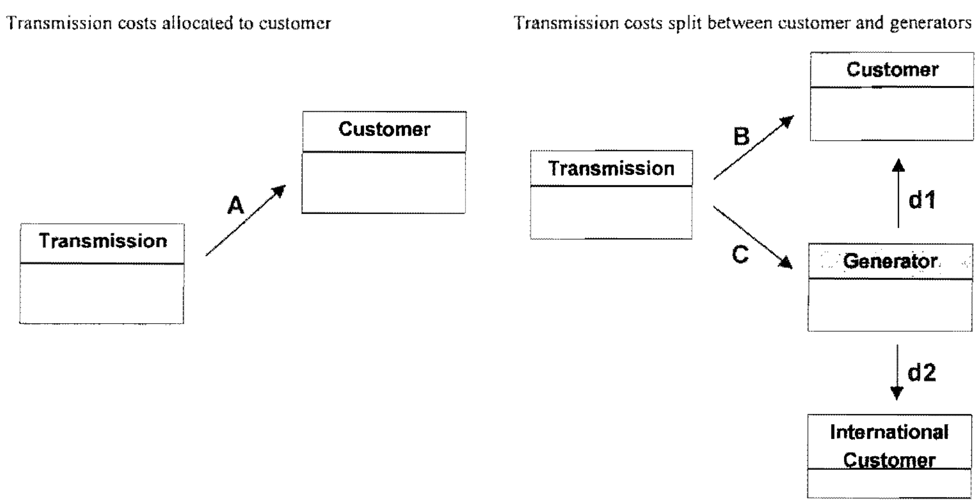
Figure 3: Illustration of Cost Split between Customers and Generators



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

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

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



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

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

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

Policy Position: 19

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

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

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

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

6.5 Geographic Differentiation

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

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

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

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

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

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

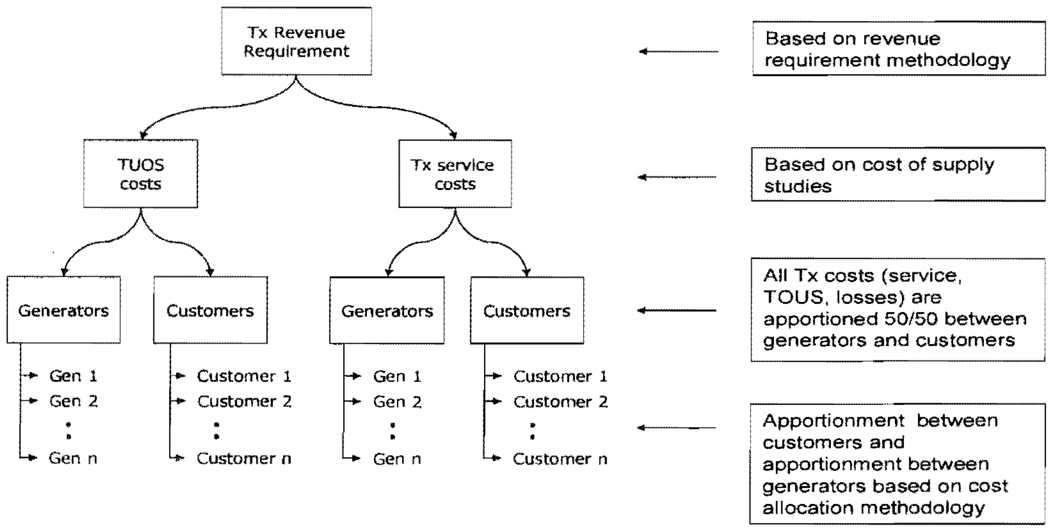
The allocation of transmission costs between different generators is usually based on a methodology that best balances the various tariff principles and objectives. On the one hand a "postage stamp" method will levy the same charge to all generators regardless of their position. This approach is simple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

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

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

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

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



Policy Position: 20

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

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

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

6.6 Transmission Charges for International Transactions

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

Policy Position: 21

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

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

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

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

7 WHOLESALE PRICING

7.1 Applicability

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

Access to wholesale electricity prices should be available to all licensed wholesale 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.

Policy Position: 22

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

b) DME in consultation with NERSA must determine qualification criteria for wholesale traders and NERSA determine implementation guidelines.

7.2 Tariff Characteristics

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

8 DISTRIBUTION PRICING

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

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

8.1 Cost of Supply Studies

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

Policy Position: 23

Electricity distributors shall undertake COS studies at least every five years, but at least when significant licensee structure changes occur, such as in customer base, relationships between cost components and sales volumes. This must be done according to the approved NERSA standard to reflect changing costs and customer behaviour. The cost of service methodology used to derive tariffs must accompany applications to the regulator for changes to tariff structures.

8.2 Refurbishment / Maintenance backlog

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

Policy Position: 24

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

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

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

8.3 Distribution Losses / Bad debt

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

Policy Position: 25

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

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

8.4 Customer Categories

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

Policy Position: 26

a) *The number of consumer categories for tariff purposes should be justifiable to NERSA based on cost drivers and customer base:*

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

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

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

8.5 Cost-Reflective Tariff Components

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

Policy Position: 27

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

- *Energy costs in c/kWh;*
- *Network demand charges in R/kVA/period covering;*
- *Network capacity charges in R/kVA/month or R/Amp/month based on annual capacity;*
- *Customer service charges in R/cust/months;*
- *Point of supply costs R/POS/month; and*
- *Cost of poor power factor*

8.6 Tariff Simplification

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

Policy Position: 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.

8.7 Seasonality

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

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

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

8.9 Cost-Reflective Versus Pricing Signal

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

Policy Position: 30

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

8.10 Time of Use Tariffs

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

Policy Position: 31

Tariffs must include TOU energy rates as follows:

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

8.11 Time of Use Tariff Structures

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

Policy Position: 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.*

8.12 Distribution Geographic Price Differentials

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

Policy Position: 33

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

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

Policy Position: 34

Licencees shall apply pooling of costs per consumer catergoty to ahieve reasonable tariff.

8.13 Voltage and Position Differentiation

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

a. The level of the differentials is in general smaller than the actual cost differences.

b. The differential is applied as either a percentage discount to the low voltage (LV) or a percentage surcharge on the high voltage (HV) tariff and the same percentage is applicable to the demand and energy rates.

c. The differentials are applied to the supply voltage only without reflecting the system voltage. Costs differ significantly for supplies directly from the LV side of a substation and that of a customer taking a supply from deep in the LV network, although both are supplied from the same voltage.

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