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Tariff Methodology for the Electricity Sector

Including amendments to 6 November 2006

Contents

Definitions

Distribution System Operator	The electricity enterprise/s licensed to undertake this activity by ERO
Inter-TSO Compensation Mechanism	The compensation mechanism between TSOs for the hosting of energy transit flows, adopted among members of the Energy Community of South-East Europe
Market Operator	The electricity enterprise/s licensed to undertake this activity by ERO
Market Rules	The rules governing trade in energy between the Market Operator and market participants and the interaction between these parties and the Transmission System Operator for the purposes of maintaining the physical balance of the market
Pricing Rule	Rule on Principles of Calculation of Tariffs in the Electricity Sector
Public Generator	A producer with a power plant of installed capacity above 5 MW, which exists and is operating on the date of the promulgation of the Law on Electricity (30 June 2004)
Public Supplier	The electricity enterprise/s licensed to undertake this activity by ERO]
Trade Code	The Market Rules
Transmission System Operator	The electricity enterprise/s licensed to undertake this activity by ERO
Wholesale Market Simulation Model	The Market Simulation Model described in Annex 1 of the Market Rules

Other terms used in this methodology have the same meanings as those given in the Law on Energy, the Law on Electricity and the Law on the Energy Regulator or in the Market Rules.

Abbreviations and Acronyms

BCIM	Balancing Costs Incentive Mechanism
CAC	Capacity Availability Certificates
CAPM	Capital Asset Pricing Model

CPI	Consumer Price Index
DLF	Distribution Loss Factor
DSO	Distribution System Operator
DSO	Distribution System Operator
DUOS	Distribution Use of System
ERO	Energy Regulatory Office
EU	European Union
GCES	General Conditions of Energy Supply
ICMM	Independent Commission on Mines and Minerals
ITC	Inter-TSO Compensation Mechanism
ITSMO	Independent Transmission System and Market Operator (Established from 1 July 2006 as KOSTT)
KCB	Kosovo Consolidated Budget
KOSTT	Kosovo Transmission System and Market Operator
LRMC	Long Run Marginal Cost
MO	Market Operator
PPA	Power Purchase Agreement
PV	Present Value
RAB	Regulatory Asset Base
SOK	Statistical Office of Kosovo
TLF	Transmission Loss Factor
TSO	Transmission System Operator
TSIM	Transmission System Operator Incentive Mechanism
TSO	Transmission System Operator
TUOS	Transmission Use of System
WACC	Weighted Average Cost of Capital
WMSM	Wholesale Market Simulation Model

Equation parameters

ACPPI	Total actual costs to the Public Supplier of power purchases from imports	Equation 3-5
ACPPK	Total actual costs to the Public Supplier of power purchases from generators located in Kosovo	Equation 3-5
ACUS	Actual number of customers at mid-point in year	Equation 3-5
ADIS	Actual energy entering the distribution network (GWh)	Equation 6-2
AELIG	Total actual revenues to the Public Supplier from sales of power to eligible customers located in Kosovo, net of TUOS and DUOS charges paid by the Public Supplier on behalf of these customers and of any additional charges or margins levied to recover the Public Supplier's own costs of service	Equation 3-5
AEXPT	Total actual revenues to the Public Supplier from exports of power	Equation 3-5
AGEN	Actual generation sent out and imports entering the transmission network (GWh)	Equation 4-2
ALOS	Total actual payments received by the Public Supplier from the TSO and DSO for the purchase of energy to cover network losses	Equation 3-5
ASUBI	Actual subsidy received for	Equation 3-5

	the purchase of imports	
ASUBL	Any other actual subsidy received including to cover part or all of non-collected revenues	Equation 3-5
ASUBV	Actual subsidy received for the protection of vulnerable customers	Equation 3-5
AVOL	Actual energy supplied to customers connected to the distribution network	Equation 6-3 Equation 6-4
AWEP	Actual average wholesale electricity price (€/MWh)	Equation 4-2 Equation 6-2
BALC	Total net balancing costs of the Public Supplier	Equation 2-1
BASF	Balancing costs sharing factor (%)	Equation 4-4
BCOS	Balancing costs of the TSO recovered from system users	Equation 4-3
BLLM	Lower limit on the balancing costs incentive payment for the TSO (determined by ERO)	Equation 4-4
BSCC	Net costs to the TSO of contracts for the availability or use of balancing services, excluding costs included within CSOB	Equation 4-3 Equation 4-4
BULM	Upper limit on the balancing costs incentive payment for the TSO (determined by ERO)	Equation 4-4
CONG	Net revenues released from congestion management fund	Equation 4-5
CPI	Consumer Price Index for Kosovo	Equation 4-5 Equation 6-3

CPPI	Total forecast costs to the Public Supplier of power purchases from imports	Equation 3-3
CPPK	Total forecast costs to the Public Supplier of power purchases from generators located in Kosovo	Equation 3-3
CSOB	Net costs to the TSO of accepted bids and offers in the balancing mechanism	Equation 4-3 Equation 4-4
CUSS	Number of eligible and non-eligible customers served by Public Supplier	Equation 3-1
DALO	Allowed loss level (%)	Equation 6-1 Equation 6-2
DEPS	Depreciation allowance for the Public Supplier, as determined by ERO, relating to assets used to provide wholesale and retail services	Equation 3-1
DISK	Correction factor for differences in allowed revenues in preceding year resulting from differences between forecast and actual volumes supplied	Equation 6-3 Equation 6-4
DLAD	Adjustment to correct for differences between loss allowance in preceding year based on forecast energy distributed and market prices and actual energy distributed and market prices	Equation 6-1 Equation 6-2
DLOS	Allowed distribution losses included in price control (€)	Equation 6-1 Equation 6-2 Equation 6-3
DMAR	DSO maximum allowed revenues, prior to	Equation 6-3

	adjustments	
DREV	DSO allowed revenue from DUOS charges	Equation 3-3 Equation 3-4 Equation 6-3
ELIG	Total forecast revenues to the Public Supplier from sales of power to eligible customers located in Kosovo in year t, net of TUOS and DUOS charges paid by the Public Supplier on behalf of these customers and of any additional charges or margins levied to recover the Public Supplier's own costs of service	Equation 3-3
EXPT	Total forecast revenues to the Public Supplier from exports of power	Equation 3-3
FDIS	Forecast energy entering the distribution network (GWh)	Equation 6-1 Equation 6-2
FGEN	Forecast generation sent out and imports entering the transmission network (GWh)	Equation 4-1 Equation 4-2
FLOS	Total forecast payments received by the Public Supplier from the TSO and DSO for the purchase of energy to cover network losses (calculated as the sum of TLOS + DLOS)	Equation 3-3
FORT	Forecast volumes exiting the transmission system for settlements purposes	Equation 4-6
FVOL	Forecast energy supplied to customers connected to the distribution network	Equation 6-3 Equation 6-4

FWEP	Forecast average wholesale electricity price (€/MWh)	Equation 4-1 Equation 6-1
INTR	Applicable interest rate (%, determined by ERO) – this compensates the firm/customers for the additional interest costs/foregone interest income resulting from the delay in applying the correction	Equation 4-2 Equation 4-4 Equation 4-6 Equation 4-7 Equation 6-2 Equation 6-4
ITCA	Actual ITC net revenues, determined on ex-post basis	Equation 4-7
ITCM	Net ITC revenues	Equation 4-5 Equation 4-7
KPS	Correction factor for difference between forecast and actual costs of Public Supplier, forecast and actual costs of power purchase and forecast and actual subsidies received	Equation 3-2 Equation 3-5
MARG	Allowed supply margin (%)	Equation 3-2 Equation 3-5
MREV	MO allowed revenue from TUOS charges	Equation 3-3 Equation 3-4
NCUS	Number of non-eligible customers at mid-point in year	Equation 3-2 Equation 3-5
NDREV	Total costs paid to TSO through TUOS charges for the provision of services related to supply to non-eligible customers	Equation 3-4
NMREV	Total costs recovered by MO through TUOS charges for the provision of services related to supply to	Equation 3-4

	non-eligible customers	
NTREV	Total costs recovered by DSO through DUOS charges for the provision of services related to supply to non-eligible customers	Equation 3-4
OPXS	Total operating and maintenance costs allowed to the Public Supplier for providing wholesale and retail services	Equation 3-1
PASS	Net balancing costs passed through to customers of the Public Supplier	Equation 2-1 Equation 3-3 Equation 3-4
PCAP	-cap weighting in price control (%, share of costs assumed to be dependent on changes in volumes)	Equation 6-3
PPUR	Allowed costs of power purchase to supply non-eligible customers	Equation 3-2 Equation 3-3
RETL	Allowed retail cost (€/customer)	Equation 3-1 Equation 3-2
RTAR	Total costs recovered from retail tariffs	Equation 3-3 Equation 3-4
SINC	TSO incentive adjustment	Equation 4-3 Equation 4-4
SUPL	Allowed revenue of the Public Supplier	Equation 2-1 Equation 3-2 Equation 3-3 Equation 3-4
SUBC	Any subsidy received to cover the costs of commercial losses	Equation 6-1
SUBI	Any subsidy provided for the purchase of imports	Equation 3-3 Equation 3-5
SUBL	Any other subsidy provided	Equation 3-4

	including to cover part or all of non-collected revenues	Equation 3-5
SUBV	Any subsidy provided for the protection of vulnerable customers	Equation 3-2 Equation 3-5
TABC	Target for $BCOS_{t-1}$ excluding $SINC_{t-1}$ (determined by ERO)	Equation 4-4
TALO	Allowed transmission loss level (%) – average across year weighted by forecast generation sent out and imports entering the transmission network in each hour	Equation 4-1 Equation 4-2
TLAD	Adjustment to correct for differences between loss allowance in preceding year based on forecast generation, imports and market prices and actual generation, imports and market prices	Equation 4-1 Equation 4-2
TLOS	Allowed transmission losses included in price control (€)	Equation 4-1 Equation 4-2 Equation 4-5
TMAR	TSO maximum allowed revenues, prior to adjustments	Equation 4-5
TRAK	Correction factor for differences in allowed TSO revenues in preceding year resulting from differences between forecast and actual volumes transmitted	Equation 4-5 Equation 4-6
TRAN	Actual volumes existing the transmission system for settlements purposes	Equation 4-6

TREV	TSO allowed revenue from TUOS charges	Equation 3-3 Equation 3-4 Equation 4-5 Equation 4-6
X	X-factor, representing real annual change in allowed revenues (determined by ERO with differing values for each firm)	Equation 4-5 Equation 6-3

1 Introduction

Pursuant to the authority given under Article 46 of the Law on the Energy Regulator No. 2004/9, the Board of the Energy Regulatory Office on a public session held on 15th of December 2005 adopted the Tariff Methodology**.** The Tariff Methodology has subsequently been amended to take account of amendments required due to the operation of a transitional market model and issues arising during the course of the first price review undertaken by ERO during 2006. ERO will continue to keep the Tariff Methodology under review and will update it as required. All such updates will be published prior to their taking effect.

The period over which the transitional market model will be considered to be in operation and the corresponding provisions of this Tariff Methodology will apply will be as notified by ERO from time to time or as established in the Market Rules in force in each period.

1.1 Background

The Law on the Energy Regulator requires that:

> The regulation of prices shall be governed by a tariff methodology, which shall be developed and issued by the Board of the Energy Regulatory Office. (Article 46.1)

The methodology covers both the determination of the total allowed revenues that can be earned from regulated tariffs and the principles governing the structure of tariffs used to recover these revenues. It will be the responsibility of licensees to, where required, propose regulated tariffs for review and approval by ERO that are consistent with the allowed revenues determined by ERO. The process for review and approval of regulated tariffs is set out in the Rule on Principles of Calculation of Tariffs in the Electricity Sector (the "Pricing Rule").

1.2 Legal basis

The Law on the Energy Regulator does not specify the legal standing of the tariff methodology, other than that it is issued by the Board of ERO. We have proposed that the methodology is issued in the form of a decision of the Board of ERO. The methodology will not have the status of a rule, making future amendments to the methodology easier to implement. Licensees will be required to comply with the provisions of the methodology under the conditions of their liscence and the Pricing Rule, which sets out the general principles with which these tariffs must comply.

1.3 Scope of regulated prices

Figure 1 provides a summary of which prices are regulated and which are not regulated. This methodology provides more detail on which individual prices are subject to regulation and the form that this regulation takes.

