1st DRAFT

APPROVED BY ERE'S BOARD OF COMMISSIONERS DECISION NO. __, DATED _______ "ON THE APPROVAL OF THE ELECTRICITY TRANSMISSION SERVICES TARIFF METHODOLOGY".

ELECTRICITY REGULATORY ENTITY

PART I

ELECTRICITY TRANSMISSION SERVICES TARIFF METHODOLOGY

Authority

This Transmission Services tariff calculation methodology is developed according to the Law No._______, dated 2________, "On Power Sector" (To be filled in with the details on the new Power Sector Law).

Purpose

The purpose of this methodology is to set transmission use-of-network tariff and ancillary services tariff on sound tariff principles and detailing the necessary data needed for fair and transparent tariff setting.

Objective

The **objective** of this tariff methodology is to establish the methodology for the calculation of the transmission access and use-of-network for the distribution system users of Albania that is consistent with the Energy Community for South East Europe (ECSEE) Treaty, and enable non-tariff customers and merchant power plants to participate in the regional electricity market.

1. Terms used in the methodology

Standard terms used in all tariff methodologies are established in the Power Sector Law, Market Rules, Metering Code, Transmission Code and other secondary legislation approved by the ERE. Terms used in this methodology have the following meanings.

1.1 **Annual adjustment factor (A) –** a percentage equal to the inflation factor minus the efficiency improvement factor applied to either revenue cap or price cap for the previous rate year..

1.2 **Base distribution system operators –** the set of transmission service tariff values determined according to costs in the base year.

1.3 **Base year –** the first year of a regulatory period

1.4 **Tariff customers –** RPS customers

1.5 **Test year** - a 12-month period prior to a regulatory period that is used as the basis for developing the revenue requirements for the base year for the distribution system operator.

1.6 **Differentiated tariffs –** tariffs for the operator for system and transmission ("OST") for access to the transmission network. It may include capacity-related charges, energy-related charges, fixed monthly charges, and reactive power charges, all related to respective voltage levels.

1.7 **Efficiency improvement factor (X factor) –** the annual percentage reduction in the cost of transmission services resulting from improvements in production efficiency and improvements in technology

1.8 **Cap Regulation –** the use of regulatory periods in which either the revenues of the licensee or the maximum price of the licensees are escalated during those regulatory periods.

1.9 **Regulated asset base (RAB) –** the value of fixed assets as defined in Article 6.1 of this tariff methodology.

1.10 **Regulatory period –** a multi-year period when prices or revenues requirements are allowed to increase at specific rates. Normally the period is 3 years for the transmission system operator.

2. General regulations and basic principles

2.1 Non-compliance with any part of this Regulation may result in a rejection by the ERE of tariff application.

2.2 This methodology is developed in conformity with Law on Power Sector as well as other legal acts which are in force in the Republic of Albania and other secondary legislation approved by the ERE.

2.3 The ERE will establish the tariff for transmission services based on the principles that:

- There should be no cross-subsidies between customer classes;
- Tariff for transmission services should reflect the actual cost of service for each customer class;

- Rates should provide proper price signals for the efficient use of the transmission network;

- Expenses included in the tariff should be transparent to all stakeholders;

- The tariff should allow the OST a reasonable opportunity to earn the ERE-approved allowed rate of return on the ERE-approved regulated asset base;

- Only prudently acquired services and assets will be accepted into the tariff for transmission services; and,

- Prices for transmission services should remain relatively stable over time.

2.4 Revenue associated with the use of the transmission system should be collected from RPS tariff customers, non-tariff customers, energy traders, qualified suppliers and merchant plants in a transparent and non-discriminatory fashion. Comparable groups of tariff, non-tariff customers, energy traders, qualified suppliers, and generating plants connected to the trasnmission system should pay the same trasnmission use of network charges, directly or indirectly.

2.5 Customers will be allocated the costs of energy losses associated with their voltage level. Energy use by customers that are not metered at their commercial point of service delivery will be adjusted to cover for energy losses from the commercial point to the metered point.

3. Regulatory Periods, Test Year and Base Year

3.1 The ERE will decide on the appropriate regulatory periods for transmission services using price cap tariff methodology.

3.2 The ERE adopts template tables for tariff applications and are included as Part II of this methodology. The OST shall use the template tables provided by ERE when filing a rate application for a regulatory period. The format of the tables can be modified as long as the information is organized in a similar manner and the breakdown of information in no less than that provided in the approved template tables. The tables will show test year results, adjustments made to test year and resulting base year including but not limited to company expenses, capital expenditures, and regulated asset base by regulated service.

3.3 The tariff should allow for recovery of the cost of ownership, construction, operation, and maintenance of lines, cables, transformer substations, transformers, and related buildings and communication facilities and any other facilities related to the provision of transmission services.

3.4 Price cap regulation is applied to the average tariff. ERE approves the average change in price. If the average price measured on the basis of historical data for one of the years in the tariff review cycle exceeds the average trasnmissiin services price established by the Energy Regulatory Entity, the OST must lower the tariff in the following year so that the customers of the OSTreceive a refund of the amount of excess revenue collected (i.e. the amount of over-recovery).

