Commission for Energy Regulation
An Coimisiún um Rialáil Fuinnimh

Electricity Tariff Structure Review: Alternative Tariff Structures

A Consultation Paper

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SUMMARY

Since 2000, the Commission has reviewed customer tariff levels on an annual basis. Whilst some changes have been made to the types of tariffs offered to customers since this date, overall transmission, distribution and PES supply tariffs, as well as network connection charges, have continued to reflect legacy structures which were in place prior to retail market opening.

The aim of the Electricity *Tariff Structure Review* has been to evaluate these legacy structures with a view to presenting alternative tariff and charge structures which more adequately deliver benefits to all electricity consumers. On commencing the review of tariff structures the Commission set out a number of principles which dealt with the obligations of the Commission under legislation. In this paper the Commission has addressed these principles and outlined how it has arrived at the proposed alternatives. Overall, the aims of this evaluation are threefold.

First of all, this review has analysed existing and potential cost allocation methods used to allocate regulated business costs to existing individual customer categories. Within customer categories the structural components or charging methods were considered bearing in mind the overall duties of the Commission and the specific objectives of the review. To achieve such an aim it was decided to explore the approach of setting tariff structures on the premise of marginal electricity industry cost drivers rather than on the basis of the cost allocation method currently in place. Tariffs based on marginal cost are formulated on the basis of how costs would change if there were a small increase (or decrease) in energy used in a given period, in demand in critical hours and in the number of customers of a particular type. The results of the cost allocation methodology used are published in a separate paper, *Marginal Cost Study*, which accompanies this consultation.

Secondly, this review has looked at the adequacy of existing tariff offerings and has suggested a number of changes that could be made to better reflect current customer characteristics and metering technology.

Many of the existing tariff elements, including those deployed by ESB PES, have been formulated over the years as a result of available technology. In reviewing the electricity tariff structures it is therefore important to consider some of the developments in technology particularly with respect to metering which may facilitate a greater variety in tariff structures now or in the future. In particular the Commission has examined the use of tariffs which vary with time across the day (or season) to more accurately reflect the costs imposed by different usage patterns by consumers. This paper examines the impact and implications of moving to Time of Use (TOU) tariffs.

Naturally any review of tariff structures is likely to result in changes to tariffs and, equally, any changes to tariffs will result in winners and losers relative to the status quo. The outcome to the study undertaken at this time has resulted in some changes for customers on a category-wide basis. The proposals outlined in this paper assume the adoption of alternative technology, which would result in introducing a time of use component to electricity charging. The consequences of this approach are that customers who use electricity at

system peak hours will end up paying more for their electricity during those hours. Where customers use their electricity predominantly in off-peak hours this will result in paying lower charges at those times. In essence what this means is that customers who contribute most to the cost of the system will result in paying more for the system. It should be pointed out that this report does not aim to make any exceptions and that all customers are treated on an equitable basis. The final results and tariffs which will be adopted will be influenced naturally by consumers, industry and also the special provisions that have been made under the legislation which the Commission will be obliged to have regard to before making any final decisions.

Any changes to tariffs structures have to be considered in light of the changing technology required to support such changes. The proposal to adopt time of use tariffs, while it may result initially in changes for some customers, will also facilitate customers where they are capable and willing to change their consumption patterns. These tariffs will facilitate customers in reducing their overall electricity bill throughout the year. In simple terms customers can contribute to reducing the overall cost of electricity by moving their electricity consumption from peak time hours to shoulder or off-peak hours. This will substantially reduce their electricity bill and thereby contribute to a more efficient electricity system for all customers.

Finally, the Commission has also, at this time, reviewed the existing charging policy with respect to network connection charges. The current policy deployed by ESB Networks and ESB National Grid have been developed many years ago and it is worth considering at this stage whether these policies are appropriate in the current climate. The current connection charging policies were formulated at a very different time with respect to financial products available to both industry and domestic customers. The Commission now wish to review the structure of connection charging policy in the light of current financial products that are available to all customers and it poses the question as to whether the current connection charging policies are appropriate or the most efficient means of recovering the cost of connections. In this paper the Commission outlines a number of alternative approaches to the current policy including the introduction of full up-front payment for connections.

Overall this paper analyses the pros and cons of various alternative tariff structures and connection charges, and uses the results of the marginal cost study to quantify a selection of illustrative tariffs using promising alternative tariff structures. This paper also presents the results of these alternative tariffs structures and the potential impact these would have on customer categories if implemented.

It should be noted that the alternatives tariffs presented in this paper are illustrative, and the resulting class revenue allocations and bill impacts are only approximate. More detailed analysis is required if tariffs are actually set on these models. This analysis will be undertaken during the implementation stage of this review.

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1. INTRODUCTION

This consultation paper documents analysis of a number of alternative tariff structures that have been investigated as part of the Electricity *Tariff Structure Review*. This review concerns tariffs and charges in the following areas:

- Transmission Use-of-System (TUoS) and connection charging;
- Distribution Use-of-System (DUoS) and connection charging;
- Supply (PES) tariffs faced by final customers

1.1 Background and Purpose of Project

1.1.1 Commission's Duties in Setting Electricity Tariffs

Under the Electricity Regulation Act, 1999 (ERA), the Commission is charged with approving the form and basis of charges to be applied for the connection to and use of the transmission and distribution system.

Regulation 31 of Statutory Instrument No. 445 of 2000 also requires the Commission to approve the form and basis of ESB PES tariffs for the period to 19th February 2005. It is anticipated that this requirement will continue under new legislation expected later this year.

1.1.2 Existing Tariff Structures

Since 2000, the Commission has reviewed transmission use of system (TUoS) and distribution use of system (DUoS) and PES customer tariffs on an annual basis with the aim of providing cost reflective tariffs for full market opening in 2005. Distribution and transmission connection charges policy has also been reviewed and approved during this period.

The primary focus of the annual tariff reviews has been on the overall level of tariffs rather than on the underlying structure of the tariff costs, categories, and structural components.

This *Tariff Structure Review* represents the Commission's first opportunity for a comprehensive review of tariff structures since market liberalisation in 2000.

1.1.3 Tariff Structure Review

The review commenced in December 2003 with the publication of a first consultation paper on the structure of existing charges and tariffs. Proposed underlying objectives and principles governing the formulation of tariffs and the allocation of costs to different customer categories were also discussed in this document.

Comments received in response to this paper were published and responded to by the Commission in March 2004. At the same time, the Commission published an information paper documenting research on tariff charging policies in existence in a selection of other countries. The main purpose of this paper was to inform market participants and customers of some of the alternatives in use elsewhere.

This consultation paper is the fourth paper of the *Tariff Structure Review* and will be followed by a *position paper* that will inform the implementation phase of the review, which will begin in the Autumn of 2004.

This paper is also accompanied by a *marginal cost study* of costs facing ESB National Grid, ESB Networks and ESB PES. The results of these analyses have informed the formulation of alternative tariff structures.

Overall, in the process of this review the Commission has:

- invited comment on the structure of existing tariffs;
- consulted on the objectives and principles that should be employed in determining alternative tariff categories and structures;
- published research on tariffs in use in other countries;
- conducted analysis of marginal costs faced by ESB National Grid, ESB Networks and ESB PES;
- investigated metering and billing system constraints on choice of tariff structures;
- developed illustrative alternative tariffs with preliminary customer impact results.

The design stage of the review will be completed with the publication of a Commission position on future tariff structures, after which the implementation stage will commence.

The Commission would like to point out that the implementation stage is likely to take a considerable period of time and we are mindful of the many changes presently underway in the industry. Therefore the implementation of any changes will require significant further consideration.

1.1.4 Structure of this Paper

Section 2 of this consultation paper outlines the methodology employed by the Commission in reviewing tariff structural design objectives and project aims, review of underlying costs and how these costs are measured and allocated to customers, how customers are categorised into separate tariff groups based on shared characteristics, how costs are recovered from these categories and, finally, what impact different tariff structures have on these customer categories and individual customers.

Section 3 applies this methodology to transmission charging for new connections and ongoing transmission Use-of-System charges. Alternative tariff structures are identified along with indicative customer impacts that would result from the introduction of these alternatives vis-à-vis present tariffs.

Section 4 is similar to section 3 of the review except it applies to distribution charges.

Section 5 considers the current PES Supply tariffs faced by all customers not served by independent suppliers.