Figure 1 Regulated tariffs

	Public Supplier	Other suppliers	TNO	DNO	Non-eligible customers	Eligible customers
Public Genco	PPA		TUOS Connection charge			
IPPs			TUOS Connection charge	DUOS Connection charge		
Public Supplier			TUOS	DUOS	Retail price	
Other Suppliers			TUOS	DUOS		
Non-eligible customers			Connection charge	Connection charge		
Eligible customers			Connection charge	Connection charge		

1.4 Structure of the methodology

The methodology is divided into eight further sections, as follows:

- Section 2 - determination of the costs of purchases of electricity by the Public Supplier for the purposes of serving non-eligible customers.
- Section 3 – determination of the costs of service of the Public Supplier and the structure of final retail tariffs charged by the Public Supplier to non-eligible customers.
- Section 4 – determination of the allowed revenues to be recovered by the Independent Transmission System and Market Operator (ITSMO), distinguishing between the Transmission System Operator (TSO) and Market Operator (MO) functions.
- Section 5 – structure of transmission use of system (TUOS) and connection charges.
- Section 6 – determination of the allowed revenues to be recovered by the Distribution System Operator (DSO).
- Section 7 - structure of distribution use of system (DUOS) and connection charges.

- Section 8 – determination of the costs of power purchase from generators

Each section commences with a description of the detailed scope of the methodology with respect to the contents of the section. This is followed by a description of the general principles applied under the methodology to the regulation of these costs and prices, including a summary of the main elements of the approach used. More detailed descriptions of these elements then follows.

2 Power purchases by the Public Supplier

2.1 Scope of methodology

Public of the Law on Electricity requires all producers with power plants of an installed capacity exceeding 5MW as of 30 June 2004 (the date of promulgation of the Law on Electricity) to offer the electricity generated by these plants to the public supplier at a regulated price, if the public supplier requires the electricity. For the purposes of this methodology, these are termed “Public generators”.

ERO has determined that this requirement will only apply to sales from Public generators to the public supplier in order to meet demand from non-eligible customers. Although eligible customers may opt to be served by the public supplier, purchases by the public supplier for this purpose will be made at unregulated prices subject to ERO confirming that these purchases are least-cost (see Section 3.3). Purchases by suppliers other than the public supplier will also be made at unregulated prices. Sales by generators other than Public generators to the public supplier, if required to meet demand from non-eligible customers, will also be unregulated. There will continue to be regulatory oversight as to the reasonableness of these prices using ERO’s powers as competition regulator for the electricity industry.

The volume and regulated price for sales by Public generators to the public supplier to meet demand from non-eligible customers will be included in power purchase agreements (PPAs) between Public generators and the public supplier. The values will be updated annually, in accordance with this methodology, while the PPA as a whole will be renegotiated every five years in accordance with the requirements of Article 21 of the Law on Electricity.

The public supplier will remain liable for or receive income from any charges, determined in accordance with the Market Rules, resulting from imbalances between actual demand from non-eligible customers in a settlement period and the contracted supply from Public generators (and other sources). Part of any resulting costs or revenues will be returned to non-eligible customers of the public supplier through a “balancing charges incentive mechanism” (BCIM).

The price of capacity availability certificates (CACs) that must be purchased by suppliers in accordance with the Market Rules is not regulated under this methodology. CAC prices will be determined by the penalty applied for shortfalls in the number of CACs held relative to the obligation placed on each supplier. This penalty price will be a regulated price in itself, and contained in an annex to the Market Rules, and there is therefore no need to introduce additional regulation through this methodology.

2.2 General principles

The intention is that, in accordance with the Market Rules, a published wholesale market price will exist reflecting the expected costs of purchasing at unregulated prices from a competitive wholesale market. This will be used to determine balancing market trades and purchases by the public supplier in excess of those covered by PPAs with public generators, thereby avoiding discrimination between eligible and non-eligible customers and reducing the risk that the regulated prices will lead to distortions elsewhere in the electricity market. The wholesale market simulated price will be determined in accordance with the wholesale market simulation model (WMSM) described in the Market Rules.

The methodology therefore requires the public supplier to prepare forecasts of demand from non-eligible customers to be met in each [hour] of the coming year. The regulated price at which Public generators sell to the public supplier is determined annually, using a simulation of expected prices in a competitive wholesale electricity market in Kosovo. This simulation forms part of the Market Rules.

In order to provide an incentive for the public supplier to make accurate forecasts, it will be required to bear part of the costs of any difference between the forecast demand incorporated into PPAs between the public supplier and Public generators and the actual demand from non-eligible customers in each settlement period.

The PPAs between the public supplier and the public generators will be written in the form of contracts for differences (CFDs) against this simulated regulated price. The PPAs will permit public generators to, provided their output meets target levels, recover their allowed revenues as determined by ERO in accordance with Section 8 of this Tariff Methodology.

2.3 The transitional market

During the transitional market phase until the implementation of the full market rules, there will be no simulated market price. Instead, sales by the public generators to the public supplier will be made under a simple PPA designed to allow the public generators to recover their allowed revenues, determined by ERO, provided that actual output is equal to forecast output. This delivers an incentive to these generators to increase output beyond forecast levels which, in turn, will allow the displacement of more expensive imports.

2.4 Calculating regulated volumes and prices

The public supplier is required to prepare an annual forecast of demand in each hour from non-eligible customers. This forecast is approved by ERO and is then included in the assumptions for the WMSM, used by the Market Operator to prepare an annual forecast of spot prices in the electricity market in accordance with the Market Rules. The WMSM develops a price duration curve for the coming year that allows the marginal generator required to meet system demand to recover its fixed costs by a mark-up above variable costs in peak hours, subject to the constraint that market prices cannot exceed the lesser of the import price or value of lost load in any hour.

The calculated wholesale price in each hour derived from the WMSM is used as the regulated price that applies to sales by public generators to the public supplier. However, as described above, the final effective price will depend on the allowed revenues included in the PPA between the public supplier and public generators.

Responsibilities for preparing and approving other parameters used in the WMSM, as well as the model itself, are detailed in the Market Rules. These are shown in summary form in Table 1.

Table 1: Wholesale market simulation model parameters

Parameter	Basis of assumption	Assumptions proposed by	Assumptions approved by
Demand			
Non-eligible customers	Historical demand Forecast demand growth Changes in eligibility	Public supplier	ERO
Eligible customers	Historical demand Contracted supplies Forecast demand growth Changes in eligibility Customer switching	Suppliers (including public supplier) submit individual forecasts to ITSMO ITSMO prepares final forecast	ERO
Exports	Contracted exports Regional market developments	Suppliers (including public supplier) submit individual forecasts to ITSMO ITSMO prepares final forecast	ERO
Available capacity			
Operational capacity	Installed capacity of operational units	Generators	ITSMO (has testing rights)
Maintenance schedules	Historic maintenance requirements	Generators	ITSMO
Forced outage rates	Historic forced outage rates	Generators	ITSMO
Variable costs			
Fuel costs			
- lignite	Historic costs, adjusted for expected efficiency improvements	Generators	Independent Commission for Mines and Minerals
- other	Fuel supply contracts Forecast international price movements	Generators	ERO
Variable operating and maintenance costs	Historic costs, adjusted for expected efficiency improvements	Generators	ERO
Fixed costs			
Asset base	[Depreciated current	Generators	ERO

Parameter	Basis of assumption	Assumptions proposed by	Assumptions approved by
	cost of assets]		
Allowed return	Estimated [commercial] weighted average cost of capital (WACC)	ERO	ERO
Fixed operating and maintenance costs	Historic costs, adjusted for expected efficiency improvements	Generators	ERO
Imports			
Included in merit order	Contracted imports Historic import costs Regional market developments	ITSMO	ERO

2.5 PPA terms

The forecast volume of demand from non-eligible customers and the regulated price will be included in PPAs between public generators and the public supplier. The price included in the PPA will be a single volume-weighted average of the hourly prices derived from the WMSM. As the regulated price is not dependent on which units are actually generating in each hour, it is not necessary to define which individual units are supplying non-eligible customers. Separate PPAs with the public supplier will therefore be required for each owner of public generators, but not for each individual public generating unit. If a public generator is unable to generate in accordance with the simulated merit order, then any additional costs from using more expensive units or purchasing supplies from other sources will fall on the public generator concerned and not the public supplier.

2.6 The BCIM

The BCIM is a sliding-scale incentive mechanism, which provides incentives to the public supplier to minimise its liability for imbalance charges, primarily through accurate demand forecasting but also by seeking opportunities to increase demand side management among its customers. Under the BCIM, not all imbalance charges are passed through to non-eligible customers, with the public supplier being required to bear some part of the resulting costs and revenues.

Only a small proportion of the public supplier's revenues can be exposed under the BCIM, as the public supplier only earns a small profit margin. Requiring the public supplier to bear balancing charges that exceed this profit margin will rapidly drive it into bankruptcy. A limit on the maximum costs that should be paid by the public supplier is therefore required. In the interests of equity, this should be matched by a limit on the maximum revenues that the public supplier might earn from imbalance charges[1].

The BCIM is described by the following formula:

Equation 2-1 BCIM

$$If\ BALC_t > 0,\ then\ PASS_t = min\ [0.01 * SUPL_t\ ;\ 0.30 * BALC_t] - BALC_t$$

$$If\ BALC_t < 0,\ then\ PASS_t = BALC_t - max\ [-0.01 * SUPL_t\ ;\ 0.30 * BALC_t]$$

$BALC_t$	*Total net balancing costs of the Public Supplier*
$PASS_t$	*Net balancing costs passed through to customers of the Public Supplier*
$SUPL_t$	*Allowed revenue of the Public Supplier (see Section 3)*

For the transitional market period, the BCIM term is set to zero.

[1] These will occur where the public supplier's imbalance is contributing to relieving the overall system imbalance. For example, if the public supplier is long and the system is short, then the public supplier would be paid for spilling energy onto the system to relieve the overall shortage, and would earn revenues from this source.

3 Power sales by the Public Supplier

3.1 Scope of methodology

Only those retail prices charged by the Public Supplier to non-eligible customers are subject to regulation. All other retail prices (excluding components related to transmission and distribution charges, which are separately regulated) are exempted from regulation.

3.2 General principles

Most purchases by the Public Supplier to serve non-eligible customers will be made at regulated prices from Public generators, although some may be made from other generators, in which case an economic purchasing requirement will apply. The costs of these purchases, together with other associated costs, such as imbalance charges and passed-through transmission and distribution charges, should be recovered from final retail tariffs structured in such a manner as to preserve cost-reflective pricing signals.

The Public Supplier will be entitled to levy a charge per customer in order to recover its direct retail costs associated with the provision of customer services and billing and metering charges. It will also be entitled to recover a supply margin on each unit sold to compensate it for risks assumed in its role as the Public Supplier.

3.3 Power purchase costs under PPAs

The Public Supplier will be allowed to pass through the actual costs of power purchase from public generators included in PPAs, where these have been made at regulated prices to supply non-eligible customers. This will include the net costs of any imbalance charges, adjusted as appropriate under the BCIM.

It is possible that available supplies from public generators may not be adequate to meet demand from non-eligible customers. In these cases, the Public Supplier will be required to purchase additional supplies from non-public generators at unregulated prices. Such purchases will be made according to the provisions of Article 21 of the Law on Electricity, which requires that:

- Purchases are made under PPAs, with a minimum duration of one and maximum duration of five years.
- The price and other charges for electricity purchases under these PPAs shall be specified in annual contracts.
- The provisions of these PPAs are subject to the approval of ERO.

Further guidance on the principles governing power purchases and the determination of allowed revenues of generators is provided in Section 8 of this Tariff Methodology.

3.4 Losses

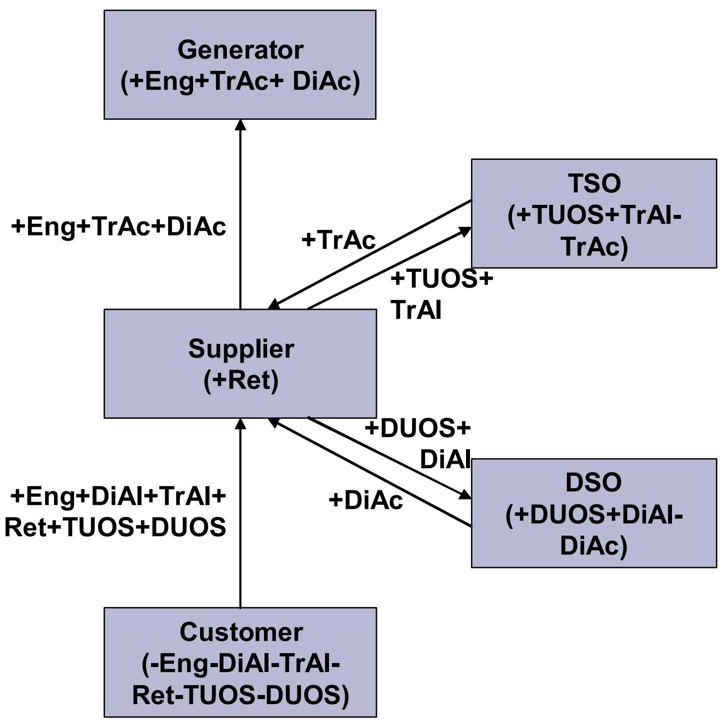
Transmission and distribution losses (representing the difference between metered energy sent out by generators or imported and energy delivered to customers) will be recovered through the use of transmission and distribution loss factors (TLFs and DLFs). The use of these loss factors is detailed in the Market Rules. During the transitional market, losses will be determined based on metered energy flows.

