ELECTRICITY REGULATORY AUTHORITY

PART I

Electricity transmission tariff calculation methodology

INTRODUCTION

Electricity transmission tariff calculation methodology is developed under the article 28, paragraph 1 of Law No.9072, dated 22.05.2003 "On power sector", and as a result of establishment of the OST sh.a. by the Government Decree No.797, dated 4.12.2003 "For establishing of the Transmission System Operator". The purpose of this methodology is to set transmission tariffs based on principles of tariff calculation evaluating the necessary data for a fair tariff.

The methodology is construed and divided in three parts:

- Electricity transmission tariff calculation methodology.
- Tables with technical and economic-financial data.
- Ancillary Services tariff calculation methodology.

1. Terms used in the methodology

1.1 **Annual adjustment factor** – a percentage equal to the inflation factor minus the efficiency improvement factor.

1.2 **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.

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

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

1.5 **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.

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

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

1.8 **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

1.9 **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.

1.10 **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.

1.11 **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.

1.12 **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.

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

1.14 **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.

1.15 **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.

1.16 **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.

1.17 **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.

1.18 **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.

1.19 **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.

1.20 **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.

1.21 **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.

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

2. General regulations and basic principles

2.1 This methodology is developed in conformity with Law No.9072, dated 22.05.2003 "On Power Sector" as well as other legal acts which are in force in the Republic of Albania.

2.2 All sources of OST revenue defined in this tariff methodology are paid by transmission system customers.

2.3 Distribution companies must not pay connection charges to the OST. The OST's cost of a new connection to the distribution network must be recovered through the transmission tariff and "spread" across all customers in Albania. A customer who needs a new connection to the distribution network will pay a connection charge to the distribution company, but this charge has no relationship to the costs incurred by the OST to enable the transmission network to supply additional power to the nearest 110/x transformer.

2.4 Connection charges for new generating facilities directly connected to the transmission system shall be established on a case-by-case basis and are outside the scope of this tariff methodology. The ownership of assets that are financed through these connection charges may be transferred to the generating company. Assets financed through connection charges may not be included in the Regulated asset base of the OST and the depreciation of these fixed assets shall not be covered by the transmission tariff.

2.5 Connection charges for eligible customers who wish to own 110/x transformers shall be established on a case-by-case basis and are outside the scope of this tariff methodology. The ownership of assets that are financed through these connection charges may be transferred to the customers. Assets financed through connection charges may not be included in the Regulated asset base of the OST and the depreciation of these fixed assets shall not be covered by the transmission tariff.

2.6 The transmission tariff should recover the cost of the following activities:

a) Ownership, construction, operation, and maintenance of lines, cables, transformer substations, dispatch centers, and related buildings and communication facilities.

b) The cost to the OST of operating reserves needed to ensure the stability and security of the transmission system. These reserves are obtained on a contractual basis from large hydropower stations located in Albania.

c) The cost to the OST of other ancillary services, including payments made to neighboring OSTs to obtain an assurance of emergency power and instant reserves, and payments (if any) for frequency and voltage regulation.

d) Reactive power compensation costs, which should be allocated to a reactive power charge.

e) The cost of providing office space, communications, and IT facilities to the Market Operator plus the personnel costs related to the Market Operator. From an accounting standpoint the Market Operator should have its own accounts, as if it were an independent legal entity with taxable income.

2.7 The transmission tariff should not be used to recover the cost of imports of electric energy, or capacity payments associated with imported energy, or any other costs incurred by suppliers and eligible users under bilateral agreements. The transmission tariff may contain provisions requiring reimbursement of the costs incurred by the OST in obtaining balancing services.

2.8 "Price cap" regulation is applied to the average transmission tariff (exclusive of balancing power reimbursements). The regulator approves the average transmission tariff ceiling. If the average transmission tariff measured on the basis of historical data for one of the years in the tariff review cycle exceeds the average transmission tariff ceiling established by the Energy Regulatory Entity, the OST must lower the transmission tariffs in the following year so that the customers of the Albanian transmission system receive a refund of the amount of excess revenue collected (i.e. the amount of over-recovery).

2.9 An "RPI-X" approach is used to give the OST an incentive to reduce its costs during the tariff review cycle. The duration of the transmission tariff review cycle is three years. If the transmission tariffs for the next tariff review cycle have not been approved before the end of the three year period, the regulator may adopt a decision to extend the tariff review cycle to four years.

2.10 Tariff setting involves two interrelated activities: setting economically justified base tariffs for the base year of the tariff review cycle, and setting the average transmission tariff ceiling for years 2 and 3 of the tariff review cycle.

2.11 The distribution tariff review cycle and the transmission tariff review cycle should begin on the same day of the year (for example, January 1 or July 1) but it is not necessary for both of them to begin on the same date (for example, January 1, 2005).

2.12 Long-term debt financing should be used to finance new capital expenditures, to the extent possible, but should not be used to cover operating costs or refinance older assets i.e. assets that were brought into operation on or before 31.12.2000. The OST should have a very high collections rate from transmission system customers, so that the OST will be able to finance capital expenditures primarily through long-term borrowing rather than after-tax cash flow from operations.

2.13 The regulated company 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.

2.14 Tariffs shall correspond to costs that would be incurred by a well-managed transmission company which tries to make prudent investments, minimize network losses, and avoid wasteful expenditures. When setting the base tariff the regulator has the right to investigate the cost levels reported by the OST, and benchmark its unit costs against other OSTs.