Section 6 previews the next steps of the project, namely the publication of a decision on alternative tariffs and the process of implementation.

The Appendices present detailed results and impacts of the tariff options screened as part of the review process.

2. TARIFF STRUCTURE DESIGN PROCESS

2.1 Objectives & Aims

In December 2003, the Commission published *objectives* and *principles/aims* for the review of existing and alternative tariff structures in respect of transmission UoS and connection charges, distribution UoS and connection charges and PES supply tariffs.

2.1.1 <u>Broad Objectives of the Review</u>

As outlined in the first consultation paper, the objectives of the review are as follows:

- *General*
  - To avoid cross-subsidies;
  - To gain transparency and simplicity within the tariff structure;
- *Competition*
  - To facilitate wholesale competition without creating artificial barriers for any generator or supplier;
  - To facilitate retail competition without creating artificial barriers for any supplier;
- *Efficiency*
  - To develop efficient price signals to consumers to guide short-run and long-run consumption decisions and choice of supplier;
  - To encourage efficient consumptions patterns across the day and year
- *Non-discrimination (Equity)*
  - To avoid unnecessary bill impacts;
  - To develop charges which are just and reasonable and not unfairly discriminatory;
- *Consistency*
  - To gain consistency with new market arrangements, including incentives for efficient location of new generators;
- *Renewables*
  - To gain consistency with government policy related to support of renewables

2.1.2 <u>Specific Aims of the Review</u>

In addition to identifying broad objectives, this paper outlined the process of arriving at new or revised tariff structures, in particular the *specific aims* of the review i.e. to identify the following:

- *Cost Allocation & Non-Discrimination*
  - Are costs being allocated appropriately according to causer pays principle?
  - Are prices reflecting marginal cost signals?

- *Existing & Alternative Tariffs and Connection Charges*
  - What other, alternative, tariffs and connection charges might better achieve the objectives of tariff setting?
  - What tariff structures are well suited to the Irish retail market?
  - How will embedded generation, in particular CHP generators and autoproducers, be facilitated?

- *Tariff Constraints: Metering & Billing Capabilities*
  - How would metering and billing technology and investment affect the choice and implementation of alternative tariffs;

- *Alternative Screening & Customer Impact*
  - How would the introduction of alternative tariff structures impact customers?

2.2 Cost Basis for Allocation and Tariff Design: Embedded or Marginal

Because one of the objectives of the tariff review is to ensure cost-based tariff structures, the first step in reviewing tariff structures is to decide upon the appropriate cost basis. The cost basis is used for allocating costs to classes, designing tariff structures, and setting the levels of each tariff component for each class of consumers.

There are two types of cost studies that can be used for these purposes: *average/embedded costing* and *marginal costing.*

2.2.1 Embedded Costs & Marginal Costs as the Basis of Tariffs

An *embedded cost* (sometimes called an *average historical cost*) *tariff analysis* starts with the total revenue requirement of the utility for a given year and takes the following steps:

- The *functionalisation step* attributes costs to the different business. (In this case it was done through separation of ESB accounts);

- The *classification step* defines costs as demand-related, energy-related or customer-related using a variety of classification methods. For example, the fixed-variable method classifies fixed costs as demand-related and variable costs as energy-related.

- The *allocation step* apportions the functionalised and classified costs to the various customer classes using a variety of allocation factors that depend upon the type of cost being allocated. For example, energy-related costs can be allocated on the basis of category annual energy use, or weighted energy use in various seasonal and time-of-day costing periods. Demand-related costs might be allocated on the basis of class contribution to system annual peak, the average of the three highest monthly peaks, the average of the 12 monthly peaks, or any of a large number of other methods.[1]

- The *tariff-setting step* divides the allocated costs by class billing determinants (kWh, billing demand, number of customers, etc.) to determine tariff charges. These charges are often adjusted because of bill impacts and other policy decisions.

Since the revenue requirement is in large part a function of investments made in the past, an embedded cost study essentially attempts to define each class' responsibility for historical costs.

In contrast, a *marginal cost[2] study* analyses how the system is planned and operated in order to determine how costs would change if there were a small increase (or decrease) in energy used in a given period, in load in critical hours, in number of customers of a particular type, etc. It is a forward-looking and hypothetical exercise – as it looks at the cost of the next unit produced (or the savings from a small decrement in expected use).[3] A marginal cost tariff analysis includes the following steps:

- *Unit Cost Estimation*: Changes in costs generation, transmission, distribution and supply costs that vary with level of service (kW; kWh; number of customers) given a sufficient time horizon is estimated. All non-marginal costs are ignored.

- *Marginal Cost Revenue:* The unit marginal costs per kWh, kW and customer identified in the first step are multiplied by the corresponding units for each customer class to establish category (and total) marginal cost revenue. Because marginal costs are forward-looking, whereas the revenue requirement is largely determined by decisions made in the past, it would be only by coincidence that charging marginal costs would produce the allowed revenue. Consequently, an additional step is required.

- *Revenue Reconciliation:* The unit marginal costs are adjusted to produce charges that will generate the revenue requirement and meet other tariff objectives (see section 2.3).

A marginal cost tariff analysis is a bottom-up exercise that begins with time-differentiated *unit* costs per kWh and per kW of monthly peak demand, and monthly costs per kW of contract demand and per customer. These unit

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1 Sometimes embedded cost studies include a time-differentiation step, but the costs are simply assigned to periods using somewhat arbitrary assignment factors, with the outcome highly dependent on the assignment approach chosen.

2 *Marginal Cost* is the change in total cost incurred to supply a very small increment of service.

3 Note that all customers are responsible for the utility's marginal costs; every customer is a marginal consumer. If load growth requires expansion of the network, existing customers are just as responsible as new customers for the new investment because they choose to continue to consume at their prior level. Moreover, an industrial customer that consumes at a steady level across the hours of the day consumes energy in the peak hours of the day when market price are high and should face tariff charges that reflect these high market prices. This customer will benefit from it purchases of large amounts of energy in the off-peak hours, when market prices are low.

costs are then multiplied by class billing determinants to determine class marginal cost revenues, and adjusted as necessary to create a set of tariffs that will yield the allowed revenues.

According to economic theory, when marginal costs are used as the basis for pricing, customers have incentives to make economically efficient decisions about their use of electricity and related goods and services because the price they pay reflects the resource costs of their decisions. Pricing above marginal cost discourages consumption that would be valued more by consumers than it costs to supply. The result is a loss of welfare. Likewise, pricing below marginal cost encourages consumption that would not take place if consumers faced a (higher) marginal cost price. Since the cost of the excess consumption exceeds the value that consumer place on it, resources are wasted.

Because the process of estimating marginal cost involves analysing the likely cost effects of hypothetical changes in load or customers, an assumption must be made about the degree of flexibility that the utility has in responding to the assumed load change. In the terminology of economics, a long-run marginal cost reflects changes in costs in a situation in which all factors of production can be altered. Thus a long-run marginal cost is the cost actually incurred to provide an additional unit of electricity only when the system is optimal, and includes the cost of capacity added to return the system to optimality. A short-run marginal cost is estimated assuming that not all factors of production can be modified. Usually this is interpreted as meaning that capacity cannot be expanded in the short-run and the utility must provide the additional service with existing facilities. However, if load grows but capacity does not, there is a higher probability of outages, and the cost of this reduced reliability to consumers is an element of short-run marginal cost. Higher load on the transmission system increases losses and congestion, which requires running higher cost generators than when there is no congestion. Since electricity systems are rarely optimal, it is short-run marginal costs that are actually incurred when load changes.

Note that the distinction between short-run and long-run marginal costs is not a matter of time horizon, but rather of flexibility to respond to load changes. There is an important connection between short-run and long-run marginal costs. When the reliability, losses and congestion components of short-run cost become large enough, it is cost-effective to add capacity – and marginal costs computed in these situations include the cost of new capacity.

Marginal cost studies conducted for use in tariff development often develop short-run cost estimates for several years into the future, taking into account capacity additions that are expected over that time period, but not assuming that the system is always in optimality. This approach, since it does have a time dimension, is referred to as a *long-term* marginal cost study.