As control of these losses rests with the TSO and DSO, rather than suppliers, ERO will require the TSO and DSO to compensate all suppliers for the costs of losses incurred in this way. This will be done by requiring the TSO and DSO to purchase these losses. For legal reasons[2], the public supplier will act as their agent for this purpose, buying losses and invoicing the costs of these to the TSO and DSO. The TSO and DSO will, in turn, be allowed to recover the costs of "normal" loss levels from customers through the charges levied for the use of their networks.

The costs of collection losses are allocated to the Public Supplier, who is best placed to control these, as described below.

Figure 2 illustrates the process for charging and compensating (through payment by the TSO and DSO of the actual costs) for losses.

Figure 2 Payments for losses



- **Supplier receives**
  - retail margin (Ret)
- **DSO receives**
  - DUOS revenues (DUOS)
  - difference between allowed (DiAl) and actual distribution losses (DiAc)
- **TSO receives**
  - TUOS revenues (TUOS)
  - difference between allowed (TrAl) and actual transmission losses (TrAc)
- **Generator receives**
  - energy sold to customer (Eng)
  - actual transmission and distribution losses

[2] As output from public generators is reserved to the public supplier, the TSO and DSO would be obliged to contract for imports to cover losses if they were to directly procure these. This would be a particular problem for the DSO which will lack the necessary infrastructure and skills for such activities.

3.5 Retail costs

The Public Supplier will be responsible for providing a range of services to non-eligible customers, including:

- Meter-reading (metering assets will be owned by the DSO)
- Billing
- Collections
- Information services (such as promoting energy efficiency)[3]
- Other operating costs

In addition, the Public Supplier will also be required to hold sufficient working capital for its needs, with associated costs. This working capital should only relate to the delays between billing and collection and should not include any allowance for bad debts. The costs and risks associated with bad debts are separately recovered.

These retail costs will be recovered through an allowance expressed in €/customer. The allowance will be based on the average cost incurred per individual customer as it is unlikely to be feasible to seek to allocate these costs by customer type and size. ERO intends to determine an appropriate allowance based on existing costs incurred by KEK and by comparison with allowances in other countries. The allowance will be set for a price control period matching that for the TSO and DSO (see Section 4.11.2).

It is assumed that the return on the Public Supplier's activities is recovered through the supply margin. Therefore, the allowed retail cost only recovers the direct costs (operating expenditures and depreciation on assets) of the Public Supplier in serving its customers.

Equation 3-1 Allowed Retail Cost

$$RETL_t = (OPXS_t + DEPS_t) / CUSS_t$$

$RETL_t$	*Allowed retail cost (€/customer)*
$OPXS_t$	*Total operating and maintenance costs allowed to the Public Supplier for providing wholesale and retail services in year t*
$DEPS_t$	*Depreciation allowance for the Public Supplier, as determined by ERO, relating to assets used to provide wholesale and retail services in year t*
$CUSS_t$	*Number of eligible and non-eligible customers served by Public Supplier in year t*

3.6 Supply margin

The supply margin compensates the Public Supplier for the risks it assumes. These will be very limited and ERO correspondingly expects that the supply margin will be small:

[3] This does not include advertising and other marketing costs. The Public Supplier holds a monopoly over non-eligible customers and does not, therefore, need to advertise to attract or retain these customers.

- The Public Supplier is allowed to pass through actual power purchasing costs, excepting a small exposure to imbalance charges under the BCIM. It therefore faces very low risk related to energy purchasing.
- Extending eligibility leaves the Public Supplier with the risk of incurring stranded costs and/or being left with higher-cost and more risky customers. However, the annual revision of PPA prices and quantities and the proposed contracting out of many customer service activities to the DSO means that there is little likelihood of the Public Supplier incurring significant stranded costs. Allowing pass-through of power purchase and other costs and the allocation of collection risks to the DSO also means that there is little risk associated with the loss of more attractive customers. The Public Supplier therefore faces very low demand risk due to customers switching to other suppliers.
- Similarly, the Public Supplier can rapidly adjust the quantity and price of regulated power purchases to match changing market conditions if customers choose to switch to alternative fuel sources. Again, therefore, there is only very low demand risk from customers switching to other fuels.

The supply margin will be expressed as a percentage increase on the allowed regulated power purchase costs passed through to consumers.

3.7 Final retail tariffs

The final retail tariffs levied by the Public Supplier on non-eligible customers will include:

- The costs of wholesale power purchases, including passed-through imbalance charges and payments for losses.
- An allowed retail cost per customer and a supply margin on each unit sold.
- TUOS and DUOS charges.

Shortfalls in collection will be the responsibility of the Public Supplier.

The final retail tariff for non-eligible customers will therefore be set to recover costs calculated in accordance with the following formula:

Equation 3-2 Public Supplier Revenues

$$SUPL_t = \{PPUR_t * (1 + MARG_t)\} + (RETL_t * NCUS_t) - SUBV_t + KPS_t$$

$SUPL_t$	*Maximum allowed revenue for the public supplier in year t for the supply of electricity to non-eligible customers.*
$PPUR_t$	*Allowed costs of power purchase to supply non-eligible customers (calculated as below).*
$MARG_t$	*Allowed supply margin (%)*
$NCUS_t$	*Number of non-eligible customers at mid-point of year*
$SUBV_t$	*Any subsidy provided for the protection of vulnerable customers*

KPS_t *Correction factor for difference between forecast and actual costs of Public Supplier, forecast and actual costs of power purchase and forecast and actual subsidies received, calculated as below.*

Equation 3-3 Allowed Power Purchase Costs

$$PPUR_t = CPPK_t + CPPI_t - FLOS_t - EXPT_t - ELIG_t - SUBI_t$$

$CPPK_t$ *Total forecast costs to the Public Supplier of power purchases from generators located in Kosovo in year t*

$CPPI_t$ *Total forecast costs to the Public Supplier of power purchases from imports in year t*

$FLOS_t$ *Total forecast payments received by the Public Supplier from the TSO and DSO for the purchase of energy to cover network losses in year t (calculated as the sum of* $TLOS_t + DLOS_t$*)*

$EXPT_t$ *Total forecast revenues to the Public Supplier from exports of power in year t*

$ELIG_t$ *Total forecast revenues to the Public Supplier from sales of power to eligible customers located in Kosovo in year t, net of TUOS and DUOS charges paid by the Public Supplier on behalf of these customers and of any additional charges or margins levied to recover the Public Supplier's own costs of service*

$SUBI_t$ *Any subsidy provided for the purchase of imports*

Equation 3-4 Total Retail Tariff Revenues

$$RTAR_t = SUPL_t + NTREV_t + NMREV_t + NDREV_t + PASS_t - SUBL_t$$

$RTAR_t$ *Total costs recovered from retail tariffs charged to non-eligible customers in year t*

$NTREV_t$ *Total costs paid to TSO through TUOS charges for the provision of services related to supply to non-eligible customers (see Section 4)*

$NMREV_t$ *Total costs recovered by MO through TUOS charges for the provision of services related to supply to non-eligible customers (see Section 4.12)*

$NDREV_t$ *Total costs recovered by DSO through DUOS charges for the provision of services related to supply to non-eligible customers (see Section 6)*

$PASS_t$ *Net balancing costs passed through by Public Supplier (see Section 2.6)*

$SUBL_t$ *Any other subsidy provided including to cover part or all of non-collected revenues*

Equation 3-5 Public Supplier Correction Factor

$$KPSt = \{(1 + MARG_{t-1}) * (ACPPK_{t-1} + ACPPI_{t-1} - AEXPT_{t-1} - AELIG_{t-1} - ALOS_{t-1} - ASUBI_{t-1} - PPUR_{t-1})\} + \{(RETL_{t-1} * (ACUS_{t-1} - NCUS_{t-1})\} - (ASUBV_{t-1} + ASUBL_{t-1} - SUBV_{t-1} - SUBL_{t-1})$$

$ACPPK_t$	*Total actual costs to the Public Supplier of power purchases from generators located in Kosovo in year t*
$ACPPI_t$	*Total actual costs to the Public Supplier of power purchases from imports in year t*
$AEXPT_t$	*Total actual revenues to the Public Supplier from exports of power in year t*
$AELIG_t$	*Total actual revenues to the Public Supplier from sales of power to eligible customers located in Kosovo in year t, net of TUOS and DUOS charges paid by the Public Supplier on behalf of these customers and of any additional charges or margins levied to recover the Public Supplier's own costs of service*
$ALOS_t$	*Total actual payments received by the Public Supplier from the TSO and DSO for the purchase of energy to cover network losses in year t*
$ASUBI_t$	*Any subsidy received for the purchase of imports*
$ACUS_t$	*Actual number of customers at mid-point in year t*
$ASUBV_t$	*Actual subsidy received for the protection of vulnerable customers*
$ASUBL_t$	*Any other actual subsidy received including to cover part or all of non-collected revenues*

The Public Supplier will be expected to determine a structure of final retail tariffs that preserves appropriate cost signals for customers. This should also take into account any specific requirements for the use of subsidies provided for the protection of vulnerable customers that may be imposed by the providing party. The detailed structure of charges should be proposed by the Public Supplier for review and approval by ERO. In giving its approval, ERO will require that the proposed final retail tariffs comply with the requirements of Article 46.2 of the Law on the Energy Regulator, and meet the following criteria:

The costs apportioned to each customer are no higher than the cost of serving that customer on a stand-alone basis and no lower than the cost of serving that customer on an incremental basis.

Charges to recover the costs of power purchase should reflect wholesale prices in each individual period. For customers with appropriate meters, a separate charge should apply for each hour or for peak and off-peak periods within a day, for customers without these meters, consideration should be given to the use of seasonal tariffs where the costs of power purchase vary significantly between months or seasons within the year.

Charges to recover the costs of providing sufficient system capacity to meet maximum demand should reflect the contribution of each customer to maximum demand, and thereby their impact on the optimal system size.

Charges to recover the costs of providing customer services should be applied on a per customer basis, distinguishing between customer types where feasible.

At this time, final retail tariffs will be uniform across Kosovo for individual customer categories, and there will be no locational element.

The criteria for the structure of TUOS and DUOS charges, which will be passed through in final retail charges, are separately described in the appropriate sections of this methodology.

3.7.1 Rising block tariff

ERO may require the Public Supplier, in accordance with Article 16 of the Pricing Rule, to introduce a rising block tariff to provide subsidized supplies to low-income customers. This will only apply to domestic customers consuming quantities of electricity below a threshold/s determined by ERO. The difference between the costs of supply to these customers and the revenues earned from them will be recovered through an increase in charges to domestic customers consuming quantities of electricity above the threshold/s determined by ERO or those on higher incomes.

It is possible that other assistance may be provided to low-income customers through direct payments to customers or other support agreed between the Public Supplier and the Government. Such support will not affect the calculation of allowed revenues and, therefore, is not included in this methodology.

4 ITSMO revenues

4.1 Scope of methodology

The allowed revenues of the TSO recover those costs associated with the provision of the high-voltage interconnected transmission system within Kosovo, including inter-connectors with neighbouring systems where these are owned by the TSO. These include the costs of:

- construction of the transmission system;
- maintenance of the transmission system; and
- operation of the transmission system.

The methodology for the determination of the direct costs of the MO function of the ITSMO, including the costs of staff, premises and systems, is also described in this section, as a separate component.

This methodology excludes the determination of costs associated with the operation of the wholesale electricity market itself, including the costs of:

- buying and selling power through the balancing mechanism, to preserve system balance; and
- purchasing ancillary services.

The methodology for the calculation and recovery of these costs is set out in the Market Rules. A separate mechanism, the "TSO incentive mechanism" (TSIM), introduces incentives for the TSO to minimise these costs.

4.2 General principles

4.2.1 Building block approach

The allowed costs of the TSO will be calculated using a 'building block' approach. Under this approach, described in more detail below, an efficient level is separately determined for the operating costs and capital costs of the TSO.

