INOGATE

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ENERGY COOPERATION BETWEEN THE EU, THE LITTORAL STATES OF THE BLACK & CASPIAN SEAS AND THEIR NEIGHBOURING COUNTRIES

Methodology For Electricity Tariff Calculation For Different Activities

EU- INOGATE programme
Project:"Support to Energy Market Integration and Sustainable Energy in the NIS" (SEMISE)

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1. EU AND NIS EXPERIENCES OF TARIFF REFORM

It is important to note that among the EU Member States, tariff-setting for vertically integrated monopolies is regulated and cannot be separated from a regulatory authority whose function is to formulate a tariff methodology and approve tariffs submitted by the utilities within that methodology. The EU as a body does not generally proscribe the manner of tariff calculation for the various Member State utilities and Section 4 below details the many and varied ways in which tariffs are formulated and regulated across the EU Member States. While the form of the tariff differs widely, what the EU has provided is the legislative framework on which such developments are ultimately based. Specifically, a Directive was promulgated in 1996 (The Electricity Directive) which set out the agreed objectives of reform, guidelines for their implementation and targets by which they were to be assessed..

1.1 Cost Basis for Tariff Setting

Generally in the EU, an integral part to setting a tariff is the method for allocating costs across categories of users. Unless the costs to be recovered are allocated appropriately then the tariff structure for an individual customer category cannot achieve cost reflectivity. The EC Commission as part of its overall review of the progress towards the liberalisation of the energy sector and the creation of an internal market examines the costing methods used for class allocation and tariff design in the electricity generation, transmission sub-sectors.

There are broadly at least three approaches to tariff setting identifiable in the EU. These are:

a. **Average Historical Cost Approach**

The average historical cost approach entails taking the expenses actually being incurred or allowed by the energy regulator and a return on capital invested in the past as a starting point. This bucket of revenue is classified as being related to demand, energy consumption, and number of customers being served. The classified costs are then allocated across the various customer classes based on measures of their demand, energy use, and customer counts. The classified and allocated costs are then converted to tariff charges by dividing the identified costs of customer group categories by billing units (e.g. kWh, customer-months).

b. **The Average Reproduction Cost**

The average reproduction cost approach modifies the average historical cost approach by adjusting assets values to reflect the cost of replacement. The revaluation affects the return on asset base, but not the depreciation charges.

c. **The Marginal Cost approach**

The marginal cost approach is a forward-looking process that estimates the change in the cost of producing or delivering energy in response to a small change in customer usage. In many systems, the marginal cost of generation will be the market price. The marginal cost of transmission however, is a function of:

- Congestion and losses reflected in locational marginal prices although these are not included in all EU Member States; and
- The annualised cost of incremental investment needed to accommodate load

growth.

The marginal cost of distribution is the annualised cost of incremental local facilities needed to connect customers and the annualised cost of higher voltage facilities needed to accommodate increased use by many customers. The output from a marginal cost study is unit marginal costs, per kWh by time period, per kW and per customer. These unit costs can be used to compute the marginal cost revenues (the marginal unit costs multiplied by units expected to be sold) by customer category and in total. Since total marginal revenue does not necessarily match the allowed revenue requirement, adjustments must be made to cover any positive or negative gap. The adjustment can be proportional (so that all classes are allocated the same percentage of their marginal cost revenues) or on a differential basis that takes other factors into account.

As applied to the generation sector, the cost of building power generation capacity is a *stock* concept, marginal cost (and more usually, long-run marginal cost) is a *flow* concept which relates to the cost per period of producing an additional kWh. Peak load pricing is a system of price discrimination whereby peak time users pay higher prices to reflect the higher marginal cost of supplying them.

There are two benefits from adopting peak load pricing:

- Peak time users pay for the higher marginal costs that they impose on the system;
- Those users who would not mind consuming at a different time (for example, residential customers who can use electricity at a different time when marginal costs are cheaper) are induced by cheaper prices to switch to consuming at off-peak times. By spreading total daily consumption more evenly, BT reduces the peak in demand and has to devote less resources to building new power stations whose number is determined by peak usage.

In some cases regulators can use a hybrid approach, which uses a combination of marginal and average allocation of costs. For example, average historical costs could be used to allocate the revenue requirement to customer categories (eliminating the need to close the marginal cost revenue gap at the class level) and marginal costs could be used for tariff design within a category (with the gap closing done at the tariff component level).

1.2 Varying European Approached to Tariffs

There is no single uniform approach to tariffs in the EU nor a specific tariff-setting methodology that is uniformly applied throughout. There is no clear tendency towards a preferred network-pricing model in Europe for example in the application of different cost concepts and there are varying approaches for transmission and distribution. The lack of uniformity is itself a function of the different physical properties of electricity transmission and distribution systems in the EU and the different scope of provided services provided by utility companies. In order to highlight the diversity of tariff options, the next sections of this report provide an overview of some of the key variations what apply to tariff-setting in the transmission and distribution networks between a number of EU Member States.

In general however, tariffs among the EU Member States are composed of the following elements:

- Locational pricing (use-of-system, point-to-point, postage stamp or zonal);
- Marginal or average cost pricing;

- Standing charges;
- Capacity/demand charges;
- Time of Use charges;
- Energy charges.

The following section examines some of the variations in tariff elements through different functions and across a selection of EU Member States.

1.2.1 Transmission Pricing Examples

Locational or Non-locational Pricing

- UK – Locational or use-of-system (UoS) charges are based on investment cost-related pricing (ICRP);
- Norway – Locational charges based on short-run marginal costs (SRMC);
- Germany – no locational charges but demand and energy charge by voltage level;
- Greece – zonal charges;
- Spain – energy and demand charge;
- Locational elements in UK, Ireland, Norway;
- No locational elements present in Germany and Spain.

Marginal or Average Cost Pricing as a Basis for Tariff Setting

This issue is discussed in greater detail in Section 4.2.2.1 below but in terms of the application of these two pricing concepts among the EU Member States, some countries opt for marginal cost pricing, for example in the UK (LRMC)[1] and Norway (SRMC)[2] while elsewhere the basis is for average cost pricing, e.g. in Germany and Austria

Tariff design (energy and/or demand charges)

- Demand charge in UK
- Energy and demand charges in Germany
- Energy charges in Bulgaria

Transmission losses

- Excluded from transmission charges in the UK
- Included in transmission charges in Germany and Austria
- Part of locational charges in Norway

System operation cost

- Explicit and separate price control in UK

[1] Long Run Marginal Cost
[2] Short Run Marginal Cost

- Integrated in transmission price control in Germany

1.2.2 Distribution System Pricing Examples from the EU

- Standing charges,[3] demand and energy charges based on long run investment replacement cost operated in the UK
- Demand and energy charge by voltage level operated in Portugal, Germany and Czech Republic
- Demand and energy charge by voltage level, time-of-use energy charge (peak-off peak period) and separate charge for network losses operated in Austria.

Variations in Distribution Tariffs Operated in the EU

The principle components of tariffs operated across the EU by the Member States are:

Locational elements whereby:

- Prices are usually determined on a regional basis; or
- Differentiated by voltage levels but without further geographical differentiation.

Marginal versus average cost

- Marginal cost is used in UK and Portugal
- Average cost is used in Germany and Austria

Tariff design (energy and/or demand charges)

- Standing charges are used in the UK but not by all suppliers
- Demand and energy charges used elsewhere

Distribution losses

- Are included in distribution charges in Germany, but
- Are not included in distribution charges using a separate losses chargein Austria

Time-of-use pricing

- Elements of time-of-use charges in Austria and Portugal
- No time differentiation in Germany

Figure 4 below, presents a possible cost allocation scheme for pricing of the distribution system. The scheme shows cost types in the left of the chart and includes both network costs such as depreciation, operation and maintenance and return on assets as well as

[3] Standing charges are fixed charges and are used to cover the energy suppliers' costs, such as meter reading, maintenance and the cost of keeping you connected to the network. Standing charges are like connection charges and recoup the cost of keeping the customer connected to the system.

losses and services costs (transmission and ancillary) which may or may not be included in the tariff. The regulator will set the regulatory asset base (RAB) at the beginning of the regulatory review period which can include the cost of these services). Annex 3 explains the 'building block' method by which the regulator will set the RAB and monitor it over successive review periods. Figure 4 also describes the connection between the cost types and the cost centres of the distribution system by network asset and voltage level and the inter-linkage with customer tariffs broken down by energy and demand charges for customers with served by networks of 6/10kV and above (i.e. non-residential end users).

1.2.2.1 The Major Pricing Concept: Average or Marginal Cost Pricing?

The principal concepts for tariff setting in the EU areaverage cost pricing and marginal cost pricing. These are defined as follows:

- **Average cost pricing**(AC) allocates the total cost of the total kW or kWh either generated or transported via the networks. In the EU, prices are set by the regulator so that they cover the average costs (at the intersection of the long-run average cost curve and demand). Cost includes also the allowed return to of the company's investors
- **Marginal cost pricing**(MC) measures additional (incremental) cost incurred to generate or transport one additional kW or kWh via the networks. In the EU, prices are set equal to marginal costs by the regulator, creating the conditions that would be achieved by the market under perfect competition.Long Run Marginal Cost (LRMC) includes incremental cost of investments to cover additional demand.

Normally, a tariff will be applied (most usually in the EU it will be regulated according to certain key principles and objectives (see section 3.6.1above of this report). The following is a taxonomy of the pros and cons of average and marginal cost pricing according to the most commonly held tariff principles:

Table 2 – Pros and Cons of Marginal and Average Cost Pricing

	Marginal Cost Pricing	Average Cost Pricing
Allocative efficiency	High	Relatively low (not optimal), size of inefficiencies depend on elasticity of demand
Cost recovery	If the Company is not financially viable, then adjustments will be needed to MC tariffs (usually government subsidies)	Ensures financial viability of regulated firm, cost recovery results automatically from the cost allocation, eliminates economic profits provides 'fair' rate of return
Efficient regulation	Depends on the regulatory role in the tariff setting process. Administration and compliance cost of MC pricing may be relatively high	Depends on the regulatory role in the tariff setting process

Transparency and simplicity	Low – MC pricing concepts may apply sophisticated modelling	High – AC pricing easily understood by users
Non-discrimination	High – but also depends on adjustments for cost recovery	Variable – depends on the rules for cost allocation and tariff setting
Implementation in practice	Used to provide short and long-term locational signals, may require sophisticated modelling	Usually used with energy and demand charges differentiated by voltage level