Although short-run marginal costs give the most precise price signals to guide efficient consumption decisions, it is sometimes difficult to estimate the reliability component of short-run marginal costs, particularly for distribution and transmission. The MAE will produce market prices of generation that reflect short-run marginal costs of generation (including shortage costs) because the price will rise when capacity is constrained. In lieu of short-run marginal costs of transmission (other than congestion and losses included in the LMPs) and distribution, marginal cost analysts typically compute, as a proxy, the average expenditure on load-related capacity additions per unit of peak load growth (annualised), along with associated operation and maintenance expenses and marginal overheads. This approach uses the relationship between short-run marginal costs and investment decisions, discussed above, to substitute the average incremental cost of projected capacity additions for the difficult-to-measure reliability component of short-run marginal transmission and distribution costs (see sections 3.2.2, 4.2.1, and 5.2.1 for a summary of the marginal cost methods used for this review.)

2.2.2 Present Cost Allocation Policy – Average Costing

At present, transmission, distribution and supply costs are allocated to different customer groups in a way that resembles the *average/embedded cost* approach.

In the current approach for DUoS and TUoS (and PES), capital costs in the allowed revenues are determined on an average replacement cost basis – historical costs are revalued to what it would cost to replace them were they to be invested in today. Models have been developed that allocate the replacement costs to customer categories using assorted allocation factors, with the choice based on an assessment of the assets required to serve them. Operating costs are then allocated by these models to customer categories based on the same cost drivers. Although the revaluing of assets is similar to a marginal cost approach, the current models include all costs, and do not focus on costs that vary with amount of service provided.

In reality, the allocation of costs to customer categories and levels of charges for the structural components in the tariffs have not been set on the basis of comprehensive cost analyses. For example, the transmission revenue requirement has been allocated between generation and demand users using an arbitrary split and the amount recovered in energy vs. capacity charges also determined using an arbitrary split.

2.2.3 Evaluation of Cost Allocation Methodology

The main advantages of embedded/average cost studies are:

- Ease of implementation (the costs are all available in the books and records of the companies.);
- Match to Revenue Requirement more easily (the allocated costs sum to the allowed revenues.);
- Minimal change in tariff structures (Given the fact that existing tariffs are based to some extent on average costs, a comprehensive average cost tariff design might not result in wholly different tariff structures. However since the present tariff structure does rely on many arbitrary allocation factors, a full use of average costs might require significant changes in tariff structures).

The principle disadvantage is that there is:

- Poor cost signals for efficient consumption and investment decisions
- Subjective choice of allocation factors since there is no theoretically "right" way to allocate or time-differentiate the costs. There is a greater number of allocation factors associated with the average cost methodology.

The main advantages of marginal cost pricing are:

- Prices signal the economic costs of consumption and investment decisions;
- Regulated tariffs mimic the cost structures faced by competitive suppliers;
- Marginal cost studies provide the information needed for detailed time-differentiated tariffs.

The main disadvantages of marginal cost pricing are:

- The forward-looking nature of a marginal cost study means it is more difficult to implement than a study that relies on the historical books and records of the company;
- Because marginal cost analysis is a bottom-up exercise, there is almost always a need to reconcile marginal cost revenues to the allowed revenues when setting tariffs.

The Commission is of the view that a marginal costing approach can result in straight-forward tariffs, despite the fact that it may be not be as simple as an average cost approach. In addition, the need to adjust marginal revenues to the revenue requirement can be done in a manner that does not overly distort the efficiency signal to customers.

Both approaches were evaluated against the objectives published in the first consultation of this review:

Table 2.1: Pricing Evaluation

Objectives		**Marginal Pricing& Average Pricing**
General	To avoid cross-subsidies;	Both methodologies may be used to define objective measure of class cost of service.
	To gain transparency and simplicity within the tariff structure;	Both approaches can be used to make tariffs that follow cost structure and are understandable to consumers.
Competition	To facilitate wholesale and retail competition without creating artificial barriers for any generator or supplier;	Marginal cost pricing should enhance competition, whereas an average cost basis may create distortions. For example, if PES supply tariffs allocated costs to categories on the basis of average costs, this might result in some customer categories paying more than marginal cost of service and

		others paying less. Those paying less than marginal cost would tend to stay with PES.
Efficiency[4]	To develop efficient price signals to consumers to guide short-run and long-run consumption decisions and choice of supplier;	Marginal Pricing is a better signal of the true resource cost of consumers' electricity decisions, and a better signal of the relative efficiency of PES as a supplier.
	To encourage efficient consumptions patterns across the day and year	Marginal Pricing with time-differentiation is the best way to encourage efficient consumption patterns. While average costing can be time differentiated, the costs must be 'assigned' to periods and there is no theoretically correct way to choose the assignment factors.
Equity	To avoid unnecessary bill impacts	Adjustments can be made to tariffs based on either costing approach to limit unacceptable bill impacts.
	To develop charges which are just and reasonable and not unfairly discriminatory	Marginal costing signals to all consumers the implications of their decisions to increase or reduce consumption. Average costing has the potential to be controversial because the results are so dependent on the allocation factors chosen.
Consistency with market	To gain consistency with new market arrangements, including incentives for efficient location of new generators	The marginal cost approach for TUoS is more likely to be consistent with new market arrangements because it is consistent with the marginal nature of short-run marginal transmission costs included in LMPs. Locational signals for new generators are more a function of connection charge policy and TUoS structure, than choice of embedded or marginal cost basis.
Renewables	To gain consistency with government policy related to support of renewables	Both approaches can be consistent with renewables policy.

Overall, the Commission is of the view that *marginal costs*, rather than of *embedded or average costs*, are the best basis for tariffs that achieve these objectives.

The Commission therefore, as part of this review process, undertook the study of the marginal costs faced by ESB PES, DSO, TSO and TAO. This *Marginal Cost Study* has been used to develop cost-based alternative tariff structures. These options are outlined in the transmission, distribution and supply sections of this paper.

[4] The term efficiency here refers to *Allocative Efficiency* which is promoted by pricing at the economic cost of the electricity supply.

The Commission invites comment on the cost basis for cost allocation and tariff design.

2.3 Reconciliation of Marginal Cost Revenue & Allowed Revenues

Revenue collected from tariffs should match the allowed revenue requirement of the regulated entity. As tariffs based on marginal costs alone rarely match allowed revenue, some form of adjustment or *reconciliation* must be made. The goal of these adjustments is to preserve as much as possible the efficient price signals that are the goal of marginal cost pricing. The reconciliation approach for one type of tariff (e.g., TUoS) may not be suitable for another type of tariff (e.g. PES Supply).

Adjustments reconciling marginal revenue to allowed revenue may be made in a number of ways (and combinations of ways), including:

a) Fixed Cost Adjustment

Making adjustments to fixed tariff elements, such as fixed monthly charges, is preferable for this purpose as this method is unlikely to affect customers' decisions about how much electricity to use.

b) Energy Charge Adjustment

If the bill impacts from making all the adjustment in fixed charges are unacceptable, adjustments can be made in the per kWh charges as well or instead. For example, blocked charges are often used for this purpose, with the adjustment made in the first block, leaving the tail block fairly close to marginal cost.

c) All Category Adjustment

Another approach is to make any needed adjustment in the usage charges consistently, preserving the marginal cost relationships between energy and demand, and among the various seasonal and time-of-day pricing periods.

d) Fixed Uplift

Reconciliation may be accomplished by increasing energy or demand charges by an absolute amount. For instance a 10c/kWh energy charge for domestics and 12c/kWh charge for businesses could rise by the same absolute amount. It the reconciliation amount was 0.5c/kWh then the domestic and business unit charge would become 10.5c and 12.5c per kWh.

Several methods of uplift have been tested and are presented in sections 3.4.3.6, 4.4.3.3, and 5.3.3.

The Commission invites comment on methods for reconciling marginal costs with allowed revenues [appropriate methods may differ depending on size of gap and type of costs.]

2.4 Identification of Alternative Structures

The distribution and transmission businesses recover most of their costs either through upfront charges for new connections or through ongoing use-of system (UoS) charges. ESB PES charges for supply costs, supply margin and pass-through costs in its tariffs.

2.4.1 Alternatives – Connection Charges

At present ESB Networks as DSO and ESB National Grid as TSO charge customers connecting to the networks part or all of the *attributable*[5] *cost* of connection. The DSO and TAO/TSO collect remaining connection costs and most other network and non-network costs through Distribution Use-of-System (DUoS) and Transmission Use-of-System (TUoS) charges respectively. Therefore, the extent of the connection charging directly affects the amount to be recouped from tariffs and other charges.