While this approach has the disadvantage that it does not directly recognize the tradeoff between operating and capital costs, ERO considers this s more feasible at this stage than the adoption of approaches based on estimates of the efficient level of total costs. Such approaches are generally sensitive to the assumptions adopted and definitions used to establish a consistent definition of total costs over time. Within Kosovo, these inherent difficulties are greatly magnified by the limited access to reliable historical records of costs, asset values and asset condition. Recognising this, as well as the differing approaches to financing these assets, this methodology also envisages a distinction between the treatment of the recovery of the capital costs associated with assets constructed during or prior to 2005, and those constructed after this date.

In setting the price control, ERO will make an allowance for a reasonable level of losses to be recovered by the TSO from users of the transmission system. The costs of losses in excess of this allowance will be the responsibility of TSO.

4.2.2 Incentive-based regulation

ERO does not propose to engage in frequent detailed 'line-by-line' analysis of the reasonableness of existing cost levels, a process that ERO considers to be ineffective, given ERO's much more limited understanding of the costs of the TSO relative to the knowledge of its management, and to involve ERO in micro-managing the TSO, which is not the regulator's function. Instead, ERO will adopt an incentive-based approach to regulating the costs of the TSO.

Under this, ERO will set allowed revenues for the TSO for a price control period lasting a number of years (as in the well-known price and revenue-cap approaches), based on forecasts of efficient cost levels over this period. These limits will be determined in real terms. Within the period, allowed revenues will be indexed to some measure of changes in input costs of TSO. This gives the following general formula to determine allowed revenues for the TSO in each year of the price control period:

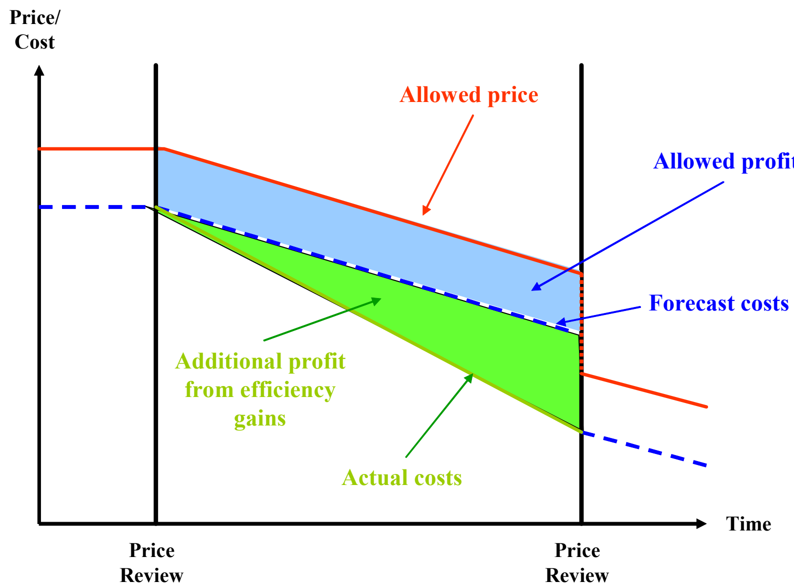
$$REV_t = REV_{t-1} * (1 + CI_t - X)$$

REV_t	*Allowed revenues (expressed as a maximum allowed revenue, average unit revenue or tariff basket)*
CI_t	*Index of change in costs of inputs (%)*
X	*Real change in allowed revenues (%) – determined by ERO*

At the end of the price control period, ERO will review actual costs against allowed levels, and reset the starting point of the price control to take account of the difference between these. A new price control period will then start.

This process is illustrated in Figure 3, below.

Figure 3 Incentive-based price control illustrated



This approach provides strong incentives on the TSO to reduce costs rapidly to 'true' efficient levels. Where it can reduce costs below the level forecast by ERO in setting the allowed revenues, then the TSO can retain the benefits in the form of increased profits until the next price review, when ERO will adjust allowed costs to reflect the actual level achieved. Similarly, where costs exceed the forecast level, then the TSO will see its profits reduced. By comparison, annual reviews of allowed costs do not allow the TSO to retain the benefits from increasing efficiency and thereby remove its incentives to do so.

The use of a multi-year price control period also offers benefits to the TSO and to customers by creating more stable and predictable prices. This is of particular importance in an environment, such as Kosovo, where it is vital to encourage new investment in the electricity industry.

ERO recognizes that the uncertainties inherent in the current Kosovan environment place significant risks on the TSO and on customers that profits may be excessively high or low due to circumstances outside the TSO's control, and which could not be foreseen or appropriately costed at the time of setting the price control. To protect against this, during the first price control period, ERO will apply 'reopeners', under which, in the event of extreme outcomes, an interim review of the price control will take place.

The detailed structure of the price control formula, its duration, the choice of cost index and the provisions for reopening are set out in the sections below.

4.2.3 Operating costs

Existing records of operating costs are incomplete and not necessarily reliable. ERO therefore proposes to focus on setting realistic targets for improvements in the operating efficiency of the TSO over the first price control period. At the end of this period, more accurate information on efficient costs levels will be available, as accounting records improve and with the incentives provided under the price control to TSO management to increase their efficiency.

4.2.4 Costs of pre-2005 assets

The TSO's existing assets, as at 2005, were largely either constructed prior to the recent conflict, with the associated loans not being serviced by the TSO, or were subsequently constructed or rehabilitated using donor financing. In both cases, the TSO has no financing charges associated with these assets. In addition, the current condition and appropriate valuation of these assets is somewhat uncertain.

In this situation, it is inappropriate to allow the TSO to earn a commercial rate of return on assets that it does not need to finance. It is also difficult to determine an appropriate depreciation allowance where the value and condition of these assets is not always known.

ERO therefore proposes to allow the TSO to recover the actual costs associated with the purchase and maintenance of these assets, comprising:

- the actual costs of financing of these assets (for example, outstanding donor loans); and
- the costs of maintaining these assets in good working order, through an infrastructure renewals charge.

If this situation changes in future, for example, as a result of the TSO assuming responsibility for debt service associated with these assets or the Government of Kosovo, as the owner of the TSO, requiring it to pay a 'charge' for the use of its assets, then ERO will allow the recovery of reasonable resulting financing costs. This is in accordance with the principle that users of the transmission system are the main beneficiaries of these assets and, therefore, should be expected to bear the costs of providing them.

4.2.5 Costs of post-2005 assets

Assets constructed after 2005 will differ from existing assets in that their costs will be known, and that the TSO will be expected to finance them, at least in part, from commercial sources. It is therefore possible to adopt a more 'conventional' approach to incorporating the costs of these assets into the allowed costs of the TSO and, at the same time, creating incentives for the TSO to finance these assets at least-cost.

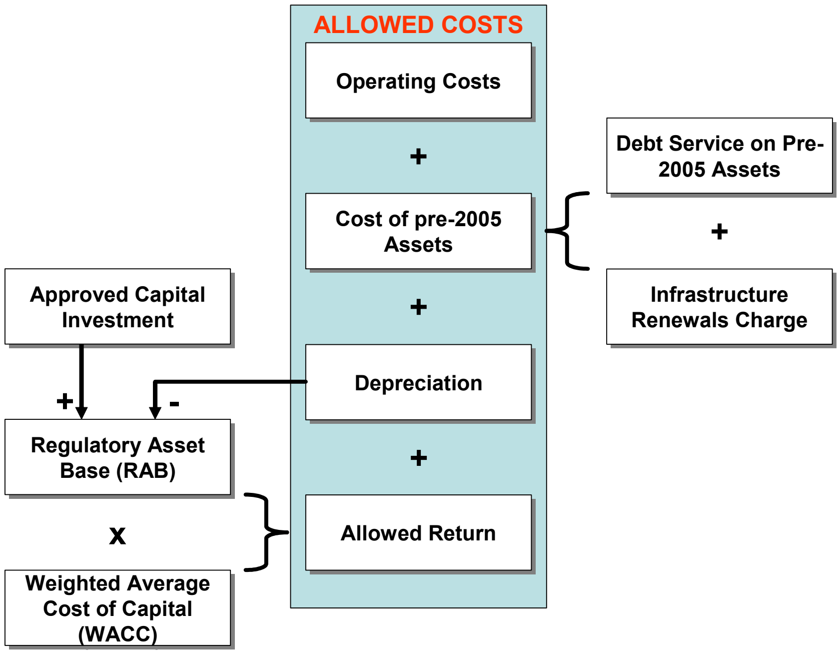
ERO therefore proposes to allow the TSO to recover the costs of new assets through:

- a depreciation charge, representing the return of the initial investment in these assets over time; and
- an allowed return on these assets, reflecting ERO's estimate of the weighted average cost of capital (WACC) of the TSO.

4.3 The building block approach

Under the building block approach to determining costs revenues for the TSO, allowed operating costs, costs associated with pre-2005 assets and costs associated with post-2005 assets (depreciation and allowed return) are separately determined and then summed to arrive at total allowed costs. This is illustrated in Figure 4.

Figure 4 Building block approach to TSO allowed costs



For the purposes of these calculations, the costs associated with the TSO and TSO functions will be separately identified, prior to combining these to determine the final allowed costs to be recovered during the price control period.

The present value of allowed revenues over the price control period will be equal to the present value of allowed costs, calculated as above. However, in individual years, the value of allowed revenues may be greater or lesser than the value of allowed costs, in order to permit a smoother and more stable profile of prices for customers. This process is described in more detail in the sections below.

4.4 Determining operating costs

ERO is concerned to ensure that operating costs included in the allowed revenues of the TSO are reasonable and efficient. At the same time, ERO recognizes the difficulties in determining an appropriate level of efficient operating costs in an environment where accounting records are incomplete and of limited reliability, where current expenditures may be constrained by cashflow problems and where there are no obvious comparators for regulated companies.

Given this, ERO proposes, under the initial price control for the TSO, to generally accept the existing levels of operating costs as the starting point for this cost component. ERO will then define a target for reductions in these operating costs based on the rate of productivity improvements demonstrated by regulated network utilities internationally.

During the period of the first price control, ERO expects that the quantity and quality of data on the TSO's operating costs will improve substantially. ERO also expects that the adoption of an incentive-based price control will encourage the TSO to reveal its 'true' cost level. When setting allowed revenues for the second and subsequent price controls, ERO expects to use this better data to undertake benchmarking of the costs of the TSO against other TSOs internationally to help form a judgment as to their reasonableness. During the period of the first price control, ERO will develop its approach to this benchmarking, drawing on the experience and methodologies being developed by other EU regulators.

4.5 Determining the RAB

The Regulatory Asset Base (RAB) represents the sum of capital invested by the TSO on which it is allowed to earn a return. It is comprised of three elements:

- The opening RAB.
- Capital expenditure added to the RAB.
- Depreciation of assets deducted from the RAB.

Special arrangements apply to the determination of the RAB where post-2005 assets are funded from concessionary loans or grants from donors. These are discussed under Section 4.6 (relating to the WACC) below.

4.5.1 Opening RAB

As ERO proposes to allow the recovery of financing costs associated with pre-2005 assets through a pass-through arrangement, and to allow an infrastructure renewals charge based on the cost of maintaining these assets in their current condition, it does not proposed to include these assets in the opening RAB. Doing so would amount to double-counting, allowing the TSO to earn a return and depreciation on these assets, while separately receiving revenues to recover the costs of debt service and maintenance of these assets.

The value of fixed assets included in the opening RAB for the TSO will, therefore, be set to zero as at 1 January 2006.

Between price control periods, the opening RAB should be updated in line with a measure of the real change in asset values (for example, the general inflation index). This will ensure that the real value of the RAB remains constant, so that the allowed return and depreciation allowance properly reflect the costs of these assets.

4.5.2 Capital expenditure

ERO will review proposed investment projects on a case-by-case basis. This review will consider:

- Whether there is a demonstrated need for the project and, in particular, whether it furthers government policies with respect to providing universal and reliable service.
- The benefits of the project, relative to its estimated costs.
- The urgency of the project and whether there are any significant negative impacts if it is postponed to the next price control period.
- The reasonableness of the costs of the project.

When assessing the reasonableness of costs, ERO does not, in general, propose to undertake detailed engineering studies of the projects. Instead, ERO will benchmark the proposed costs of the project against those recorded historically in Kosovo and those seen in comparator countries, looking at both the estimated unit costs (such as cost per km) and the estimated costs relative to outputs (such as the cost per customer or MW of demand). ERO recognizes that significant elements of judgment will be required in this analysis, but is unconvinced that any simple mechanical rule can be applied.

