REGULATORY STUDIES – LOT 2

ACTIVITY 4 : TRANSMISSION TARIFF METHODOLOGY

REPORT 1 : DRAFT ASSESSMENT REPORT

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1 - INTRODUCTION

1.1 - Background

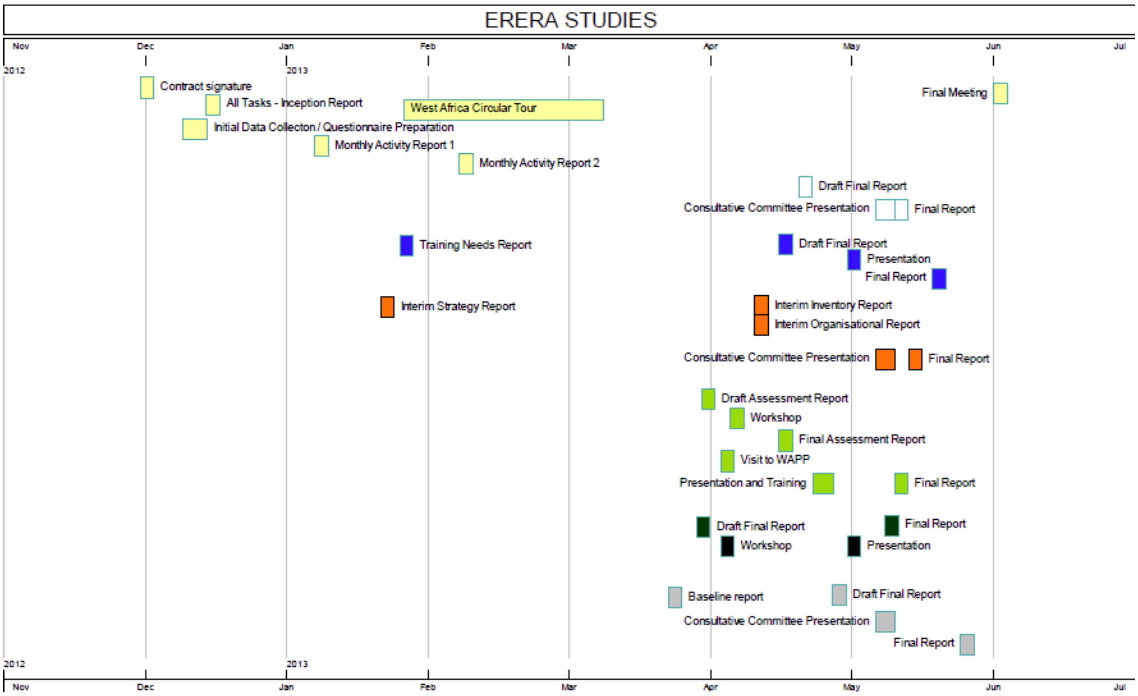
Task 4 involves the recommendation as to an appropriate methodology which can be adopted across the ECOWAS countries for the determination of transmission tariffs. The methodology should be applied for the calculation of transmission tariffs in the countries which are buying and selling power, as well as third countries through whom the power might flow.

It is important to recognise the work is associated only with the transmission element of the tariff. The overall tariffs for energy exchanges will be governed by rules for bilateral contracts and the day-ahead market. These tariffs will be dictated by the market rules, and will not be subject to regulation by ERERA. They should, however, include remuneration to the appropriate transmission companies.

As noted in the Terms of Reference, there are a number of key issues which need to be covered within the tariff:

- Responsibility for determination of, and payment for, losses incurred as a result of the energy trading flows;
- Use of system charges, covering:
    - Operation and maintenance costs;
    - Return on equity and allowance for depreciation; and
- Costs incurred as a direct result of the resolution of transmission constraints caused by the energy trading flows.

1.2 - Task 4 milestones



1.3 - Contents of Report

1.3.1 - Review of response to questionnaires

A review of the responses to the questionnaires, circular tour and bilateral agreements provided is covered. The aspects of importance to understand if a consistent methodology between ‘in country’ transmission tariff charges and international transmission tariff charges can be provided for the ECOWAS region. There should be a minimisation of cross subsidies between international and local trading of electricity.

The aspects reviewed are:

- How are end-user prices regulated?
- What is the market structure and are transmission tariffs calculated separately from energy tariffs?
- What is the method for price control for transmission and how tariff costs calculated?
- Is there cross subsidisation from government in transmission tariff?

- How are stakeholders engaged?
- How are transmission losses calculated and is there an incentive within the tariff mechanism for a reduction in the level of losses?
- What is the allowed Return on Equity, debt equity ratio, interest on debt and WACC for public and private transmission companies?
- How are transmission assets valued and the depreciation period?

1.3.2 - Review of WAPP reports on transmission

This section is a review of the WAPP reports associated with proposed arrangements for transmission pricing. We will review the Nexant study[1] which was completed for WAPP in 2008 and was funded by US-AID. This work was undertaken prior to the creation of ERERA, and we will follow up with WAPP the extent to which agreement was reached between the countries.

1.3.3 - Review of international practices for transmission

This section is a review the approaches which have been adopted for transmission pricing by others. The interconnections reviewed are European Interconnection (ENTSO), UK (National Grid), USA Eastern Interconnection (PJM), Southern African (SAPP), New Zealand, Ireland and Brazil

1.3.4 - Economic efficiency and transparency for transmission

The transmission tariff methodology should aim to be economically efficient, transparent, and easy to calculate and to update. In practice these objectives are not often complementary – tariffs which are easy to calculate seldom achieve the object of fairly compensating the different parties. This initial assessment report elaborates these problems in, and to guide delegates through the implications of the alternative approaches in the scheduled workshop.

At the workshop scheduled subsequent to the submission of the draft assessment report, we will present viable alternative methodologies. It will be important to achieve a consensus as to the appropriate methodology to be adopted, which will then be further developed in the final assessment report.

[1] “A methodology to calculate the demand and energy components of a transmission tariff within WAPP”, Final Report, October 2008, Nexant

2 - WHEELING CHARGE METHODOLOGY

2.1 - Introduction

The development of charges for wheeling power across transmission and distribution networks may be regarded as a special case of the more general requirement for transmission and distribution charges to enable network operators to recover the costs of their systems. The key difference lies in the proportion of the energy that is carried by the network to which the charges are applicable. The existence of a charging methodology for wheeling that has the potential to be applied to all electricity transactions is important to achieve in order to avoid distortions in pricing at a later stage.

Key aspects of wheeling charge design, and transmission pricing more generally, concern:

- the basis on which revenues are recovered, i.e. the size of the asset base and its associated valuation, and the possible inclusion of charges related to congestion and/or network losses;
- the way in which costs are allocated to the users of the transmission and distribution services, i.e. whether any distinction is drawn between charges faced by generators and consumers, or whether charges are differentiated on the basis of locational factors.

2.2 - Transmission Pricing Principles

The core principles of transmission pricing are to:

- **Promote efficiency** by providing appropriate price signals to generation and demand, giving incentives for appropriate investment and promoting competition. It is important to consider the link between transmission pricing and the associated electricity trading arrangements, particularly in relation to congestion charging.
- **Recover costs** – different methodologies can be applied to determine the costs to be recovered, for example historic costs vs forward looking costs. Security in cost recovery lowers the risk of investment, and hence cost of capital.
- **Be transparent, fair and predictable** to encourage new market participants. Ideally the methodology should be easy to explain and should be stable in the long-term, avoiding "price shocks".
- **Be non-discriminatory**, i.e. treat network users who have the same impact on the transmission network equally, and for example ensure that

the recovery of any residual costs (where price signals do not recover the full costs required) is allocated in a fair way.

2.3 - Cost recovery

A number of cost components can be recovered through transmission prices, including:

- capital costs of network plant and equipment;
- operation and maintenance costs;
- losses; and
- congestion.

2.3.1 - Capital costs

Historical cost approaches rely on obtaining an accurate calculation of the annuitised cost of network assets. This needs to be based on an accurate assessment of the cost of the existing network, from an asset valuation. The asset costs can be modified to include an allowance for the costs of system operation and maintenance. These approaches are generally good at recovering actual system costs, although there are tradeoffs in the extent to which historical costs are considered to be economically efficient.

Greater economic efficiency is gained from so-called "forward-looking" pricing methodologies. These assign part or all of the costs of providing new transmission facilities for a transaction directly to that transaction. Thus only the new transmission costs caused by a new transaction are considered in calculating the transmission charge. There are a number of methodologies using forward-looking concepts, which differ in their use of incremental and marginal costs, and of the short-run and long-run.

The incremental cost of a transaction is found by comparing the total system costs with and without the transaction. This can be very different to the marginal cost of the transaction, which is calculated by assessing the extra cost of providing an extra unit of transmission. This is due to the likelihood that a transmission system is sub-optimally designed for current patterns of use for historic reasons, and the "lumpy" nature of transmission investment which leads to the provision of over-capacity being cost-effective on occasion.

In the short-run only operating costs are considered, with the result that it is unlikely that system prices will be allowed to rise to the levels necessary to recover the full costs of required new investment. In a perfect market, short-run and long-run costs would be identical. In practice, the presence of large fixed costs and economies of scale in transmission systems means that short-run costs (in which the network is considered to be invariant) are below long-run costs (which include the costs of system expansion/reinforcement).

Whichever method is used for signalling capital costs to network users, there is likely to be a requirement to scale the final incomes received to meet the revenue requirements of the network company. A key issue in transmission pricing concerns the relative size of this scaling component compared with the level of revenue recovered through the application of the “pure” prices. If the scaling component becomes too significant, there is the risk that the method reverts towards a flat charge that is unrelated to the use of network assets, which risks losing a significant degree of economic efficiency.

2.3.2 - Operation and maintenance costs

Operation and maintenance costs are most readily recovered by allowing a predetermined margin on the capital costs of equipment to cover an appropriate amount on an annual basis to cover the O&M costs of each asset. Annual allowances vary from utility to utility, but typical figures in the range 2%-5% of the capital cost per annum are applied to cover O&M costs for the system as a whole. This needs to be sufficient to cover the costs of operating the centralised control functions within the transmission operator business, as well as the maintenance requirements of the individual assets themselves.

2.3.3 - Network losses

In principle, the cost of transmission losses can similarly be included in the costs recovered by the transmission pricing methodology, although this is dependent on understanding the costs that are actually involved in covering these. Many international market models leave the allocation of losses for the electricity market to resolve, through the adjustment of metered quantities in the settlement process. A key consideration here is the route by which the costs of losses are recovered, and how the transmission operator is incentivised to reduce losses.