2.4.2 Alternatives – Tariffs – Categories & Structural Components

Once connection revenues are determined, remaining distribution and transmission costs to be recovered in use-of-system (UoS) charges should be allocated based on the cost of serving different customer categories. Furthermore, the structure of tariff components (energy, capacity, fixed, etc.) should reflect the structure of the cost of service.

2.4.2.1 Tariff Categories

Tariff categories are classes of customers with common/shared characteristics that are grouped together for ease and consistency of charging.

While categories may be based on a number of shared characteristics, tariff categories are usually defined by one or more of the following criteria:

a) *type of consumer* (e.g., domestic, commercial, industrial, street lighting);
b) *usage characteristics* (e.g., load factor, percent of use on-peak);
c) *quality of service* (e.g., firm or interruptible; type of distribution layout);
d) *voltage level of service*;
e) *location* (e.g., geographical area)

Transmission tariffs normally apply to broader groupings of customers than distribution or supply tariffs. Supply tariffs vary considerably by customer type, particularly in deregulated markets such as the UK. However, in

[5] The *Attributable Cost* is a proxy for the incremental cost of connecting a new customer or group of customers to the networks, including network reinforcement costs. The attributable cost is the estimated cost of the portion of the network that has to be built or existing capacity expanded to provide capacity to the connecting customer. Where standard or average charges exist, all new customers in the category pay these generic charges, rather than individually-determined connection costs.

Ireland regulated supply and distribution tariffs have until now been defined according to:

a) *voltage level* (in general);
b) *domestic/commercial use* (of connected premises at LV level);
c) *metering* (also at LV level)

Low voltage customers are divided by the domestic and commercial use of the connected premises. Business customers are often sub-categorised according to their size and what metering is in place – electromechanical metering or Maximum Demand metering. Larger Customers, on the other hand, are associated with the voltage level at which they are connected.

2.4.2.2 Tariff Components

Tariff components refer to the number and nature of the charges applicable to customers in a given customer category. Components can be fixed monthly charges or depend on customer usage during the billing period, can be blocked, and can be time-differentiated in various ways.

Cost-Components

Tariff components should be primarily based on the cost structure of providing service. Typical components include:

a) *Fixed Customer Charges (per customer per month)*

   Fixed Charges are charges that are not a function of the customer's usage during the billing period and are often used to recover costs that vary with the number of customers being served.

   Examples of such costs include:

   - Meter and meter services;
   - Customer billing and accounting expenses;
   - Customer information and service expenses

b) *Generation (Market Price) Charges (per kWh)*

   Energy charges, with the commencement of the new market, will be based on the MAE spot price.

c) *Capacity Charges (per kVA of MIC)*

   Capacity charges (as the term is used in Ireland) are another form of fixed charge as they are assessed on the customer's kVA of MIC (Maximum Import Capacity[6]), a cost that does not vary unless additional investment is made to increase or reduce MIC.

   The term *capacity charge* may also be associated with *maximum demand* at peak. At present, customers in DUoS DG6 category and

[6] Maximum Import Capacity (MIC) is the capacity that a customer contracts when seeking a connection to the networks. ESB Networks construct the networks to provide this capacity.

upward are charged a capacity charge per kVA of MIC in any given month in their DUOS tariff component These customers are not charged demand or maximum demand charges for their network usage. However, the PES tariff for the same customers does include a charge on the basis of kW of maximum demand.

Customers' maximum demand is monitored and, where a customer (DG6 and larger) exceeds its MIC, the customer is subject to penalties.

d) *Network Energy Charges (kWh)*

Network facilities are sized to handle their expected peak loads and to ensure that customers' capacity requirements can be met on an ongoing basis, assuming that peak load is the more significant driver. It is important to note that it can occur at different times in different parts of the network, and at times other than the time of the peak demand on the system as a whole. Since load growth at times when capacity is adequate does not require additional capacity, it is important to recover these network costs on a time-of-day usage basis for customers with time-of-use metering, and on a seasonal basis for customers with simple metering. Because the exact time of the peaks on various facilities cannot be predicted with complete accuracy, it is appropriate to recover these costs on the basis of energy used within the critical periods when the peaks are likely to occur.

As distribution substations and the transmission network is built for local or *system peak* their costs should be recovered based on usage or contribution to peak conditions, and *not on the basis of a customer's MIC.*[7] These costs can be charged on the basis of time-differentiated energy throughput (kWh) or by maximum demand (kW used) at during the peak period.

e) *Demand Charges (per KW of metered peak demand during the billing period)*

An alternative to time-differentiated per-kWh network charges is time-differentiated (or seasonal) charges per kW of monthly-metered demand. 'Maximum' demand charging i.e. charging customers on the basis of their maximum demand in any given, say, quarter hour in a billing period has traditionally been used as a means to recover capacity costs described above in (d), the idea being that the maximum usage of a customer in a billing period is a proxy for that customer's contribution to the need to invest in capacity to cover peak demand.

However, the problem with this approach is that a customer's peak demand does not necessarily coincide with peak demand on the transmission, and higher voltage distribution systems. Also, once max demand has been reached in a billing period, the customer has little

[7] For example the *Marginal Cost Study* accompanying this paper identified 5 time periods – a peak, shoulder and off-peak for the four winter months and a shoulder and off-peak for the eight summer months.

incentive to restrain demand at other times, which may be equally or more critical for the system.

A time-differentiated marginal cost study shows that responsibility for capacity costs lies in many hours – not just the peak hour -- because of uncertainty over loads and capacity availability. As such, charging for all capacity costs on the basis of use in one hour during the billing period does not follow cost-causation. Time-differentiating demand charging (billing on the basis of maximum kW demand in various pricing periods is a better approach, but requires meters capable of recording peak demand in particular periods (see constraints).[8]

In essence, the more pricing periods there are, the more similar are billing on a per-kWh and a per kW-basis.

f) *Other Charges: Low Power Factor Penalties*

Certain types of loads and generators consume (or produce) reactive power in addition to real power. The relationship between real and reactive power is called "power factor." The network operators must compensate for power factors outside a normal range in order to keep voltage within safe limits. The DSO and PES currently charge or penalise larger customers with a low power factor.

In terms of potential customer impact, the higher the fixed components of a customer's bill (and by inference the lower the variable components), the less the incentive to reduce usage. Of course, if the objective is to give efficient price signals, the variable components of the tariff should be set as close to marginal cost as possible, even if this means encouraging additional use. Efficiency is achieved when customers make consumption decisions based on the underlying economic (marginal) cost. There is a welfare loss if additional consumption is discouraged by pricing above marginal cost.

Energy or Demand 'Blocks'

Instead of a fixed price for each kWh or kW used in a particular pricing period, sometime the price varies with blocks of kWh or kW.

a) *Energy Blocks*

To encourage energy efficiency or to discourage overuse where marginal cost is above average revenue requirement, an increasing *energy block* prices the first quantity of kWh used in a given period at a lower rate, with the price for remaining kWh set higher (closer to marginal cost).[9] Increasing energy blocks are also used to assist lower income customers who use fewer units than the average customer. Conversely, to encourage use when marginal cost is below average revenue requirement, to recover fixed costs not included in the fixed charges, or to increase revenue certainty for the supplier, a declining

[8] At the extreme of hourly prices, a charge per kWh is the same as a charge per kW - a kW of demand imposed over an hour is a kWh.
[9] This description limits the blocks to two, but additional blocks are also common.

energy block structure prices the first units used at a higher rate than all subsequent units.

b) *Demand Blocks*

It is also possible to design increasing (or decreasing) metered demand charges, in which the first block of demand is priced below (or above) the second block.

c) *Load Factor Block*

Load factor blocks define the size of energy blocks in terms of kWh per kW of metered peak demand, instead of simply in terms of kWh. Declining load factor blocking is another means to incentivise customers to increase their load factor.

Time Differentiation

Another important characteristic of tariff structure is time-differentiation, i.e., to apply different charges to usage in different time periods to reflect underlying cost differences. Charges can be time-differentiated using multiple periods with a billing period, or simply changed seasonally.