Once an investment project has been approved for inclusion in the allowed costs to be recovered under the price control, then ERO will expect this investment to be undertaken. Where an investment has not been completed within the time scale approved at the time of setting the price control, ERO will exclude this from the opening RAB for the subsequent price control period, only including it at such time as it is completed. In addition, ERO will adjust the allowed costs for the subsequent price control period downwards to recover any revenues earned by the TSO in relation to this investment through the allowed return and depreciation allowances in the price control period just completed (a process known as ‘clawback’).

The TSO will retain the responsibility to make this investment and ERO will not approve any increase in the allowed costs for this investment project under future price controls. ERO will also expect the TSO to deliver the benefits that are claimed for the investment (for example, in the form of reduced losses) whether or not it has actually been undertaken. This leaves responsibility for delivering investments on time and within budget with the TSO.

Conversely, ERO will not reduce future allowed revenues where the TSO has completed an investment project for less than the allowed costs included in the price control. The TSO will be able to keep the resulting savings, as an incentive to look for efficiency improvements. ERO will use the evidence that the TSO can deliver projects at lower cost than forecast in assessing the reasonableness of the costs of proposed investment projects in future review—thus allowing customers to benefit from these savings in future.

ERO does not, at this time, propose to apply any optimization or ‘used and useful’ test to investments once these have been completed and incorporated into the RAB. This will increase the regulatory risks associated with new investments very considerably, while delivering only limited benefits. However, ERO reserves the right to introduce a regulatory test of this form at a future date, with appropriate safeguards for the protection of existing investments.

4.5.3 Depreciation

In determining allowed depreciation, ERO proposes to emphasize simplicity and consistency with existing accounting practices over more economically efficient but complex and less familiar approaches. A straight-line depreciation allowance will therefore be made. An average asset life will be used, based on the estimated value-weighted average life of the various assets represented by the approved investment projects.

4.6 Determining WACC

The WACC used to calculate the allowed return represents the estimated cost of financing for the TSO. It is a weighted average of the cost of debt and equity financing where each of these is expressed as a risk-free rate (representing the cost of financing for a 'riskless' asset), plus a risk premium representing the additional risks in lending to the TSO or purchasing equity in the TSO. This is represented by the following equation.

$$WACC = (1 - g) * (r_f + ERP_i) + g * (r_f + DRP_i)$$

WACC	*Weighted average cost of capital*
g	*Gearing (debt / debt + equity)*
r_f	*Risk-free rate*
ERP_i	*Equity risk premium for company i*
DRP_i	*Debt risk premium for company i*

An estimated return, rather than actual financing costs, is used to provide an incentive for the TSO to seek commercial financing at a cost below the WACC determined by ERO, retaining the difference. In turn, this will provide evidence to ERO of the true costs of financing of the TSO, which can be used to adjust the allowed WACC appropriately in future price control periods.

4.6.1 Commercially financed assets

ERO proposes that, for assets funded on a commercial basis, the following approach will apply to determining the WACC:

- The risk-free rate will be determined from the yield on long-term, Euro-denominated bonds issued by European Union (EU) Member States.
- This will be adjusted by a country risk rating, reflecting the additional risk of investing in Kosovo relative to those of EU Member States.
- The company risk premium associated with lending to the TSO rather than the Kosovan government will be determined based on evidence from international comparators.
- The risk premium associated with equity investments in the TSO will be calculated using the Capital Asset Pricing Model (CAPM) and international comparator data. ERO recognizes the limitations of this model but, in common with other regulators

internationally, also considers it is the best practical and theoretically supported approach available at this time.

- The assumed ratio of debt to equity (gearing) used in the WACC calculation will be based on expected future financing arrangements and not on historic ratios.
- WACC will be calculated on a pre-tax basis, leaving the TSO liable for taxes without specific allowance being made for these in the allowed costs.

4.6.2 Post-2005 donor-financed assets

A difficulty arises where new assets are funded from grants and concessionary loans provided by donors or from the Kosovan Government budget. Allowing the TSO to earn a commercial rate of return on these assets will lead to it benefiting from a return that exceeds its actual costs of financing. It will also work against the intentions of donors in providing financing below commercial rates—which is that Kosovan customers should benefit from the resulting savings to the TSO.

To resolve this, ERO will, for assets funded from donor revenues:

- Separate the RABs used for the purposes of calculating the allowed return and depreciation.
- Include donor-financed assets into the RAB used for calculating the allowed return at a value adjusted on a *pro-rata* basis for the difference between their actual financing costs and the commercial WACC established by ERO. For example, if a commercial WACC was determined to be 10% and an asset was financed by a concessionary loan with an interest rate of 2%, it would be included in the RAB at 20% (= 2%/10%) of its allowed cost. The resulting allowed return on this asset is therefore consistent with the costs of financing it to the TSO.
- Include donor-financed assets into the RAB used for calculating depreciation allowances at the full allowed cost. The resulting depreciation allowance is therefore consistent with the costs of 'consuming' these assets over their lifetime for the purposes of providing the regulated service.

This approach is simple to apply, and avoids any requirement to create large numbers of asset classes depending on their source and cost of financing, which will add complexity to the regulatory reporting process..

4.7 Pass-through of pre-2005 costs

Costs associated with assets constructed pre-2005 will be passed through in the form of actual financing charges associated with these assets, and the costs of maintaining them in their existing condition. The former will be determined on the basis of the payments to made over the coming price control period, adjusted to state these in real terms. The latter will be recovered through an infrastructure renewals charges. This charge will be based on the average historic costs of maintaining these assets and, recognizing that historic costs may be a poor guide to future costs due to the impact of cashflow constraints in previous years, the average forecast cost of maintaining these assets. This charge will not cover the costs of major renewals or rehabilitation of existing assets, which will be treated as a new investment project and regulated accordingly.

4.8 Losses

To the allowed costs determined in this way, an allowance for reasonable transmission losses is added. This allowance is used by the TSO to compensate suppliers for the costs of losses allocated to them under the Market Rules, as discussed in Section 3.4 and illustrated in Figure 2. The value of the allowance will, at least initially, be calculated as the simulated market price in each hour, multiplied by the forecast quantity of energy entering the transmission network in that hour, multiplied by the allowed loss level applicable to that hour. At the end of each year, a comparison will be made between revenues recovered through this approach and those that would be recovered if calculated using actual market prices and quantities of energy, while continuing to apply allowed rather than actual loss levels, in each hour. The difference will be applied as a correction factor to the allowed revenues of the TSO in the following year. This process will be administered through the settlements mechanism described in the Market Rules (including any transitional rules that apply).

The formula for determining allowed losses to be included in the price control is shown below.

Equation 4-1 Transmission Loss Allowance

$$TLOS_t = TALO_t * FGEN_t * FWEP_t + TLAD_t$$

$TLOS_t$	*Allowed transmission losses included in price control (€)*
$TALO_t$	*Allowed loss level (%) – average across year*
$FGEN_t$	*Forecast generation sent out and imports entering the transmission network (GWh)*
$FWEP_t$	*Forecast average wholesale electricity purchase price (€/MWh) across year*
$TLAD_t$	*Adjustment to correct for differences between loss allowance in preceding year based on forecast generation, imports and market prices and actual generation, imports and market prices. Calculated as below*

Equation 4-2 Transmission Loss Adjustment Factor

$$TLAD_t = [TALO_{t-1} * (AGEN_{t-1} * AWEP_{t-1}) – (TLOS_{t-1} – TLAD_{t-1})] * (1 + INTR_t)$$

$AGEN_t$	*Actual generation sent out and imports entering the transmission network (GWh)*
$AWEP_t$	*Actual average wholesale electricity market price (€/MWh*
$INTR_t$	*Applicable interest rate (%, determined by ERO) – this compensates the firm/customers for the additional interest costs/foregone interest income resulting from the delay in applying the correction*

The level of allowed losses will be based on historic loss levels, the results of modeling of the transmission system, taking into account the impacts on losses of new investments and changing power flows and on benchmarking against the levels of losses recorded in other comparable transmission systems.

4.9 Excluded costs and revenues

The calculation of allowed costs, and the determination of allowed revenues under the price control, excludes income from non-regulated sources such as leasing of premises for commercial purposes, charges for the use of sports and health facilities and so forth. The management of the costs of these businesses costs and the revenues from them is a matter for the TSO.

The calculation of the RAB costs excludes new network assets financed from connection charges as this would amount to allowing the TSO to earn a return on assets it has not paid for. Where, in future, network assets (as opposed to the costs of direct connections) originally financed from connection charges are replaced, then they will enter the RAB at this time.

Inter-connectors are included in the RAB. However, revenues from the auctions of inter-connector capacity, undertaken in accordance with the congestion management mechanism, are ring-fenced from other regulated revenues. Instead, they are accumulated in a separate fund. In accordance with the principles set out in the EU regulation on cross-border exchanges[4], revenues will be released from this fund, on an annual basis as approved by ERO, for the purposes of:

- guaranteeing the actual availability of allocated inter-connector capacity; and
- investments maintaining or increasing inter-connection capacities, the costs of which are subject to review and approval by ERO as for other proposed investments.

If revenues earned through the congestion management mechanism exceed the sums required for these purposes, then the surplus will be retained for release in future years.

Where revenues are released from the congestion management fund, these will be offset against the allowed revenues of the TSO in that year, thus reducing TUOS charges.

The TSO will also earn or pay out sums under the Inter-TSO Compensation Mechanism (ITC), representing payments for the use of a TSO's (TSO's) network for international electricity transit. Expected payments are calculated in advance of each year, using historical data on net flows[5] of electricity across borders. During the year, payments calculated on this basis but using actual flows are made monthly. At the end of the year, a final settlement adjusts for any resulting over or under funding of compensation.

Current uncertainties over future transit flows and therefore ITC payments mean that it is not possible for ERO to forecast the net revenues earned by the TSO from this source over the period of the price control. Instead, for the initial price control period at least, ERO will allow pass-through of the actual net revenues earned under the ITC during the preceding year to transmission system users, based on the *ex-ante* values estimated in

[4] Regulation (EC) No. 1228/2003 on Conditions for Access to the Network for Cross-Border Exchanges in Electricity

[5] Transit volumes are calculated as total imports into minus total exports out of the country.

accordance with ITC requirements, and with a correction factor to take account of the *ex-post* adjustment to ITC payments. As the ITC uses historic data and standard costs and calculation methodologies agreed by all participating TSOs to determine ITC payments, the ability of an individual TSO to change the level of these payments is extremely limited. Therefore, the loss of incentives from allowing pass-through of these revenues is not considered to be a concern.

4.10 The TSIM

The TSIM provides an incentive on the TSO to minimize the costs of actions taken to ensure the balance of demand and supply on the system. The TSO trades through the balancing mechanism with generators to buy and sell power for this purpose, selecting from the bids and offers submitted by generators. In addition, the TSO can contract with generators for reserve power. This is dispatched through the balancing mechanism, but paid for at the exercise price included in the contract. The generator will also receive an availability fee under the contract.

Under the TSIM, the TSO will forecast the costs of its balancing actions, the sum of the costs of trades through the balancing mechanism and contracts for reserve power, for the coming year. This forecast will be reviewed by ERO, who will set the final level of target costs for balancing actions undertaken by the TSO. Where the TSO's costs are below this target, it will be able to retain part of the resulting savings, with a limit on the maximum savings permitted, with the remainder being returned to customers through a reduction in allowed revenues in subsequent years. Where the TSO's costs exceed this target, then an equivalent upward sharing will apply. ERO will also determine the appropriate rate of sharing and upper and lower limits on the difference between actual and target costs retained by the TSO on an annual basis.

The TSIM formula determining the balancing costs recovered from system users is set out below.

Equation 4-3 Balancing Costs of TSO

$$BCOS_t = CSOB_t + BSCC_t + SINC_t$$

$BCOS_t$ *Balancing costs of the TSO recovered from system users*

$CSOB_t$ *Net costs to the TSO of accepted bids and offers in the balancing mechanism*

$BSCC_t$ *Net costs to the TSO of contracts for the availability or use of balancing services, excluding costs included within* $CSOB_t$

$SINC_t$ *TSO incentive adjustment, calculated as below*

Equation 4-4 TSIM

$$SINC_t = BASF_t * (TABC_{t-1} - CSOB_{t-1} - BSCC_{t-1}) * (1 + INTR_t)$$

subject to

$$\text{If } SINC_t < 0,\ SINC_t = \max [SINC_t, BLLM_{t-1}]$$

$$\text{If } SINC_t > 0,\ SINC_t = \min [SINC_t, BULM_{t-1}]$$

$BASF_t$ *Balancing costs sharing factor (%)(determined by ERO)*

$TABC_{t-1}$ *Target for $BCOS_{t-1}$ excluding $SINC_{t-1}$ (determined by ERO)*

$BLLM_{t-1}$ *Lower limit on the balancing costs incentive payment for the TSO (determined by ERO)*

$BULM_{t-1}$ *Upper limit on the balancing costs incentive payment for the TSO (determined by ERO)*

During the initial stages of the new market, the ability of the TSO to control balancing charges will be severely limited. Only a very small number of generators will submit bids and offers, and the prices of these bids and offers will be regulated under the market rules. Therefore, the .exposure of the TSO to changes in its allowed revenues under the TSIM will be kept small and, for an initial period, may be set at zero. This will also allow a period of 'shadow' operation in which ERO and the TSO can investigate the accuracy of TSO forecasts against actual costs.