2.15 The regulator does not have a right to exclude from the tariff calculation the cost of investments that would have been made by a well-managed transmission company on the basis of the information available to the company when the investment decision was taken.

2.16 In preparing a tariff application the OST shall try to present all costs with precision up to 10,000 leke. The regulator should not question amounts less than 10,000 leke unless there is a dispute about compensation or payment to specific physical persons.

3. Electric energy and power balances

3.1 The electric energy balance sheet of the OST for the base year shall be prepared by estimating the total amount of energy in GWh received by the transmission network during the base year. This total equals energy received from Albanian generating stations connected to the transmission network plus energy received from the transmission networks of neighboring countries. Total energy received must be allocated to:

a) energy delivered to Albanian distribution networks

b) energy delivered to eligible users connected to the transmission system

c) transits or loop flows

d) energy delivered to pumped storage hydro stations (if any)

e) energy losses in the transmission network (excluding losses in 110/x transformers owned by distribution companies and large customers)

f) consumption of energy for technological purposes by the OST.

3.2 The coincident peak load flow balance of the OST shall be prepared by estimating the total power in MW received by the transmission network in the peak hour.

This total equals power received from Albanian generating stations connected to the transmission network plus power received from the transmission networks of neighboring countries. Total power received must be allocated to:

a) power delivered to Albanian distribution networks

b) power delivered to eligible users connected to the transmission system

c) transits or loop flows

d) power delivered to pumped storage hydro stations (if any)[1]

e) power losses in the transmission network (excluding losses in 110/x transformers owned by distribution companies and large customers)

f) consumption of power for technological purposes by the OST.

3.3 Energy and power balances for the entire Albanian transmission and distribution network are not an acceptable substitute for balances for the transmission system.

3.4 Annual energy associated with transits and loop flows should be illustrated with a diagram showing which countries delivered energy to Albania and which countries received energy from Albania. Peak power flow associated with transits and loop flows should be illustrated with a load flow diagram, showing which countries delivered power to Albania and which countries received power from Albania.

3.5 If transits and loop flows are more than 1 percent of the load flow in the transmission network during the annual coincident peak hour, the OST should state whether new transmission network capacity in Albania is being built to serve neighboring countries, and should explain whether the OST receives adequate compensation for providing peak load flow capacity to neighboring countries.

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

3.7 If there exists any significant import, export and transit of electric energy through the Albanian distribution system, rather than the transmission system, this should be reported in the transmission tariff application. Hydroelectric generators located near the border of Albania should not be allowed to build direct lines to other countries, to export electric energy through direct lines.

3.8 Energy consumed by OST facilities at low or medium voltage and delivered through the distribution network should be included in the total amount of energy delivered to the distribution network. The OST may purchase energy at low or medium voltage according to the tariff for budget institutions.

3.9 During a transitional period it may be necessary for the OST to estimate some values, due to the absence of meters. The OST should aim to have a meter at every

[1] This value should equal zero, unless there is an area with a surplus of hydropower production relative to load, and the transmission network is damaged and therefore the area is isolated.

point where assets owned by the OST are connected to assets owned by a transmission system customer. For example, the power flow from a 110 kV line into a 110/x transformer owned by a distribution company or large industrial customer should be metered on the 110 kV side of the transformer.

4. Costs to be included in the tariff calculation

4.1 Costs to be included in tariff calculation and recovered through capacity-related charges, energy-related charges, and fixed monthly charges consist of capital costs, operational costs and taxes. Only economically justified costs that pertain to the provision of regulated services shall be included in tariff calculation. The target level of revenue to be collected in the base year is equal to:

$$\mathbf{C = C_{capital} + C_{operating} + C_{tax}}$$

4.2 VAT is not included in the formula shown above because it is calculated by the OST for each transmission system customer's monthly bill for transmission service, and shown as a separate item in the monthly bill.

4.3 Reactive power costs incurred by the OST should be recovered through a separate 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.

4.4 Capital costs equal the return on capital, plus depreciation and amortization.

$$\mathbf{C_{capital} = R + D}$$

$\mathbf{C_{capital}}$ - capital-related component of the target revenue for the base year

R - return on capital

D - depreciation of fixed assets and amortization of other assets

4.4.1 The return on capital is calculated by the formula:

$$\mathbf{R = B * r}$$

B – Regulated Asset Base at the beginning of the base year of the tariff review cycle

r – the allowable rate of return on the Regulated Asset Base.

4.4.2 The value of the regulated asset base should be equal to the replacement cost of the fixed assets used to provide transmission service, less depreciation, less an adjustment for economic obsolescence. The regulator has the right to ask the OST to hire an auditing firm or expert in asset valuation to conduct an asset valuation study, if such a study has not been completed for at least five years. Unless the regulator has some reason to believe that the OST has incurred excessive costs on its recent construction projects, the regulator should assume that the replacement cost of any asset less than five years old is equal to the actual cost incurred.

4.4.3 Land and rights-of-way used by the OST may be valued at original purchase cost, adjusted for inflation. It is not necessary to estimate the market value of this land.

4.4.4 The depreciation lifetimes of different categories of assets should be based upon the expected operating life of these assets. If financial data have been distorted by the use of unreasonably high numbers for depreciation lifetimes, the regulator may instruct the OST to prepare a set of financial accounts for tariff making purposes, using depreciation lifetimes approved by the regulatory authority.

4.4.5 None of the assets of the OST should be considered stranded assets. If they are valued according to depreciated replacement cost and are in operation, then it is reasonable to assume that they are needed to provide transmission service in a competitive Southeast Europe electricity market.

4.4.6 The allowable rate of return on the Regulated Asset Base is calculated from an allowable rate of return on equity in the base year, an estimated average interest rate on long-term debt during the base year, and a debt/equity ratio. All three of these values must be given in the tariff decision issued by the regulatory authority so that the assumptions used to calculate the allowable rate of return will be clearly presented. The allowable rate of return on the Regulated Asset Base is:

$$\mathbf{r = roe * (1-d) + i * d}$$

roe – allowable after-tax rate of return on equity; a target set by the regulatory authority

d – debt ratio - i.e. the ratio of long-term debt to long-term assets - which is set by the regulatory authority and applied to the Regulated Asset Base

i – weighted average interest rate on long-term debt

4.4.7 The allowable rate of return on equity should be selected by the regulator on the basis of the OST's need to obtain cash flow for capital expenditure, as shown in the statement of sources and uses of funds in the base year. All profits must be used to support the OST's capital expenditure program and increase the book value of share capital. The OST may not pay dividends to its shareholder, the Ministry of Economy of Albania.

4.4.8 If the OST can demonstrate that there is an urgent need for specific capital expenditures and that debt financing for these assets is not available, the ERE may decide to set a high allowable rate of return on equity and thereby enable the OST to generate the additional cash flow needed. The ERE recognizes, however, that this approach will increase the tax liability of the OST and therefore it is not simply a method of financing capital expenditures; it is also a method of increasing Government tax revenues. The decision taken by the regulatory authority should be based upon the customers' interests and not the Government's need for tax revenue.4.4.9 The weighted average interest rate on long-term debt should be determined as either (a) the sum of interest payments on long-term debt during the base year, divided by the total principal on long-term debt (the total amount borrowed) at the beginning of the base year or (b) the sum of interest payments on long-term debt during the 3-year tariff review cycle, divided by the sum of the amount borrowed at the beginning of the base year, the amount borrowed beginning of year 2, and the amount borrowed at the beginning of year 3. Unless the regulatory authority finds some reason to believe that the OST has borrowed money at interest rates that are higher than necessary to obtain OST financing, the weighted average interest rate on long-term debt should be calculated by the OST and shown in the tariff application.

4.4.10 Before submitting a tariff application, the OST may submit an application for the regulator to set the allowable rate of return on the Regulated Asset Base. The regulator must respond to this application according to the approved procedures for tariff applications.

4.4.1 All essential components of the transmission 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.

4.4.12 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. For a transmission tariff calculation there is no reason to capitalize the value of intangible assets.

4.5 The OST's operating costs include:

$$\mathbf{C}_{\mathbf{operating}} = \mathbf{C}_{\mathbf{metering}} + \mathbf{C}_{\mathbf{maintenance}} + \mathbf{C}_{\mathbf{salaries}} + \mathbf{C}_{\mathbf{losses}} + \mathbf{C}_{\mathbf{tech}} + \mathbf{C}_{\mathbf{outsource}}$$

$\mathbf{C}_{\mathbf{metering}}$ - the cost of measuring the power and energy delivered to transmission system customers, and the cost of billing and settlement of accounts with transmission system customers[2]

$\mathbf{C}_{\mathbf{maintenance}}$ - spare parts, supplies, vehicles, fuel, and other maintenance costs; this component excludes the maintenance costs that have been allocated to $\mathbf{C}_{\mathbf{metering}}$

$\mathbf{C}_{\mathbf{salaries}}$ - salaries, wages, medical insurance, and costs (other than taxes) associated with employee benefit programs; this component excludes the salary costs that have been allocated to $\mathbf{C}_{\mathbf{metering}}$

$\mathbf{C}_{\mathbf{losses}}$ - an allowance for the true economic cost of all electric energy losses in the transmission network, including losses associated with export and transit

[2] This category measures customer-related costs, and does not include the cost of measuring electric energy losses, electricity consumption for technological purposes, and export, import, and transit flows. The purpose of measuring $\mathbf{C}_{\mathbf{metering}}$ is to calculate the fixed monthly charge to each transmission system customer based on the number of points at which the customer is connected to the transmission system.

$\mathbf{C}_{\mathbf{tech}}$ - an allowance for the true economic cost of energy consumption for technological purposes; this is similar to the allowance for network losses

$\mathbf{C}_{\mathbf{outsource}}$ - expenditures for professional services including accounts, lawyers, financial advisors, consultants, IT specialists, and advertising agencies (excluding expenditures already included in salaries and wages)

4.5.1 Costs related to dispatch center operation should be included in the categories shown above. There is no need to show dispatch costs separately.

4.5.2 In the transmission tariff calculation, the price assigned to transmission network losses is not determined by KESH or its affiliates and does not depend on contracts between the OST and KESH. Instead, it is an estimate derived from the Southeast Europe regional electricity market:

$$\mathbf{C}_{\mathbf{losses}} = \mathbf{E}_{\mathbf{losses}} * \mathbf{P}_{\mathbf{regional}}$$

$\mathbf{E}_{\mathbf{losses}}$ - energy losses in the transmission network during the base year

$\mathbf{P}_{\mathbf{regional}}$ - the average price of electric energy that would be imported from the Southeast Europe regional electricity market during the base year

4.5.3 An estimate of the value of $\mathbf{P}_{\mathbf{regional}}$ should be provided by the OST in its tariff application. One method of estimating this value is to calculate the average price of electric energy imports and exports over the base year, based on hourly prices and an equal weight for each hour of the year. Another method of estimating this value is to conduct a competitive tender for 10 MW of energy to be imported in each hour by the Market Operator.[3] Another method would be to calculate the annual average price of base load energy on the Slovenian power exchange and then adjust this value on the basis of an estimate of the difference between average price in Slovenia and average price at the Albanian border. The ERE shall select the best method.

4.5.4 The same price $\mathbf{P}_{\mathbf{regional}}$ is used to measure the annual cost of electric energy consumption for technological purposes:

$$\mathbf{C}_{\mathbf{tech}} = \mathbf{E}_{\mathbf{tech}} * \mathbf{P}_{\mathbf{regional}}$$

$\mathbf{E}_{\mathbf{tech}}$ - electric energy consumption for technological purposes during the base year

4.5.5 In its tariff application the OST may submit a proposal to assign some price other than $\mathbf{P}_{\mathbf{regional}}$ to network losses and to energy consumption for technological purposes. However, the OST may not propose any price that can be manipulated by KESH and may not use this pricing issue to delay or extend the schedule for review and approval of the transmission tariff.

[3] This energy could be sold either to Albanian customers, to Albanian suppliers, or to customers and suppliers located in neighboring countries.

4.5.6 In special circumstances the repair and maintenance of the transmission system may be done by private firms rather than employees of the OST. After a major storm, for example, urgently needed repair work may be contracted to private firms. The costs should be included in $\mathbf{C}_{\mathbf{outsource}}$.

4.6 The $\mathbf{C}_{\mathbf{tax}}$ component enables the regulatory authority to show clearly the portion of the tariff which is attributable to taxes and therefore beyond the regulator's control.[4] Although it is possible to reduce electricity rates by lowering the contribution of the electric sector to tax revenues, the regulator's role is simply to provide the figures that show the tax component of electric sector tariffs including the transmission tariff. The tax component of the OST's target revenue for the base year, excluding VAT, is:

$$\mathbf{C}_{\mathbf{tax}} = \mathbf{C}_{\mathbf{social\ tax}} + \mathbf{C}_{\mathbf{property\ tax}} + \mathbf{C}_{\mathbf{profit\ tax}} + \mathbf{C}_{\mathbf{ERE}}$$

4.6.1 The cost component labeled $\mathbf{C}_{\mathbf{social\ tax}}$ includes all taxes related to salaries, such as pension taxes. This includes salary-related taxes that are used by the government to provide unemployment benefits and training to workers who lose their jobs. Insurance purchased by the OST is considered a part of operating expenses, even if it is required by government regulations, and not a part of social taxes.

4.6.2 The cost component labeled $\mathbf{C}_{\mathbf{property\ tax}}$ includes all taxes other than social taxes, income taxes and VAT. For example this component includes fees charged by government authorities other than ERE for permits and licenses. Property tax on buildings, constructions and land owned by the OST is calculated based on the legal acts of the Republic of Albania.

4.6.3 The cost component labeled $\mathbf{C}_{\mathbf{profit\ tax}}$ includes all profit taxes paid by the OST to the Government of Albania. For the base year, this cost component may include an allowance for taxes paid in year 2 and subsequent years, but attributable to after-tax income earned in the base year.

4.6.4 The cost component $\mathbf{C}_{\mathbf{ERE}}$ includes all fees paid to ERE by the OST.

4.6.5 The OST should not collect revenue for the purpose of covering KESH's tax obligations. The transmission tariff should not contain any component which is related to tax obligations incurred by KESH before the OST started its operations.

5. Allocation of costs to capacity, energy, and fixed monthly charges

5.1 Each transmission system customer must pay a capacity charge, in leke/kW/Month, based on the customer's peak load during the 12-month period ending with the billing month. If the customer has signed an agreement with the OST in which the customer must pay for a specific amount of capacity guaranteed by the agreement,

[4] Under international financial accounting standards, salary-related taxes and property taxes are normally included in operating expenses, and profit taxes are included in income before tax, and therefore associated with the return on equity.

then the capacity charge is applied to whichever is higher – the contractually guaranteed capacity, or the customer's peak load during the 12-month period ending with the billing month.

5.2 Each transmission system customer must pay an energy charge, in leke/kWh, based on the number of kWh delivered from the transmission system to the transmission system customer during that month.

5.3 Each transmission system customer must pay a fixed monthly charge which is intended to cover the metering, billing, and settlement costs incurred by the OST to provide service that customer during the base year.

5.4 In a tariff application the OST must provide a forecast of:

a) the total capacity in kW that will be shown in transmission system customers' bills in each month of the base year, and the sum of these monthly totals

b) the total energy in kWh that will be shown in transmission system customers' bills in each month of the base year, and the sum of these monthly totals

c) the number of delivery points to transmission system customers at the beginning of the base year, and number of delivery points at the end of the base year, and the average of these two figures

5.5 The total revenue to collected through capacity charges in the base year equals:

$$\mathbf{C}_{\textbf{capacity}} = \mathbf{C}_{\textbf{capital}} + \mathbf{C}_{\textbf{profit tax}}$$

5.6 The capacity charge, in leke per kW per month, equals:

$$\mathbf{P}_{\textbf{capacity}} = \mathbf{C}_{\textbf{capacity}} \;/\; \mathbf{L}$$

L **-** sum of the monthly total capacity shown in transmission system customers' bills, over the 12 months of the base year

5.7 The total revenue to collected through energy charges in the base year equals:

$$\mathbf{C}_{\textbf{energy}} = \mathbf{C}_{\textbf{maintenance}} + \mathbf{C}_{\textbf{salaries}} + \mathbf{C}_{\textbf{losses}} + \mathbf{C}_{\textbf{tech}} + \mathbf{C}_{\textbf{ouOSTurce}} + \mathbf{C}_{\textbf{social tax}} + \mathbf{C}_{\textbf{property tax}} + \mathbf{C}_{\textbf{profit tax}} + \mathbf{C}_{\textbf{ERE}}$$

5.8 The energy charge, in leke per kWh, equals:

$$\mathbf{P}_{\textbf{energy}} = \mathbf{C}_{\textbf{energy}} \;/\; \mathbf{E}$$

E **-** total energy in kWh that will be shown in transmission system customers' bills during the base year

5.9 The total revenue to be collected through fixed monthly charges in the base year equals $\mathbf{C}_{\textbf{metering}}$.

5.10 The fixed monthly charge, in leke per delivery point, equals:

$$P_{monthly} = C_{metering} / N$$

N - the average of the number of delivery points to transmission system customers at the beginning of the base year, and the number of delivery points at the end of the base year

6. Calculation of the average transmission tariff

6.1 In each year of the tariff review cycle, the average transmission tariff equals:

$$P_{average} = (C_{capacity} + C_{energy} + C_{metering}) / E$$

$P_{average}$ - average transmission tariff

6.2 The average transmission tariff reflects the cost of ownership, construction, operation, and maintenance of lines, cables, transformer substations, dispatch centers, and related buildings and communication facilities. It does not reflect the cost of all of the other activities listed in paragraph 2.6, because those costs should be recovered by the OST through additional charges and fees. For example, costs related to reactive power charges are excluded from the average transmission tariff.

6.3 The average transmission tariff may be calculated for any 12-month period. The monthly data may be forecast or historical or a combination of forecast data for future months and estimated data for recent months.

7. The transmission component of the tariff to captive customers

7.1 In its tariff application the OST must present an estimate, for each distribution company supplier, of the total OST revenue to be collected from that supplier during the base year through capacity charges, energy charges, and metering charges.

7.2 It is the responsibility of the distribution company supplier to prepare a tariff application in which the total OST revenue for that distribution company is collected from captive and eligible customers in a transparent and non-discriminatory fashion. Comparable groups of captive and eligible customers connected to the distribution system should pay the same transmission charges, directly or indirectly.

7.3 In the captive customer tariff methodology and in the distribution system use-of-network tariff methodology, the capacity charges paid by the distribution company supplier to the OST should be allocated among groups of customers connected to the distribution system, according to the contribution of each group to the coincident peak load of the distribution company. This calculation should take into consideration the technical losses at different voltage levels, as well as each customer groups' annual load factor and annual peak load in kW.

7.4 If the OST energy charge is applied to energy consumption in kWh shown in customer bills at medium and low voltage, the total revenue will be less than the amount of energy charges paid by the distribution company to the OST, which includes the energy charges associated with distribution network losses. If the OST capacity charge is applied to peak load in kW shown in customer bills or estimated for customer groups, the total revenue will probably be greater than the amount of capacity charges paid by the distribution company to the OST, because there will be some diversity among peak loads. Therefore, it may be possible to include the OST energy charge and the OST capacity charge in the tariff to captive customers and collect the "correct" amount of revenue. This is a very simple way to set the transmission component of the tariffs to captive customers, and it would be acceptable to the ERE, provided the distribution company recovers no more and no less that its total cost of transmission service through these energy and capacity components of its tariff.

7.5 The OST should review tariff applications submitted by distribution company suppliers, to ensure that the total OST revenue for that distribution company is collected from distribution company customers in a transparent and non-discriminatory fashion. The OST should send a letter to the ERE saying whether transmission system costs are being charged to captive customers in a transparent and non-discriminatory fashion. The OST's opinion will be taken into consideration by the ERE in reviewing the proposed tariffs to captive customers.)

8. Setting the average transmission tariff ceiling

8.1 For the base year, the average transmission tariff ceiling is equal to the average transmission tariff calculated according to costs in the base year.

8.2 For the second year of the tariff review cycle (Year 2), the average transmission 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

8.3 The ERE may, at its discretion, add to this formula a performance improvement factor based on the quality of supply to transmission system customers at 110 kV or the level of transmission network energy losses. 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 supply data needed to accurately measure its performance improvement.

8.4 The value of X should be determined on the basis of a benchmarking study of transmission system operators, in which the performance of at least 3 OSTs is examined over a period of at least 3 years. If the ERE does not have time to conduct such a benchmarking study or review the results of other benchmarking studies then the value of X should equal zero.

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

8.6 For the third year of the tariff review cycle (Year 3), the average transmission tariff for the second year is multiplied by the annual adjustment factor, using an RPI value corresponding to Year 3.

8.7 For the fourth year of the tariff review cycle (Year 4), the average transmission tariff for the third year is multiplied by the annual adjustment factor, using an RPI value corresponding to Year 4. If transmission tariffs for the next tariff review cycle have been approved before the end of the three year period then there will be no need to calculate the average transmission tariff for Year 4.

8.8 Over-recovery of revenue should be refunded to transmission system customers by making an adjustment to the level of the energy charge in the transmission tariff. There is no need to adjust the capacity charge or the fixed monthly charge.

8.9 The OST should never be "punished" for over-recovery of revenue, through an adjustment to the allowable rate of return on equity or through an adjustment of the price $\mathbf{P}_{\mathbf{regional}}$ that is assigned to network losses and to electric energy consumption for technological purposes. Over-recovery of revenue can result from forecasting errors and from unanticipated events and trends in the power sector.

8.10 An over-recovery of revenue during the last year of a tariff review cycle should be refunded to transmission system customers by making an adjustment to the level of the energy charge in the base year of the following tariff review cycle.

8.11 If a "force majeure" event disrupts the transmission system, the OST may submit a request to ERE at any time, for permission to adjust the energy charge in the transmission tariff so that a specific amount of additional revenue will be collected by the OST. However, an increase in the transmission tariff will not provide significant revenue for the power sector unless the tariff to captive customers is raised. The OST should aim to achieve stable and predictable transmission tariffs.

9. Filing procedures of electricity transmission tariff

9.1 The filing of request for new tariff or change of existing tariff shall be initiated by:

a) A formal filing by the OST with the ERE for approval of new tariffs. The request shall be filed with the ERE no later than 6 (six) months ahead the day when the new proposed tariffs by the OST are requested to become effective.

b) An ERE preliminary review of the formal request filed under paragraph (9.1.a) and notification of the OST 30 (thirty) calendar days for reviewing or not by the ERE of the proposed tariffs.

All filings of tariffs and rates shall be conducted in accordance with paragraph 9.2.

For first three years of OST functioning the ERE shall review the tariffs every year.

9.2 Form and Content of Tariff Filing

9.2.1 OST filings with the ERE must be accompanied by a cover letter, which shall contain:

a) A statement describing the purpose and effect of the filing;
b) The anticipated revenue effects, if any, of the proposed tariffs; and
c) Any significant change in rate design, which is anticipated to result from the filing.

9.2.2 All proposed tariffs must contain the following information:
9.2.2.1 The rates charged by the applicant to its customers for any electricity services, including:

a) Any minimum charges to customers for service, and any additional charges for particular services;
b) Any rates associated with any special program, including a description of the program;
c) Any other charge to customers for which the applicant is required to file proposed tariffs; and
d) Any other information necessary to identify the applicant's rates

9.2.3 The terms and conditions upon which electricity services will be provided to customers, including:
a) The availability of service to different customer classes;
b) The character of the service to be provided, including any technical information necessary to differentiate such service from other services;
c) If applicable, the applicants various service and rate areas; and
d) Any further information necessary to identify the terms and conditions of service.

9.1.4 Rate filings must contain, where applicable, a statement of the test year to be used , including an annual report for the test year, expenses, revenues and rate base during the test year and, if applicable, proposed adjustments to test year expenses, revenues and rate base including, statements, exhibits, or work papers showing the basis for each adjustment.

9.2.5 Rate filings must contain, where applicable, a description of any significant changes in rate design including the basis for the changes, the effect of the proposed changes on the various classes of customers and categories of service provided, the total annual revenue change for each class of customers and category of service and the change in typical bills for each class and category.

9.2.6 If the submitting applicant contends that any of the information required by this Article is not applicable, the applicant must state the basis for that contention. Failure to supply an adequate basis for any omission shall cause the filing to be treated as a defective filing.

9.1.7 The ERE shall issue rate decisions in accordance with Articles 32 and 33 of Rules of Practice and Procedure.

9.3 Defective Filing

9.3.1 Any filing, which is not in compliance with the requirements of Article 22, is a defective filing. Within (15 fifteen) calendar days after receiving a defective filing, the ERE must notify the applicant of the defect and, if the filing is nevertheless in substantial compliance with the requirements of paragraph 9.2, the ERE may allow the applicant to cure the defect within 15 (fifteen) calendar days of the notification.

9.4 Public Hearing

9.4.1 The Board shall schedule and supervise a public hearing in an area conveniently located for the public, in the general area served by the applicant, at a time to take place no less than 3 months after proper receipt of the rate filing under paragraph 9.2. At the public hearing, members of the general public may present testimony and ask questions of the applicant or the ERE regarding the proposed rate filing.

9.4.2 In its discretion, the Board may require the presiding officer to schedule public days for hearings at locations other than where the public hearing is being held so that members of the general public in that area may present testimony and ask questions of the applicant or the Board regarding the proposed rate filing. At such public days, at least one member of the Board and one representative of the applicant shall be present. The ERE shall publish notice of such public day hearing in a newspaper of general circulation in the general area of the scheduled public day hearing.

9.4.3 Public hearings shall be organized according to procedures set out in the Rules of Practice and Procedure.

9.5 Notice

9.5.1 An applicant filing rates under paragraph 9.2 must provide notice:

a) To the general public by publishing twice, in a newspaper of general circulation, or in the area served by the applicant, a notice containing the amount of the proposed rate change, the percentage rate change for each customer class clearly indicating the customer class.

b) To individual customers at least 10 (ten) calendar days before the public hearing. The notification on the rate filing shall be done by the same means it uses to distribute its individual customer electricity bills.

c) The ERE shall organize the hearing and shall publish the notice from 10 (ten) to 15 (fifteen) calendar days before the day of the public hearing. The notification shall contain the date, time, place, and purpose of the public hearing.

Upon the approval for filing of a rate change, applicant must provide notice containing the amount of the rate change, the percentage rate change for each customer class and the effective date, to the general public by publishing twice in a newspaper of general circulation in the area served by the applicant. The first notice must be published not later than five (5) calendar days after receiving approval of the rate change. The second notice must be published not less than five (5) and not later than fifteen (15) calendar days after receiving approval of the rate change.

PART II

Value of network assets

Category of assets	Amount in Dec 2003	Unit of measure	Replacement cost, 000 USD/unit	Gross value at 31.12.2003, 000 leke	Depreciation as a percent of gross value	Accumulated depreciation at 31.12.2003, 000	Net value of assets at 31.12.2003, 000 leke	Depre-ciation lifetime, years
Overhead lines								
400 kV single line, 2x500 mm2								
220 kV double line, 500 mm2								
220 kV single line, 500 mm2								
110 kV double line, 240 mm2								
110 kV double line, 120 mm2								
110 kV single line, 240 mm2								
110 kV single line, 150 mm2								
Substation civil works, road, buildings								
400/110 kV or 400/220 kV								
220/110 kV								
Substation equipment								
Busbar coupler 400 kV								
Transformer bay 400 kV								
Transformer bay 220 kV								
Line bay 400 kV								
Line bay 220 kV								
Transformers								
400/220 kV 300 MVA								
400/110 kV 300 MVA								
400/110 kV 150 MVA								
220/110 kV 120 MVA								
220/110 kV 100 MVA								
220/110 kV 90 MVA								
220/110 kV 60 MVA								
220/110 kV 30 MVA								
Assets subject to depreciation								
- Lines 400, 220, 154, 110 kV								
Transformer stations 400/220, 400/110, 220/110								
Buildings, vehicles, office equipment								
National dispatch center + SCADA								
Assets not subject to depreciation								
Land								
Transmission assets, total								

Valuation based on standard costs used in the CBT mechanism

Category of assets	Amount in Dec 2003	Unit of measure	Standard cost, 000 Euro/unit	Gross value at 31.12.2003, 000 leke
Overhead lines				
400 kV line				
220 kV line				
150 kV line				
110 kV line				
Transformers				
400/220 kV				
400/110 kV				
220/110 kV				
150/110 kV				
Transmission assets, total				

Capital expenditure

		2002	2003	2004	2005	2006	2007	2008	2009	2010
Transmission										
Expenditures for network expansion	millions of USD									
National Dispatch Center project	millions of USD									
Expenditures for network expansion	thousand leke									
Reconstruction of existing assets	thousand leke									
Growth rate of capital expenditures										
National Dispatch Center project	thousand leke									
Purchase of fixed assets, total	thousand leke									

Capital expenditures, 2004- 2005

Category of assets	Gross value of assets in service at 31.12.2003	Percent of total	Plus: Assets brought into operation in 2004	Plus: Reconstruction of existing assets in 2004	Less: Assets fully depreciated during 2004	Equals: Gross value of assets in service at 31.12.2004	Percent of total	Plus: Assets brought into operation in 2005	Plus: Reconstruction of existing assets in 2005	Less: Assets fully depreciated during 2005	Equals: Gross value of assets in service at 31.12.2005
Assets subject to depreciation											
Lines 400, 220, 154, 110 kV											
Transformer stations 400/220, 400/110, 220/110											
Buildings, vehicles, office equipment											
Subtotal											
National dispatch center + SCADA											
Assets not subject to depreciation											
Land											
Transmission assets, total											

Value of network assets at 31.12.2004 and 31.12.2005

Category of assets	Net value of assets at 31.12.2003	Less: Depreciation in 2004	Plus: New assets + reconstruction in 2004	Equals: Net value of assets at 31.12.2004	Less: Depreciation in 2005	Plus: New assets + reconstruction in 2005	Equals: Net value of assets at 31.12.2005
Assets subject to depreciation							
Lines 400, 220, 154, 110 kV							
Transformer stations 400/220, 400/110, 220/110							
Buildings, vehicles, office equipment							
National dispatch center + SCADA							
Assets not subject to depreciation							
Land							
Transmission assets, total							

All values are in thousand leke

Cash flow, 2004 - 2005

All values are in thousand leke

			2002	2003	2004	2005
		Transmission				
1		Cash and cash equivalents held by Transmission at the beginning of the year				
2	Plus:	Interest earned on cash and equivalents				
3	Plus:	Cash flow provided by depreciation				
4	Plus:	Cash flow provided by new loans				
5	Plus:	Revenue from connection charges				
6	Plus:	Cash flow provided by the profit allowance included in the Transmission network tariff				
7	Less:	Capital expenditures for new Transmission assets				
8	Less:	Capital expenditures for reconstruction of existing Transmission assets				
9	Less:	Transmission contribution to principal payments on long-term bank loans and government loans				
10	Less:	Transfer of profit from Transmission to KESH				
11	Equals:	Cash and cash equivalents held by Transmission at the end of the year				
12		Value of fixed assets at the end of the accounting period (at December 31)				
13		Average of start-of-year and end-of-year values of fixed assets				
14		Suggested weighted average rate of return on capital, to be applied to the regulatory asset value				
15		Total return on regulatory asset value, given this weighted average rate of return on capital				
		Interest rate on long-term debt, for Transmission				
		Interest rate earned on cash and cash equivalents				

Energy Demand and Peak Load

Line			Energy in GWh 2001	2002	2003	2004	2005	Peak load in MW 2001	2002	2002	2003	2004	2005
		High voltage flows in the High Voltage network											
1		KESH hydro generation delivered at 400,220,154,110 kV											
2	Plus:	KESH thermal generation at 400,220,154,110 kV											
	Less:	KESH local consumption at power stations											
3	Less:	KESH power plant "losses" (consumption)											
5	Plus:	Imports											
6	Equals:	Total input to the 400, 220, 154, and 110 kV network											
7	Less:	Exports											
		TSO local consumption at transmission substations											
8	Less:	Billed consumption at transformers that are owned by customers and directly connected to 110 kV lines											
9	Less:	Energy delivered to transformers that are owned by Distribution and directly connected to 110 kV lines											
10	Equals:	Physical losses in the transmission network											
11		*Percentage loss in the high voltage network*											
		Energy delivery from 110/x transformers											
12		Energy delivered to transformers that are owned by Distribution and directly connected to 110 kV lines											
13	Less:	Billed consumption - HV customers											
14	Less:	Energy delivered to MV lines											
15		Equals: transformer station losses HV/MV											
16		*Percentage loss in the transformation HV/MV*											
		Medium voltage network (including 35 kV)											
17		Energy delivered to MV lines											
	Plus:	Generation by Medium HPP											
		Generation by Small HPP											
18	Plus:	Generation by Medium and Small IPP											
19	Equals:	Total input to the MV network											
20	Less:	Billed consumption - MV customers											
21	Less:	Energy delivered to the low voltage network											
22	Equals:	Physical losses, stolen and unbilled electricity at medium voltage											
23		*Percentage loss in the medium voltage network*											
		Low voltage network											
24		Energy delivered to the low voltage network											
25	Less:	Billed consumption – LV customers											
26	Equals:	Physical losses, stolen and unbilled electricity at low voltage											
27		*Percentage loss in the low voltage network*											
		All voltage levels											
		Total generation minus local consumption											
	Plus:	Net imports											
	Equals:	Energy supplied to grid, minus exports											
	Less:	Billed consumption											
	Equals:	Total losses, technical and non-technical											
		Total losses in relation to energy supplied to grid											

Revenue requirement

Line	Base year: 2004	KESH total: 2003 actual expenses, 000 leke	Transmission: 2004 revenue requirement, 000 leke	Transmission tariff: revenue target, leke/kWh	Costs allocated to demand, 000 leke	Costs allocated to energy in the transmission tariff, 000 leke	Costs allocated to energy in the customer tariff, 000 leke: High Voltage delivery	MV delivery from HV network	MV delivery from MV network	Low Voltage delivery	Price of energy losses, leke/kWh
1	Depreciation										
2	Depreciation and amortization										
3	**Operational and maintenance expenses**										
4	Personnel expenses										
5	Purchase of materials & product										
6	Supplies and services										
7	Other operating expenses										
8	Transmission share of general and administrative expenses of KESH										
9											
10	Losses in the high voltage network										
17	**Interest expense**										
18	Transmission share of interest payments on KESH's long-term debt										
19	Transmission share of interest payments on KESH's short-term debt										
20	**Profit allowance**										
21	After-tax profit allowance based on capital expenditure needs										
22	Allowance for income tax										
23	**Annual revenue requirement**										
	revenue from energy charges, %										
	Customer demand in GWh										
	energy charge, leke/kWh										
	revenue from demand charges										
	revenue from demand charges, %										
	revenue from energy and demand charges										
	average revenue per kWh, leke/kWh										
	average revenue per kWh, cents/kWh										

Demand-related component of the tariff

	Depreciation in 2004	Percent of total	Cost allocated to demand, thousand leke/month	Delivery to Distribution and HV customers, kW	Delivery to High Voltage customers, kW	MV delivery from HV network, kW	MV delivery from MV network, kW	Low Voltage delivery, kW	Delivery to all customers, kW	Demand-related component, leke/ coincident peak kW/ month
<u>Demand-related component of the transmission tariff</u>			*This charge is based on coincident peak demand and applied to the invoice submitted to Distribution.*							
Lines 400, 220, 154, 110 kV										
Transformer stations 400/220, 400/110, 220/110										
Buildings, vehicles, office equipment										
National dispatch center + SCADA										
Subtotal										
<u>Demand component used to calculate tariffs to final customers</u>			*This is applied to the kW of coincident system peak demand attributable to each customer group.*							
Lines 400, 220, 154, 110 kV										
Transformer stations 400/220, 400/110, 220/110										
Buildings, vehicles, office equipment										
National dispatch center + SCADA										
Subtotal										

	Delivery to Distribution and HV customers	Delivery to High Voltage customers	MV delivery from HV network	MV delivery from MV network	Low Voltage delivery	Delivery to all customers
Energy delivered by the network in 2004, MWh						
Coincident peak load supplied by the network in 2004, MW						
Demand-related component of the transmission tariff, leke/coincident peak kW/month						
Revenue collected from this demand-related component, thousand leke/month						
Demand-related component of the final customer tariff, leke/coincident peak kW/month						
Revenue collected from this demand-related component, thousand leke/month						

PART III

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 self-regulation 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.