As discussed above, marginal costs of generation, transmission and high voltage distribution vary by time-of-day and season. Costs are higher in hours when load growth is likely to require additional capacity, or when high-cost generators must be dispatched to meet load. Customer-related and local distribution facilities charges do not vary with use and require no time-differentiation. The charges currently faced by most customers do not vary by time of day because a significant proportion of existing installed metering does not measure consumption on a time-of-use basis. This situation has changed somewhat in recent years with the proliferation of new metering technology and meter data processing structures.

a) *Non Time-Differentiated Charging*

Non-time-differentiated charging imposes the same charges irrespective of the time of use or season.

b) *Seasonal Charging*

Seasonal charging, as the name suggests, refers to charges that change across the year. This form of charging is easily executed and is inexpensive to implement because it requires no special metering. It could be used to signal the higher winter cost of service in Ireland. However, the cash flow issues associated with charging more in winter than in summer may adversely affect some customers.

In countries that have seasonal tariffs, customers are often permitted to pay their bills under a "budget billing" plan that smoothes out the payments over the year. The annual bill is estimated and divided by 12. Any deviation of the actual charges from the estimate is 'trued-up' (charged or refunded) at the end of the year. Under these plans the bill shows the actual costs incurred each month, along with the (levelised) amount due. While this may lead to more complicated billing systems it maintains price signals to customers while at the same time smoothing cashflow considerations.

c) *Time of Day (TOD)*

TOD charging improves the efficiency of price signals because the charges vary for consumption in pre-defined periods within the billing period. The requirement for more complex metering means that the implementation of TOD charging to customers who lack the necessary meters is only cost-effective if savings from load shifts from peak to off-peak periods (or reductions in peak period use) are sufficient to cover the added metering costs.

TOD pricing periods are selected by grouping contiguous hours with similar costs (all costs that vary by time of day) together. The number of TOD periods selected is ultimately a trade-off between, on the one hand, the accuracy that is conveyed by having a large number of periods, and on the other, customer understanding and billing and metering constraints. Another factor is the likely response of customers to new time-differentiation. If the shifts from the peak period are very large, they may create a new peak outside the defined peak period. This is called "peak chasing." It may be necessary to model customer response and resulting changes in cost patterns to iterate to a set of pricing periods that will be appropriate for an extended period of time.

Below is a table containing system peak, shoulder and off-peak periods identified by the *Marginal Cost Study* undertaken for purposes of this tariff study.

Table 2.2: System Time Periods

Summer: March-October (8 months)	
Shoulder	Monday - Friday
	08.00 – 21.00
Off-peak	All remaining hours

Winter: November-February (4 months)	
Peak	Monday - Friday
	17.00 – 20.00
Shoulder	Monday - Friday
	08.00 – 17.00
	20.00 – 21.00
	Saturday 17.00 – 21.00
	Sunday 17.00 – 18.00
Off-peak	All remaining hours

As can be seen from the table below, peak charges apply from 17.00 to 20.00 on weekdays in winter. Peak/shoulder charges combined apply from 08.00 to 21.00 in winter. The same time period 08.00 to 21.00 accounts for weekday shoulder hours in summer. This consistency would facilitate the introduction of time-of-use charging for customers not accustomed to it.

Table 2.3: Peak/Shoulder/Off-Peak Time Periods

Hour Ending	Weekday	Saturday	Sunday	Hour Ending	Weekday	Saturday	Sunday
1	O	O	O	1	O	O	O
2	O	O	O	2	O	O	O
3	O	O	O	3	O	O	O
4	O	O	O	4	O	O	O
5	O	O	O	5	O	O	O
6	O	O	O	6	O	O	O
7	O	O	O	7	O	O	O
8	O	O	O	8	O	O	O
9	S	O	O	9	S	O	O
10	S	O	O	10	S	O	O
11	S	O	O	11	S	O	O
12	S	O	O	12	S	O	O
13	S	O	O	13	S	O	O
14	S	O	O	14	S	O	O
15	S	O	O	15	S	O	O
16	S	O	O	16	S	O	O
17	S	O	O	17	S	O	O
18	P	S	S	18	S	O	O
19	P	S	O	19	S	o	O
20	P	S	O	20	S	o	O
21	S	S	O	21	S	o	O
22	O	O	O	22	O	O	O
23	O	O	O	23	O	O	O
24	O	O	O	24	O	O	O

At the implementation stage, many practical issues require consideration. For example, what periods should be used to time-differentiate tariffs for customers with meters that can record usage in only two periods? The set of periods illustrated below, developed as part of the marginal cost study, defines a peak period (16:01 to 21:00 on Weekdays) that is the same in the Winter and the Summer, as these meters cannot differentiate between seasons. (Note that the values used for the two-period definition are not the same as for the three-period definition.)

Table 2.4: Shoulder/Off-Peak Time Periods

COSTING PERIOD: WINTER				COSTING PERIOD: SUMMER			
Hour Ending	Weekday	Saturday	Sunday	Hour Ending	Weekday	Saturday	Sunday
1	O	O	O	1	O	O	O
2	O	O	O	2	O	O	O
3	O	O	O	3	O	O	O
4	O	O	O	4	O	O	O
5	O	O	O	5	O	O	O
6	O	O	O	6	O	O	O
7	O	O	O	7	O	O	O
8	O	O	O	8	O	O	O
9	O	O	O	9	O	O	O
10	O	O	O	10	O	O	O
11	O	O	O	11	O	O	O
12	O	O	O	12	O	O	O
13	O	O	O	13	O	O	O
14	O	O	O	14	O	O	O
15	O	O	O	15	O	O	O
16	O	O	O	16	O	O	O
17	S	O	O	17	S	O	O
18	S	O	O	18	S	O	O
19	S	O	O	19	S	O	O
20	S	O	O	20	S	O	O
21	S	O	O	21	S	O	O
22	O	O	O	22	O	O	O
23	O	O	O	23	O	O	O
24	O	O	O	24	O	O	O

Other Components

In the first paper of this review, the possibility of interruptible tariffs for Distribution and PES customers was raised. An interruptible tariff offers customers a discount from the standard tariff in return for willingness to interrupt consumption when requested to do so. This flexibility allows the utility to build less network capacity and to contract for less peak-period energy in the (future) MAE.

The Commission invites comment on the structural components described here.

2.5 *Identification of Tariff Constraints*

An evaluation of alternative tariff categories and time-of-use[10] pricing, must consider available or/and possible new metering and billing infrastructure.

This section outlines the types of meters that are currently in use, the form in which consumption data is recorded, and a breakdown of the present installed metering per DUoS customer category. This information is presented in three parts:

- Current Metering Capabilities;
- Future Metering;
- Metering, Billing & Settlement;
- Individual Category Meter Cost Thresholds;
- Benefits of Time-of-Use for Customers

2.5.1 <u>Current Metering Capabilities</u>

At present, customers have one of five types of metering:

1. *Flat Rate meters* – These meters are electromechanical and collect a single element of consumption data, namely consumption between two dates on which the meter is read. Therefore, only one data register is required in such meters. These meters are by far the most common, particularly in the domestic sector.

2. *Day/Night meters* – These meters are similar to flat rate meters, except that they collect two streams of data, the amount of electricity consumed by day and by night. These meters are also electro-mechanical and a timer is used to switch between the day and night meter registers.

3. *Basic Maximum-Demand (MD) meters* – The most basic type of MD meter is also electro-mechanical and is similar to the flat rate meter described in one above. However, in addition to the data collected in the standard meter an additional component is added to measure the maximum demand (integrated consumption over a 15 minute period).

4. *Multi-function meters (MFM)* – With the advent of newer technology, MD metering has also advanced and at present all new customers with contracted capacity greater than 50kVA have digital, interval meters that can provide consumption data in a number of ways depending on how the data are processed. For example, MFM may provide MD and energy consumption data for several defined tariff periods, or it may provide data on 15 minute intervals. Such metering is reasonably flexible and will have a bearing on the types of tariff structures that can be offered to the market.

5. *On-line multi-function meters* – this type of metering utilises MFM metering technology which collects the volume of electricity consumed in each 15 minute interval. However, this type of metering also has a

[10] Time-of-Day and Seasonal.

communication link that allows the meter to be read/downloaded each night. This results in up-to-date information being available to the market. At present, such metering is only installed for customers whose MIC is greater than 100kVA or who have 300MWhrs consumption per annum.

6. *Unmetered supplies* – there is a sixth category of customers that are presently not metered, including public lighting, which has a predictable load.

It should be noted that the discussion above centres on consumers; naturally generators and autoproducers are also metered and such metering may utilise meters which measure both imports and exports.