For the transitional market, the TSIM and its components will be set at zero.

4.11 Price control

4.11.1 Converting allowed costs to allowed revenues

Over the period of the price control, the present value (PV) of the allowed revenues earned by the TSO should equal the allowed costs determined as described above. However, there is no requirement that allowed revenues and allowed costs are equal in any single year. Indeed, this may introduce substantial volatility into tariffs—which is not in the interests of customers or the TSO.

The general approach to determining the PV of allowed costs and the corresponding PV of allowed revenues under the price control is illustrated in Figure 5, below. This example is for an average revenue-cap—its use does not imply that ERO will apply a price control of this form. However, the general approach is valid for all forms of price control.

Figure 5 Determining allowed revenues (average revenue cap)

All numbers are illustrative only

Assumptions	WACC	10.0%				
	Asset life	25	years			
Year		0	1	2	3	**Total**
Discount factor		1.000	0.909	0.826	0.751	
Regulatory Asset Base (RAB)						
Opening RAB	€m		0.00	8.00	17.68	
Capital expenditure	€m		8.00	10.00	6.00	
Depreciation	€m		0.00	-0.32	-0.71	
Closing RAB	€m	0.00	8.00	17.68	22.97	
Average RAB for year	€m		4.00	12.84	20.33	
Allowed return (WACC * average RAB)	€m		0.40	1.28	2.03	
Allowed Costs						
Operating costs	€m		1.30	1.29	1.27	
Depreciation	€m		0.00	0.32	0.71	
Allowed return	€m		0.40	1.28	2.03	
Debt service (pre-2005 assets)	€m		0.00	0.00	0.00	
Infrastructure renewals (pre-2005 assets)	€m		4.00	4.00	4.00	
Total allowed costs	€m		5.70	2.89	4.01	
PV allowed costs	€m		5.18	2.39	3.02	**10.59**
less **Excluded Revenues**						
Congestion management revenue		(Not included in price control calculation - incorporated through adjustment factor in price control formula)				
Allowed Revenues						
Average revenue	€c/kWh	0.125	0.112	0.101	0.091	
		P_0	$P_1=P_0*(1+P_0\ Adj)*(1-X)$	$P_2=P_1*(1-X)$	$P_3=P_2*(1-X)$	
Volumes transmitted	GWh		4,000	4,200	4,410	
Total allowed revenues	€m		4.49	4.24	4.00	
PV allowed revenues	€m		4.08	3.50	3.00	**10.59**
Price Control Parameters						
	P_0 adjustment	**0.0%**				
	X-factor	**10.2%**				

1. Select P_0 adjustment

2. Set X, such total PV allowed revenues is equal to total PV allowed costs

The calculation is undertaken in real terms, with the discount rate used being equal to the WACC of the TSO, calculated in real terms.

In setting allowed revenues, ERO will be required to select an initial price/revenue adjustment, the P_0 adjustment, and real annual adjustment, the X-factor, sufficient to equalize allowed revenues and allowed costs over the period of the price control. This requires a trade-off between:

- A large initial P_0 adjustment, which leads to a smaller X-factor. At the extreme, the P_0 adjustment is used to correct for all differences between current price/revenues and the efficient level determined by ERO. In this case, the X-factor represents the expected annual real change in costs of a firm already operating at the efficient cost level. Where an upward adjustment is required, then this improves the cashflow of the enterprise which may be particularly important where it is unable to borrow against future revenue expectations.
- A small P_0 adjustment, which leads to a larger X-factor. At the extreme, no P_0 adjustment is applied with all adjustment to efficient cost levels taking place through the X-factor.

The first approach does not require customers to pay for any existing inefficiencies. However, it also supposes that the TSO can immediately adjust its costs to the efficient level—something that may not be feasible. In particular, where there are significant social impacts incurred in adjusting existing costs to efficient levels, it may be more appropriate to allow time for this transition. ERO believes this to be the case in Kosovo, and therefore favours an approach, for the initial price control, under which there is little or no P0 adjustment and a correspondingly higher X-factor.

4.11.2 Length of price control period

Under an incentive-based price control, a balance needs to be struck between a longer price control period, which provide stronger incentives to companies to reduce their costs (as they retain the benefits for longer), and a shorter period, which reduces the risk that actual costs and allowed revenues diverge by excessive amounts.

Where there are significant uncertainties over existing data or future forecasts, both of which apply in Kosovo, then greater emphasis should be placed on managing these risks by shortening the price control period. Recognizing this, ERO proposes that the initial price control for the TSO will last for three years. Subsequent price controls may last for longer periods. Additional protection against the risks of current uncertainties in Kosovo is provided through the use of re-openers, as described below.

4.11.3 Price control formula

In developing the price control formula that will govern the calculation of allowed revenues of the TSO during the price control period, ERO needs to determine:

- What will be the main drivers of changes in the costs of the TSO that are outside the control of its management over the price control period?
- How can these be represented in the price control formula?

ERO considers that, in the short term, costs of the TSO are largely unrelated to the numbers of customers served, the quantity of energy transported or the maximum demand met. These will, particularly the last, influence investment requirements. However, these requirements are already allowed for through the inclusion of ERO-approved investment programmes in allowed costs to be recovered over the duration of the price control and through the use of deep connection charging, which ensures that new users compensate the TSO for the costs they impose on the system.

ERO therefore proposes that the transmission price control take the form of a revenue-cap, where maximum allowed revenues to be recovered in each year of the price control period are fixed, irrespective of the volumes transmitted. A correction factor will be used to adjust for differences between actual revenues earned and allowed levels in the preceding year, as a result of differences between forecast volumes at the time tariffs were approved for the coming year, in accordance with the allowed revenues under the price control, and actual volumes.

This choice does increase risks to customers in that poor forecasting of volumes leads to higher prices, as actual volumes are lower than those used to calculate allowed revenues while the actual allowed revenue remains the same. However, ERO considers these risks are reasonable and that the small share of transmission costs in final customer bills means that the impact on individual customers of this risk is very small.

Ideally, ERO would like to be able to use an index of costs that accurately reflects the composition and changes in price of the inputs used by the TSO. However, no reliable index or individual indices from which such an index could be constructed is available. Under current circumstances, the only broad-based index of price changes in Kosovo is the Consumer Price Index (CPI) developed by the Statistical Office of Kosovo (SOK), which ERO proposes to use. As decisions on adjustments of input prices by suppliers and employees of the TSO are likely to use the CPI as a measure of what level of adjustments are reasonable, ERO considers that this is likely to provide a reasonable reflection of changes in the costs of the TSO's inputs.

As costs are denominated in Euros and ERO has assumed that financing also comes from Eruo-denominated sources, there is no need to consider exchange rate risks in the calculation of the cost index.

The resulting formula for the calculation of allowed revenues earned by the TSO during the price control period is shown below.

Equation 4-5 TSO Allowed Revenues

$$TREV_t = TMAR_{t-1} * (1 + CPI_t - X) + TRAK_t - CONG_t - ITCM_t + TLOS_t + BCOS_t$$

$TREV_t$ *TSO allowed revenue from TUOS charges*

$TMAR_t$ *TSO maximum allowed revenues, prior to adjustments*

CPI_t *Consumer Price Index for Kosovo*

X *X-factor, representing real annual change in allowed revenues (determined by ERO with differing values for each firm)*

$TRAK_t$ *Correction factor for differences in allowed TSO revenues in preceding year resulting from differences between forecast and actual volumes transmitted, calculated as shown in Equation 4-6, below*

$CONG_t$ *Net revenues released from congestion management fund (see Section 4.9)*

$ITCM_t$ *Net ITC revenues for the preceding year (see Section 4.9), calculated as shown in Equation 4-7, below*

$TLOS_t$ *Loss allowance (see Section 4.8 and Equation 4-1)*

$BCOS_t$ *Balancing costs allowance (see Section 4.10 and Equation 4-3)*

Equation 4-6 TSO Correction Factor

$$TRAK_t = \{TREV_{t-1} - [(TREV_{t-1} / FORT_{t-1}) * TRAN_{t-1}]\} * (1 + INTR_t)$$

$FORT_t$ *Forecast volumes exiting the transmission system for settlements purposes, used for the purposes of calculating TREVt in period t-1*

$TRAN_t$ *Actual volumes existing the transmission system for settlements purposes, determined following the completion of period t*

Equation 4-7 ITC Allowed Revenues

$$ITCM_t = ITCA_{t-1} * (1 + INTR_t)]$$

$ITCA_t$ *Actual ITC net revenues earned in preceding year*

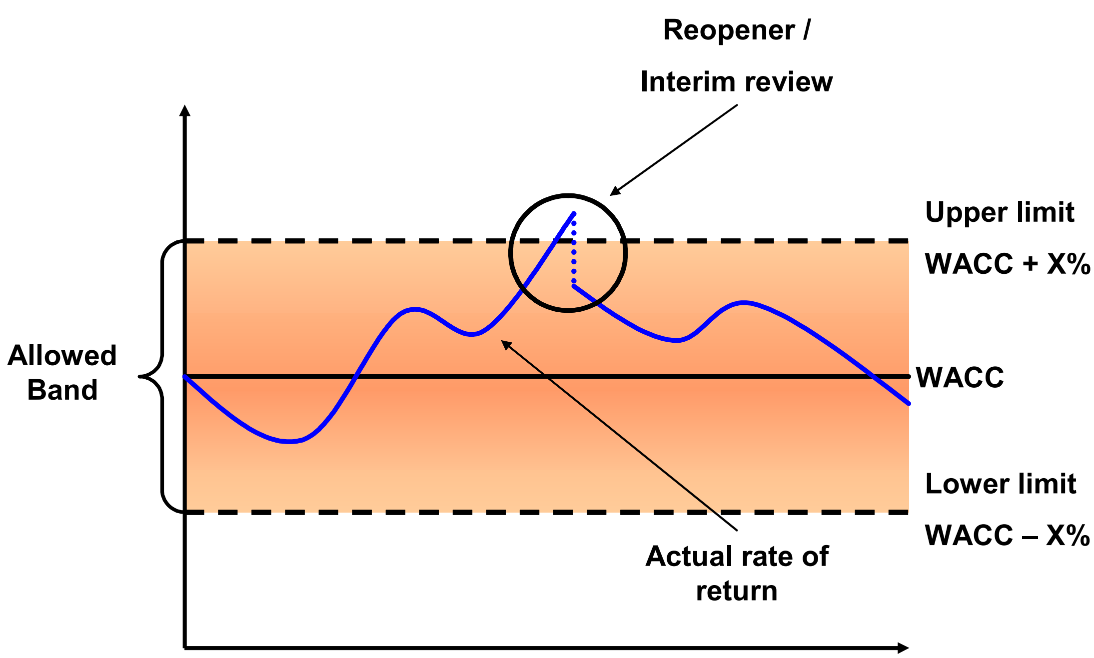
4.11.4 Reopeners

ERO recognizes that, despite its best efforts and those of the TSO, there remains a high risk that the TSO will earn excessively high or low profits under any price control given the level of uncertainty over current and future costs in Kosovo. For the initial price control period, at least, ERO therefore proposes to apply re-openers.

These re-openers take the form of a provision that, where the actual rate of return earned by the TSO (calculated in accordance with regulatory reporting requirements specified by ERO) diverges from the estimated WACC outside a specified band, then ERO will undertake an interim review of the price control. This interim review will not consist of a full review of the allowed costs of the TSO. Instead, it will consist of a reassessment of forecast against actual changes in inputs costs and outputs and an adjustment to the price control such that, using actual outcomes and updated forecasts for these cost drivers, the TSO is restored to a position where its allowed return falls within the specified band for the remaining duration of the price control. To retain incentives on the TSO to manage its costs, it will not be returned to an allowed return equal to its estimated WACC. Instead, the adjustment will return it to a level close to the upper or lower boundary of the band, typically within one percentage point.

This process is illustrated in Figure 6, below.

Figure 6 Reopeners illustrated



4.12 MO costs and revenues

The above excludes the direct costs of the MO itself (staff, premises and the requisite hardware and software). These are to be separately identified and approved by ERO and recovered from a separate component of the TUOS charge.