3.5 An "RPI-X" approach is used to give the OST an incentive to reduce its costs during the regulatory period.

3.6 Long-term debt financing should be used to finance new capital expenditures, but should not be used to cover operating costs.

3.7 The OST shall clearly and unambiguously report the costs of each regulated service including only the assets and activities related to the regulated services. The cost allocation method shall be comprehensive and approved by the ERE. (This should be part of the regulatory accounting manual).

3.8 Costs included in the tariff for transmission services shall correspond to costs that would be incurred by a well-managed TSO which makes prudent investments, minimizes network losses, and avoids wasteful expenditures. When setting the distribution system operator tariffs for the base year, the ERE has the right to investigate the cost levels reported by the distribution system operator, and benchmark its unit costs against other distribution system operator in the region taking into consideration the differences in characteristics of those distribution system operators.

3.9 The program for reduction and eventual elimination, to the extent possible, of non-technical losses are the responsibility of the distribution system operator. The ERE will set target reductions for non-technical energy losses within the regulatory periods.

3.10 In preparing a tariff application, the OST shall try to present all costs with precision up to 100,000 Leke. The regulator should not question amounts less than 100,000 Leke unless there is a dispute about compensation or payment to specific physical persons.

4. Electric energy and power balances

4.1 The electric energy balance of the OST for the base year shall be prepared by estimating the total amount of energy in GWh received by the transmission system during the base year. This total equals energy received from imports plus energy received from generating stations connected to the trasnmission system. Total energy received must be allocated to:

a) Energy delivered to distribution network;

b) Energy delivered to non-tariff customers connected to the transmission system;

c) Technical energy losses in the transmission system; and,

d) Energy exported..

4.2 The coincident peak load flow balance of the trasnmission system shall be prepared by estimating the total power in MW received by the trasnmission system in the peak hour. This total equals power received from power received from generating stations connected to the trasnmission system and import power. Total power received must be allocated to:

a) Power delivered to distribution network;

b) Power delivered to non-tariff customers connected to the transmission network;

c) Technical power losses in the transmission system

d) Power exported.

4.3 For each of the last ten years, energy losses in the transmission system must be shown as a percentage of energy received by the transmission system.

5. Revenue Requirements for the Base Year

5.1 The test year expenses for establishing base financial costs will be based on accounting information in accordance with the ERE-approved Uniform System of Accounts. The test year should be a representative 12-month historical period of company operating costs. The ERE has the right to perform, or contract to perform, a regulatory audit of the OST's test year accounting information during the rate application proceedings.

5.2 The OST may propose changes to the test year expense results for setting tariff for the base year of the next regulatory period. Any such changes must be both known (a specific item) and measurable (quantifiable). Contingency funds to cover unexpected costs will not be approved by the ERE. The ERE will consider adjustments to test year results such as:

1) demand growth or decreases;
2) inflation;
3) contract price changes;
4) changes in taxes and insurance;
5) the number of customers served;
6) increased levels of the regulatory asset base;
7) cost of capital;
8) level of depreciation expense; and,
9) efficiency factor.

5.3 The OST will provide justification for each forecasted adjustment to the test year results. The adjustments must be specified on the tables provided by the OST in the rate application and written testimony will be included in the rate application providing evidence for the reason(s) for each adjustment and the amount for each adjustments.

5.4 For licensed services regulated under price cap regulation, the OST will provide estimated factors to be included for each rate year in the regulatory period. The factors will include:

1) Average annual cumulative regulatory asset base for the regulatory period;
2) Total energy losses;
3) Bad debt level;
4) Annual Inflation factor; and,
5) Annual Efficiency Factor.

5.5 Revenue requirements for the base year will be calculated as follows:

RR = C + (RAB * WACC)

where:

RR are the annual revenue requirements;

C the allowed annual costs of operation for the licensed activity,

RAB the Regulatory Asset Base;

5.6 The weighted average cost of capital will be calculated as follows:

WACC = Weighted Average Cost of Capital

Where:

WACC = [ES * ARoE/ (1-T)] + (DS * CoD)

ES + DS = 1

Where:

ES = Target for equity ratio of the RAB

T = Corporate Tax Rate

ARoE = Allowed return on equity after tax

DS = Target for debt ratio of the RAB

CoD = Cost of debt

5.7 All essential components of the distribution system must be owned by the OST and not leased. Payments associated with leasing (for example, motor vehicle leasing) may be included in operating expenditures.

5.8 Costs associated with the acquisition of intangible assets such as patents, licenses, trademarks, software licenses, and information obtained through research and development should be shown as operating expenses. (This should be part of the regulatory accounting manual).

5.9 The OST's operating costs that can be included in the revenue requirements for licensed services are specified within the template tables for transmission services tariff application.

5.10 The OST will develop for ERE approval the average technical losses on the transmission network at each voltage level. The cost of purchasing energy/capacity to satisfy technical energy losses will be an operating expense of the OST allocated to Use of Network services at the various voltage levels.

5.11 The rate of return on equity is assumed to be post profit tax. The revenue requirements for the base year include all profit taxes planned to be paid by the OSTr to the Government of Albania.