2.5.2 Future Metering Arrangements

2.5.2.1 Consistency between Metering Arrangements and Categories

At present, the policy for installing meters depends on the expected customer consumption and tariff category of the customer as well as technical requirements (e.g. single or 3 phase metering etc.). Generally MFMs are installed for new customers with a maximum import capacity (MIC) greater than 30kVA that are on a retail MD tariff. Where metering is already in place, the installation may have depended on the expected consumption of the original customer. Over time the actual consumption may have varied from that envisaged when the meter was installed. Some MD customers may have relatively low consumption levels, while some general purpose customers may have relatively high maximum demand levels (e.g. MIC>=50kVA).

As a result there are at present some anomalies in the metering of DG5 and DG6 customers. If customers have MD meters, they are free to choose between being an MD customer (DG6) or a General Purpose customer (DG5), provided there are no stranded costs or the customer pays any stranded costs. If the premises do not have an MD meter installed, the customer does not have the option of the MD tariff. The Commission is looking into this issue, as underlying costs may not be fully recovered if certain customers switch to a GP tariff, depending on their consumption patterns.

MD tariffs were introduced in the past as a proxy for measuring consumption at certain times, since the installed meters were not capable of recording kWh consumption in more than one period within the billing period. The introduction of Time-of-Use (TOU) tariffs would eliminate the need for MD tariffs.

The Commission is also investigating the costs and benefits of installing MFM meters in order to ascertain a threshold level for their introduction (see section 3 below). It is also expected that, as a result of this study, the anomalies between the DG5 and DG6 groups will be clarified and rules on customer categories will be made. Customers will be categorised according to their consumption patterns and installed metering and should not be able to switch to a category that is not designed for their consumption levels if this leads to inconsistencies between tariffs and underlying costs of serving the customer.

2.5.2.2 Prepayment Meters

The domestic distribution and supply categories will need to be expanded to incorporate prepayment meter customers. The DUoS charges on these customers may be different from other domestic customers to reflect the different costs they impose. It is envisaged that these meters will also have a number of tariff registers, enabling suppliers to offer basic time-of-use tariffs (e.g. one or two peaks periods, as well as shoulder and off peak periods with different summer and winter charges).

2.5.3 Metering and Billing

The implementation of different tariffs is dependent on the installed metering. For instance, time-of-use tariffs cannot be charged to customers with single register EM meters. However, if the savings resulting from the introduction of Time-Of-Use (TOU) tariffs are greater than the cost of installing meters capable of supporting TOU), then it will be worthwhile to introduce such meters. Where this is not the case, more advanced metering should be introduced on a replacement basis. However the underlying economic case for such metering should still stand before more expensive metering is installed.

While this approach makes sense in terms of metering and associated costs it may lead to situations where customers within the same category group will face different charges solely due to their installed meters and the replacement cycle. Equity issues may arise as a result, since only some customers will be able to save money by altering their consumption pattern. This could be addressed by placing an obligation on ESB Networks to change the metering on request from the customer, thereby allowing the customer to benefit from any new tariff structure. The phasing out of old tariffs, such as the MD tariff, will partly be dependent on the rollout costs of meters that support the new tariffs, or the ability of old meters to be adjusted to support new tariffs. This issue will need to be addressed and quantified, and is very much dependent on the cost of replacement meters.

Furthermore, any change in the structure of tariffs may affect the billing systems of suppliers. New tariffs may lead to implementation costs for suppliers, which will ultimately be passed on to consumers. This needs to be borne in mind so that new tariffs are introduced with minimum cost implications for billing systems. However most new billing systems incorporate significant flexibility and implementation costs associated with supplier billing systems should therefore be minimal.

2.5.4 Time-of-Use & Settlement

In order for suppliers to be able to pass generation cost signals through to customers, the settlement process will need to incorporate the recorded time of use, rather than applying a consumption profile as is currently done for domestic customers. Otherwise the opportunity to exploit the ability of these meters to influence usage patterns will be reduced, and the customer will be unable to gain from the reduction in costs imposed on the system.

2.5.5 Individual Category Cost/Benefit Thresholds

At present all customers with an MIC greater than 100kVA or annual consumption greater than 300MWh should have an online multi-function meter installed. This is the only threshold that currently exists regarding appropriate metering. As part of this tariff structure review, the Commission has looked at this issue of appropriate threshold levels for different types of metering.

Time-of-Use pricing improves the efficiency with which resources, both fixed and variable are used. The quantity of electricity consumed in each pricing periods under TOU pricing is different from that demanded under a flat pricing structure. It is possible to evaluate the losses and benefits arising from such changes in consumption, and therefore to decide if such benefits outweigh the costs of installing meters capable of supporting TOU tariffs.

The costs used for this analysis were limited to the annual unit and installation costs of the meters. The annual costs of different meter types were calculated by using a methodology for calculating the annual economic carrying charges associated with fixed assets, such as meters. The preliminary cost of introducing TOU meters is the difference between the annual material costs associated with non-TOU and TOU meters. Further possible costs arising from administrative and maintenance differences were not calculated. These points are addressed at the end of this section. As such, the findings below give initial cost-benefit indications only. A comprehensive cost-benefit analysis encompassing all extra costs would need to be undertaken before any decision on the timing and scale of the introduction of TOU metering could be taken.

Using a model that evaluates the annual benefit, per customer group (General Purpose and Domestic), of TOU pricing by calculating the changes in consumer and producer surpluses brought about by the introduction of TOU pricing, the Commission arrived at a number of threshold levels where TOU metering should be installed.

For single-phase customers, the costs of TOU meters are above those associated with 24hr metering. The extra annual costs of TOU meters are also due to the fact that they have a shorter life span (approximately 10 years, compared to 30 years for 24hr meters). Nevertheless, the benefits accruing from TOU pricing outweighed the extra costs for annual consumption levels above 5,000 kWh. The Commission is of the view that the installation of TOU meters for customers with single-phase connections should be further investigated. These benefits were based on the standard profile used by the DSO for domestic customers.

Metering costs for three-phase connections are significantly higher than for single-phase connections. However, there is only a relatively small cost difference between three-phase TOU and EM meters without MD measurement functionality. As a result, the benefits of installing TOU metering outweigh the associated extra costs at all levels of annual consumption over 10,000 kWh. This is higher than the threshold level for domestic customers, as lower elasticity values were used for GP customers. These benefits were based on the standard profile used by the DSO for GP customers.

It is also important, for connections of a significant capacity, that the installed meters are capable of recording the maximum demand in any period. This is to ensure that the contracted MIC is not exceeded and to ensure that in cases where the MIC is exceeded that appropriate penalty charges can be applied. Monitoring of the MIC is critical from a DSO viewpoint, especially at connection points with higher capacity needs, to ensure the system is being used according to its design. A threshold therefore is also needed for meters that are capable of recording the maximum demand in any period. The benefit of such a threshold cannot easily be quantified, since its use is only for monitoring purposes (in the absence of MD charges) and therefore is of value only in cases where the MIC has been exceeded. The Commission is of the view that it is appropriate that meters with MD capabilities be installed at locations with an MIC of 50kVA and above. In many cases, however, TOU meters with a lower threshold level may have MD capabilities, and these should be used for MD monitoring purposes.

Table 2.5 MFM Meter Threshold

Current customer category	**Annual Extra Material Cost**	**Threshold at which TOU benefit>cost**
Domestic, single phase	€12.20	5,000 kWh
General Purpose 3-phase	€12.40	10,000 kWh

These threshold levels in the table may be on the conservative side. As part of the calculations, electricity price elasticities were used for the General Purpose and Domestic customer groups. The values used were conservative, and as a result the benefits may be understated. Nevertheless, any assumptions around customer responsiveness to pricing structures are inherently difficult to quantify and are subject to qualification. For example, the price differentials between pricing periods, the length of those periods, the amount of discretionary consumption, customer awareness and the type and number of appliances at a site will all influence consumption behaviour. The volume of literature on the subject illustrates the wide range of results that can be achieved according to different circumstances.

The exercise was repeated to evaluate the benefits of meters with two tariff registers, such as the current Day-Night meters. This type of meter can support a peak/off-peak tariff structure. NERA identified peak hours in such a structure as being weekdays from 16.00 - 21.00. The annual cost of a two-register meter is only slightly higher than that for a 24hour meters, but the price differentials over two periods are less than the differentials over three period; as a result, the benefits of introducing two-register meters equalled the extra costs of such meters at threshold levels similar to those for TOU meters.