Because of the uncertainty surrounding these costs during the introduction of the new wholesale electricity market , the limited ability of management to control them except through appropriate procurement processes (which will be separately reviewed by ERO) and the very small proportion that they represent of total costs, ERO expects to review and approve MO costs annually on a cost-of-service basis.

5 TUOS and connection charges

5.1 Scope of methodology

It will be the responsibility of the TSO to submit tariff applications to ERO setting out the proposed tariffs to be charged for connection to and use of the transmission system. The revenues recovered from these charges must fall within the maximum limits determined by ERO, following the approach described in Section 4. The structure of these charges will be determined by the enterprise, but should conform with the general principles laid down by ERO and described in this section. These principles relate, in particular, to:

- The boundary between assets funded from connection charges and those funded from TUOS charges.
- The basis for TUOS charging and, in particular, the extent to which these are differentiated by geographic location, voltage level, demand, energy flows and other factors.
- The incidence of TUOS charging or which users pay which charges.

The detailed processes and calculation approaches for determining individual charges, in accordance with the principles set out in this methodology, and for review of these by ERO should be set out in charging statements published by the TSO.

5.2 General principles

ERO is concerned to ensure that TUOS and transmission connection charges are economically efficient—i.e. that they send appropriate signals to users of the system as to the costs that their choice of location and pattern of use impose on the transmission system as a whole. Without these signals, new and existing users have no incentives to minimise these costs and, as a result, total costs for all users will rise.

At the same time, TUOS and connection charges should also be simple, in order to assist users in understanding and verifying them, stable so as to allow users to predict future charges and make appropriate investment decisions and feasible to implement under current metering and other constraints.

5.2.1 Connection charges

Given the small size of the Kosovan system and the large impacts that individual connections to the transmission system have on the need for investment in reinforcement elsewhere on the high-voltage network, ERO intends that the TSO should adopt 'deep' connection charging. Under this approach, new users connecting to the transmission system are charged the costs of both their direct connection from their location to the existing system and for the costs of any investment in strengthening the transmission network in order to accommodate the additional and changed loads and flows they create.

Deep connection charging is more complex to apply than shallow connection charging, in which only the cost of the direct connection is charged. In larger, complex intermeshed systems, the difficulties in identifying the impact of a new connection on system loads and flows, and therefore investment requirements, is much more challenging. At the same time, the size of a new connection relative to total demand is relatively small and therefore the impacts of any individual connection tend to be limited. Neither of these conditions holds in Kosovo and ERO therefore considers deep connection charging is feasible and appropriate.

5.2.2 TUOS charges

With deep connection charging, TUOS charges will recover the costs of existing network assets and new common network assets not required to serve individual users. These costs are not attributable to any individual user and, as 'sunk' costs, should not affect decisions on future connection to the network. However, they will continue to be partially determined by demand from network users—if an existing user increases their demand while remaining within their connection capacity or shifts demand from off-peak to peak times, this will impact on the need for investments in the common network. ERO therefore proposes to apply TUOS charges to recover these common costs based on the contribution of network users to peak demand.

ERO intends that TUOS charges to recover the costs of common network assets should be applied to load (demand) users alone:

- The most important issue in determining network costs is the decision on location by the users. As the costs of the choice of location are already signaled by the use of deep connection charging, there is no need for TUOS charges to be applied for this purpose. Once a decision on location has been made, it is also not possible to reverse this, meaning that using TUOS charges to signal these costs to already-connected users does not increase economic efficiency except, possibly, where it affects patterns of system use by encouraging reduced use at times of system peak demand.
- Where generators are required to pay TUOS charges, these should be based on connected capacity with firm access rights, rather than on actual output, to avoid perverse incentives to reduce generation at times of peak demand. However, this means that generators will not be able to reduce TUOS charges by shifting their patterns of system use, once connected, and therefore there are no efficiency gains from this source. This does not apply to load, which should be charged on the basis of its contribution to system peak demand.
- Generators will pass through TUOS charges to suppliers and, ultimately, customers. Requiring generators to pay TUOS charges does not, therefore, mean that customers will see their final charges fall.
- EU regulations require that the share of TUOS charges paid by generators is 50% or less, with no lower limit.

TUOS charges will also recover the costs of the TSO in balancing and operating the system and of the MO. These costs should be recovered through separately identified elements of the charges, allowing them to be allocated in differing ways between users depending on causality and enabling users to monitor the level of these charges.

TUOS charges should be geographically uniform. Differences in the costs imposed by users connected in differing locations are captured by the use of deep connection charges. Where congestion on the transmission system does exist, it will be the responsibility of the TSO to manage this at least cost through the trading of power through the balancing mechanism.

5.3 Connection charges

5.3.1 Basis of charges

The costs associated with connecting a new user to the system include the costs of the necessary investments themselves, as well as a capitalized allowance for future maintenance costs over the lifetime of the assets. The required assets are defined as:

- For a new user, those assets yet to be constructed which will enable the connection of the customer to their 'linkage point' with the network and those network assets required to be constructed on the side of the linkage point where assets are shared among network users to provide service to the new user without reducing or limiting the service provided to existing users.
- For existing users, those additional assets required to meet an increase or change in the capacity and/or use of a connection to the network on both sides of the linkage point to the network.

The linkage point is the point on the transmission network at which the use of assets changes from being dedicated to one user or more than one user where these share the costs of the connection assets to being shared among customers generally.

The assessment of the impacts of new connections and the associated costs will be based on system studies and standard investment costs. The actual studies may be undertaken by the TSO or by consultants employed by the applicant and approved by the TSO. Reasonable costs associated with studies undertaken by the TSO may be recovered from the applicant. The standard investment costs used will be determined by the TSO, based on the historic and forecast unit costs of investments in similar assets. Where applicable, consultants employed by the applicant may propose unit costs of investment for use in determining the connection charges, with these costs being reviewed by the TSO.

In determining the costs of connections, the TSO is required to ensure that the assets selected are the economic optimum size required given the user's connection capacity, other loads and the expected growth in other loads.

5.3.2 Recovery of charges

Connection charges will be levied on a one-off basis and must be paid prior to the commencement of work. Although ERO recognizes that this imposes a significant up-front cost on new users, the likely financial status of the TSO is such that it cannot be expected to become a lender to new users—which is what a requirement to allow payment of connection charges over time represents.

The TSO will not earn a return on assets financed from connection charges, as the up-front payment avoids the need for it to fund these investments from its own resources.

Where a second user subsequently connects at the same location as an existing user, who has paid a connection charge determined on the above basis, then they will be required to rebate part of the connection charge to the existing user. This rebate should be proportional to the share of the original connection assets utlised by the new user. An appropriate limit should apply to the time period for which this provision applies. ERO considers that second users connecting within [7] years should be expected to pay a rebate to initial users.

ERO considers it appropriate to allow the TSO to negotiate discounts on connection charges, where it considers that doing so reflects other benefits[6] that can be expected to result from the connection of a new user. In order to maximize transparency, the terms of any such discount and the justification for it must be published and are subject to review and approval by ERO.

Existing users will be exempted from a requirement to pay connection charges, unless they increase the size of their existing connection or otherwise modify it, in which case they will pay the associated costs. ERO considers that trying to determine an appropriate connection charge for these users will be complex and extremely subjective—violating the principles that charges should be simple and feasible to implement. There will be no offsetting gains from increased economic efficiency, as these users have already made the decision as to their location and the costs associated with this have already been incurred.

Where common network assets originally funded from connection charges are replaced at the end of their life, the costs of the associated investment will be included in the TSO's RAB and an allowed return and depreciation charge calculated as for other common assets. By the time of their replacement, these assets can be considered to have become part of the common network and their costs cannot be readily allocated between users. By this time, too, the initial decision on location by the user has long since been made and is unlikely to be reversed or changed. The costs of replacing assets connecting a user to the linkage point with the common network will continue to be borne by that user.

5.4 TUOS charges

TUOS charges determined according to the principles of this methodology will recover the costs of:

- Investment in and maintenance of common network assets.
- Direct costs of the TSO's system operations, including premises, staff, hardware and software.
- Direct costs of the MO, while this function is undertaken by the TSO.

[6] These might come, for example, from an expected reduction in the need for future investment elsewhere on the system, lower transmission losses or where connection assets are oversized due to the 'lumpiness' of individual investments, creating spare capacity for future demand growth.

Each of these cost components should be separately identified.

Costs associated with the operation of the wholesale electricity market itself, including the balancing mechanism and purchases of ancillary services will be recovered through the mechanisms described in the Market Rules.

5.4.1 Common network assets

TUOS charges for the recovery of the costs of common network assets should be applied to load customers alone. As the requirement for these assets is largely driven by the maximum network demand to be served, charges for load customers should be based on their contribution to system peak demand. ERO proposes that this be done by applying charges to the average demand of each user at the time of the [five] highest system peaks in each year.

ERO considers that it may be appropriate for common network TUOS charges to vary by the voltage level of connection, to increase transparency in the resulting charges.

5.4.2 System operation costs

All system users benefit from the services of the system operator, and therefore should contribute to recovering these and be provided with incentives to help monitor them. ERO therefore considers it appropriate that both generators and load customers pay TUOS charges to recover the direct costs of the system operator.

The direct costs of the system operator should be recovered through a simple uniform charge per unit of energy entering or leaving the system and attributed to a generator or supplier (including allocated transmission losses). Charging on this basis will be reasonably cost-reflective, in that larger users who are likely to make greater calls on the system operator's services, will pay a greater share of costs, and is simple to apply.

5.4.3 MO costs

As with the system operation function of the TSO, all users, whether generators or load, benefit from the services of the MO. TUOS charges recovering the direct costs of the MO should therefore be applied on the same basis.

6 DSO revenues

6.1 Scope of methodology

The allowed revenues of the DSO recover those costs associated with the provision of the medium and low-voltage distribution system within Kosovo. These include the costs of:

- construction of the distribution system;
- maintenance of the distribution system; and
- operation of the distribution system.

6.2 General principles

The allowed costs and revenues for the DSO are calculated in a similar way to those for the TSO (see Section 4). Therefore, these principles and the remainder of this section only describe those aspects of the calculation that differ from those applying to the TSO.

The most significant of these differences is that relating to the treatment of losses. The DSO will assume responsibility for technical and commercial losses in the distribution network. It will be required to offer meter-reading, billing and collection (MBC) services to the public supplier and other suppliers at a regulated price, which, in the case of the public supplier, will include an allowance for collection losses (where a bill is issued but payment is not collected within the due period). Suppliers will have the option to provide these services themselves or negotiate with the DSO for a lower price. Other than for the public supplier, suppliers will also assume responsibility for negotiating the extent to which the DSO bears collection risks and the compensation it receives for this.

The DSO combines the functions of the DSO within it. In general, these functions are carried out in a largely passive manner, and the DSO is not expected to engage in active trading of energy. It may undertake activities such as contracting with distributed generation or redesigning networks to minimise losses, but incentives for these are already provided through the calculation of loss allowance. Therefore, no separate calculation of allowed costs of the DSO function or incentives to reduce system operation costs is provided.

The DSO will also not receive revenues from congestion management or the ITC mechanism, and the issues associated with these can therefore be ignored.

6.3 Losses

The DSO will receive an allowance for reasonable technical and commercial losses in the distribution network. These allowances are used by the DSO to compensate suppliers for the costs of losses allocated to them under the Market Rules.

The value of the allowance for technical and commercial losses will, at least initially, be calculated in the same way as for allowed transmission losses, i.e. as the simulated market price in each hour, multiplied by the forecast quantity of energy entering the distribution network in that hour, multiplied by the allowed loss level applicable to that hour. At the end of each year a reconciliation between this allowance and the costs of losses if calculated using actual market prices and quantities of energy, while continuing to apply allowed rather than actual loss levels will be made. The difference will be applied as a correction factor to the allowed revenues of the DSO in the following year.

ERO expects to distinguish between technical and commercial losses in the way that these allowances are funded. The allowance for technical losses will be added to the allowed costs recovered from DUOS charges, in the same way as the allowance for transmission losses is recovered from TUOS charges. However, subject to approvals, ERO expects that the allowance for commercial losses will be funded from the KCB, with only the correction for differences between the forecast and actual value of this allowance passing-through to DUOS charges.

The formula for determining allowed losses to be included in the allowed revenues recovered form DUOS charges is shown below.