5.12 Revenue requirements include all fees paid to ERE by the OST except for fines and sanction-related costs.

6. Return on Regulatory Asset Base

6.1 The regulatory asset base for transmission services include both tangible and intangible assets less accumulated depreciation plus a working capital component. The RAB is calculated according to the following formula:

$$RAB = A - CG - D + WC + INV;$$

where:

RAB the Regulatory Asset Base;

A the recognized value of used and useful fixed assets;

CG the value of assets acquired through gratuitous transfer or constructed with financial resources of transmission customers;

D the accumulated depreciation for the past period of asset used to perform the licensed activity;

WC the working capital requirement;

INV the forecast average cumulative nominal amount of investments approved by the ERE, which will be invested during the regulatory period.

6.2 The ERE will approve the RAB for the base year. Not all assets of the OST may be included in the regulatory asset base for a separately priced licensed service. Assets that do not support the licensed services will be disallowed from the regulatory asset base. Examples of disallowed assets include assets used for non-licensed activities, recreational facilities, and premiums paid for assets purchased by the OST above market value. The ERE based on its consultant or its own staff evaluation should determine the market value only in cases of disputed levels of investment.

6.3 Prudent levels of investment approved by the ERE may be included in the regulatory asset base for transmission services for the initial regulatory periods. The OST will provide the ERE with written testimony on the breakdown of the proposed investment program for the regulatory period, providing details how each major category will provide additional needed capacity or improve service and energy quality performance.

6.4 The OST shall show the estimated accumulated depreciation and amortization for all assets in the regulatory asset base through the last rate period of the current regulatory period and propose an estimate of the depreciation and amortization for the first rate period of the next regulatory period.

6.5 Regulatory or deferred assets are expenses that are non-recurring or periodically recurring expenses that should be recovered over a period of time by the OST. Non-recurring expenses include catastrophic storm damage. Period recurring expenses include rate application preparation and rate application *hearing expenses*.

6.6 Depreciation of assets will be based on the most recent deprecation study provided by the OST that will show the lives of assets by category. (This should be part of the regulatory accounting manual).

6.7 TheOST should provide proposals for the amortization of non-tangible assets and regulatory/deferred assets. The ERE will approve all amortization schedules.

6.8 The working capital allowance in the regulatory rate base should be based on a study of the funds required to maintain a suitable level of material and supplies and the cash required to meet current obligations and to maintain minimum back accounts. Any such study will be included in the rate application by the OST to the ERE. In absence of the study, theOST may provide an estimate of the working capital allowance with written evidence justifying such an estimate.

6.9 The OST shall not earn a return on any assets acquired through gratuitous transfer or constructed with financial resources of electricity consumers. The OST will be allowed to recover depreciation on such assets.

6.10 The OST will provide the results of any revaluation of tangible assets which was performed in accordance with the Albanian Accountancy Act and International Accounting Standards and which was completed after the last rate application proceeding for the OST. The OST will provide a breakdown of the asset, by categories, included in the regulatory asset base, before and after the revaluation. (Aspects of evaluation should be provided in the Corporate Accounting Practices and Procedures).

6.11 The ERE will determine the appropriate after-tax Return on Equity for the OST which will be the rate for a riskless security in Albania plus a risk premium related to the risk inherent for a state-owned TSO. .The allowed after-tax return on equity will be initially set at [ ]% for the first and second regulatory period using price cap (2009-2012). In future regulatory periods, the ERE will use the Capital Asset Pricing Model or other methodologies, where the ERE will use a number of factors for consideration, including: (1) comparisons with other companies having corresponding risks; (2) the attraction of capital; (3) current financial and economic conditions; (4) the cost of capital; (5) the risk of the enterprise; (6) the financial policy and capital structure of the utility; (7) the competence of management; and, (8) the company’s financial history.

6.12 The ERE will determine the normalized cost of debt for calculating the debt component interest rates. The calculation of the normalized cost of debt will be based on interest rates for outstanding debt of the OST. The interest rates used for determining revenue requirements may or may not be the same as actual interest rates for debt. The OST must show that the interest rates for debt are in-line with commercial interest rates for debt assumed by other companies with similar credit risks. Any debt included in the calculation of average debt interest rate that has an interest rate higher than the current market level will be adjusted downward to the market level.

6.13 The ERE has set a long-term target capital structure of [ ]% equity and [ ]% debt for the network companies. The ERE will expect that the OSTwill start using this capital structure for determining the weighted cost of capital starting in the third regulatory period. Until then, the ERE will use the most recent year's equity to debt ratio plus the expected investment level during the regulatory period to determine an appropriate capital structure. The ERE will assume that the OST will acquire 100% debt for all new required investments.

7. Transmission Services

7.1 The OST will provide the following regulated transmission services.

1. Transmission use-of-network services (capacity charge, energy charge):
2. Access Charges (optional);
3. Wholesale Market Settlements;
4. New and expanded transmission network connections (design and construction)
5. Metering and meter reading
6. Disconnection and reconnection
7. Ancillary services (including the correction of power factor)
8. Dynamic Scheduling Services
9. International interconnection capacity
10. Participation in the SEE CBT mechanism

8. Customer Groups

8.1 The OST will provide three types of services: use-of-network services, ancillary services, and connection services. (What about an access charge – providing incentives to locate new generating plants and new large customer load – that is, pay to generators to locate in the South and new load to locate in the North and to charge generators locating in the North and new customer load locating in the South? - Seems to the used quite often now throughout Europe))

8.2 The RPS, qualified suppliers, IPPs, SPPs selling into the competitive power market,, energy traders, and non-tariff consumers will contract for transmission use-of-network services.

8.3 The OST will offer connection service to the DSO, IPPs, and end-users connected to the transmission network.

8.4 The DSO on behalf of end-users connected to the distribution network and the end-consumers (end-users and off line generating plants) connected to the transmission system will contract for reactive power compensation.

8.5 Balancing groups will be formed to cover regions of the country for dynanmic scheduling service (system balancing and imbalance service).

8.6 The costs for all ancillary services other than reactive power and dynamic scheduling service provided by the OST will embedded in the charges that OST customers pay for use-of-network services.

9. Allocation of costs to energy and capacity use-of-network charges

9.1 Each customer must pay an energy charge, in Leke/kWh, based on the number of kWh delivered from the transmission system to the use-of-network service customer during that month.

9.2 Customers will also pay a capacity charge for transmission, in Leke/kW/month, based on the higher of the customer's coincidental peak load during the 12-month period ending with the billing month or its contractually guaranteed capacity. A penalty may apply for any coincidental peak demand excess above the contractually guaranteed capacity.

9.3 In an OST tariff application, the distribution system operator must forecast the following figures, for each customer:

a) An estimate of the total delivery capacity in kW required to provide a reliable supply of electricity to use-of-network customers;

b) The total energy in kWh that will be sold to each transmission use-of-network customer in each month of the base year, and the sum of these monthly totals.

c) A forecast of the technical losses at each voltage level (the cost of losses will be included in the variable cost for each customer class).

9.4 For each customer,, the fixed cost of the revenue requirements are allocated to that cusotmer in the base year equals:

9.5 The price of capacity, in Leke per kW per month, equals:

$$\mathbf{P_{capacity} = Allocated\ Fixed\ Costs\ /\ L}$$

L **-** total delivery capacity, kW

9.6 For each customer group (customers at 110/x kV transformers, medium voltage, and low voltage) the energy-related portion of the revenue requirements is allocated to each customer group.

9.7 The price of energy, in leke per kWh, equals:

$$P_{energy} = \textbf{Allocated Variable Costs} \; / \; E$$

E - total energy in kWh that will be shown in transmission use-of-network customers' bills during the base year.

9.8 The OST may submit a tariff application to ERE for interruptible use-of network prices . In this application there will be two values of capacity payments: one corresponding to firm capacity and the other corresponding to interruptible, or non-firm, transmission capacity. The interuptible service approach require complex meter and communications facilities with direct control over customer load. The prices for interutible capacity should be justified by the value of interrupting customer load.during system emergencies and congested transmission interconnections. The rates may vary by the niumber hours of interruptions per year or per season.

10. Setting the average distribution tariff ceiling

10.1 For the base year, the average transmission use-of-network tariff price is equal to the average transmission tariff calculated according to costs in the base year.

10.2 For the second year of the tariff review cycle (Year 2), each component of the transmission use-of-network tariff for the base year is multiplied by the annual adjustment factor:

$$\mathbf{A = (1 + RPI - X)}$$

A - annual adjustment factor

RPI - rate of consumer price inflation forecast for Year 2 by the National Bank of Albania, or set by the ERE on the basis of the trend in consumer price index over the most recent 3 year period for which historical data are available

X - efficiency improvement factor set by ERE

10.3 The ERE will add to this formula a performance improvement factor based on the quality of energy and services to transmission customers. Such performance improvement factors must be defined very clearly and simply, and the OST must provide an assurance to ERE that the OST is able to provide the quality of energy and services data needed to accurately measure its performance improvement.

10.4 The value of X should be determined on the basis of a benchmarking study of TSOs, in which the performance of at least 3 TSOs is examined over a period of at least 3 years.

10.5 The X-factor will include at least four categories of expenses: direct and indirect labor, labor productivity, procurement, and technology. The technology will include implementation of management systems and reduction in technical losses.

10.6 If the OST's actual financial performance in any year of the regulatory is better than indicated by the financial projections in the OST application, or better than expected by the ERE, bonuses may be given to the top management of the OST and to the employees of the OST without raising the average transmission use-of-network tariff above the ERE-approved average transmission tariff price. Therefore the OST has an incentive to improve efficiency and reduce its costs, even when the value of X is equal to zero.

10.7 For each succeeding year of the regulatory period, the transmission use-of-network tariff for the previous year are multiplied by an annual adjustment factor as was done in Year 2.

10.8 According to this methodology an adjustment is made to the price cap in the next rate year even if the adjustment is made in the next regulatory period.

11. Reactive Power Charges

11.1 Reactive power compensation is normally an ancillary service provided by generators to the OST and therefore reactive power charges are part of the transmission distribution system operator. If the distribution system operator continually fails to meet its voltage standard set at the interconnection between the transmission and distribution network, the OST can charge the distribution system operator reactive power penalties. The distribution system operator can install reactive power capacity or reactors as the need requires rather than pay the penalty to the transmission company. (this should be part of the fix to transmission tariff)

11.2 Consumers connected to the transmission network pay an allowance over the value of the active electric power depending on the reactive electric power used and released at average monthly capacity factor less than 0.9 during the day and peak daylight zone.

11.3 The quantity of used reactive electric power, for which an allowance is paid under Section 10.2, is the positive difference between the quantity of used reactive electric power and the product of the quantity of used active electric power and a coefficient corresponding to the average monthly power factor, according to the formula:

$$E_{r\ alwn} = E_{r\ used} - (E_{a\ used} \text{ X } (1 - F))$$

where:

$E_{r\ alwn}$ is the quantity of reactive electric power which is paid, kVarh;

$E_{r\ usd}$ the quantity of reactive power consumed by the customer during the daytime zones;

F = 0.9, for reactive power consumption not charged between 1.1 and 0.9 power factor.

$E_{a\ usd}$ the quantity of active electric power used by the consumer by daytime zones, determined through the readings of the device for commercial metering of active electric power, kWh.

11.4 The consumers under Section 10.2 pay an allowance for the quantity of reactive electric power ($E_{r\ alwn}$) determined according to Section 10.3 at a price for 1 kVarh, equal to 10 per cent of the regulated public supply price for 1 kWh active electric power for the respective daytime zone and the respective voltage level.

11.5 The consumers under Section 10.2 pay an allowance for the quantity of reactive electric power released throughout the peak hours, determined according to the readings of the commercial metering devices, at a price for 1 kVarh, equal to the public supply price for 1 kWh peak active electric power for the respective voltage level.

11.6 Whenever the consumers under Section 10.2 produce electricity and heat under combined generation cycle, they do not pay to the distribution system operator an allowance over the released reactive electric power produced under combined generation cycle.

12. Pricing of New Connections to the Transmission Network

12.1 The OST determines the prices for customer connecting to the transmission network. These prices are paid by newly-connected consumers, existing consumers increasing their power, and by owners of new power facilities.

12.2 Customers must apply to the OST for a new connection or expansion of an existing connection. The form and rules relating to the connection application are specified within the grid rules.

12.3 The costs of the OST for analyzing and providing an estimate of a proposed new connection is differentiated by voltage level. The costs of connecting consumers' facilities are determined under an individual project and are formed through a calculation of the individual expenses on the project, including the expenses necessary for making the connection between the facility's installation and the nearest point of the respective network at which it is possible for the connection to be made.

12.4 The OST will provide the applicant with the estimated costs of the new interconnection, the estimated cost required to upgrade the upstream transmission network facilities and a proposed schedule to complete all necessary work for interconnecting and operating the new facilities. The pre-paid charge in 2008 for each study will be:

1. 400 kV connection - 1000000 Leke
2. 220 kV connection – 750000 Leke
3. 110 kV connection – 500,000 leke

The cost of the studies will be increased annually by the Albanian CPI for the previous year.

12.5 Electricity consumers pay the price for connecting to the transmisison network, which includes only the direct expenses for connecting the installations of the consumers to the network of the electric power company. (This should only be true if the ERE elects to introduce transmission access charges. The generators and large consumers must be given the proper incentive to locate their facilities, to the extent possible, where there are no negative impacts.)

12.6 The above price determination is for a single line connection, or third level (III) of reliability of service for consumers. There are two other higher levels of security, Level II and Level I. The improved reliability is ensured through increased protection including multiple circuits into a customer's premise. This has to be consistent with the transmission code

13. Deadlines

13.1 Based on this methodology, the OST shall submit to the ERE a request for the approval of new tariff no later than 6 months before the day that the new proposed tariffs are required to enter in force.

13.2 The OST shall submit to the ERE data on previous year costs and average tariff (prices) according to the sale structure, within April of the next year.

13.3 ERE shall examine these data within May of each year, and if deviations from the approved costs and tariff (prices) that impair the customers are evidenced, the ERE shall decide on the company reimbursements for the next year.

14. Transitional Provisions

14.1 The tariff year is March through February.

14.2 The first regulatory period will be the tariff year 2009. The second regulatory period will be the tariff year 2010. This third regulatory period will be 2011 - 2013.

14.3 The rates for the third regulatory period will be based on financial data in accordance with IFRS and National Accounting and Reporting Standards.

14.4 For the initial regulatory periods,

(1) The OST tariff structure in the first regulatory will remain the same as it exists as of January 1, 2009.

(2) The OST may file an application to the ERE to revise the rate structure within the second or third regulatory period if the OST provides a rate design study based on customer usage patterns and cost of service for its customers..

(3) The rates for each transmission use-of-network service will be uniformly increased based on the increase of revenue requirements for the previous period.

15. Final provisions

The Electricity Transmission Services Tariff Calculation Methodology was approved by ERE’s Board of Commissioners on ________.

Part II

Tariff Application Tables

PART III
(Existing methodology)

Ancillary services tariff calculation methodology

1. Terms used in this methodology

1.1 **Average transmission tariff –** average revenue per kWh reflected in transmission system customer bills over a 12-month period, calculated as the total revenue from capacity-related charges, energy-related charges, and fixed monthly charges divided by the total kWh delivered by the transmission system to distribution companies and eligible electricity users located in Albania.

1.2 **Average transmission tariff ceiling –** the maximum allowable level of the average transmission tariff for a specific 12-month period.

1.3 **Base tariffs –** the set of transmission service tariff values determined according to costs in the base year.

1.4 **Base year –** the first year of the tariff review cycle, corresponding to a 12-month period in which the transmission tariffs approved by ERE are applied to customer bills. The beginning of the base year is the date on which the cost of transmission service is charged to transmission system customers according to the new transmission tariffs. This date may be no more than 30 days before and no more than 30 days after the date of official approval of the new transmission tariffs.

1.5 **Differentiated tariffs –** tariffs for customer service that include capacity-related charges, energy-related charges, fixed monthly charges, and reactive power charges.

1.6 **Distribution system –** Distribution system comprises all system's elements at voltage levels below 110 kV, which are under posses of Distribution Companies.

1.7 **Efficiency improvement factor (X factor) –** the annual percentage reduction in the cost of transmission service resulting from improvements in production efficiency and improvements in technology.

1.8 **Electricity consumption for technological purposes –** shunt reactor consumption, synchronous compensator consumption, condenser battery consumption and energy that is consumed by the OST for its own use and taken directly from transformer substations and facilities owned by the transmission system. Network losses are excluded. Energy consumed by generating stations is excluded.

1.9 **Electricity meter –** a device for measuring the flow of active and reactive power and energy within the transmission network, or measuring the flow of active and reactive power and energy across international borders, or measuring the active power and energy delivered to transmission system customers.

1.10 **Electricity supply –** energy marketing activity consisting of the purchase of electric energy from producers and the sale of electric energy to users, and the buying and selling of electric energy in a spot market or exchange.

1.11 **Eligible Customer –** Electricity user which, according to legislation in force or regulation adopted by the ERE, has the right to choose the electric supplier for the electricity he uses for his own needs.

1.12 **Energy regulatory entity –** A state institution that regulates electricity sector activity according to the Law on Power Sector.

1.13 **Grid Code –** Transmission System Code is a document determining boundaries and relations between OST sh.a. and customers, and sets up procedures for operation, planning, connection to, and development of Transmission System according to Albanian and Regional electricity market development. It summarizes the required information and governing procedures of relations between OST sh.a. and users of Transmission System.

1.14 **Independent power producers –** Electricity producers which under their responsibility, separated from the Power System, cover electricity demand of their own, specific customers or sell electricity to the Power System.

1.15 **Network losses –** The difference between the quantities of electricity delivered to the electricity network and the quantity of electricity withdrawn from the electricity network over the respective time period.

1.16 **Regulated asset base (RAB) –** The value of fixed assets that are owned by the OST and are used to provide service to transmission customers and to fulfill the OST's obligation to ensure the reliability and security of the electric system. The regulated asset base does not include financial investments, securities, accounts receivable, or cash.

1.17 **Tariff review cycle –** The time period for which new tariffs become effective and are adjusted according to a decision taken by the Energy Regulatory Entity, following a complete and detailed review of a tariff application submitted by the transmission system operator.

1.18 **Transmission system –** Transmission System is composed by a set of lines of high voltage (at 110 kV, 150kV, 220kV, 400kV), transformer substations, or any other installation which functions comprise transmission or international interconnection. All assets, including communication, protection, control, ancillary services, land, buildings and other auxiliary assets of electric nature or not, which are necessary for proper functioning of particular installations of Transmission System are part of Transmission System.

1.19 **Transmission system customers (users) –** Physical and legal persons which perform licensed activities in the Power System such as Generators, Distribution Companies, Suppliers, Eligible Customers, as well as any legal person benefiting Transmission Services.

1.20 **Transmission system operator (OST) –** A company which owns and operates the transmission system and guarantees the security of electricity supply. The OST is a legal person which has been granted a license for electricity transmission.

1.21 **Electricity User –** A legal or natural person who purchases electricity for his own needs or for different processes which are performed in its activity.

1.22 The definitions presented in the UCTE Operation Handbook are applicable to this methodology.

1.23 If a term is defined in both documents, both definitions are valid unless there exists some contradiction.

1.24 In adopting this tariff methodology the ERE assumes that a definition of balancing services in the Energy Community of South East Europe (ECSEE) will be developed under the Athens Process and will be stated in a Grid Code for the electricity market. The ERE also assumes that the market design will include balancing services at two levels, national and regional. Definitions related to national balancing service are presented in this section

1.25 **Balancing market –** A competitive market for bids and offers to provide balancing energy to ensure a real-time system balance in each hour.

1.26 **Imbalance –** The difference between the energy flow defined by a bilateral contract and the actual metered energy flow, for a particular hour. A generator is *in balance* when his metered generation equals his contracted delivery, in a particular hour. A supplier is in balance when his metered offtake matches his contracted offtake. A generator is *short* when his metered generation is less than his contracted delivery. A supplier is short when his metered offtake is greater than his contracted offtake. A generator is *long* when his metered generation is greater than his contracted delivery. A supplier is long when his metered offtake is less than his contracted offtake.

1.27 **National balancing price –** The price per kWh charged to electricity market participants who hold national bilateral contracts and have an imbalance. The same price will be charged to all participants regardless whether they are short or long.

1.28 **National balancing service –** A service provided by a transmission system operator to compensate for imbalances by selling energy to all market participants who are short and buying energy from all market participants who are long.

1.29 **National bilateral contract –** A bilateral contract for electricity supply, in which both the buyer and the seller are located in Albania.

2. Definitions found in the UCTE Operation Handbook

2.1 Ancillary Services are Interconnected Operations Services identified as necessary to effect a transfer of electricity between purchasing and selling entities (Transmission) and which a provider of transmission services must include in an open access transmission tariff.

2.2 Black-start Capability is the ability of a generating unit to go from a shutdown condition to an operating condition and start delivering power without assistance from the electric system.

2.3 A Control Area is a coherent part of the UCTE interconnected system (usually coincident with the territory of a company, a country or a geographical area, physically demarcated by the position of points for measurement of the interchanged power and energy to the remaining interconnected network), operated by a single OST, with physical loads and controllable generation units connected within the control area. A control area may be a coherent part of a control block that has its own subordinate control in the hierarchy of secondary control.

2.4 Primary Control maintains the balance between generation and demand in the network using turbine speed governors. Primary control is an automatic decentralized function of the turbine governor to adjust the generator output of a unit as a consequence of a frequency deviation / offset in the synchronous area. Primary control should be distributed as evenly as possible over units in operation in the synchronous area. The global primary control behavior of an interconnection partner (control area / block), may be assessed by the calculation of the equivalent droop of the area (basically resulting from the droop of all generators and the selfregulation of the total demand). By the joint action of all interconnected undertakings, primary control ensures the operational reliability for the power system of the synchronous area.

2.5 Reactive Power is an imaginary component of the apparent power. It is usually expressed in kilo-vars (kVAr) or mega-vars (MVAr). Reactive power is the portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers and causes reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors, and directly influences the electric system voltage. The reactive power is the imaginary part of the complex product of voltage and current.

2.6 Secondary Control is a centralized automatic function to regulate the generation in a control area based on secondary control reserves in order to maintain its interchange power flow at the control program with all other control areas (and to correct the loss of capacity in a control area affected by a loss of production) and, at the same time, (in case of a major frequency deviation originating from the control area, particularly after the loss of a large generation unit) to restore the frequency in case of a frequency deviation originating from the control area to its set value in order to free the capacity engaged by the primary control (and to restore the primary control reserves). In order to fulfill these functions, secondary control operates by the network characteristic method. Secondary control is applied to selected generator sets in the power plants comprising this control loop. Secondary control operates for periods of several minutes, and is therefore dissociated from primary control. This behavior over time is associated with the PI (proportional-integral) characteristic of the secondary controller.

2.7 System Frequency is the electric frequency of the system that can be measured in all network areas of the synchronous area under the assumption of a coherent value for the system in the time frame of seconds (with minor differences between different measurement locations only).

2.8 Tertiary Control is any (automatic or) manual change in the working points of generators (mainly by re-scheduling), in order to restore an adequate secondary control reserve at the right time.

2.9 Transmission is the transport of electricity on the extra-high or high-voltage network (transmission system) for delivery to final customers or distributors. Operation of transmission includes as well the tasks of system operation concerning the management of energy flows, reliability of the system and availability of all necessary system services / ancillary services.

3. National balancing service

3.1 The OST is authorized to import and export any amount of electric energy at any time, if import or export is necessary to provide national balancing service.

3.2 For any hour in which Albania is a net importer of electric energy, the national balancing price equals the incremental cost to the OST of importing an additional kWh.

3.3 For any hour in which Albania is a net exporter of electric energy, the national balancing price equals the incremental revenue to the OST of exporting an additional kWh.

3.4 The OST may not charge a “service fee” or margin in addition to the national balancing price. The salary-related cost and capital-related costs of national balance service shall be included in the overall costs of the OST and recovered through the basic capacity component and the basic energy component of the transmission tariff.

4. Reactive supply

4.1 The Grid Code should define the acceptable range of power factor variation for transmission system customers. No reactive power charges will be imposed by the OST for transmission system customers complying with the norms defined in the Grid Code.

4.2 Transmission system customers with power factor below the acceptable level should pay a reactive power charge, measured in leke/kvarh, that will be shown in the OST’s monthly invoices to distribution companies and eligible customers connected directly to the transmission system. Operating costs incurred by the OST to compensate for these customers’ low power factor should be recovered through the reactive power charge.

4.3 Operating costs in 4.2 include the fuel costs associated with the operation of thermal generating units in Albania for reactive power control.

4.4 All other operating costs of compensating for reactive power in the transmission network shall
be included in the overall costs of the OST and recovered through the basic capacity component and the basic energy component of the transmission tariff.

4.5 Capital expenditures needed to reduce reactive power problems in the transmission network shall be included in the capital expenditure plan of the OST and recovered through the basic capacity component of the transmission tariff..

5. Ancillary services and CBT charge

5.1 The OST shall provide an estimate of the OST’s annual contribution to the Southeast Europe CBT Fund in each year, in leke. This is a payment for transits and loop flows in the high voltage network of Southeast Europe. The cost of CBT should be included in the ancillary services and CBT charge, even if the OST is not a signatory party to the CBT Agreement.

5.2 The total cost of CBT should be divided by total kWh delivered to transmission system customers. The result in leke/kWh is part of an additional charge, called the ancillary services and CBT charge, which is added to the basic energy component of the transmission tariff.

5.3 The allowable cost of primary control, secondary control, and tertiary control is defined in sections 6, 7, and 8 below. The sum of these allowable costs should be divided by total kWh delivered to transmission system customers. The result in leke/kWh is part of the ancillary services and CBT charge.

5.4 To obtain primary control, secondary control, and tertiary control for the Albanian power system, the OST is authorized to sign contracts with UCTE, with the legal entity or entities responsible for building and operating large hydropower stations in Albania, and with neighboring TSOs.

5.5 ERE shall be provided with a copy of the Southeast Europe CBT Agreement; the Interface Agreement with UCTE; the contracts between the OST and the legal entity or entities responsible for building and operating large hydropower stations in Albania; and the contracts between the OST and neighboring TSOs to obtain primary control, secondary control, and tertiary control for the Albanian power system.

6. Primary control

6.1 Payments to UCTE or to any members of UCTE for Primary Control service shall be included in the ancillary services and CBT charge.

6.2 Operating costs needed to enable a generating unit in Albania to provide primary control shall be included in the ancillary services and CBT charge, if they are paid by the OST and covered by a contract between the generator and the OST.

6.3 Capital expenditures needed to enable a generating unit in Albania to provide primary control shall be included in generation costs and not in the ancillary services and CBT charge.

6.4 The OST's capital expenditures needed to comply with the UCTE Interface Agreement shall be included in the capital expenditure plan of the OST and recovered through the basic capacity component of the transmission tariff.

7. Secondary control

7.1 Payments to UCTE or to any members of UCTE for Secondary Control service shall be included in the ancillary services and CBT charge.

7.2 Albanian generators' operating costs related to Automatic Generation Control shall be included in the ancillary services and CBT charge, if they are paid by the OST and covered by a contract between the generator and the OST.

7.3 Capital expenditures needed to enable a generating unit in Albania to have Automatic Generation Control shall be included in generation costs and not in the ancillary services and CBT charge.

7.4 The OST's capital expenditures needed to comply with the UCTE Interface Agreement shall be included in the capital expenditure plan of the OST and recovered through the basic capacity component of the transmission tariff.

8. Tertiary control

8.1 Payments to UCTE or to any members of UCTE for Tertiary Control service shall be included in the ancillary services and CBT charge.

8.2 Operating costs needed to enable a generating unit in Albania to provide tertiary control shall be included in the ancillary services and CBT charge, if they are paid by the OST and covered by a contract between the generator and the OST.

8.3 For a hydro generator located in Albania, the book value of fixed assets at December 31 should be divided by the "guaranteed" level of generating capacity available at the system peak hour,to obtain a “price” of capacity in leke/kW. The capacity price paid by the OST for each MW of tertiary control reserve equals the levelized annual cost of this capacity based on a 20-year operating lifetime and an interest rate of 18 percent (or some other value which is established by the ERE as the weighted average cost of capital for Albanian hydropower generation).

8.4 The total annual cost of capacity payments to Albanian generators for reserve capacity associated with tertiary control shall be included in the ancillary services and CBT charge.

8.5 Payments to Albanian generators for tertiary control have no relation to wholesale market prices for electric energy. The generator should not expect the OST to pay the “opportunity cost” of holding a portion of installed generating capacity in some category of reserve needed for primary, secondary or tertiary control rather than using that capacity to sell additional energy (for example, to export energy).

8.6 The OST’s capital expenditures needed to comply with the UCTE Interface Agreement shall be included in the capital expenditure plan of the OST and recovered through the basic capacity component of the transmission tariff.

9. Scheduling, system control, and dispatch service

9.1 The operating cost and capital-related costs of scheduling, system control, and dispatch service shall be included in the overall costs of the OST and recovered through the basic capacity component and the basic energy component of the transmission tariff. These services are not ancillary services. There is no reason to identify a separate charge for these services.

9.2 Costs incurred by the hydro stations should be called *generation costs*. If day-to-day management of the reservoirs in large hydro stations is conducted by the National Dispatch Center, and the optimization of the water level in each reservoir is the responsibility of the National Dispatch Center, then these costs are already included in the basic energy component of the transmission tariff and are not generation costs.

10. Final Provision

The ERE backs the principle that an agreement between the OST and the UCTE should be achieved