In light of these findings it is clear that the slightly higher costs of TOU meters may not be a major deterrent to their introduction. These extra costs can be outweighed by the benefits brought about by the change in consumption patterns that TOU tariffs incentivise.

Beyond the higher cost of TOU meters there are a number of further areas where the introduction of TOU tariffs may impose additional costs. The DSO has informed the Commission that the extra administration costs can be broken down to the following areas:

- Upskilling of Network Technicians – A requirement to train NTs in the installation, operation and reconfiguration of these meters.

- Purchase of Additional Hardware – Laptops and software required to support TOU meters

- Enhancement and Data Configuration of IT systems

- Meter Reading Process – There may be a need to introduce probe reading in parallel with TOU tariffs.

- Increased back office procedures – The more complex data will require a more complex business process to support additional validation and DUoS Billing.

In addition, the timing of any installation program for TOU meters would have different cost implications. A gradual "new for old" approach avoids stranded assets but imposes costs from supporting both systems during the transitional phase. A wholesale replacement program involves significant one-off installation costs as well as the costs of stranded assets.

The Commission intends to explore these matters further with industry and the DSO in order to quantify the costs described above. It will then be possible to carry out a thorough cost-benefit analysis that will inform subsequent decisions on the introduction of TOU metering to the market.

The Commission invites comment on the above described metering and billing constraints.

2.5.6 Benefits of TOU tariffs for customers

Under a TOU tariff, all customers are in a position to reduce the energy component of their bill by shifting their consumption pattern. One of the proposed PES TOU tariffs was analysed from an individual customer's point of view, and it was found that the energy component of the bill could be reduced by 5%-10% by shifting the consumption pattern of the customer. TOU tariffs, unlike flat tariffs, give the ability to price sensitive customers to reduce their bill. The likelihood of a customer shifting their consumption pattern will depend on the price incentives on them and also on their ability to change their consumption pattern.

The incentive to change consumption pattern will depend on the difference in the unit price in the different periods; the larger the difference, the greater the incentive. The ability to change consumption pattern will depend on the length of the period and the type of end-use. To illustrate these points, we can take the case of a typical domestic customer.

Let us first of all assume that the peak period price is four times greater than the shoulder price, and that the customer is aware of the large difference in price. Consumption behaviour may then change in two ways. Firstly, the customer may choose to postpone the use of some electrical appliances to shoulder or off-peak hours, rather than use them during peak hours. Examples could include the use of the washing machine, hot water heater or dishwasher. This will be dependent on the timing of the peak period. If the peak period extends to midnight, for example, it would be impractical to do some of the tasks that require electrical appliances after this time. However, if the peak period is reasonably short (ending at 9pm for example), it will still be possible to perform many tasks in the shoulder or off peak periods. A customer who chooses to do so will then avoid the peak unit price and instead pay the shoulder or off peak unit price for the equipment being used, thereby reducing their bill. Commercial customers have less scope for changing their consumption patterns since most of their consumption is non-discretionary – more equipment needs to be running at certain hours, and cannot simply be delayed for a later stage.

Secondly, consumption may be eliminated rather than being shifted to another period. When an average price of electricity is used, there is less incentive to turn off lights or other unused equipment during peak hours. With higher prices in peak hours, customers may achieve significant savings simply by turning off electrical appliances that are not being used. Investment in more efficient light bulbs and appliances in response to time-of-day pricing would also result in an absolute reduction in peak (and perhaps other period) consumption.

Under the assumption that the flat average price reflects the costs of the average consumption pattern, a customer with an average profile who does not change their consumption pattern will have the same energy charges under flat and TOU tariffs. Customers who have different profiles will have higher or lower charges under TOU tariffs, depending on the exact shape of their consumption profiles. However, *all* customers on TOU tariffs will have the possibility of reducing their energy charges by changing their consumption pattern.

Furthermore, under a flat tariff structure, the price during peak hours is below the actual cost in those hours. As a result, peak time use will be higher than if customers were charged the actual cost in those hours. This results in higher average unit prices for all customers, including those with relatively low peak time use. In this sense, TOU tariffs remove cross subsidies and may be viewed as more equitable and in line with the “causer pays” principle.

Table 2.6: Example of savings from consumption pattern shift under TOU tariff	
	Flat rate: 4000 units x .086 = €342

	Winter				Summer		
4000 units:	**Peak**	**Shoulder**	**Off Peak**		**Shoulder**	**Off Peak**	**Energy Charges (€):**
Unit price	.43	.12	.05		.09	.04	
Old consumption pattern	205	549	797		1063	1385	342.46
New consumption pattern	143	510	847		1059	1458	316.17
(All unit prices have been rounded)						Saving:	-26.29 (-7.7%)

The table above reflects consumption patterns over one year. The drop in winter peak consumption of 62 units in this example is the equivalent of 3.6 units per week. Domestic appliances typically have ratings of 2-2.5 kW, so a reduction in the use of such an appliance in the peak period of one hour per week translates into a weekly saving of 2-2.25 units, or an annual saving of 43 peak period units. Similarly, a single 50W light bulb in a vacant room, if turned off for the four peak hours for each of the five weekdays translates to a reduction in use of 1 unit per week or 17 units per winter period. Both of these scenarios are realistic and achievable by customers if they chose to do so.

Such savings are in theory possible under flat tariffs, but there is little incentive and more effort required on the part of the customer to reduce their bill. A TOU tariff with a well-defined peak period greatly increases the likelihood of customers changing their consumption pattern, thereby saving themselves money and reducing peak time demand.

2.6 Customer Impact: Screening of Alternatives

The Commission selected a large number of tariff structures for evaluation, and identified advantages and disadvantages of each[11]. Key elements taken into account in this analysis included:

- Consistency between TUoS and DUoS structure and the charges reflected in PES;
- Consistency with marginal cost structure and incentives for efficiency;
- Avoidance of cross-subsidies;
- Administrative simplicity; and
- Other objectives noted in section 2.1.1

The purpose of screening these tariffs structures is to investigate if the advantages of changing from existing structures outweigh the disadvantages.

Suitable, or promising, alternatives were then screened for impact on customers' bills. 2004 billing determinants were used and 2004 revenue requirements inflated to 2005 to be consistent with the marginal costs, which are stated in 2005 values. In scenarios that involve a change in connection charge policy, assumptions were made assumptions about the change in revenue that would need to be recovered in UoS charges (see section 4.2).

In the marginal cost analysis preliminary pricing periods were selected. Two sets of periods were developed – one for customers with MFM meters which can accommodate multiple periods each month, and another set for customers whose meters can handle only two periods within a month. (See section 2.4.2.2 above).

[11] Alternative tariffs are appraised in sections 3, 4 & 5.

3. TRANSMISSION CHARGING

3.1 Introduction

The transmission system comprises high voltage networks used for the bulk transport of electricity from generating stations to substations, from generating stations to other generating stations, from substations to other substations, to or from interconnectors or to final customers. There are over 5800km of transmission lines and cables at voltage levels of 400kV, 220kV, and 110kV. At the 110kV level[12] there are interface stations or exits points between the transmission and distribution system and directly connected customers. There are approximately 1.8 million distribution customers and 20 large directly connected transmission customers. Generators are connected to transmission system at all transmission voltage levels.

ESB National Grid, in its capacity as the Transmission System Operator (TSO), is required to operate, ensure the maintenance of, and develop a safe, secure, reliable, economical and efficient transmission system. ESB Networks, in its role as Transmission Asset Owner (TAO), is responsible for maintaining the transmission system and carrying out construction work in accordance with the TSO's transmission development plan. The costs incurred in carrying out these duties form the basis of the transmission allowed revenues and Transmission Use of System (TUoS) tariffs.

This section on transmission charges (Section 3) discusses:

- transmission marginal costs;
- present transmission connection charging policy and potential alternative options;
- present structure of transmission use of system (TUoS) tariffs and potential alternative options.

This section also provides an overview of the screening and evaluation of the potential alternatives.