Equation 6-1 Distribution Loss Allowance

$$DLOS_t = DALO_t * FDIS_t * FWEP_t - SUBC_t + DLAD_t$$

$DLOS_t$ *Allowed technical distribution losses included in price control (€)*

$DALO_t$ *Allowed loss level (%)*

$FDIS_t$ *Forecast energy entering the distribution network (GWh)*

$SUBC_t$ *Any subsidy received to cover the costs of commercial losses in year t*

$DLAD_t$ *Adjustment to correct for differences between loss allowance in preceding year based on forecast energy distributed and market prices and actual energy distributed and market prices, as well as between forecast and actual allowed commercial and transmission losses. Calculated as below*

Equation 6-2 Distribution Loss Adjustment Factor

$$DLAD_t = \{DALO_{t-1} * [ADIS_{t-1} * AWEP_{t-1}] – (DLOS_{t-1} – DLAD_{t-1}) * (1 + INTR_t)$$

$ADIS_t$ *Actual energy entering the distribution network (GWh)*

6.4 Excluded costs and revenues

By law, the DSO is the owner of customer meters. Metering assets, as distinct from the costs of reading these meters, will therefore be included in the revenues recovered from DUOS charges for existing meters (in the same way as for other pre-2005 assets). For new meters, the costs will be recovered through connection charges for new customers or where a meter must be replaced due to customer action or upon a customer's request, or where the life of the existing meter has expired. The costs of these meters will be excluded from the calculation of allowed costs and revenues.

Customers and small generators connecting to the distribution network will only pay shallow connection charges. The costs of system reinforcement by new connections of this type will, therefore, be included in allowed costs and revenues recovered from DUOS charges. This is distinct from the approach adopted at the transmission level.

6.5 Price control

The DSO price control will follow the same approach as that for the TSO as regards length and choice of cost index. However, rather than a pure revenue-cap, ERO proposes to adopt a hybrid price and revenue-cap control. This recognizes that it is appropriate to allow the revenues of the DSO to increase as volumes of energy distributed and customers served increases:

- The use of shallow connection charges means that not all the costs of connecting new customers and meeting growing demand may be recovered by the DSO.
- Including a price-cap element further strengthens the incentives on the DSO to reduce commercial losses—which is one of the areas of greatest concern and where reductions can, in many cases, be undertaken without the need for large-scale investments requiring approval by ERO. As billed volumes rise, DSO revenues will also rise.

DSO costs are affected by both customer numbers and volumes distributed. ERO expects to link the price-cap component of the control to volumes alone. This is because the number of customers and volumes tend to be closely correlated, and because this provides appropriate incentives to reduce commercial losses (the DSO will see its revenues increase if volumes rise but customer numbers fall, which may well be the result of a sustained campaign to reduce commercial losses).

Equation 6-3 DSO Allowed Revenues

$$DREV_t = DMAR_{t-1} * (1 + CPI_t - X) * [(1 - PCAP) + PCAP * (FVOL_t / AVOL_{t-1})] + (PCAP * DISK_t) + DLOS_t$$

$DREV_t$	*DSO allowed revenue from DUOS charges*
$DMAR_t$	*DSO maximum allowed revenues, prior to adjustments*
CPI_t	*Consumer Price Index for Kosovo*
X	*X-factor, representing real annual change in allowed revenues (determined by ERO with differing values for each firm)*
$PCAP_t$	*Price-cap weighting in price control (%, share of costs assumed to be dependent on changes in volumes) (determined by ERO)*
$FVOL_t$	*Forecast energy supplied to customers connected to the distribution network*
$AVOL_t$	*Actual energy supplied to customers connected to the distribution network*
$DISK_t$	*Correction factor for differences in allowed revenues in preceding year resulting from differences between forecast and actual volumes supplied, calculated as shown in* Equation 6-4*, below*
$DLOS_t$	*Loss allowance (see Section 6.3 and Equation 6-1)*

Equation 6-4 DSO Correction Factor

$$DISK_t = \{DREV_{t-1} - [(DREV_{t-1} / FVOL_{t-1}) * AVOL_{t-1}]\} * (1 + INTR_t)$$

6.5.1 Re-openers

Re-openers will apply in a similar manner to those applying to the TSO.

7 DUOS and connection charges

7.1 Scope of methodology

The allowed revenues of the DSO recover those costs associated with the provision of the medium and low-voltage distribution system within Kosovo. These include the costs of constructing, operating and maintaining the distribution network. Unlike TUOS charges, ERO does consider it necessary to distinguish between these categories for the purposes of determining DUOS charges, but instead only between those costs recovered from connection charges and those recovered from DUOS charges. This reflects the lesser importance of the system operation function at the distribution level and the lack of an equivalent to the MO function.

As with transmission charges, the DSO will be expected to publish a statement of the processes and calculation approaches used to determine individual connection and DUOS charges.

7.2 General principles

As with the delineation between TUOS and connection charges (see Section 5). ERO favors the use of deep connection charges at the distribution level, reflecting the general increase in economic efficiency resulting from such charges. However, it is clearly not feasible to apply deep connection charges to all customers, irrespective of their size. For small customers the gains in economic efficiency are likely to be negligible, given their very limited impact on the existing system, and to be very significantly outweighed by the costs associated with undertaking the necessary system studies and analysis to determine a deep connection charge.

ERO therefore feels it appropriate to limit the use of deep connection charging at the distribution level to larger generators only. Smaller generators and load customers will only be required to pay shallow connection charges. Reflecting the greater contribution made, as a result, by larger generators and the limited gains in economic efficiency that would result from also requiring them to pay a contribution to the costs of existing common network assets, these generators will be exempt from having to pay DUOS charges. Generators of all sizes connected to the distribution network will also be exempt from paying TUOS charges, recognizing that they make little or no use of the transmission system.

The use of shallow connection charges means that the role of DUOS charges in sending appropriate cost signals increases. Although there is no intention, at this stage, to introduce DUOS charges that differ by geographical location, DUOS charges should vary by the voltage level at which a customer is connected to the network.

7.3 Connection charges

7.3.1 Basis of charges

Deep connection charges will apply for large generators. ERO considers it appropriate to define these generators as those with a capacity exceeding 5MW, and which are therefore obliged to obtain a liscence. The arrangements for calculating connection charges for these generators will be the same as those applicable to calculating deep connection charges for users of the transmission network.

Smaller generators and load customers will pay shallow connection charges, covering only the costs of new or additional assets connecting the individual customer to their linkage point with the distribution network.

For the smallest customers located close to the existing network, and where only limited investments are required, a schedule of standard connection works and associated costs should be adopted in order to minimize the costs to customers and the DSO of applying for new or enhanced connections.

The details of the standard offer, including the service to be provided, the process for the calculation of charges and payment of these and for variations on the standard offer to accommodate differing service requirements or where the customer's location or circumstances mean that the standard offer does not apply will be set out in the General Conditions of Energy Supply (GCES), separately prescribed by ERO.

7.3.2 Recovery of charges

Connection charges will be levied on a one-off basis and must be paid prior to the commencement of work. As with charges for connection to the transmission network, the DSO assets financed from connection charges will be excluded from the RAB used in determining the allowed revenues of the DSO, and the DSO will not be permitted to earn a return on these assets. Second and subsequent users making use of connection assets paid by a previous user will be expected to pay a rebate to the original user. Existing users will be exempted from a requirement to pay connection charges, unless they increase the size of their existing connection or otherwise modify it.

The DSO will be permitted to negotiate discounts on connection charges and is encouraged to do so for smaller distributed generators, in recognition of the contribution that these generators can make to reducing distribution system costs by relieving the need for new investments or reducing losses. The basis for determining any such discounts, as well as restrictions such as the types of generating technology that are eligible, should be set out in standard rules published by the DSO. These will require approval from ERO.

7.4 DUOS charges

Economic efficiency requires that charges should reflect the costs imposed by a decision by an individual generator or load customer to increase their use of the system by an additional unit—their marginal cost. Where deep connection charges apply, as for larger generators, then these costs are captured through the calculation of the costs of connecting new customers, including the required investments in the common network. For other users, these costs must be signaled through DUOS charges. DUOS charges should be differentiated by the voltage level at which a user is connected, with those connected at higher levels not paying for the costs of assets at lower voltage levels.

The appropriate measure of marginal cost for the purposes of determining DUOS charges under this approach is the long-run marginal cost (LRMC)—which is more stable than short-run marginal cost (SRMC) and which, in the absence of markets in network access at the distribution level, better captures the investment implications of a decision to increase use of the distribution network. For convenience, it is generally appropriate to approximate LRMC by the calculation of the long-run average incremental cost (LRAIC), representing the PV of the additional investment and operating costs associated with meeting a sustained incremental increase in demand. This can be calculated using existing planned investment programmes to meet forecast demand growth or by assessing the increased investment requirements resulting from a demand increase using a full or stylized system model. The latter is more economically efficient at the cost of added complexity.

Using either approach, a number of basic parameters are required. ERO intends that the following should be applied:

- Time horizon of [10] years.
- Discount rate (used in PV calculations) equal to the DSO's estimated WACC.
- Demand increment (used if a system model is applied) equal to approximately 10% of peak demand.

It will be necessary to reconcile the resulting revenues that would be recovered from the application of the resulting LRAIC charges with those allowed under the price control applying to the DSO. This should be done by adding or subtracting a common factor, such that the final charge is consistent with allowed revenues, as shown in simplified form below.

$$\sum^{i}_{t}\sum^{i}_{t} (DUOS_{i,t} \;\; DFAC_{t}) * FVOL_{i,t} = DREV_{t}$$

$DLRC_{i,t}$ *LRAIC charge for customer category i (€/kW)*

$DFAC_{t}$ *Common adjustment factor applied to each LRAIC charge (€/kW)*

The basis for DUOS charges should be the demand of individual users at times of system peak. In many cases, existing metering arrangements will be inadequate to measure this, in which case appropriate assumptions based on load profiles or other available information should be applied.

The DSO will be encouraged to offer rebates and reductions on DUOS charges for smaller distributed generators, where those provided through discounts on connection charges are inadequate to reflect the benefits provided by these generators. The principles and basis for determining any such rebates and reductions should be included in the standard rules published for this purpose by the DSO.

8 Purchases of electricity from generators

8.1 Scope of methodology

This Section sets out the principles that will govern the determination of allowed power purchase costs from generators included in regulated tariffs. The actual mechanisms for determining these costs and for incorporating them in final regulated retail tariffs will need to evolve over time as the wholesale electricity market develops. ERO will set out the approach used in its justification issued at the time of determining allowed revenues and approving tariffs.

8.2 Purchases from public generators

As described in Section 2, public generators will sell power to the Public Supplier under PPAs. These PPAs will include a target quantity of energy to be supplied and an average price sufficient for public generators to recover their costs associated with the supply of energy to the Public Supplier. The terms of these PPAs will be subject to review by ERO.

The allowed revenues to be recovered by public generators under these PPAs will be determined by ERO, consistent with the principles adopted elsewhere in this Tariff Methodology. These include:

- No depreciation or return on pre-2006 assets, unless KEK subsequently incurs financing costs associated with these.
- Recovery of non-fuel operating and maintenance costs on existing assets.
- Recovery of fuel purchase costs.
- Reductions in allowed revenues recovered under the PPAs for income from the sale of ancillary services, any subsidies provided to public generators and income from any other sources.

It is expected that all new significant investments in generation, including rehabilitation and refurbishment of existing facilities, will be undertaken using commercial finance on a concession or similar basis. Such investments will mark an increase in either capacity and/or lifespan of existing generators and will, consequently, lead to them no longer being considered as public generators within the meaning of Article 8 of the Law on Electricity. The costs of purchasing power from generators which have benefited from commercial investment under these arrangements will, therefore, be recovered in the same way as the costs of purchases from non-public generators.

8.3 Purchases from non-public generators without certificates of origin

In general, purchases from non-public generators will be made at the prices included in the relevant PPAs, with the costs being passed through to retail tariffs.

ERO expects that the terms of existing PPAs will be left unchanged. In general, ERO will expect that any new or amended PPAs entered into by the Public Supplier with non-public generators will be consistent with economic or least-cost purchasing. Where the

PPA results from a competitive tendering process, this will generally be considered to satisfy this requirement.

Where a PPA does not result from a competitive tendering process or the level of competition was inadequate (for example, with only one bid being received) then ERO will assess the economic nature of the price offered against benchmarks. These will include:

- The historic costs of other power purchases, including imports.
- The wholesale prices obtained from the WMSM.
- The estimated long-run marginal cost (LRMC) of electricity generation in Kosovo (representing the price of meeting new demand).

Where ERO considers that the power purchase costs represented by the PPA are excessive, it may require the Public Supplier to enter into a new PPA or, disallow part of the costs of power purchase under the PPA for the purposes of determining the costs to be passed-through to non-eligible customers.

8.4 Purchases from non-public generators with certificates of origin

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Chairman of the Board of ERO

Members of the Board: