**Technical Support for Continued Support on Regional Market Framework Implementation to RERA**

Transmission Pricing Methodology

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Acronyms

|  |  |
| --- | --- |
| AfDB | African Development Bank |
| BPA | Blanket Purchase Agreement |
| DAM | Day Ahead Market |
| DOS | U.S. Department of State |
| ENR | Bureau of Energy Resources |
| ENTSO-E | European Network of Transmission System Operators for Electricity |
| ERERA | Economic Community of West African States Regional Electricity Authority |
| IDM | Intra Day Market |
| IPP | Independent Power Producer |
| LRIC | Long-run Incremental Cost |
| LRMC | Long-run Marginal Cost |
| MIF | Market and Investment Framework |
| NGET | National Grid Electricity Transmission PLC |
| POC | Point of Connection |
| RERA | Regional Electricity Regulators Association |
| RTO | Regional Transmission Organization |
| SADC | Southern African Development Community |
| SAPP | Southern African Power Pool |
| SMO | System and Market Operator |
| SOW | Scope of Work |
| SRIC | Short-run Incremental Cost |
| SRMC | Short-run Marginal Cost |
| STEM | Short Term Energy Market |
| TNUoS | Transmission Network Use of System |
| TSO | Transmission System Operator |
| UTT | Unit Transmission Tariff |
| WAPP | West Africa Power Pool |
| ZIZABONA | Zambia, Zimbabwe, Botswana, and Namibia |

# Executive Summary

Work under *Technical Support for Continued Support on Regional Market Framework Implementation to the Regional Electricity Regulators Association of Southern Africa (RERA)* is funded by the United States Department of State (DOS) through the Bureau of Energy Resources (ENR) Power Sector Program (PSP). This work will continue support to RERA, as well as three selected pilot countries – Zambia, Namibia, and Botswana – to develop tools and procedures identified by the Market & Investment Framework (MIF) and the Framework Roadmap. The primary objective is to make further progress with specific generation and transmission projects, as identified by the Southern Africa Power Pool (SAPP) and RERA and to increase SAPP membership and participation in the regional electricity market.

The regional transmission capacity needed to facilitate cross-border power trading in the Southern African region remains highly constrained due to the lack of investment in new infrastructure and enhancement of capacity of the existing infrastructure. Meeting national and regional electricity demand through competitively operating transmission interconnections requires development of transmission interconnection tools that incentivize the development of cross border transmission infrastructure.

An important component of a transmission interconnection toolkit is a transmission pricing methodology that is consistent or harmonized across countries in the Southern African region and in the member countries of the Southern Africa Power Pool (SAPP). This report examines some of the key issues that must be considered in the development of a transmission pricing methodology that can be consistently applied across the SAPP region.

With the goal of proposing a transmission pricing methodology consistent with current conditions in the region, the Deloitte Team sought to build on past efforts by SAPP and the Regional Electricity Regulators Association of Southern Africa (RERA). During the course of this project, the Deloitte Team conducted a sustained effort to secure an NDA with SAPP (through RERA), in order to obtain detailed information on existing and proposed cross-border transmission tariff agreements and guidelines. However, the required NDA was never secured. As a result, the Deloitte Team has only examined publicly available information on the existing approaches for pricing cross-border transmission services within SAPP.

This report is based on discussions and a review of information gathered during the Inception Mission and a subsequent trip to the region during which the Deloitte Team met with stakeholders in the three pilot countries. It is also informed by a review of international leading practices in transmission pricing methodology for cross-border connections.

# BACKGROUND ON Cross-Border Transmission Pricing

## What are Cross-border Transmission Tariffs?

The principal functions of a cross-border transmission tariff structure and tariff are to recover the cost of transmitting power through an interlinked transmission network, and to fairly allocate tariffs to all counterparties and entities through whose network assets power flows. The tariff structure and tariff can vary depending on the objectives and network operational considerations, which may include:

Recovery of capital costs of the line and operational and maintenance costs;

Levy on the basis of capacity (MW), consumption (MWh), or both;

Inclusion of charges to recover the costs of ancillary services and losses and network congestion;

Deep, shallow, or hybrid connection charges for entities accessing the transmission network[[1]](#footnote-2);

Locational and marginal cost charges based on the point and time of interconnection;

Reconciliation to fully recover all costs incurred by the transmission system operator and owner;

Recovery of marginal or historical costs associated with the transmission network; and

Recovery from only the generator or the generator and the load.

The entity responsible for covering transmission costs varies between electricity markets. Costs may be borne by the generator only, the load only or shared between the generator and load. In cases where the generator and load share the costs, the allocation of costs between the two entities varies across markets and countries. The objectives for the electricity market, and the fair and transparent allocation of costs to foster efficient operations and competition, drive the rationale for the pricing mechanism. For instance, in EU electricity markets, load and generation may have different incentives for the use of the transmission system in different countries[[2]](#footnote-3). To foster market integration, the EU markets more often apply time of use pricing signals and Entry Exit pricing rather than locational price signals, which was found to hinder trade. The recovery of costs incurred from transmission losses and provision of ancillary services also varies across European countries.

The long-term objective for an integrated Southern African electricity market should be to develop an efficient cross border pricing mechanism that lowers the cost of meeting customer demand though price signals that accurately reflect the cost of transmitting electricity.

## Principles of Cross-border Transmission Pricing

Transmission charges are driven by the principles of cost reflectivity and cost recovery, and include the following charges:

Use of the transmission network;

Ancillary services (Spinning and Non-Spinning Reserves, Scheduling and Dispatch, Load Following, Voltage and Frequency Control, Black-start capability, etc.);

Transmission losses; and

Connection.

Some of the key principles of cross-border transmission pricing include the following[[3]](#footnote-4):

Non‐discriminatory access to transmission infrastructure and transparent tariffs to enable cross-border trading;

Independent and transparent regulatory review and oversight over transmission services agreements for cross‐border transactions including pricing for services and predictability of transmission tariffs;

Transparent market price signals to promote economic investments in cross-border transmission interlinkages through cost-recovery;

Harmonization of transmission pricing structures and frameworks;

No cross‐subsidies between domestic and cross‐border transmission pricing;

Harmonization between national and cross‐border pricing arrangements; and

Procurement and pricing of ancillary services and transmission losses that ensures operational and financial efficiency of the cross-border and domestic transmission system consistent with SAPP’s operational guidelines.

### Wheeling Charges

Wheeling charges are a form of transmission charge, where the charge is based on the proportion of transmission assets used to facilitate transfer of power between a generator and a load. In the SAPP network, cross-border power flows through third party networks are charged based on wheeling charges agreed between member countries of SAPP (see Annex 1).

## Impact of Transmission Pricing on Cross-border Investments

The impact of transmission tariffs on investment decisions to site generation assets is not clear-cut since multiple factors influence the siting and operation of generation assets to meet regional electricity demand. The decision to site generation assets to meet loads across national boundaries is dependent on a number of operational, financial, regulatory and market considerations. The transmission network and interlinkages, tariff structures and tariffs also influence investment decisions. Further, the costs to be recovered by different entities vary based on the value of assets used for transmission of electricity. While harmonization of transmission pricing structures and frameworks across countries in the Southern African region is desirable to promote investment in transmission and generation assets, it is not necessary to harmonize transmission tariffs since the region presently does not have a unified common electricity market.

The SAPP has an active, albeit small, Day Ahead Market (DAM), and with increased integration of the power market in the region, there may be a need to harmonize cross border transmission tariff mechanisms to promote competition and market integration. Increased market integration in an interconnected transmission network will likely lead to congestion in the network, which may require SAPP to adopt nodal and/or zonal tariff mechanisms.

# Different Approaches to Estimate Cross-border Transmission Tariffs

Several tariff mechanisms are available to estimate cross-border transmission prices in integrated electricity networks. The basic objective is to fully recover the costs of providing transmission services. Figure 1 illustrates the key components of a transmission charge.

Figure 1: Components of a Cross-Border Electricity Transmission Charges

Some transmission methodologies are transaction-based and allocate costs to specific entities in a bilateral transaction. Other non-transaction-based methodologies allocate costs to all the participants in the power pool. Some of the commonly applied transmission pricing methodologies include the following:

Postage Stamp Method (transaction / non-transaction);

Contract Path Method (transaction based);

MW-Mile Method (transaction based);

* Distance Based MW-Mile Method
* Power Flow Based MW-Mile Method

Forward-Looking Transmission Tariff Models (transaction / non-transaction);

* Short-run Marginal Cost (SRMC)
* Short-run Incremental Cost (SRIC)
* Long-run Marginal Cost (LRMC)
* Long-run Incremental Cost (LRIC)

Nodal Pricing (transaction based);

Zonal Pricing or Entry-Exit Pricing (transaction based);

Power flow tracing based on proportionate sharing principle (non-transaction); and

Equivalent bilateral exchange (EBE) method (non-transaction).

## Postage Stamp Methodology

The “Postage stamp methodology” is a simple approach to transmission pricing, which effectively applies a fixed charge per unit of power transmitted within a particular zone (as a postage stamp). The rate does not account for the distance involved in wheeling power within the zone. The postage stamp transmission charges are allocated on the basis of an average embedded system cost and the magnitude of transacted power. Postage stamp rates may include energy and capacity charges, and may vary for peak and off-peak periods, by season, and be different for weekdays and weekends.

Some of the advantages of Postage Stamp Method are:

Simple and easy to implement;

Transparent and easily understood by market participants;

No mathematical rigor involved;

Recovers sunk cost of transmission system; and

Politically easy to implement.

 Some of the disadvantages of the Postage Stamp Method are:

In case power is transmitted through multiple utilities or zones, pancaking of transmission charges leads to inefficient pricing signals;

Does not provide economic price signals to market participants; and

Does not account for the actual system power flows and use of the network – a load close to a generator may pay the same as a load a long distance from the generator.

## Contract Path Methodology

The contract path method charges entities based on a pre-defined path of power flow, which is usually the shortest route from the point of power uptake to the point of delivery. The contract path method captures the embedded capital costs for facilities that lie along the assumed contract path. This method is relevant for networks that do not have multiple paths of interconnection since the reality is that power flows through multiple parallel paths depending on network characteristics.

Some of the advantages of this methodology are:

Relatively simple to implement;

Directly or indirectly accounts for the distance involved in wheeling; and

Avoids pancaking of rates to a large extent.

 Some of the disadvantages of the methodology are:

The contract path between the points of power take-off and injection is decided a priori without any simulation of actual power flows;

Power flows cannot be restricted to a particular path if parallel paths are available; and

The methodology fails to provide correct economic signals since only the entities along the contract path are compensated.

## MW-Mile Methodology

The MW-mile method is based on charging entities based on the magnitude of power transacted and the distance between the source (point of delivery) and the sink (point of receipt). There are two versions of the MW-Mile methodology – the first method does not use load flow simulations and is based on distance of flow, and the second method uses load flow simulations to estimate parallel flow paths in interlinked networks.

**Distance Based MW-Mile Methodology**

This method estimates the use of transmission assets based on the product of the quantity of the transacted power and the geographical distance between the source and sink. In practice, due to the effect of interlinked networks, there is no fixed relationship between the geographical distance and the actual costs. The drawback of this approach is that it does not consider the actual transmission assets involved in the transaction.

**Power Flow Based MW-Mile Methodology**

This method accounts for the quantity of transacted power and the distance between source and sink and also considers parallel flow paths to allocate costs. The power flow-based MW-Mile methodology uses load flow analysis and is reflective of the actual usage of the transmission system in allocating costs. The methodology considers the change in power flows on the transmission assets and the distance across which power flows.

Some of the advantages of this methodology are:

Considers each transaction separately and is insensitive to the order of wheeling transactions;

Gives the right price signal to both short-distance and long-distance entities; and

Intuitively logical and conceptually straightforward.

Some of the disadvantages of this methodology are:

A DC power flow approximation is used to estimate power flows which may inaccurately estimate the extent of use of the network by a particular transaction (actual AC power flows in multiple transactions are non-linear)

Attributes no merit to the transactions which give rise to counter flows, thereby reducing loading of the system.

## Forward-Looking Transmission Tariff Models

**Short-run Marginal Cost (SRMC)**

The SRMC methodology includes the incremental operating cost for the use of the transmission system caused by a new transaction. The SRMC is estimated at all the delivery and receipt points and is usually below the average total cost of the system, which could lead to under-recovery of costs.

The primary advantage of this approach is:

* it promotes economic efficiency, as the price of an individual wheeling transaction is almost equal to the cost imposed on the network due to the transaction.

Some of the disadvantages of this approach are:

Difficulty in estimating the SRMC of every individual transaction; and

SRMC-based transmission tariffs can be volatile.

**Short-run Incremental Cost (SRIC)**

The SRIC recovers the additional cost caused by new transactions on the network. In calculating the SRIC, only the operating costs of the existing facilities and new transactions are taken into account and allocated to that transaction.

**Long-run Marginal Cost (LRMC)**

The LRMC approach accounts for both the capital and operational costs by calculating the marginal capital investment plus the marginal operating costs. This approach takes account of future transmission expansion projects.

Some of the advantages of this approach include:

Provides correct price signals to users of the network; and

Prices are stable and predictable, enabling long-term contracts with transmission system owners.

Some of the disadvantages of this approach are:

Difficulty in estimating the incremental investment costs attributable to individual wheeling transactions, when multiple transactions occur simultaneously; and

Fails to account for transmission system reliability.

**Long-run Incremental Cost (LRIC)**

The LRIC accounts for both the capital and operating costs, and also for the costs of any grid upgrades and reinforcement.

## Nodal Pricing

Under the nodal pricing approach, each uptake and injection node has its own price based on locational economic signals. Prices are based on the marginal impact on the system and not on the path followed by flows between the nodes.

Some of the advantages of this approach are:

Leads to allocative and dynamic efficiency[[4]](#footnote-5);

Provides potential transmission network investors an indicative return on their investment; and

Provides market participants an indication of the price of power transfers between nodes.

Some of the disadvantages of this approach are:

Potential to result in under-recovery of fixed costs;

Price variations over different nodes instantaneously and over time can create significant instability in prices; and

Can be complex to understand and implement.

## Zonal Pricing or Entry-Exit Pricing

Zonal transmission pricing approaches are appropriate to manage congestion in networks. Load flow simulation on the network helps identify constraints in zones and estimate a new transmission system price for each zone, accounting for the maximum transfer capacity between the areas. Congestion is addressed by lower prices in generation surplus areas and higher prices in generation deficit areas. Also called the Entry and Exit charge methodology, this approach charges market entities based on metered import and export of power flows at each node of a transmission network. The actual load flows and not distance determines the revenues recovered through the charge (also described in Section 5).

## Power Flow Tracing Based on Proportional Sharing Method

Power flow tracing methods notionally quantify the usage of the network elements by various generators and loads and allocate transmission losses. Network costs can thus be allotted to various entities based on the physical flow of power through transmission assets and traces both active and reactive power flows in the network. The power flow tracing approach determines the most economical transmission path to be used to deliver power based on estimating transmission losses on transmission lines and avoiding paths with higher losses. This approach requires finding a valid power flow solution based on the principle of proportional sharing of transmission lines between generator and load.

## Equivalent Bilateral Exchange (EBE) Method

The equivalent bilateral exchange model works on similar principles as the power flow tracing methodology with the exception that each generator is assumed to supply a fraction of each load in proportion to its contribution to total generation capacity on the power system. Each demand is supplied by a fraction of each generator uniformly divided among all generators on the system. Each generator supplies a fraction of each demand uniformly divided among all demands. So, all generators do not contribute to all loads and a generator or a load may contribute to flows of only some lines and not all. The EBE method of transmission pricing works well for pool structures of power markets and can also be used for bilateral trades. The nodal charges for customers in the power pool are calculated by applying proportionate sharing principle.

# Process for Applying a Transmission Tariff Methodology

## Cross-border Transmission Pricing and Tariff Models

Once a cross-border transmission tariff structure and methodology is adopted, a transmission pricing model is developed. Developing a transmission pricing model entails significant costs and includes modules for asset databases, tariff algorithms, and billing and settlement processes. The modules of the transmission pricing module will depend on the electricity market structure. In the context of the SAPP market which operates as a power pool, the Transmission System Operator (TSO) would provide information to a System and Market Operator (SMO) under SAPP, and the SMO would define the periodicity of submission of information for the pricing model. The pricing model may be tested and refined using data from existing regional bilateral trades.

## Transmission Tariff Approval Process

Typically, the regulator(s) approves transmission tariffs that are estimated each year using the model. Loads (utilities and large customers) may continue to enter into bilateral agreements for specific contracts. In the case of the Southern Africa region, SAPP, the national regulators and RERA must approve transmission pricing models for pool and bilateral operations in an integrated regional market. Intra-country transmission pricing models would be approved only by the national regulator.

## Procedures for Review and Modification of Tariffs

The regulator will typically define the periodicity of tariff review, as well as review and revise the tariff methodology and model as necessitated by changing market objectives and operational conditions.

## Revenue Collection and Payment Mechanisms

Typically, an SMO collects the revenue from purchasers of bilateral trades, and this revenue covers the cost of the power trade (capacity and energy charges), any charges for losses and congestion, and a fee for the operations of the SMO and the regulator[[5]](#footnote-6). The SMO then pays the TSO based on the agreed tariff allocation methodology. Billing and settlements for power trades are done on a periodic basis based on energy trading schedules provided by the purchaser of the regional bilateral trade.

# review of international practice for Cross-border Transmission Tariffs

The structure for cross-border transmission tariffs is driven by the objectives of a given regional electricity market. While the basic principle is to recover the cost of electricity transmission services, approaches to transmission pricing are also driven by national objectives of countries and transmission network operators participating in the common market. Internationally, there is no consensus on an approach and many different pricing systems and associated tariff structures are in use depending on the objectives of each market and the consensus of participating entities. The key consideration in adopting any methodology is to examine the extent to which it promotes market integration, competition and effective functioning of the electricity market[[6]](#footnote-7).

## West Africa Power Pool (WAPP)

The Economic Community of West African States Regional Electricity Regulatory Authority (ERERA) has adopted a power flow-based MW-km methodology for pricing transmission services in the WAPP[[7]](#footnote-8). Under this approach, the tariff is calculated for all regional bilateral trade within ECOWAS based on the following steps.

1. Determine regional transmission assets and asset value;
2. Calculate annual revenue requirements for each TSO asset used for regional bilateral trading;
3. Calculate use of transmission system and associated transmission losses for each regional bilateral trade;
4. Calculate transmission revenue requirements for each TSO for regional bilateral trades; and
5. Calculate transmission tariff and transmission losses for the purchaser of each regional bilateral trade.

Regional transmission revenue and losses are estimated annually to update the transmission tariffs.

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

The ENTSO-E employs a Unit Transmission Tariff (UTT) approach, which is designed to recover the following costs:

TSO costs: infrastructure costs such as operational expenses, depreciation, return on capital, costs of purchasing system services and loss compensation costs; and

Non-TSO Costs: costs not related to TSO’s activities such as stranded costs, costs of renewable energy or co-generation support schemes, regulatory levies etc.

Different European countries have applied different transmission tariff structures. The differences between the approaches include6:

Allocation of charges between generation and load;

Tariff levied on a capacity (MW) or energy (MWh) basis;

Locational differentiation of tariffs;

Time differentiation of tariffs;

Scope of services and costs recovered through the transmission tariff; and

Cost concepts used to determine tariffs.

Different users bear the costs of providing transmission services in different European countries. While in some countries, transmission tariffs are paid only by the load (e.g. Germany and Netherlands), in others they are paid by the load and the generator (e.g. Great Britain and Sweden). Additionally, transmission tariffs are applied by different countries on an energy only basis, on a capacity only basis, or for both energy and capacity. Locational transmission pricing is applied in some countries (Great Britain, Ireland, Norway, Sweden and Romania), while others do not apply locational prices. European countries also do not have a consistent approach to applying connection charges; while some apply deep charges, others apply shallow charges. The framework for recovering costs related to transmission losses and ancillary services also varies with some countries including it in the transmission charge and others recovering it through the energy market. Further, some countries estimate transmission charges based on average costs while others apply marginal costs.

## National Grid of Great Britain

The National Grid Electricity Transmission PLC (NGET) recovers the costs of installing, operating and maintaining the National Grid System through the levying of Transmission Network Use of System (TNUoS) charges on users of the system. Costs are split between generators and load in the ratio of 23%/77% and are designed to enable bulk power trade while providing system security and reliability.[[8]](#footnote-9) The TNUoS provides efficient economic signals to market participants and capture locational and marginal costs of transmission services.

## PJM

The PJM Interconnection is a regional transmission organization (RTO) in the U.S. that utilizes locational marginal pricing (LMP) to price energy purchases and sales in the PJM wholesale electricity market. The LMP accounts for the effect of actual operating conditions on the transmission system in determining the price of electricity at different locations in the PJM region. The LMP is higher in areas with congestion compared to areas with little or no congestion. The LMP is calculated by PJM and posted on its website (www.pjm.com) every five minutes, enabling market participants to factor the information into their decision-making[[9]](#footnote-10).

## Nord Pool

In Nord Pool, the transmission pricing approach for access to the grid is a “Point-of-Connection” (POC) tariff. Under this pricing approach, payment of a transmission tariff at the point of connection gives a network user access to the entire network.

# Review of Cross-Border Transmission Tariff Approaches used in SAPP and pilot countries

Publicly-available information on the existing approaches for pricing cross-border transmission services in SAPP indicate past use of the following approaches[[10]](#footnote-11)

## Postage Stamp Methodology (1995-1998)

The methodology for transmission pricing initially used by SAPP for short and long-term bilateral trades from 1995 to 1998 was a standard postage stamp charge based on the number of transit countries involved in wheeling the power.

The transmission tariff was based on 7.5% of the value of the energy transferred in case power was wheeled through one transit country, and 15% of the value of the energy transferred in case power was wheeled through more than one country. This methodology did not account for transmission line losses. A further disadvantage was that the counterparty (ies) to each trade had to be known, which becomes difficult in an interconnected and integrated electricity market. With SAPP moving to day-ahead market operations, a pricing approach based on bilateral contracts and identification of counterparties to each trade was not practical.

## MW-km Load-flow Methodology (1999-2015)

The MW-km load flow methodology was used for estimating wheeling charges for all bilateral trades in SAPP from 1999 to 2015. This methodology was based on the proportion of transmission assets in a country actually used for wheeling power. The wheeling charge applied was thus based on the power flow including losses explicitly analyzed for each transaction and the buyer paid for 100% of the wheeling charge. The charges are however based on historical asset values. This approach was suitable for bilateral trades and for market clearing prices for bilateral day-ahead market trades. Figure 2 illustrates the basic steps in estimating transmission charges using the MW-km load flow methodology.

Figure 2: Steps in Estimating Transmission Charges Using the MW-km Load Flow Methodology

*Source: Adapted from AEMI – HAPUA Forum, Ricardo Presentation, Jonathan Hedgecock, Practice Director, PPA Energy May 24 – 26, 2016*

While this approach worked well under SAPP’s cooperative pool model, the high wheeling charges for transit through longer distances dissuaded power trade, and the approach did not address congestion management. Further, the methodology is not adequate when the counterparties to a trade are not explicitly known.

As SAPP moved towards a competitive electricity market in 2006, it revised the wheeling charge and capped it at 15% of the transaction cost based on SAPP spot market prices. In the case where a single network wheeled the power, SAPP capped the wheeling charge at 7.5% of the spot market price (similar to the earlier Postage Stamp methodology). This percentage-based cap on transmission pricing was also considered inadequate for increased regional power trade.

## Development of a New Transmission Tariff Methodology (2016-Present)

As the market matures, SAPP has begun to consider alternative methods based on international leading practices. The guiding principles for the new tariff guidelines are:

Promote efficient day-to-day operation of the bulk power market;

Signal locational advantages for investment in generation and demand;

Signal the need for investments in the transmission system;

Compensate the owners of existing transmission assets;

Be simple, transparent and predictable;

Be politically implementable;

Recognize that trade counterparts are not always known;

Fully recover the costs of transmission facilities associated with wheeling; and

Not restrict opportunities for cross‐border trading.

In the meantime, utilities continue to use the MW-km method and negotiated tariffs for bilateral trade. According to the Deloitte Team’s understanding based on public sources of information, the following approaches are under consideration.

### Entry - Exit Pricing:

The Entry - Exit methodology, as the name implies, is a charge based on metered import and export of power flows at each node of a transmission network. The actual load flows and not distance determines the revenues recovered through the charge. SAPP has been testing this approach since 2016 and reportedly intends to develop and publish entry and exit charges for every node and zone (country border & IPP connection point) in the SAPP-wide transmission network. This approach does not capture congestion charges and ancillary services based on actual load flow at a given time and these components would have to be charged for separately.

The Entry - Exit approach is similar to the European approach to transmission pricing where revenues for the TSO are recovered from the load and generator based on locational pricing and are not dependent on the number of counterparties in the trade. The UK has adopted a similar approach where users of the national transmission network are subject to three elements of transmission charges to ensure that costs related to congestion and ancillary services are also captured[[11]](#footnote-12):

1. Connection charges for the provision and maintenance of connection assets;
2. Transmission Network Use of System (TNUoS) charges for the provision and maintenance of any shared transmission infrastructure assets; and
3. Balancing Services Use of System (BSUoS) charges to recover costs incurred by the System Operator in its day-to-day operations.

The Entry - Exit approach is compatible with the day ahead market and recovers the expected return on network assets involved in wheeling when the counterparties to the trade are not explicitly known[[12]](#footnote-13).

### Contribution to Line Flow Model

This model, which reportedly has not progressed beyond initial studies, is based on a combination of the power flow MW-km and Nodal method and results in charges for both the generator and load. Figure 3 shows the estimated transmission tariff.

Figure 3: Transmission Charges Based on the “Contribution to Line Flow Model”



 *Source: SAPP*

This methodology provides the right price signals since it is based on the actual use of the transmission network asset including parallel path flows. The load flow analysis accounts for network constraints and potential congestion at nodes when calculating the transmission tariff. It would however be important to also ensure that there is sufficient transmission capacity for such regional trades in an integrated electricity market. Insufficient transmission capacity could be a cause for disallowing certain bilateral trades and may be preferable to imposing congestion charges. Such a strategy could help allocate transmission capacity in the intra-day and day-ahead and Forward Physical Markets operations of SAPP (see Section 6).

SAPP completed its review in early 2016 but this methodology has not been accepted and adopted by all member countries. SAPP had requested an independent international expert to review the methodology and provide recommendations, but the status and outcome of this review process was not available to the Deloitte Team.

# Review of Existing Agreements and Guidelines in SAPP and pilot countries

Our understanding based on publicly available information and discussions with stakeholders is reflected below.

## SAPP Market Overview

Trading arrangements under SAPP are designed to fulfill the organization’s vision[[13]](#footnote-14) as follows:

Facilitate the development of a competitive electricity market in the Southern African region;

Provide end users a choice of electricity supply;

Ensure that the Southern African region is the region of choice for investment by energy intensive users; and

Ensure sustainable energy developments through sound economic, environmental & social practices.

SAPP initially operated through bilateral contracts under a Short-Term Energy Markets (STEM) system. SAPP has since transitioned to a Day-Ahead Market (DAM) under a cooperative power pool operating regime.

### SAPP Electricity Markets

Under the STEM regime, bilateral markets operated mainly to meet long-term demand and supply balance in the region driven by trading arrangements mutually agreed between bilateral parties with a transmission path secured in advance. Bilateral contracts could be firm or non-firm.

SAPP also has a Forward Physical Markets operation, which is based on competitive trading in monthly or weekly contracts (or any other defined periods longer than one day ahead) for future delivery according to the contract specifications.

Under the DAM regime, the objective is to trade electricity a day in advance of the delivery of such trades. This is based on hourly energy contracts for each of the 24 hours of the following day, or a future day. This is a continuous Intra Day Market (IDM), and trading takes place every day around the clock until one hour before delivery. Prices are set based on a first-come, first-served principle. Trading can also be for hourly energy contracts for one or more hours for periods as specified by the SAPP Market Operator.

A “Market Book of Rules” and “Participation Agreements” between participants and the SAPP Market Operator govern trading under SAPP.

### Transmission Interconnectivity in SAPP

Figure 4 illustrates transmission interlinkages between SAPP member countries, with dashed lines indicating planned linkages. There is a need for significant additional investment in the transmission network, with estimates of over USD 5.6 billion of required investment to develop the following transmission interlinkage projects[[14]](#footnote-15):

ZIZABONA;

Zambia-Tanzania;

Malawi-Mozambique;

DRC-Zambia; and

Mozambique Backbone.

Figure 4: Transmission Interconnections in SAPP



 *Source: SAPP Website*

## Pilot Country Overview

The SAPP approach described above is not mandated for member countries. Member countries, including the pilot countries of Botswana, Namibia and Zambia, do not have a consistent or harmonized framework or tariff structure for cross border power trade. In fact, discussions with stakeholders held during the Deloitte Team’s two missions indicate cross-border power flows are presently charged based on bilateral negotiations. The agreements of these bilateral contracts were not made available for review by the Deloitte Team.

Cross-border power flows through third party networks which may serve as transit between two countries with a bilateral agreement are presently charged based on wheeling charges agreed between member countries of SAPP. Annex A provides SAPP-approved wheeling charges payable to transit countries.

## Laws and Regulations Governing Cross-Border Transmission Pricing

In 2011, RERA developed an enabling framework for cross border power trading outlined in “Regulatory Guidelines on Cross Border Power Trading in Southern Africa”. RERA had previously identified regulatory constraints as one of the major causes for the lack of investment in cross-border transmission projects and developed the Guidelines as a first step to harmonizing national electricity regulatory systems to encouraging cross-border power transactions[[15]](#footnote-16). The Guidelines provide principles, rules and procedures to support cross-border transmission projects, and seek to:

Clarify the role of regulators in regulating cross-border electricity transactions to minimize regulatory risks for power investors and customers;

Promote efficient and sustainable cross-border electricity transactions that are fair to all parties; and

Promote least-cost sector development and ensure security of supply.

While the Guidelines have no legal precedence over the decisions of national regulators, the Southern African Development Community (SADC) Energy Ministers adopted them later that year, and a number of regulatory authorities in RERA member countries including those in Lesotho, Malawi, Mozambique, Namibia, South Africa, United Republic of Tanzania, and Zambia have since adopted the Guidelines.

The Regulatory Guidelines for cross-border power trading in SADC region address the following nine items:

1. Regulator’s powers and duties in cross-border trading;
2. Work to ensure compatible regulatory decisions;
3. Timing of regulatory interactions for proposed cross-border transactions;
4. Licensing cross-border trading facilities, imports and exports;
5. Approving cross-border agreements in importing countries;
6. Approving cross-border agreements in exporting countries;
7. Approving cross-border agreements in transit countries;
8. Approving transmission access and pricing and ancillary services; and
9. Promoting transparency in the regulation of cross-border trading.

# USE OF THE ZIZABONA Transmission Line as a basis for developing A transmission pricing framework for sapp

The Zimbabwe, Zambia, Botswana, and Namibia (ZIZABONA) transmission line, when completed, will directly link utilities in the four Southern African countries and serve as a backbone transmission interlinkage to support increased trade between the countries and more broadly between SADC members.

ZIZABONA a priority project under the African Development Bank’s (AfDB) regional integration strategy, is a segment of the PIDA (Programme for Infrastructure Development in Africa) interconnection corridor, and is sponsored by ZESA Holding (Zimbabwe), ZESCO (Zambia), BPC (Botswana), NamPower (Namibia) and the Southern African Power Pool (SAPP)[[16]](#footnote-17) (see Figure 5). Table 1 provides a rough estimate of the capital investment needed for the interconnection.

Table 1: ZIZABONA Capital Investment Costs



*Source: Deloitte discussions with stakeholders*

Figure 5: ZIZABONA Transmission Interconnection



*Source: Deloitte discussions with stakeholders*

The ZIZABONA line has the potential to support multiple power trading regimes or portfolios as approved by SAPP, including:

* Negotiated long-term bilateral trading between the interconnected countries with appropriate wheeling charges paid to transit countries;
* Over-the-counter (OTC) trading between countries to meet short-term demand and supply balance with SAPP providing market operator, settlement and clearance functions;
* Day-ahead market (DAM) trading between countries with trading concluded daily for delivery next day, with SAPP providing market operator, settlement and clearance functions;
* Post Day-ahead market (PDAM) trading between countries with trading concluded by 4 PM on the trading day, with SAPP providing market operator, settlement and clearance functions’ and
* Allowance of additional new generators to connect to the ZIZABONA line to participate in the SAPP market.

The transmission pricing framework for the ZIZABONA line will have to be applicable to each of the above trading portfolios. The tariff also will have to recover the investment in the transmission line. In effect, the transmission pricing framework for the ZIZABONA line will have to satisfy SAPPs guiding principles for new tariff guidelines (see Section 5.3).

The pilot countries have not yet developed a pricing framework for the ZIZABONA line and will be seeking guidance from SAPP.

The Deloitte Team recommends that the pilot countries and SAPP use the ZIZABONA cross-border transmission line as an example on which to base development of a transmission pricing framework, which will be more broadly applicable under SAPP to all member countries and utilities.

# Next Steps in the Development of Transmission Tariff Mechanisms for Southern Africa

A transmission tariff methodology for the Southern Africa Region must accomplish the SAPP principal objectives described in Section 5.3. Simplicity of application must also be a prime consideration. Beyond that, there are multiple components to consider given the various objectives of market participants and stakeholders. Figure 6 below provides an illustrative comparison of transmission tariff methodologies with respect to economic efficiency and degree of complexity.

Figure 6: Economic Efficiency of Tariff Methodology vs. Complexity of the Approach



*Source: Recommended Continental Transmission Tariff Methodology for Africa, Summary Report, EU Technical Assistance Facility (TAF) for the Sustainable Energy for All (SE4ALL) Initiative (East and Southern Africa)*

The MW-Km (Load flow-based) transmission tariff approach, which SAPP has used in the past, has the advantage of meeting multiple objectives while providing economic locational signals to market participants and promoting competition. However, as noted earlier, this methodology was found to be a hindrance to long-distance trade and did not adequately address congestion on the lines. SAPP is thus seeking to move to an approach that combines the power flow MW-km and the Nodal pricing method.

The Deloitte Team recommends that SAPP base its decision on a new transmission pricing methodology on the needs of the electricity market model in the short-term and long-term. The Deloitte Team also recommends that RERA review the legal and regulatory framework for tariffs and its applicability to all member countries.

# Annex A: SAPP WHEELING CHARGES - 1 JANUARY 2016 TO 31 DECEMBER 2016



**WHEELING CHARGES - 1 JANUARY 2016 TO 31 DECEMBER 2016 (Bilateral/Firm)**

|  |  |  |
| --- | --- | --- |
| **Transaction:****Seller to Buyer** | **WHEELERS , USc /kWh** | **Total****USc /kWh** |
| ***BPC*** | ***ESK-OM*** | ***EDM (S)*** | ***EDM (N)*** | ***SEC*** | ***ZESA*** | ***ZES-CO*** | ***CEC*** | ***NAMPO-WER*** |
| SNEL - ZESCO  |  |  |  |  |  |  |  | 0.042 |  | 0.042  |
| SNEL - ZESA  |  |  |  |  |  |  | 0.141 | 0.042 |  | 0.183  |
| SNEL - BPC  |  |  |  |  |  | 0.189 | 0.141 | 0.042 |  | 0.372  |
| SNEL - ESKOM  | 0.006 |  |  |  |  | 0.189 | 0.141 | 0.042 |  | 0.378  |
| SNEL - NAMPOWER  | 0.051 | 0.261 |  |  |  | 0.189 | 0.141 | 0.042 |  | 0.685  |
| SNEL - SEC  | 0.051 | 0.100 |  |  |  | 0.189 | 0.141 | 0.042 |  | 0.523  |
| SNEL - LEC  | 0.051 | 0.199 |  |  |  | 0.189 | 0.141 | 0.042 |  | 0.623  |
| SNEL - HCB  |  |  |  | 0.032 |  | 0.137 | 0.141 | 0.042 |  | 0.352  |
| SNEL - EDM\_S  | 0.051 | 0.137 |  |  | 0.004 | 0.189 | 0.141 | 0.042 |  | 0.565  |
| SNEL - NamPower (Zambezi)  |  |  |  |  |  |  | 0.087 | 0.026 |  | 0.114  |
| ZESCO - BPC  |  |  |  |  |  | 0.189 |  |  |  | 0.189  |
| ZESCO - BPC via 220 kV  |  |  |  |  |  | 0.135 |  |  |  | 0.135  |
| ZESCO - ESKOM  | 0.006 |  |  |  |  | 0.189 |  |  |  | 0.195  |
| ZESCO - NAMPOWER  | 0.051 | 0.261 |  |  |  | 0.189 |  |  |  | 0.502  |
| ZESCO - SEC  | 0.051 | 0.100 |  |  |  | 0.189 |  |  |  | 0.340  |
| ZESCO - LEC  | 0.051 | 0.199 |  |  |  | 0.189 |  |  |  | 0.440  |
| ZESCO - HCB / EDM\_N  |  |  |  | 0.032 |  | 0.138 |  |  |  | 0.170  |
| ZESCO - EDM\_S  | 0.051 | 0.137 |  |  | 0.004 | 0.189 |  |  |  | 0.382  |
| ZESCO - ESKOM via CAPRIVI  |  |  |  |  |  |  |  |  | 0.351 | 0.351  |
| ZESA - ESKOM  | 0.006 |  |  |  |  |  |  |  |  | 0.006  |
| ZESA - NAMPOWER  | 0.051 | 0.261 |  |  |  |  |  |  |  | 0.313  |
| ZESA - SEC  | 0.051 | 0.100 |  |  |  |  |  |  |  | 0.151  |
| ZESA - LEC  | 0.051 | 0.199 |  |  |  |  |  |  |  | 0.251  |
| ZESA - EDM\_S  | 0.051 | 0.137 |  |  | 0.004 |  |  |  |  | 0.193  |
| ZESA - SNEL  |  |  |  |  |  |  | 0.141 | 0.042 |  | 0.183  |
| ZESA - NamPower (Zambezi)  |  |  |  |  |  |  | 0.016 |  |  | 0.016  |
| BPC - ZESCO  |  |  |  |  |  | 0.189 |  |  |  | 0.189  |
| BPC - SNEL  |  |  |  |  |  | 0.189 | 0.141 | 0.042 |  | 0.372  |
| BPC - NAMPOWER  |  | 0.261 |  |  |  |  |  |  |  | 0.261  |
| BPC - SEC  |  | 0.100 |  |  |  |  |  |  |  | 0.100  |
| BPC - LEC  |  | 0.199 |  |  |  |  |  |  |  | 0.199  |
| BPC - HCB  |  |  |  | 0.032 |  | 0.222 |  |  |  | 0.254  |
| BPC - EDM\_S  |  | 0.137 |  |  | 0.004 |  |  |  |  | 0.141  |
| ESKOM - ZESA  | 0.006 |  |  |  |  |  |  |  |  | 0.006  |
| ESKOM - ZESCO  | 0.051 |  |  |  |  | 0.189 |  |  |  | 0.240  |
| ESKOM - SNEL  | 0.051 |  |  |  |  | 0.189 | 0.141 | 0.042 |  | 0.423  |
| ESKOM - HCB  | 0.051 |  |  | 0.032 |  | 0.222 |  |  |  | 0.305  |
| ESKOM - SEC  |  |  | 0.010 |  |  |  |  |  |  | 0.010  |
| ESKOM - EDMS  |  |  |  |  | 0.004 |  |  |  |  | 0.004  |
| NAMPOWER - SNEL  | 0.051 | 0.261 |  |  |  | 0.189 | 0.141 | 0.042 |  | 0.685  |
| NAMPOWER - ZESCO  | 0.051 | 0.261 |  |  |  | 0.189 |  |  |  | 0.502  |
| NAMPOWER - ZESA  | 0.006 | 0.261 |  |  |  |  |  |  |  | 0.267  |
| NAMPOWER - BPC  |  | 0.261 |  |  |  |  |  |  |  | 0.261  |
| NAMPOWER - SEC  |  | 0.204 |  |  |  |  |  |  |  | 0.204  |
| NAMPOWER - LEC  |  | 0.204 |  |  |  |  |  |  |  | 0.204  |
| NAMPOWER - HCB  | 0.051 | 0.261 |  | 0.032 |  | 0.222 |  |  |  | 0.566  |
| NAMPOWER - EDM\_S  |  | 0.246 |  |  | 0.004 |  |  |  |  | 0.250  |
| NAMPOWER Zambezi - EDM\_N  |  |  |  |  |  | 0.127 | 0.016 |  |  | 0.143  |
| HCB - SNEL  |  |  |  | 0.032 |  | 0.138 | 0.141 | 0.042 |  | 0.353  |
| HCB - ZESCO  |  |  |  | 0.032 |  | 0.138 |  |  |  | 0.170  |
| HCB - BPC  |  |  |  | 0.032 |  | 0.222 |  |  |  | 0.254  |
| HCB - SEC  | 0.051 | 0.100 |  | 0.032 |  | 0.222 |  |  |  | 0.404  |
| HCB - LEC  | 0.051 | 0.199 |  | 0.032 |  | 0.222 |  |  |  | 0.504  |
| HCB - EDM\_S  | 0.051 | 0.137 |  | 0.032 | 0.004 | 0.222 |  |  |  | 0.446  |
| HCB - ESKOM  | 0.006 |  |  | 0.032 |  | 0.222 |  |  |  | 0.260  |
| HCB - NAMPOWER  | 0.051 | 0.261 |  | 0.032 |  | 0.222 |  |  |  | 0.566  |
| EDM\_S - SNEL  | 0.051 | 0.137 |  |  | 0.004 | 0.189 | 0.141 | 0.042 |  | 0.565  |
| EDM\_S - ZESCO  | 0.051 | 0.137 |  |  | 0.004 | 0.189 |  |  |  | 0.382  |
| EDM\_S - ZESA  | 0.006 | 0.137 |  |  | 0.004 |  |  |  |  | 0.147  |
| EDM\_S - BPC  |  | 0.137 |  |  | 0.004 |  |  |  |  | 0.141  |
| EDM\_S - LEC  |  | 0.211 |  |  | 0.004 |  |  |  |  | 0.215  |
| EDM\_S - HCB  | 0.051 | 0.137 |  | 0.032 | 0.004 | 0.222 |  |  |  | 0.446  |
| EDM\_S - NAMPOWER  |  | 0.246 |  |  | 0.004 |  |  |  |  | 0.250  |
| EDM\_S - ESKOM  |  |  |  |  | 0.004 |  |  |  |  | 0.004  |
| EDM\_S - SEC  |  | 0.082 |  |  |  |  |  |  |  | 0.082  |
| SEC - SNEL  | 0.051 | 0.100 |  |  |  | 0.189 | 0.141 | 0.042 |  | 0.523  |
| SEC - ZESCO  | 0.051 | 0.100 |  |  |  | 0.189 |  |  |  | 0.340  |
| SEC - ZESA  | 0.006 | 0.100 |  |  |  |  |  |  |  | 0.106  |
| SEC - BPC  |  | 0.100 |  |  |  |  |  |  |  | 0.100  |
| SEC - NAMPOWER  |  | 0.204 |  |  |  |  |  |  |  | 0.204  |
| SEC - LEC  |  | 0.144 |  |  |  |  |  |  |  | 0.144  |
| SEC - HCB  | 0.051 | 0.100 |  | 0.032 |  | 0.222 |  |  |  | 0.404  |
| SEC - ESKOM  |  |  | 0.010 |  |  |  |  |  |  | 0.010  |
| SEC - EDM\_S  |  | 0.082 |  |  |  |  |  |  |  | 0.082  |
| LEC - SNEL  | 0.051 | 0.199 |  |  |  | 0.189 | 0.141 | 0.042 |  | 0.623  |
| LEC - ZESCO  | 0.051 | 0.199 |  |  |  | 0.189 |  |  |  | 0.440  |
| LEC - ZESA  | 0.006 | 0.199 |  |  |  |  |  |  |  | 0.205  |
| LEC - BPC  |  | 0.199 |  |  |  |  |  |  |  | 0.199  |
| LEC - NAMPOWER  |  | 0.204 |  |  |  |  |  |  |  | 0.204  |
| LEC - HCB  | 0.051 | 0.199 |  | 0.032 |  | 0.222 |  |  |  | 0.504  |
| LEC - EDM\_S  |  | 0.211 |  |  | 0.004 |  |  |  |  | 0.215  |
| LEC - SEB  |  | 0.144 |  |  |  |  |  |  |  | 0.144  |
| Average Wheeling Charge, USc /kWh  | 0.041 | 0.176 | 0.010 | 0.032 | 0.004 | 0.191 | 0.125 | 0.041 | 0.351 | 0.279  |
| Utility  | BPC | ESKOM | EDM (S) | EDM (N) | SEC | ZESA | ZESCO | CEC | NAMPOWER | SAPP  |

1. A shallow connection charge charges the generator and load for all direct costs associated with its connection to a transmission network, which includes the cost of any direct assets required to be installed to enable the connection. A deep connection charge, on the other hand, charges the generator and load for all costs associated with the connection, including the cost of direct assets and any new network reinforcement assets associated with the new connection. A hybrid connection charge combines the two pricing principles. [↑](#footnote-ref-2)
2. “Scoping towards Potential Harmonisation of Electricity Transmission Tariff Structures”, Agency for Cooperation of Energy Regulators (ACER), Cambridge Economic Policy Associates, Ltd. August 2015. [↑](#footnote-ref-3)
3. Adapted from RERA’s Regulatory Guidelines and transmission pricing frameworks in the EU-ENTSO-E [↑](#footnote-ref-4)
4. In the short run, electricity is allocated to its highest-value uses (allocative efficiency); and in the long run the timing and location of new investment ensures continued allocative efficiency (dynamic efficiency). [↑](#footnote-ref-5)
5. Congestion in the network is typically managed on a “first come first serve” basis, whereby the latest signed regional bilateral trade will be the first to be curtailed. [↑](#footnote-ref-6)
6. European transmission tariff structures, Cambridge Economic Policy Associates, March 2015 [↑](#footnote-ref-7)
7. Resolution No. 006/ERERA/15, Adoption of the Tariff Methodology for Regional Transmission Cost and Tariff, ECOWAS Regional Electricity Regulatory Authority, August 2015. [↑](#footnote-ref-8)
8. Recommended Continental Transmission Tariff Methodology for Africa, Summary Report, EU Technical Assistance Facility (TAF) for the Sustainable Energy for All (SE4ALL) Initiative (East and Southern Africa) [↑](#footnote-ref-9)
9. <https://www.pjm.com/~/media/about-pjm/newsroom/fact-sheets/locational-marginal-pricing-fact-sheet.ashx> (Posted by PJM on February 23, 2017) [↑](#footnote-ref-10)
10. AEMI – HAPUA Forum, Ricardo Presentation, Jonathan Hedgecock, Practice Director, PPA Energy May 24 – 26, 2016 [↑](#footnote-ref-11)
11. https://www.ofgem.gov.uk/ofgem-publications/54213/projecttransmitacallforevidencetechnicalannexpdf [↑](#footnote-ref-12)
12. Overview of new SAPP transmission pricing methodology. GA Chown, A Chikova, JJ Hedgecock, Power Planning Associates, Energize - July 2010 [↑](#footnote-ref-13)
13. SAPP website: http://www.sapp.co.zw/market-overview-0 [↑](#footnote-ref-14)
14. Meeting growing power demands through Southern African regional integration, Johnson Maviya, Southern African Power Pool SAREE/IRENA Workshop, Windhoek, Namibia, 24 -25 April 2017 [↑](#footnote-ref-15)
15. Lack of financing and security of supplies have been identified as other major constraints to cross-border transmission interconnections. [↑](#footnote-ref-16)
16. http://nepadippf.org/projects/energy/zizabonapowertransmission/ [↑](#footnote-ref-17)