Particular attention to losses is required in the design of wheeling charge methods, to ensure that only those incremental losses associated with the impact of specific wheeling trades on the network are taken into consideration.

2.4 - Historic Cost Methodologies

2.4.1 - Postage Stamp

The postage stamp approach is generally regarded as the simplest to implement. The methodology allocates system costs between users on the basis of their share of total peak load on the system. It therefore results in a flat transmission charge per unit of demand equal to the total transmission costs divided by peak load. The postage stamp method is often supported with reference to the fact that, in power transactions, electrons do not actually travel from the seller to the buyer, and the system is operated on an integrated basis.

There are a number of clear advantages of such a transmission charge methodology:

- Full historic cost recovery is ensured. As this allows investors to recover their investment costs, it solves the problem of under investment apparent in nodal pricing approaches.

- The system results in a clear, simple and stable transmission charge as each consumer pays the same charge, regardless of location. Also as the peak load is likely to increase at a relatively moderate pace in most cases, the charge is largely invariant with time.

- Postage stamp pricing is most justified in systems in which there are few constraints and load and generators are fairly equally spaced. In such systems bulk power transmission costs do not significantly increase with the distance between buyers and sellers.

However the postage stamp method does suffer from a number of significant problems:

- As the methodology does not consider the actual utilisation of the system, it does not create the correct incentives for system users. This can result in serious efficiency concerns as users are not liable for the full costs of their actions. For instance a transaction whose costs in terms of system upgrades and investments exceed its benefits may still occur as the parties to the transaction face only a small part of the extra transmission cost.

- As all users face the same transmission tariff, the postage stamp methodology discriminates against low-cost transmission users in favour of higher-cost users. In effect those parties engaging in high-cost transmission deals are subsidised by those who, for instance because they utilise only a small part of the network, create a smaller fraction of the transmission costs. This provides incentives for low-cost users to bypass the existing transmission network.

2.4.2 - Contract Paths

Under the contract path methodology, a specific path is agreed for an individual wheeling transaction between two points. This 'contract path' does not take account of the actual path of the power flow that would occur. A share of the asset costs, including the costs of new investment, along the contract path is allocated to the wheeling customer in proportion to their use.

The contract path methodology does create a number of benefits. The most notable of these are similar to the postage stamp method:

- Full cost recovery is possible as all asset costs along the contract path are considered, including the costs of new assets if they are required. This will allow investors to benefit fully from their actions, and so encourage an efficient level of investment.

- The system creates a simple and stable pricing regime, and is easy to implement.

- Relative to the postage stamp methodology, the contract path approach provides an improved ability to signal the costs of decisions by individual users.

However, as with the postage stamp method, the methodology ignores the actual system operation and any congestion issues. An energy transaction will affect all assets on the transmission system, not just those along the contract path. This may lead to investments being necessary in areas of the system which are not on the contract path at all. Therefore, the use of a contract path approach is low in economic efficiency, as well as potentially discriminating between users.

2.4.3 - MW-km (distance based)

This methodology is an extension of the concept behind the postage stamp and contract path approaches. The distance travelled by the energy transmitted under a specific transaction is either determined on a ‘straight-line’ basis between the points of entry and exit to the network, or on a contract path approach. The MW-km of the transaction is then determined and the ratio of this to the total system MW-km determined. This ratio is then used to determine the cost of the transaction.

As an enhancement of the postage stamp method, this methodology enjoys the majority of the former’s advantages. The total cost of all transmission activities includes fixed and variable costs, allowing investors to fully recover their costs and so providing efficient investment incentives. Also the relatively simple and clear nature of the methodology makes it easy both for the users to understand the system of transmission prices and for the method to be implemented.

However as with the previous methodologies, the actual operation and costs incurred in the system are not fully considered. Although the distance between delivery and receipt does provide some indication of actual use of the system, it still fails to take account of the impact of Kirchoff’s Law; which states that electricity will follow the path of least resistance. Thus the distance-based approach does not provide the correct economic signals to users, leading to reduced allocative and dynamic efficiency and discrimination between users.

2.4.4 - MW-km (load flow-based)

The load flow-based MW-km methodology reflects, to some extent, the actual usage of the power system. Transmission prices are determined in relation to the proportion of the transmission system used by individual transactions, as determined by load-flow studies.

A power flow model is used to calculate the flow caused by the transaction on each circuit of the transmission system. The ratio of the power flow due to the transaction and the circuit capacity is then determined. This ratio is multiplied by the circuit cost to obtain a cost for the transaction on each circuit. The share of the total system costs for the transaction is the sum of the costs for each circuit.

The relatively simple and clear calculation of transmission charges using this method increases the degree of transparency of charges. In addition, one of the major problems with the distance-based methodology is reduced by making users face prices that more closely relate to their use of the network and hence the costs they impose on the network, resulting in decreased discrimination between users and increased allocative efficiency. However, this approach still fails to signal the costs of future investment caused by individual users' decisions, based as it is on the recovery of historic costs. Additionally it is expected that the total power flows are less than the circuit capacity, hence not all the transmission system capital cost may be recovered. If congestion occurs due to the transactions this will be observed from the results of the load flow and a methodology to address congestion can be considered.

Refinements to this method are:

- to replace the circuit capacities with the total power flow caused by all transactions to fully recover the costs of network assets;
- to take account of the direction of the flow, if the flow due to the transaction is in the opposite direction to the net flow then the transaction is not charged as a net flow reduction is beneficial to the system.

2.5 - Forward Looking Methodologies

2.5.1 - Short Run Pricing

Short-run forward pricing methodologies include short-run incremental cost (SRIC) pricing and short-run marginal cost (SRMC) pricing. Within the SRIC methodology, all operating costs associated with a new transmission transaction are allocated to that transaction. As described in Section 2.3.1 - , this differs from the marginal cost methodology, in that the SRMC method includes the operating cost of extra use of the transmission system caused by a new transaction (the increase in losses and congestion costs).

Under the SRIC approach, costs are calculated using a model of optimal power flows, whilst to estimate the SRMC, the marginal operating cost of an extra MW of power is calculated at all points of delivery and receipt. This is then multiplied by the size of the transaction to provide SRMCs.

Despite the different methods of calculation, analysis of the advantages and disadvantages of the two methods is very similar. In using the pricing methods, a number of common concerns must be addressed:

- It is difficult to accurately evaluate the operating costs of a single transaction when multiple transactions occur simultaneously and an assessment has to be made about which investment cost relates to which individual transaction.

- The use of SRIC methodology requires the forecasting of future operating costs. Such forecasts clearly become decreasingly accurate as the time horizon increases.

- The short-term nature of the pricing methodology leads to two issues: it is likely that transmission prices based on the methods will be volatile, and the use of SRMC/SRIC approaches may lead to underinvestment.

In addition there are some additional disadvantages in using the SRMC process.

- If the individual transaction is very large in relation to the transmission system load, then the SRMC price may not be an accurate estimate of the actual extra costs imposed by the transaction, as they fail to capture additional system reinforcement costs imposed.

- Once any investment is made, the future SRMC prices will fall, reducing the potential for the network owner to fully recover these costs.

However, with these transmission pricing methodologies, the transmission price for a transaction is approximately equal to the actual cost placed upon the network due to the transaction, thus promoting efficiency in the recovery of the transmission system cost.

2.5.2 - Long Run Pricing

Long-run forward pricing methodologies include long-run incremental cost (LRIC) pricing and long-run marginal cost (LRMC) pricing. The LRIC methodology is similar to that of the SRIC however both operating and investment costs are considered. The investment costs are estimated from the change caused in long-term investment plans due to the individual transaction.

The LRMC method only differs from the SRMC methodology in the use of marginal investment costs as well as marginal operating costs to determine transmission costs. To calculate the extra investment costs, future transmission expansion projects are costed. This cost is then divided by the size of new planned transmission transactions to calculate the marginal investment cost.

The advantages and disadvantages of LRIC and LRMC pricing are almost identical. Estimating the investment costs and evaluating the costs caused by the individual transactions can be difficult. Multiple transactions occurring simultaneously create problems in assessing which investment cost relates to which individual transaction, and therefore the extent to which users should contribute to new investments. This is particularly so where new beneficiaries connect to the system at a later date. The sensitivity of future investment programmes to assumptions on future system use means that transmission prices can be rather unstable. There may also be concerns over double-counting of investment requirements, in that these are driven by congestion costs that are also captured in LRMC pricing through the inclusion of operating costs.

Despite these problems, there are advantages apparent under the long-run methodologies that are not apparent with short-run methods.

- Users face the full long-term costs of their actions, including the costs of new investments.

- Prices are more stable in the long-run than under short-run pricing, allowing users to more easily engage in long-term contracts.

2.6 - Nodal Pricing

The nodal pricing methodology, where a node can be any point in the network, can be seen as the economically ‘ideal’ transmission pricing system as prices are calculated to accurately reflect the costs imposed on the system by the transaction. The difference in charges at each node on the system (which is equal to the transmission charge between these nodes) is set on the basis of the marginal cost of losses and congestion at that node i.e. the cost of injecting one additional unit of energy at that node. Nodal prices obviate the issue of which assets are used for wheeling purposes by not defining the path followed by flows between nodes. Instead, prices are set on the basis of the marginal impact on the system as a whole.

The nodal methodology provides for any busbar, or node, on the network, a pricing signal relative to any other node. For nodes located in areas with surplus generation there will be a comparatively high cost for adding additional generation, and conversely for nodes located in areas with a deficit of generation the price for adding additional load will be high. Parties considering electricity trading can obtain an indication of the price of power transfers between nodes on the network. Similarly, potential investors in transmission lines can obtain an indication of the returns they might make on investments in different parts of the network.

In its simplest form, the optimal dispatch problem is to:

- minimise, at each node, the cost of supply; while
- limiting line flows to their capacity limits; and
- ensuring that total demand equals total supply.

In this simple model, the nodal pricing system solves the dispatch problem in a decentralised market by ensuring the marginal cost at all supplying nodes is equal to the marginal benefit at all consuming nodes. This results in users consuming electricity up to the point where their marginal value of power is equal to the marginal cost of supply, the nodal price, ensuring that both allocative and dynamic efficiency are maximised.

Nodal pricing can continue to lead to optimal dispatch in a more complex model incorporating transmission losses and congestion costs. Each nodal price is equal to the cost of providing an extra unit of electricity to the node, including costs of losses and congestion. Thus efficiency is still maximised within the more complex model. The methodology results in transmission charges being variable by time and location. Individual nodal prices can change instantaneously to allow for changes in supply and demand, as well as being dependent on distance from generation.

Although nodal pricing methodology leads to maximum efficiency benefits, there are a number of issues that have resulted in the system being rarely adopted in practice:

- It is probable that nodal pricing will result in under-recovery of fixed costs, as pricing is a function of marginal costs. This does not allow for the recovery of the significant existing fixed costs that characterise transmission networks, which lead to average total costs exceeding short-run marginal costs. For these costs to be more fully recovered, it is necessary to move to a system of 'second-best' pricing in which economic efficiency is sacrificed for prices that allow the network operator to recover all their costs, including variable and fixed costs.

- To set the prices, the transmission system operator would require constant real-time information about all loads, generators, bids and the condition of all equipment. Prices would not only vary over different nodes, but also over time as elements such as supply, demand and transmission constraints change. This creates significant instability and complexity in implementation, requiring advanced information technology and communications, often resulting in countries adopting different pricing systems or simplifications of full nodal pricing.

2.7 - Congestion Management

The issue of congestion on transmission interconnectors is one that straddles transmission pricing and market operation, and as such needs to be considered carefully in terms of its treatment in relation to wheeling.

Transmission congestion has several principal impacts on system and market operation:

- it can affect the dispatch of generation, resulting in "out of merit" generation being required to counteract bottlenecks on the transmission network and to avoid system overloads;

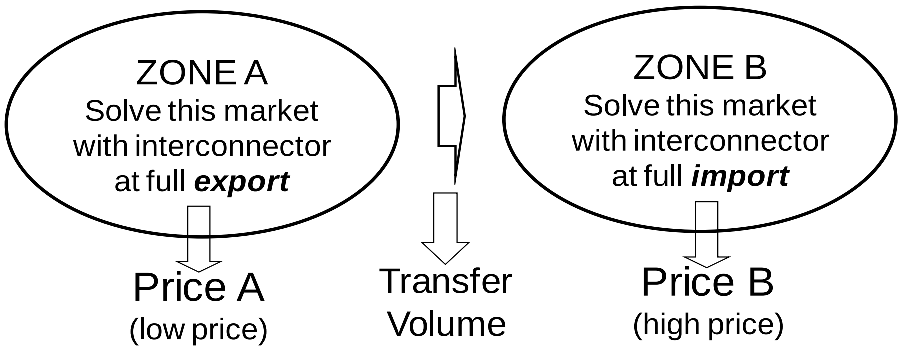
- it can require procedures to be developed for giving access to transmission circuits for specific transactions, including the management of "Available Transmission Capacity"; and

- it can lead to the separation of an electricity market into different physical zones for the purposes of defining market prices (so-called "market splitting").

The presence of congestion can be signalled relatively simply in transmission pricing by allowing charges for the use of specific lines to vary depending on whether the flow created by a given transaction increases or decreases the prevailing flow on the line. If a wheeling trade, for example, is proposed that runs counter to the main power flow, it could be argued that this should not face as high a charge as one that *adds* to the existing flow. The way that transmission prices are determined under any of the methods outlined above is essentially an ex ante process requiring prices to be published ahead of electricity trading taking place, and therefore calculations would need to be based on a predicted base case of power flows. The resulting signals relating to congestion can only therefore be approximate.

Under a more dynamic approach, the possible existence of congestion is predicted and managed through the splitting of a market into zones, or even nodes, at which separate prices are calculated. The ability to do this depends on the sophistication of the electricity market and the existence of some form of short-term market in which the costs of electricity are time varying. As demand changes and the flows on the network change, so the loading on different transmission lines varies to the point where operational ratings are at risk of being exceeded. In this situation, shown graphically in Figure 1, the price at which energy is traded in two zones of the electricity market changes once the capacity of the interconnector between them is reached. This generates a difference between the price at which the transferred volume of energy is sold to a consumer in Zone B and purchased from a generator in Zone A. The resulting "congestion price", and the "congestion rent" that it generates, can be used in a variety of ways, but is typically either returned to market participants or used to create a fund for investment in interconnector capacity.

Figure 1: Demonstration of Market Splitting and Congestion Management



Congestion Price = (Price B – Price A)

Congestion Rent = Congestion Price * Transfer Volume

The interconnector capacity in the above example could be allocated via a process such as an auction, in which it is made available to specific combinations of buyers and sellers on either side of the interconnector in advance. This approach is straightforward to administer; the challenge comes in maximising the utilisation of the interconnector as trading evolves towards real time. This so-called "explicit auction" approach is sometimes criticised as being less economically efficient than the alternative "implicit auction", in which energy and capacity are traded together, such that the interconnector capacity is fully utilised by the trades that are entered into.

The complexity of the congestion management approach outlined in Figure 1 is unlikely to be justified for the situation of wheeling energy between self-generators and their associated demand, and would be dependent on the evolution of the electricity market towards shorter term contracting arrangements such as a day-ahead or spot market. Nevertheless, it will be important to signal to self-generators the impact of their exports on the network, in order to encourage optimum utilisation of the network assets.

3 - REVIEW OF INTERNATIONAL PRACTICES FOR TRANSMISSION COSTING AND TARIFF METHODOLOGIES

3.1 - Introduction

In practice transmission pricing methodologies adopted by countries rarely fit exactly to the 'standard' methodologies described in Chapter 2. As electricity markets develop and increase in sophistication the complexity of the transmission pricing increases. The methodologies adopted by different countries are described below.

3.2 - Nord Pool

Nord Pool covers six countries in Europe: Denmark, Finland, Sweden, Norway, Estonia and Lithuania. Each country has its own TSO and may have different levels of transmission grid, for example Norway has a central grid, which spans from the very North to the very South of Norway and connects Norway to the surrounding countries, below the central grid are regional grids. Norway has five defined market areas, Denmark has two and Sweden has four defined market areas while Finland, Estonia, Lithuania operate one market area each. The Nord Pool spot market (Elspot) operates 14 market areas in six countries.

The Nord Pool transmission pricing methodology is based on a point or stamp tariff system, where the producers and consumers pay a fee for the kWh injected or drawn from the system. The distance or transmission path between the seller and buyer is of no significance to the transmission price.

The actual transmission price depends on where (what point in the grid) the power is injected or consumed and how much power is injected or consumed. The charges are determined by the individual TSOs and paid to the TSO to which the connection is made. However the payment allows trading of electricity across the whole Nord Pool market area.

Within each member country there is a transmission tariff payable within the country. For example, in Norway the transmission tariff comprises several components, a fixed component, a load component and an energy component.

- The load or capacity component considers congestion and compares prices between an unconstrained pricing model and a constrained pricing model.

- The energy charge considers transmission losses, if the transaction reduces losses the energy charge is negative. This provides long term locational signals for the connection of generation and demand.

- The fixed component considers customer-specific costs and a share of the other fixed costs in the network e.g. operation and maintenance.

The allocation of charges between generation and demand differs across the countries: Sweden 25:75; Norway 35:65; Finland 12:88; Denmark 2-5:95-98; Estonia 0:100; Lithuania 0:100.

In addition to the transmission tariff cost congestion costs are recovered through congestion rents which are the income or cost that arise due to the price differences between the areas. The congestion rent from the interconnectors is shared among the four TSOs in accordance with a separate agreement.

The Nord Pool spot market carries out the day-ahead congestion management on external and internal transmission lines. The available transmission capacity and the price differences in the surplus and deficit area manage the congestion day ahead implicitly within the energy market auctions.

Transmission losses are recovered by a standard Elspot trading fee in EUR/MWh which is paid by both buyers and sellers.

3.3 - The European Network of Transmission System Operators for Electricity (ENTSO-E)

The regulatory arrangements that apply across Continental Europe are implemented by national energy regulators in each member state of the European Union. The regulations are required to comply with policy criteria determined by the European Parliament and implemented through European Directives and Regulations. To assist with this process in relation to electricity networks, a number of bodies have been set up that represent regulators and transmission system operators.

ENTSO-E represents all Transmission System Operators (TSOs) in the European Union (EU), as well as other TSOs connected to member countries. This comprises 41 TSOs across 34 countries. Continental Europe is one of five synchronized zone of ENTSO-E, the other synchronized zones being Irish, British (Great Britain), Nordic and Baltic. There are also isolated systems in Iceland and Cyprus. ENTSO-E has made significant progress in putting transparent arrangements in place for cross-border electricity trading.

The mechanism for cross-border trading is called Inter Transmission System Operator Compensation (ITC). The ITC mechanism, based on Commission Regulation (EU) 838/2010, was implemented on 3rd March 2011. ENTSO-E operates the ITC mechanism, through the ITC Agreement, and the Agency for the Co-operation of Energy Regulators (ACER) oversees and reports on the implementation. The Regulation (838/2010) established an ITC fund to compensate TSOs for the costs incurred hosting cross-border flows. The fund aims to cover the cost of transmission losses and making infrastructure available, for cross-border flows. TSOs participating in the mechanism either contribute to the fund, or are compensated, according to their net imports / exports. Note that this method is significantly different from previous iterations of the ITC, which made use of a Transit Key and Transit Horizontal Network.

The steps for determining the revenue requirements, levels of compensation and payment (contribution), and the values of these components in 2011, are as follows:

1. Determine costs to recover (Compensation Fund) associated with:

    a. Cross-border infrastructure – the assessment of costs should be based on forward-looking Long Run Average Incremental Costs (LRAIC). This method and assessment is currently under review; in the meantime a figure of EUR 100 million per year is used. (EUR 100 million)

    b. Losses – based on a With and Without Transits (WWT) model and the value of losses allowed by national regulators. (EUR 125 million)

2. Determine the compensation owed to each party from the Compensation Fund according to:

    a. Cross-border infrastructure – the use of two factors; Transit Factor and Load Factor. (EUR 100 million)

    b. Losses – WWT model and national loss values. (EUR 125 million)

3. Determine the contribution to the Compensation Fund from each party based on:

    a. Net flows (the absolute value of net flows onto and from national systems as a share of the sum of the absolute value of net flows onto and from all systems) (EUR 205 million); and

    b. Perimeter fees – a transmission use of system fee levied on all scheduled imports and exports from perimeter countries, in EUR/MWh. The fee is calculated by ENSTO-E each year in advance. (EUR 20 million)

4. Calculate the net financial result for each party (i.e. compensation – contribution).

In determining the cross-border infrastructure fund, the Regulation (838/2010) specifies that the method should be based on forward-looking Long Run Average Incremental Costs (LRAIC). The details of the method are not known, as they are currently under review. However:[2]

- "Long-run" means that future investment costs should be included; and
- "Forward-looking" suggests that replacement costs should be used, rather than historic costs.

The method will signal future investment costs, rather than recover historic costs. In general the advantages of long-run pricing methods include the fact that users face full long-term costs. Disadvantages can include the difficulties associated with estimating future investment costs, and the instability that can be caused to prices in depending on future investment scenarios.

3.4 - Ireland

EirGrid is the independent system operator for the Republic of Ireland (RoI) and SONI (System Operator Northern Ireland) is the system operator for Northern Ireland (NI). A system operator agreement exists between the two TSOs and ensures the required coordination between the two. The electricity market in NI and RoI together is referred to as the All Island market.

The SEMO (Single Electricity Market Operator) is responsible for the operation of the centralised gross pool/wholesale market. Electricity is marketed through market clearing mechanisms. Generators are paid the System Marginal Price (SMP) plus the capacity component for that half an hour and constraint payments for the differences between market schedule and system dispatch. Suppliers who buy energy will pay the SMP for each half an hour along with capacity costs and system charges.

According to the All Island transmission methodology, the transmission costs are allocated at 25:75 split with generators paying 25% and demand paying 75% of the transmission related costs.

The All Island transmission tariffs have been designed to recover a maximum of 30% of allowed revenue from a locational element which apportions the share of the cost that a generator uses of new assets. (New assets are those to be built in the next 5 years or those that have been built in the previous 7 years). The remaining amount is collected through a postage stamp methodology. Any revenue not recovered by the locational tariff component is be shared across all units by a flat €/MW charge to obtain a postage stamp charge.

[2] Consentec; Assessment of the annual cross-border infrastructure compensation sum; October 2012

Transmission losses are allocated to generators/interconnectors, by means of Transmission Loss Adjustment Factors. This includes generators connected to the distribution network. Transmission losses are recovered through transmission prices in NI and through energy market in the RoI.

3.5 - Southern African Power Pool (SAPP)

The SAPP members are the utilities and ministries involved in energy usage in Angola, Botswana, Lesotho, Malawi, Mozambique, Namibia, Swaziland, Tanzania, Zaire, Zimbabwe and South Africa. The transmission systems in the majority of these countries are interconnected. A fundamental SAPP objective is to allow wheeling of energy through the transmission systems, where wheeling is the transfer of power through a country who is neither the buyer or the seller of the power.

The original wheeling charge was based on the postage stamp principle. This applied a scaling factor of 7.5% to the value of the energy wheeled through one country, or 15% if the energy was wheeled through two countries, split between the two countries. The increase (or decrease) in loss was supplied by the seller of the energy and paid for by the buyer.

This method was replaced in 2003 by a MW-km methodology where the charges are determined according to the proportion of assets used for wheeling. The use of assets for wheeling purposes is determined using load flow studies to calculate the proportion of total available capacity on each contract path accounted for by a wheeling transaction. Wheeling charges are then levied in accordance with this proportion as a share of the total asset values affected by the wheeling transaction.

Work was undertaken in 2005/6 to develop a nodal transmission pricing model, however due to various regional factors which resulted in a significant reduction in the amount of wheeling being undertaken with SAPP this has not yet been implemented. This was designed to coincide with the introduction of a Day-Ahead Market (DAM), which permits trading across constrained interconnectors in real time. A relatively sophisticated market model has been introduced that permits the splitting of the SAPP region into market zones that are able to split as constraints become binding on the interconnectors, with differentiated prices in each zone.

3.6 - Great Britain

National Grid is the System Operator for the Great British (GB) system covering England, Scotland and Wales. Transmission Network Use of System (TNUoS) charges reflect the cost of installing, operating and maintaining the GB transmission system. TNUoS charges are allocated at 27:73 split with 27% of the charges being levied on generators and 73% on demand.

The GB transmission system is divided into 14 geographical demand zones and 20 generation zones.

The GB transmission pricing methodology is based on a nodal pricing methodology. The TNUoS charges reflect not only the incremental cost of transmission but also take into account a locational factor. A DCLF (Direct Current Load Flow) ICRP (Investment Cost Related Pricing) model is used to determine marginal cost of investment which would be required as a consequence of an increase in demand or generation at each node on the transmission system. From this the TNUoS are developed. In some zones there are negative charges providing an incentive for generators.

Transmission losses are recovered as part of the energy market, through the application of loss factors that relate the impact of generation and demand at specific nodes on the network to marginal changes in losses in the whole transmission system.

Transmission congestion management is dealt with by the use of constraint management balancing services.

3.7 - United States: PJM

PJM is a regional transmission organisation which is responsible for the movement of wholesale electricity in all or parts of 13 states and the District of Columbia. PJM manages the continuous buying, selling and delivering energy. PJM undertakes interconnection management and is the market operator.

Demand users (load) pay for the cost of transmission infrastructure i.e. 100% transmission costs are allocated to the demand customers in accordance with their energy usage. PJM uses locational marginal pricing (LMP) that reflects the value of the energy at the specific location and time it is delivered. Prices are calculated for individual buses, aggregates, and transmission zones hence this is a form of nodal pricing.

If the lowest-priced electricity can reach all locations, prices are the same across the entire grid. However when there is transmission congestion, the locational marginal price is higher in the affected locations. Financial Transmission Rights (FTR) are used to provide a hedging mechanism that can be traded separately from the transmission service. The congestion rents are used to pay the holders of FTRs.

The PJM Day-Ahead Market is a forward market where hourly LMPs are calculated for the next operating day based on generation offers, demand bids and scheduled bilateral transactions. The Real-Time Market is a spot market in which current LMPs are calculated at five-minute intervals based on actual grid operating conditions.

The California Independent System Operator also uses LMPs.

3.8 - New Zealand

The New Zealand transmission network comprises the North and South Islands. TransPower is the transmission system operator and the owner of grid in New Zealand.

The New Zealand transmission pricing methodology reflects locational marginal pricing and is based on full nodal pricing. Transmission use of system charges comprise an interconnection charge for all the load customers. This interconnection charge is calculated as the weighted-average RCPD (Regional Coincident Peak Demand). The costs of the HVDC link between the north and south island are charged for the generators only on the south island. 100% of the other transmission costs are allocated to loads.

NZEM, the New Zealand wholesale Electricity Market, calculates prices that reflect the cost of electricity at a node. The energy market is driven by long term bilateral contracts alongside a spot market. Contract and spot markets together are collectively referred to as the wholesale market.

Transmission losses and congestion costs are reflected in the half hourly prices that are generated for each of the pricing nodes in the market.

3.9 - Brazil

In Brazil, the National Electric System Operator (ONS) is responsible for managing the dispatch of electric power from the generating stations in optimal conditions. The transmission related costs are split as 50% to generation and 50% to demand and a nodal pricing system is used to calculate the transmission related charges.

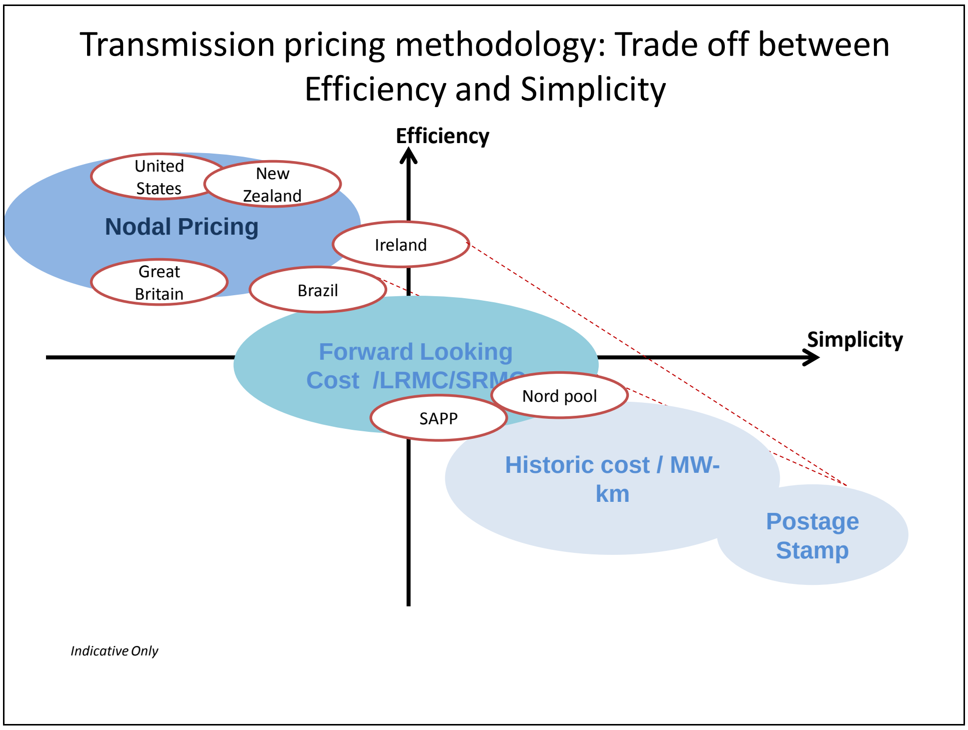
Up to 20% of transmission costs are recovered by a flow-based cost allocation. The flow based method is very similar to LRMC and is more suitable to lines with large power flows, as it enables a higher percentage cost recovery if utilisation is measured in relation to the capacity of the lines. The remaining 80% of the cost is recovered from charges based on peak usage for load or maximum capacity for generators.

The self-producers with a consumption unit connected directly to the basic grid are subject to a different charging mechanism. These charges are calculated on nodal basis and are associated with the connection point of the generation, with the addition of an element of socialised sectoral charges.

3.10 - Comparison of International Methods

Figure 2 show a graphical comparison of the international methods of transmission pricing reviewed above, giving an estimate of where they are located on axes indicating relative economic efficiency vs. the simplicity of the method in its application.

Figure 2: Comparison of International Methods of Transmission Pricing



The chart demonstrates in relative terms the strengths and weaknesses of the different approaches. In summary, it can be observed that whilst nodal pricing approaches in overall terms offer relatively high levels of economic efficiency, this comes at the price of significant complexity in the development and application of the methods. It should be noted that the choice of method for any international market is highly dependent on the nature of the market itself; in addition, the observations about efficiency and complexity that emerge relate only to the process of recovering the costs of transmission network assets. They do not consider wider issues such as the effectiveness of the market trading arrangements.

The trade-offs involved between simplicity and efficiency are one factor that needs to be considered in developing wheeling charge methodology recommendations for ERERA.

4 - REVIEW OF RESPONSES TO QUESTIONNAIRES

4.1 - Responses received and circular tour

Responses were received from the following countries:

- Côte d'Ivoire
- Benin
- Senegal
- Togo
- Burkina Faso
- Mali
- Nigeria
- Ghana
- The Gambia

Countries visited in the circular tour, scheduled over the period 28th January to 6th March 2013: The consultant visited six countries in addition to Ghana, in order to clarify responses to the questionnaire and obtain more detailed information. The list of countries is agreed as follows:

- Francophone countries
  - Côte d'Ivoire
  - Senegal
  - Togo
  - Burkina Faso
- Anglophone countries
  - Nigeria
  - Ghana (data was collected by local representative) and team met with ERERA to discuss transmission tariff methodology

  - The Gambia

- ERERA offered to contract the appropriate authorise in these countries to assist in the provision of visas, and to arrange meetings.

4.2 - Transmission Tariff methodologies within ECOWAS countries

4.2.1 - Introduction

All countries are vertically integrated with the exception of Ghana and Nigeria. The transmission tariff is only separately calculated in Ghana and Nigeria.

The review of the ECOWAS countries covers the methods for the evaluation of assets, calculation of Weighted Average Cost of Capital (WACC), calculation of transmission revenue requirements and calculation of tariff.

4.2.2 - Summary of key factors from questionnaires and visits

The following table is a summary of the in country transmission charges for ECOWAS members:

Table 4-1 Transmission charges summary for ECOWAS member countries

	Country	Benin	Burkina Faso	Cap Vert	Côte d'Ivoire	Gambia	Ghana	Guinée	Guinée Bissau
LOCAL TRANSMISSION CHARGES									
	Unbundled ?	Partially	No		Partially	No	Partially		
	Separate KVA charge ?				Yes	No			
	Portion generator pay of transmission	> 0			0%	0%			
	Locational transmission prices ?	No			Yes	No	No		
	Transmission losses calculated separately ?	Yes	Yes		Yes	No	Yes		

Country	Libéria	Mali	Niger	Nigeria	Senegal	Sierra Leone	Togo	
Unbundled ?		No		No	No		Partially	
Separate KVA charge ?		Yes		No but 20% fixed prop			No	
Portion generator pay of transmission		0%		0%			0%	
Locational transmission prices ?		No		No	No			
Transmission losses calculated separately ?		No		Yes	Yes		No	

The following table is a summary of the international trading and associated transmission charges between ECOWAS member countries

Table 4-2 International trading in ECOWAS member countries

Country	Benin	Burkina Faso	Cap Vert	Côte d'Ivoire	Gambia	Ghana	Guinée	Guinée Bissau
INTERNATIONAL TRADING								
Is wheeling allowed?				No	N/A			
Can consumer buy from international IPP	No			No	No			
Can IPP export?	No			No	No			
Is utility purchasing power from neighbouring countries?	No?			No	No			
Is utility purchasing power from non neighbouring countries?	No			No	No			
Is there congestion on international connectors	No			No	No			

	Country	Libéria	Mali	Niger	Nigeria	Senegal	Sierra Leone	Togo	
	Is wheeling allowed?				No			No	
	Can consumer buy from international IPP		No		No			No	
	Can IPP export?		No?		No			Yes	
	Is utility purchasing power from neighbouring countries?		Yes (no charge) ?		No			Yes (only CEB, so no wheeling charge)	
	Is utility purchasing power from non neighbouring countries?		No		No			Yes (only CEB, charges unknown)	

4.2.3 - Valuation of Transmission Assets

Transmission investments are capital intensive and the value of the transmission assets is an important component of determining the transmission tariff.

Table 4-3 Valuation of Transmission Assets in ECOWAS member countries

	Country	Benin	Burkina Faso	Cap Vert	Côte d'Ivoire	Gambia	Ghana	Guinée	Guinée Bissau
VALUATION OF TRANSMISSION ASSETS									
	Asset Valuation				Value after depreciation	Value after depreciation	Depreciation Replacement Cost		
	Depreciation Period HV Lines				25	40			
	Depreciation Period Transformers				25	40			

	Depreciation Period Substations, Building				25	40			
	Depreciation Period Other (IT,…)								
	Other comments								

	Country	Libéria	Mali	Niger	Nigeria	Senegal	Sierra Leone	Togo	
	Asset Valuation		Value after depreciation		Depreciation Optimised Replacement Cost (DORC)	Value after depreciation			
	Depreciation Period HV Lines		30		50	25			
	Depreciation Period Transformers		30		50	25			
	Depreciation Period Substations, Building		25		50	25			
	Depreciation Period Other (IT,…)				10				

For example SENELEC values assets in a given year at Ki, which is calculated as follows:

$$Ki = (K_0 + \sum_{j=0}^{i-1} I_j) + \frac{\sum_{j=i}^{i+p-1} I'_j}{p}$$

Where K_0 the value of all assets of the networks as estimated in 1999

I_j the total of real investments in year j

I'_j the total of forecast investments for year j

i the number of years after 1999

p the duration of the period (here p = 3)

4.2.4 - Calculation of Weighted Average Cost of Capital (WACC)

The calculation of Weighted Average Cost of Capital is to provide a return on existing assets and possibly incentives for future investment. The cost of capital is an important component of the tariff and is included in the annual revenue requirement calculation as a return on the value of capital invested.

The value of the assets for the particular period with the WACC determines the income to the asset owner.

WACC mainly considers the cost of debt, the rate of return on equity and the ratio between debt and equity. However other factors such as exchange rate, inflation rate and tax on company profits are also included. Care needs to be taken when comparing one WACC against another.

Table 4-4 Investment Conditions in ECOWAS member countries

Country	Benin	Burkina Faso	Cap Vert	Côte d'Ivoire	Gambia	Ghana	Guinée	Guinée Bissau
INVESTMENT CONDITIONS								
RoE authorized					13%	8%		
RoE real						5%		
MIN WACC (real after tax WACC)					5%			
MAX WACC					12%			
MIN internal loan rate					20%			
MAX internal loan rate					20%			
MIN external loan rate				3%	5%	5%		
MAX external loan rate				5%	12%	12%		

	Country	Libéria	Mali	Niger	Nigeria	Senegal	Sierra Leone	Togo	
	RoE authorized								
	RoE real								
	MIN WACC (real after tax WACC)		7%		7%				
	MAX WACC		7%		7%				
	MIN internal loan rate				24%				
	MAX internal loan rate				24%				
	MIN external loan rate								

Specific examples of WACC calculations are provided for Nigeria and Senegal as follows:

4.2.4.1 - Nigerian transmission WACC calculation[3]

The cost of capital included in the Multi Year Tariff Order (MYTO) is intended to provide a return on existing assets and appropriate incentives for future investment. The cost of capital is an important component of the tariff and is included in the annual revenue requirement calculation as a return on the value of capital invested. The regulated asset value at the start of a given year is calculated by taking the depreciated replacement cost of capital assets at the start of the immediate proceeding twelve months and adding the investments in new capital assets acquired during the same period.

The Capital Asset Pricing Model (CAPM) is used to estimate a WACC for the Nigerian Electricity Supply Industry. While this approach gives a method for estimating the average cost of capital in a sector and is widely used by regulators, it requires consideration of volatility of returns in the sector as well as the domestic cost of debt. Even in developed economies the calculation of a WACC frequently requires estimation of a number of the inputs. This is the case in Nigeria and most of the inputs in the WACC calculation are, at this point, NERC

[3] Multi Year Tariff Order for Determining Cost of Electricity Transmission and the Payment of Institutional Charges for the period 1 June 2012 to 31 May 2017, NERC Nigeria, 1 June 2012.

estimates. The WACC is set at the level that attracts investment funds to the industry but is not sufficient to produce windfall profits.

The CAPM provides estimates of the appropriate return on equity and the returns to equity are measured in relation to the risk premium on the equity market as a whole. Thus:

$$Re = Rf + ße\,(Rm - Rf) \qquad (1)$$

Where:

R_e is the return on equity

R_f is the risk free rate observed in the market

$ß_e$ is the correlation between the equity risk and overall market risk

R_m is the return on the market portfolio

$R_m - R_f$ is the market risk premium

The WACC lies between the cost of equity and the cost of debt and is calculated as:

$$WACC = Rd \text{ x } D/(D + E) + Re \text{ x } E/(D + E) \qquad (2)$$

Where:

D is the total market value of debt

E is the total market value of equity

R_d is the nominal cost of debt; and

R_e is the nominal cost of equity.

This formulation does not include the effects of tax. The formulation of the WACC that allows for the effects of taxation (T_c) and used extensively by regulators is as follows:

$$\text{Nominal post tax WACC}\,(w) = Re \text{ x } E/V + Rd\,(1 - Tc) \text{ x } D/V \qquad (3$$

Where:

T_C is the company tax rate,

V is the total market value of the business, i.e. debt plus equity

A transformation is applied to derive an estimate of the real pre-tax WACC, as follows:

$$\text{Real pre tax WACC (RW)} = [(1 + w/(1 - Tc)) / (1 + i)] - 1 \quad \text{(4}$$

Where:

W is the nominal post tax WACC, as given by equation (4)

I is the inflation rate

The company tax rate used is the statutory corporation rate of 30% plus 2% education tax.

Estimating the WACC Components for Nigeria

This section provides NERC's estimates of the various components required to calculate a WACC for the NESI. These estimates are then drawn together as shown above in a description of the process used for the first WACC calculation.

The Risk Free Rate for Nigeria

The yield on government bonds is regarded as the risk free rate and NERC has had regard to relevant yields on Nigerian Treasury bonds and has selected a risk free rate of 18%

Many regulators use 10-year bond rates or 10-year (index-linked) bonds or their local equivalent. The longer term also ensures consistency with the risk free rate used to estimate the market risk premium - that is also based on 10-year bonds.

The Cost of Debt for Nigeria

NERC adopted a nominal cost of debt of 24% reflecting current debt levels for most businesses. The cost of debt is generally determined by adding a debt premium, and sometimes a transaction cost, to the risk free rate.

$$Rd = Rf + DRP + DIC \quad \textbf{(5)}$$

Where:

DRP is the debt risk premium

DIC is the debt issuance cost lending in Nigeria

Betas for Nigeria

Betas reflect the risk weighting of an asset relative to the market as a whole (usually represented by the stock market). Equity betas will reflect the financial risk carried by shareholders, which is in turn influenced by the level of gearing since high levels of debt increase the risk to shareholders.

Electricity supply is not an area with any history of investment from which to draw information on the relative risk and it is not considered possible to derive at statistically significant betas.

The Commission has decided not to apply any value to beta for the current tariff order and appropriate estimate will be made against next tariff review when enough data exists for estimates to be made.

Gearing for Nigeria

The ratio of equity and debt is used to weight the equity and debt returns in the WACC calculation. In the past, independent power producers in developing countries were financed with high gearing ratios – commonly 80:20 debt to equity. However, the World Bank considers that in future greater caution by lenders will result in project sponsors being expected to assume a greater degree of the project risk, by accepting lower debt-equity ratios.

The Bank suggested that future ratios would be closer to 60:40. This level would also apply to regulated assets, such as transmission and distribution. The Commission has selected a gearing ratio of 70:30 in the development of the WACC for the NESI.

WACC estimate for Nigeria

The following are the main assumptions used in the WACC calculations:

risk free rate	18%
nominal cost of debt	24%
gearing level (debt/equity)	70:30
corporate tax rate	32%

These assumptions provide the following WACC estimates:

Nominal pre-tax WACC	25%
Nominal post- tax WACC	17%
Real pre-tax WACC	11%
Real after tax WACC	7%

4.2.4.2 - Senegal WACC calculation

The WACC is laid down according to the respective proportions of equity costs and debt cost after tax in the financial structure

g : Estimate of debt/capital ratio = **45%**

Rd : cost of debt after tax = policy rate of BCEAO (6.5%) + bank operating margin (2%) = **8.5%**

Re : Estimated cost of capical = *Rf + β x Rm*

Rf : Risk-free rate of return after State loans taxes = **6.5%**

β: Sensibility = **0.8**

Rm = Rentability premium of the market = **5%**

Ts = Tax rate on tax settlement = **17%**

Tc = Tax rate on corporate profits = **30%**

Therefore :

- Normal WACC before tax = 11.38%
- Normal WACC after tax = 9.6%

4.2.5 - Operating and Maintenance Costs

The countries have included operating and maintenance costs. Internationally these costs are 3-8 % of the replacement value of the transmission assets. Nigeria has the operating and maintenance cost components for variable O&M costs, fixed O&M costs and admin costs as follows.

		2012	2013	2014	2015	2016
TCN Variable O&M Costs - excluding Admin	TSP	9,999,870	11,499,851	13,224,828	15,208,552	17,489,835
	MO	0	0	0	0	0
	SO	0	0	0	0	0

		2012	2013	2014	2015	2016
	Total Variable O&M	**9,999,870**	**11,499,851**	**13,224,828**	**15,208,552**	**17,489,835**
TCN Fixed O&M Costs - excluding Admin	**TSP**	5,271,948	6,754,826	8,297,019	8,628,900	8,974,056
	MO	1,251,518	1,301,579	1,353,642	1,407,788	1,464,099
	SO	2,919,768	3,036,559	3,158,021	3,284,342	3,415,716
	Total Fixed O&M	9,443,234	11,092,963	12,808,682	13,321,029	13,853,870
TCN Fixed Costs - Admin	**TSP**	7,131,412	7,252,646	7,375,941	7,501,332	7,628,854
	MO	169,179	172,055	174,980	177,954	180,979
	SO	2,317,620	2,357,020	2,397,089	2,437,839	2,479,283
	Total Admin	9,618,210	9,781,720	9,948,009	10,117,125	10,289,116

The total Transmission costs amount to Naira 20 million for 2012. Depreciation and Return on capital accounts for Naira 12 million. The proportion between the costs is much higher than the international practice that is probably due to the valuation of the transmission assets at depreciated value and not at replacement value, and a high level of maintenance required due to poor maintenance in the past.

4.2.6 - Transmission losses

Transmission losses in ECOWAS countries is estimated in most countries as there is not sufficient metering.

Incentives are provided for transmission losses to be reduced through incentive based regulation.

The actual performance is difficult to measure and most countries are looking to improve SCADA and metering to get a more accurate measure of transmission losses.

All countries apply losses equally to all consumers and charged to all consumers except for Nigeria. In Nigeria the generator schedule is increased by the average losses (8% for the current year). This generator hence provides and pays for losses and recovers the money through the generation tariff.

4.2.7 - Congestion management

Generation is dispatched on merit order and congestion is managed through the selection of the next cheapest generator that will not cause a constraint.

No ECOWAS country has a market based congestion management philosophy such as apportioning generator outputs or nodal pricing.

Nigeria allocates the total available generation to each DISCO based on relative size. There have been DISCO complaints that some generators are constrained because they cannot export the proportion allocated to other DISCOS because of transmission constraints. These generators could provide the local DISCO but the allocation methodology does not allow this degree of freedom. Hence some of the generators capacity is unallocated and the DISCO who can take the energy is load shedding.

4.3 - Transmission Tariff methodologies between ECOWAS countries

The transmission pricing methodology in the following international electricity contracts between specific member states as provided by ERERA were reviewed:

- Contract CIE – SONABEL between Burkina Faso and Côte d'Ivoire, 6 November 1997

- Contract VRA – SONABEL between Burkina Faso and Ghana, 22 March 2000.

- Contract PHCN – NIGELEC between Nigeria and Niger, 23 June 1992 and amended on 21 December 2010.

- Contract NEPA – CEB between Nigeria, Benin and Togo, 30 October 1997 and amended on5 July 2001.

4.3.1 - Transmission Costing and Charging Methodologies

Transmission charges are not specifically mentioned in any of the PPAs reviewed.

In the Nigeria to Niger and Nigeria to Benin and Togo PPAs it is hinted that the transmission is paid under the PPA but the ownership of the transmission assets and whether the transmission company has included assets in its tariff application is unclear.

If there are transmission charges these are included in the energy tariff.

4.3.2 - Wheeling arrangements

There is no mention of any specific wheeling arrangements in any of the PPA's reviewed

4.3.3 - Open Access

The exclusive first rights of the transmission network belong to the companies that built the international interconnectors. This is common practice and this capacity needs to be respected as a first come first serve principle.

There is no mention of the ability to make excess transmission capacity available for third party users. Therefore a framework will have to be developed for calculating available capacity and allocation methodology any revenue derived from allowing third party access.

4.3.4 - Transmission losses

The PPAs reviewed make the responsibility of transmission losses to the generating company. The point of billing and settlement is at the consumer point of interconnection.

Senelec mentioned there is an allocation methodology for losses between Senegal and Mauritania for energy provided from Mali. The PPA has not been made available to understand the details of the allocation methodology.

4.3.5 - Congestion management

Congestion is not mentioned in any of the PPA's. All transmission capacity must be made available. There is no mention of allocation methodology if a generator provides more than one country across interconnector. Typically there will be an apportioning of the capacity to each country in proportion to their maximum allocation.

5 - REVIEW OF WAPP REPORTS ON TRANSMISSION COSTING AND TARIFF METHODOLOGY

Review of the Nexant report of October 2008, entitled “A Methodology to Calculate the Demand and Energy Components of a Transmission Tariff within WAPP”, and the Mercados reports entitled “Development of WAPP Market Design and Market Rules”, which were commissioned by the WAPP.

5.1 - Market Phases

The implementation of the regional market in the WAPP region is foreseen by Mercados to be in phases; the evolution from the current situation where some trades are carried out using the existing transmission infrastructure and negotiated on a case by case basis is expected to evolve through different stages until a situation with a liquid and competitive regional market with different products to be traded is achieved.

Three phases are considered:

Phase 1: from now to 2015 approximately when most regional transmission infrastructure is expected to be commissioned. Main characteristics of this phase would be:

- Formalise trading that today is carried out on a “case by case” basis and standardise procedures such as:
    - Bilateral agreements (countries, regional companies)
    - Commercial Instruments (type of contracts, short term exchanges)
- Transmission pricing agreed between parties
- Initiate the regional operational and commercial coordination
- Preparation for the following stage
- Regional regulator: enforcement of rules and dispute resolution
- Market operator: appoint an institution which will begin developing market operation functions

Phase 2: based on the preparations carried out during the 1st phase, and will include but not limited to the following:

- Bilateral agreements with transit through third countries, based on standard commercial instruments
- Transactions can be carried out between individual agents of the countries
- Back up of contracts in the market (possibility)
- Short term exchanges through day ahead market (regional optimization model)
- Regional transmission pricing
- Regional System and Market Operator (SMO)

Phase 3: a long term vision which would include:

- A liquid and competitive market in the region made possible by the availability of enough regional transmission capacity and enough reserve in the countries so as to make possible a competitive market.
- Countries or a group of countries can voluntarily decide to put their resources under a common optimisation system. This phase can coexist for some time with phase 2.
- Possibility of trading different product integrating other markets: market for some ancillary services, financial products.

The market phases considered are the same process as the development of the Southern African Power Pool.

Phase 2 has the possibility of an interim phase where short term bilateral trade up to a few hours ahead is allowed through a bulletin board trading mechanism.

The development of a day-ahead market is probably still some way from realisation and requires market certainty and excess capacity not linked to long term bilateral arrangements. Even though the Southern African Power Pool has developed a day-ahead market, phase 2 mentioned above, trades are very small. This is due to:

- Lack of available transmission capacity allocated to the day-ahead market. Most international transmission capacity is allocated to bilateral agreements. The international transmission lines are built for specific bilateral arrangements.

- Lack of spare generation capacity. The SAPP region has a lack of generation capacity in most of the interconnected countries.

The report does not make any proposals on transmission pricing and as the first phase is mainly bilateral trades a MW-km or postage stamp concept is possible as the counter parties to all trades are known.

The network used can be based on the asset identification method used for determining the transit key in ENTSOE and SAPP. That is for 100 MW injection and withdrawal any asset that changes by more than 1 MW is considered as a wheeling asset.

5.2 - Regional Network Owner

The reports mention of a regional network owner in the two consulting documents and we need to identify whether this is a reality or not. In this case all the assets owned by the regional network owner need to be included in the transmission tariff methodology. Probably the best solution would be to move towards a postage stamp system where the costs of the network are recovered by all users on the network. In this case there is no identification method required to identify the assets.

With a regional network owner there needs to be rules dealing with connection charges.

5.3 - Nodal vs Zonal pricing

The reports mention the possibility of zonal and nodal pricing. No conclusions are drawn on this issue except it is not applied in the bilateral trading phase where transmission charges are based on a case by case basis.

The use of zonal and nodal transmission pricing is open to large debate and it is unclear if this drives transmission investment. In all the ECOWAS countries, it is politically unacceptable to have a varying transmission tariff as poorer areas are generally far from the network.

5.4 - What is transmission charges and what does it include?

The Nexant report entitled “A Methodology to Calculate the Demand and Energy Components of a Transmission Tariff within WAPP” details a tariff methodology covering energy, transmission costs, transmission losses and connection charges.

The scope of task 4 is to cover the calculation of transmission network costs including losses and to develop the transmission tariff to recover these costs.

The scope of task 4 includes management of constraints and ancillary services costs with respect to the transmission network. Energy prices including balancing costs are outside the scope of this task. It is expected that energy prices will be either bilaterally negotiated or determined by a central trading platform. Connection Charges should be determined by each country but might be applicable to a regional network but outside the scope of Task 4.

5.5 - Open Access

The principle of "first-come-first-serve" is proposed in both consulting documents for bilateral trades. This is standard practice as the initial transmission asset is justified by the first bilateral agreement and this must have precedence to transmission access.

The consulting papers require that any unused transmission capacity must be released back to the various trading markets. This is a principle that must be adhered to.

The allocation of transmission when clearing a particular market is subject to the rules of the market. The reports mention the options of pro ratio, cheapest energy first and market splitting.

The allocation of transmission capacity is technically outside the scope of Task 4 but the principle of "first-come-first-serve" for bilateral trades and releasing unused capacity is possibly the best solution.

5.6 - Transit flows and loop flows

The Nexant report proposes the following definitions for transit and loop flows:

Transit load flows

Transit load flow *is a load flow pattern in which country A receives power at the border with B and delivers power at the border with C, to implement transactions among market participants outside A. In other words, even when electric energy is flowing through the network of power company A, there is no transit load flow unless the transmission system operator of A is helping to implement transactions among market participants outside A. Transit load flow does not exist in a situation in which power company A imports energy from power company B on the basis of a power purchase agreement with B, and exports energy to power company C under a separate agreement. For example, suppose there is a town in country A which depends on electric energy imports from a nearby power station in B, and a town in country C that depends on imports from nearby power station in A. In this case power company A is a buyer on one border and a seller at the other border, but there is no transit.*

From a tariff standpoint, transit load flows raise some very difficult issues, which have been discussed in great detail in the European electricity market. However, it is important to keep in mind that the simplest trading arrangements in the WAPP region do not need to involve transit load flows at all. It would be possible for the member companies of WAPP Zone A to agree that there will be no transit load flows at all, during an initial phase of transmission tariff development. In this case the trading arrangements will be simple: when country B has a power surplus and country C has a power deficit but country A is located in the middle, A would have two separate agreements – an import contract with B, and an export contract with C.

In this situation, if A chooses to act like a monopolist, and tries to capture 100% of the margin between B's export price and C's import price, A's behaviour will be detrimental to economic efficiency and it will be "unfair" to B and C. Therefore a decision to prohibit transit load flows would not be a good solution for the later phases of electricity market development. However, it would be a simple way to defer discussion of the complicated tariff issues related to transit load flows.

If transit load flows are allowed, transit fees might be subject to regulation by the national regulatory authorities. If the national regulatory authority of country A calculates a "transit fee" in the form of a price per kWh, but instead of a transit load flow there are two separate agreements - to import from B and export to C - the regulatory authority could suggest that the price in the export contract with C equals the price in the import contract with B plus the "transit fee." However, from a legal perspective international trade would have to be regulated on the basis of cooperation among national authorities, or on the basis of the creation of a regional regulatory authority.

Loop flows

In the European electricity market the analysis of the cost of loop flows is closely related to the analysis of the cost of transit flows; the Inter-TSO Compensation mechanism is intended to deal with both of these issues. In the early phases of development of the high voltage network of the WAPP region, it is possible that there will be no loop flows simply because the grid will have a "linear" structure. Suppose, for example, that all power flows in Zone A can be described in terms of a single transmission corridor based on the Coastal transmission backbone plus the Cote d'Ivoire-Burkina Faso interconnection plus the Nigeria-Niger interconnection. In this situation the question of who should pay for loop flows is not an issue that needs to be solved in the near term. Rather, it is an issue that may be addressed in the later phases of regional market development when there are additional transmission corridors such as Burkina Faso-Niger, Burkina Faso-Ghana, and so on.

The principles proposed are correct. The ENTSO methodology for determining the use of the transmission network looks at the minimum of net imports and net export. The examples Country A buying from country B and in a separate transaction Country A selling to country B will create a wheeling transaction if both transactions are entered into a day-ahead market clearing platform (such as is required for SAPP). The points are:

- Are these two transactions likely to occur, because it would be cheaper for Country C to buy directly from Country B. Unless of course country A is making a loss.

- Power provided to neighbours on a distribution level are not recorded as international trades so there are no energies to be billed. Further because the lines are radial the assets will not be counted as a wheeling asset.

- Country A should charge Country B an import transmission tariff (as a generator at the border between A and B) and Country C as an export transmission tariff (as a consumer at the border between A and C). When these transmission charges added together it will be close to the wheeling charge if the same asset value and rate of return on asset is used.

5.7 - Transmission tariff

The transmission tariff determines how costs are recovered from users of the transmission network.

The Mercados report does not propose a transmission tariff methodology. The report suggests that the transmission tariff should be negotiated bilaterally between the parties for bilateral trades. The report also mentions that the regional regulator and country regulators could oversee the process.

The Nexant report proposes the following possible methods for transmission tariff:

Alternative methods of recovering the cost of transit and loop flows, in transmission pricing

Four alternative methods of recovering the cost of transit and loop flows were discussed at the 1st meeting of the transmission tariff task force:

- Concept #1: The whole regional network is owned and operated by one big transmission company.

- Concept #2: The regional network consists of several zones. In each zone, the TSO owns the network assets. TSOs charge transit fees and export fees.

- Concept #3: In each zone, the TSO owns the network assets. TSOs pay each other for costs related to transit, through an Inter-TSO Compensation mechanism.

- Concept #4: In each zone, the TSO owns the network assets. TSOs pay each other, based on the difference between total revenue and total fixed cost in each zone.

The Nexant report further notes:

The introduction of transmission tariffs into the WAPP region will have to proceed in a serious of steps, beginning with a relatively simple transmission tariff structure and moving toward a more sophisticated tariff structure. To develop a methodology for calculating capacity and energy charges we need to define the assumptions for the first phase of the regional electricity market. It is important to note, however, the method of recovering the cost of transit and loop flows does not need to be "fixed" throughout the whole period of market development. The method chosen for the final phase of the market will probably be different from the method chosen for the initial phase.

For the tariff methodology developed in this study, Concept #2 was selected. The following statement was issued by WAPP and approved by the task force:

The introduction of transmission tariffs into the WAPP region will have to proceed in a serious of steps, beginning with a relatively simple tariff structure and moving toward a more sophisticated tariff structure. The concept No. 2 is the one which fits more the present and predictable level in the medium term of the energy exchanges within WAPP.

The report correctly notes that transmission tariff will sometimes have to change as the market develops. This is very dependent on the market structure of any new developments.

The approval of Concept # 2 needs to be confirmed with WAPP. In this concept only consumers pay a transmission tariff. Some of the key assumptions around capacity charges based on allocated transmission capacity, scheduled or actual energy flows is not reported on. Key to our work is whether this concept is already embedded in the existing bilateral arrangements?

5.8 - Transmission asset determination

The Nexant report proposes that Transmission is defined as 132 kV and above. This definition needs to be confirmed with ERERA. Nexant further proposes for phase 1:

Phase 1: Bilateral trading, with transit flows only in Ghana. Measurement of Net Transfer Capacity (NTC). Unbundling of accounts for the regional network

Under the leadership of the transmission task force, WAPP power companies will identify the transmission lines and substations that are part of the regional network and are projected to be used for import, export, and transit. The regional network includes four voltage levels: 330 kV, 225 kV, 161 kV, and 132 kV. All other transmission lines and transmission substations belong to the national networks. Each power company will calculate the number of km of transmission line (by voltage level) and the number of kVA of transformer capacity (by voltage level) in its portion of the regional network. Each power company should provide a short explanation of the methodology it used to identify the regional network within its country or countries of operation. All of this technical information should be provided to the ICC.

In addition, each power company will estimate the net book value of the assets in the regional network, and show the components of this total i.e. the net book value of transmission lines (by voltage level) and transformer substations (by voltage level). Each power company should provide a short explanation of the methodology it used to calculate net book value (for example, historical cost or replacement cost) and the number of years over which various categories of transmission assets are depreciated. All of this accounting information should be provided to the ICC.

The proposal that the determination of what the transit network is in each country to the individual countries opens the area of disputes and varying methodologies to suit individual countries. A common methodology should be used to determine the transmission network and the proportion of the network used for transit flows.

The proposal that each country determines asset values is not ideal there should be a common database where all agree on asset values. The valuation of the assets based on current depreciated value or replacement value needs to be agreed by all members.

The proposal again brings up the possibility of various zones and transmission companies. The methodology for each zone could be different and this could lead to complications if the zones are interconnected.

5.9 - Private Sector Participation

The Nexant report brings up the complexity of private transmission companies requiring rate of return on assets for transmission based on the source of funding and equity return requirements.

Whilst this is a complex issue this could be solved by agreeing to a different Weighted Average Cost of Capital (WACC) for private investment as opposed to government funded transmission.

5.10 - Transmission tariff point to point vs nodal

The Nexant report compares two final options for a transmission tariff:

- A postage stamp tariff, or
- Point-to-point service with distance-related tariff

The proposal is that the postage stamp tariff is the only solution that will work with a power exchange in operation.

The WAPP transmission tariff task force also preferred zonal pricing over nodal pricing. Zonal in this document is interpreted as each country having a different loss factor depending on position and flows on the network. This similar to methodology developed for SAPP.

No ECOWAS country has nodal or zonal transmission tariff pricing. Thus there is no current need to blend zonal and nodal countries into the regional methodology.

5.11 - Congestion management

There is mention of congestion management in both Nexant and Mercados reports. The expectation is that transmission congestion will be handled by market mechanisms and not through the transmission tariff.

We are in agreement with the congestion proposals for two reasons:

- In the bilateral market the principle of first-come-first serve is proposed. The older bilateral agreements have the first right to the transmission capacity. Any bilateral transaction that exceeds available transmission capacity is curtailed or excluded. Transmission congestion is managed at this level.
- Centrally cleared markets will have market splitting or nodal techniques to solving congestion. Thus the problem is solved in the market clearing.

6 - KEY POINTS FOR DISCUSSION AT WORKSHOP ON TRANSMISSION PRICING AND TARIFF METHODOLOGY

6.1 - Definition of regional transmission network

Three options for consideration

- Regional transmission assets are owned by a regional transmission company

- Transmission assets based on contractual flow

- Transmission assets defined by transit load flow studies. SAPP and ENTSO use a rule where any asset where the flow changes by more than 1 MW for 100 MW injection and extraction through the network is included in the transit asset database.

6.2 - Definition of transit flows and loop flows

Transit load flows

Transit load flow *is a load flow pattern in which country A receives power at the border with B and delivers power at the border with C, to implement transactions among market participants outside A. In other words, even when electric energy is flowing through the network of power company A, there is no transit load flow unless the transmission system operator of A is helping to implement transactions among market participants outside A. Transit load flow does not exist a situation in which power company A imports energy from power company B on the basis of a power purchase agreement with B, and exports energy to power company C under a separate agreement. For example, suppose there is a town in country A which depends on electric energy imports from a nearby power station in B, and a town in country C that depends on imports from nearby power station in A. In this case power company A is a buyer on one border and a seller at the other border, but there is no transit.*

Loop flows

Loop flow *is a load flow pattern in which country A receives power at the border with B through transmission line 1 and delivers power at the border with B through transmission line 2, to implement transactions among market participants outside A. In other words, even when electric energy is flowing through the network of power company A, there is a loop flow when the transmission system operator of A is helping to implement transactions among market participants outside A.*

Loop flows currently do not exist in ECWAS countries are methodologies to solve loop flows transmission charges not going to be specifically considered in the current methodology.

6.3 - Point of connection to regional transmission network

For bilateral agreements there are two options for the point of connection:

- Point of connection is at the generator / consumer substation, or
- Point of connection is at the boundary of the country of export.

If the point is at the boundary then the individual countries' regulators will determine the transmission charges from the generator to the boundary. The individual countries' regulators treat the export as a consumer at the border. An importing country regulator treats the import as a generator at the border of the country. In this case there are no specific regional transmission charges for neighbouring bilateral contracts.

6.4 - Calculation of the transit flow through a network

Transit flows can be calculated three ways:

- Scheduled or measured imports and exports. Based on schedule or actual flows through a particular country as import / export charges.
- Scheduled transit flows. Transits flows through a third party country are based on bilateral contractual information. Each bilateral contract will be charged for transit flow through any country based on contractual flows and not on physical flows. This is the basis of current ECOWAS bilateral arrangements. Scheduled transit flows that are opposite in direction needs to be clarified.
- Load flow based transit flows. Transit flows based on net measured flows. This is the EU method where the net flow is the minimum of total import and total export (min (import, export)).

6.5 - Calculation of asset value

Three methods for calculating asset value.

- Depreciated cost. This is the most popular method for single investments. The asset needs to be paid for and there is no need to accumulate profit for future transmission investments.

- Depreciated replacement cost. This method is used in Nigeria recognises that the replacement of specific parts of the transmission line (transformer, switch gear) will be at current asset value.

- Replacement cost. Transmission companies accumulate profits for future transmission expansion. This method is often used for countries where network is expanding and transmission company is incentivised to develop the network.

In addition to the above methods future approved investments are often included to allow the transmission network to build up equity for investment plans over the next 5 or so years. Future investments are also bankable as loans repayments are in the revenue base.

6.6 - Calculation of WACC

The methodology used in Nigeria and Senegal for calculating WACC is proposed.

The formula provides estimates of the appropriate return on equity and the returns to equity are measured in relation to the risk premium on the equity market as a whole. Thus:

$$Re = Rf + ße\,(Rm - Rf) \quad (6)$$

Where:

R_e	is the return on equity
R_f	is the risk free rate observed in the market
$ß_e$	is the correlation between the equity risk and overall market risk
R_m	is the return on the market portfolio
$R_m - R_f$	is the market risk premium

The WACC lies between the cost of equity and the cost of debt and is calculated as:

$$WACC = Rd \times D/(D + E) + Re \times E/(D + E) \quad (7)$$

Where:

D is the total market value of debt

E is the total market value of equity

R_d is the nominal cost of debt; and

R_e is the nominal cost of equity.

This formulation does not include the effects of tax. The formulation of the WACC that allows for the effects of taxation (Tc) and used extensively by regulators is as follows:

$$\text{Nominal post tax WACC}\,(w) = Re \times E/V + Rd\,(1 - Tc) \times D/V \qquad (8$$

Where:

T_C is the company tax rate,

V is the total market value of the business, i.e. debt plus equity

A transformation is applied to derive an estimate of the real pre-tax WACC, as follows:

$$\text{Real pre tax WACC}\,(RW) = [(1 + w/(1 - Tc)) / (1 + i)\,] - 1 \qquad (9$$

Where:

W is the nominal post tax WACC, as given by equation (4)

I is the inflation rate

6.7 - Taxation on International Transmission Company Profits

The formula for WACC allows for company taxation of the transmission companies profits. The transmission company will be registered in one particular country and the taxation will apply to that country only.

Intergovernmental agreements will have to be reached if an alternative taxation arrangement is required.

6.8 - Who pays Transmission Tariff

Transmission tariff can be paid by generators, consumers or a percentage each.

In ECOWAS countries only consumers pay the transmission tariff. In vertically integrated utilities the transmission tariff is embedded in the end use tariff.

Allocating a portion of transmission tariff to generators encourages them to seek places on the network where there are no other generators. In reality, the location of a generator is driven by the location of primary energy and access to transmission network.

Therefore for ECOWAS consumer pays is recommended.

6.9 - Zonal, Nodal or flat Transmission Tariff

- Zonal is where a group of sub stations pay the same price for transmission tariff. The group can be a transmission company or all the transmission in a country.
- Nodal is charge per transmission substation or higher than an agreed voltage level. No ECWAS country has nodal charging.
- A flat transmission tariff is either a percentage of the transaction value or equal allocation per kWh traded.

6.10 - Connection Charges

ECOWAS countries have connection charges which pay for the lines required to the nearest substation. Network strengthening from that substation is the transmission company's responsibility.

Connection charges should apply in the country of location if the generator connects to the local transmission system. Where dedicated lines are built for international trade, these lines are compensated for under the international transmission charges and no specific connection fee is required.

6.11 - Managing Transmission Congestion

Transmission congestion is solved in the bilateral agreements phase by the first come first serve principle. When central trading platforms are introduced then congestion is managed through the central clearing process. The management of congestion in bilateral and central clearing is the market operator's responsibility, in this case WAPP.

The regional regulator needs to ensure the process for allocating transmission capacity is fair.

6.12 - Calculating Available Transmission Transfer Capacity (ATC)

The available transmission capacity needs to be calculated on a regular basis to enable short term trading. The available transmission capacity is the available capacity for bilateral trading after long term bilateral trades are considered. The available transmission capacity considers limitations due to short term support, thermal transmission limits and dynamic transmission transfer limits.

It is proposed that bilateral agreements for hours of the following week are sent to WAPP on Thursday 12:00. This should be the firm capacity and expected physical flows not just the contractual flows. WAPP then publishes available capacity for each hour of the week ahead. This will allow short term trading to begin as countries enter into bilateral short term surplus agreements. The time period can be adjusted to day ahead once market participants are actively trading.

6.13 - Calculation of Transmission Losses

Transmission losses can be estimated using two techniques:

- Measured losses. Measurement of losses is easy for long transmission lines where meter accuracy is not a significant portion of the losses. In a single transmission system the transmission losses can be calculated relatively easily. Calculation of losses using this method works well in centrally cleared markets where generators and consumers are measured at their point of connection and the losses is defined as the mismatch between the two.

- Calculated losses. Transmission losses can be estimated through load flow studies. Typically the studies are DC load flow studies for typical load flow periods for peak and off peak and seasonal flows. The transmission losses calculated are theoretical minimum losses and penalises transmission companies who are not operating efficiently. If load flow patterns change due to change in network configuration, changing of generation pattern, or commissioning of a new generator then losses needs to be recalculated.

6.14 - Who pays Transmission losses

Transmission losses can be compensated for by generators or consumers or a combination thereof. There are the following techniques available:

- Generators schedule adjusted for losses.
    - All generators can be adjusted by an equal amount

    - Generator schedule could be adjusted according to position in the network (nodal or zonal)

- Consumer pays for losses
    - All consumers pay the same amount
    - Consumers pay according to location in the network (nodal or zonal)

- Consumers and generator pay according to their position in the network. Marginal loss factors are calculated by injecting 1 MW and calculating the marginal change in transmission losses. This method introduces the concept of negative losses where generators are compensated for reducing losses.

6.15 - Ancillary Services

Ancillary services can be grouped into three broad categories:

- Frequency control services which includes the provision of operating reserves,
- Voltage control services including the provision of reactive power and reactive power reserves, and
- Black start and restoration services.

Transmission companies are only directly involved in the provision of voltage control services. This would be the provision of specialised equipment for voltage control such as Static Var Compensators (SVC), Static Compensator (Stat Com) or Synchronous Condensers.

The compensation of the specialised transmission equipment can be through two methods:

- Through the transmission tariff. The specialised transmission device is compensated by all consumers as all consumers benefit from a stable transmission system. The asset and operating costs are included in the transmission tariff application and not as an ancillary service.
- Compensated by a specific consumer/s or generator/s who directly benefit from the installation of the specialised device. This method is common when the device is specifically installed for increasing transfer capability (or stability) on a specific transmission line. The

compensation is then regarded as an ancillary service, but not paid for by all the users of the transmission network.

7 - ANNEX 1 – TERMS OF REFERENCE

A copy of the Terms of Reference for all Activities was included in the Inception Report.