For a detailed discussion of the present structure of transmission charges the reader should refer to the paper entitled, *Existing Structure of Tariffs in Ireland: Transmission, Distribution, Supply*, CER/03/298.[13]

3.1.1 <u>Transmission Costs</u>

Transmission costs are currently recovered through a combination of upfront connection charges and annual transmission tariffs:

3.1.1.1 Connection Charges

Connection related charges are predominantly in the form of upfront payments (capital contributions) designed to recover the shallow costs or a

[12] Interface stations between the transmission and the distribution system also exist at the 220kV level in the Dublin region.
[13] This paper can be downloaded from http://www.cer.ie/cerdocs/cer03298.pdf

portion of the costs[14] of network assets that are specifically installed to provide access to users (or small group of users) to the network.

In addition an on-going annual service charge, which covers the annual Operating and Maintenance (O&M) costs of the relevant elements of the customer's connection equipment and the transmission station, is levied on transmission connected generation and demand customers. .

3.1.1.2 Annual Transmission Tariffs

TUoS tariffs recover the costs of all assets that are not recovered through connection charges. The transmission costs currently recovered through TUoS tariffs are categorised under two headings: 'network' and 'non-network' costs (also known as 'wire' and 'non-wire' costs).

Non-network costs of the transmission business are associated with system operation. Network costs are associated with the physical transmission of electricity and are treated as an internal cost of the transmission business.

Non-network costs include the following TSO External Operating Costs:

- Constraints
- Ancillary Services (Operating Reserve, Black Start, Reactive Power)
- Insurance
- Regulatory Levy (TSO & TAO)

Network costs include:

- TSO and TAO Internal Operating Expenditure; and
- TSO and TAO Capital Expenditure.

In 2002 the network costs of the transmission business amounted to 71% of the overall approved revenue requirement, with non-network costs therefore constituting 29%. In 2003 and 2004 this split was 72:28 and 77:23, respectively.

3.1.2 Impact of the new Market Arrangements in Electricity (MAE) on Transmission Network and Non-network costs

The MAE is expected to replace the current interim electricity trading arrangements and is expected to come into effect in 2006. Under the MAE certain non-network costs will no longer be recovered through the TUoS tariff. In addition a change in the recovery method of certain network costs may be warranted under the new market arrangements.

3.1.2.1 Non-Network Costs

It is anticipated that the non-network costs to be recovered through the TUoS tariff will exclude constraint payments and operating reserves to the

[14] Demand customers currently pay 50% of their shallow connection costs upfront.

extent that generators pay for them.[15] These costs may be dealt with through the MAE settlement arrangements. However, in the absence of any detailed assessment of reserve requirements caused by demand at this point, this has been omitted from the base-case revenue requirement used for the purposes of screening tariff alternatives.

3.1.2.2 Network Costs

Some TSO costs, related to system and market schedule and operation, may vary directly with the number of market participants. These costs should ideally be excluded from network costs and levied directly on all market participants (generators and suppliers).

However, at the moment no detailed cost data is available to estimate the portion of these costs that is fixed and the portion that varies with the number of participants.

[15] Reserve costs caused by demand load will continue to be recovered from demand via the TuoS tariff where appropriate (for example in the case of regulation reserve).

3.2 Transmission Revenue Requirement & Marginal Costs

Two key inputs to the evaluation of alternative transmission tariff structures are the transmission revenue requirement and the marginal cost of providing the transmission service.

3.2.1 <u>Revenue requirement</u>

The revenue requirement used to analyse various TUoS tariff alternatives was based on the 2004 revenue requirement as allowed by the Commission, adjusted by an inflation factor of 3.5% and with separate adjustments for:

- the removal of operating reserve costs and constraints from TUoS (recovered through the MAE settlements, as explained above); and
- a change in connection policy for demand users (100% shallow connection costs paid upfront, as opposed to current 50% policy).

These adjustments result in a TUoS revenue requirement for the purposes of this analysis of €226.9 million shown above, which is about 80% of the current TUoS revenues.

3.2.2 <u>Transmission Marginal Costs</u>

Short-run marginal transmission cost is the additional cost of supplying a small increment of transmission service with no addition to transmission capacity. This cost consists of marginal losses and congestion costs, where the latter are the costs of having to dispatch generators out of merit order to get around transmission constraints. An increment of load at certain hours may also trigger longer-term transmission capacity expansion.

Locational Marginal Prices (LMPs) reflect the short-run marginal costs of transmission. LMPs do not reflect the full marginal costs of transmission usage in so much as the long-term marginal transmission costs are not reflected in LMPs and therefore should be recovered through the TUoS tariff.

The marginal transmission costs can be categorised as follows:

- short-run marginal costs of the transmission system (the congestion costs and losses reflected in LMPs)
- marginal costs associated with general expansion of the transmission network (depreciation, return on investment, operation and maintenance expenses, taxes);
- marginal costs of reactive power;
- marginal costs of new connections (assumed to be recovered in 100% shallow connection charges);
- TSO's settlement, market operation and administrative costs.

The typical marginal investment in transmission network capacity was estimated by dividing growth-related incremental investment cost by the kilowatts of peak transmission load that is driving the need for the investment. This typical investment was then annualised and assigned to hours or periods within the year based on a probability of peak analysis that determines each hour's likelihood of being the peak hour. The results by period (in 2004 inflated prices) are shown in Table 3.1 below:

Table 3.1: Marginal Transmission Costs by Period

Time-of-Use	Cent
Winter peak	11.173 cent per kWh
Winter shoulder	0.312 cent per kWh
Winter off-peak	0.006 cent per kWh
Summer shoulder	0.001 cent per kWh
Summer off-peak	No marginal network cost

Costs associated with other ancillary services (i.e., black-start capability and reactive power) will still be recovered through TUoS charges. Black-start capability is not a marginal cost because the need for this service does not change with marginal changes in electricity consumption. To estimate the marginal cost of reactive power, annual payments by the TSO to generators was divided by energy transmitted at the transmission level in 2001 and 2002[16], and the two figures were averaged. The result was 0.06 cent per kWh transmitted (2004 inflated prices).

Some TSO internal costs, such as 'Customer Records and Billing', settlement, participant training, telecoms, etc. are likely to vary with the number of market participants (generators and suppliers) who are the direct customers of the TSO. However, at present no detailed cost data is available to estimate the portion of these costs that is fixed and the portion that varies with the number of participants. As a result a marginal cost estimate was not developed for this element. Additional information will be gained as the market develops.

3.2.3 Transmission Marginal Cost Revenue Gap

If marginal costs were to be charged directly as tariff components, the resulting revenue would fall short of the revenue requirement used for the purposes of this rate structure study. Table 3.2 below shows the marginal cost revenues, the assumed TUoS (after the adjustments mentioned in 3.1.3), and the gap. This gap must be closed when tariffs are set to ensure that the transmission revenue requirement is met. The approach for revenue reconciliation is explained in Section 2.3.

Table 3.2: Transmission Marginal Revenue Gap

Transmission Marginal Cost Revenues	2005 TUoS Revenue Requirement	Marginal Cost Revenue Gap	
2005 € 000	2005 € 000	2005 € 000	%
1	2	(2)-(1)	
130,529	226,888	96,359	42.5%

[16] TSO Revenue Submissions, 2000 and 2003.

3.3 Transmission Connection Charges (Demand & Generation)

Generally connection charges are levied on connecting parties by way of either a deep or shallow connection charging policy. Under a shallow connection policy the connecting customer is charged directly for its respective portion of new assets required to connect it to the transmission system. Under a deep connection policy the connecting customer is charged for both the assets required for connection to the system and all wider system development costs incurred as a result of its connection.

Shallow and deep connection charges are often in the form of an upfront, one-off charge. A deep connection charging policy results in higher upfront charges for the customer and as a result reduces the transmission revenue to be recovered through the TUoS tariff.

3.3.1 Present Policy

Currently generation, transmission-connected demand customers and the Distribution System Operator (DSO) connecting directly to the transmission system are required to pay connection charges. The DSO is treated as a demand customer because the points of connection between the transmission and distribution networks (DSO Exits) impose the same effects on the transmission system as a transmission-connected demand customer.

Historically ESB employed a deep connection charging policy for generation and demand customers. However, the Commission's direction in December 1999 instructed ESB to move to a shallow connection policy. This resulted in transmission-connected demand customers paying 50% of the shallow connection costs upfront, with 50% included in TUoS charges, and transmission connected generators paying 100% of shallow connection costs upfront. In addition generators and demand customers pay an ongoing O&M charge for their connection.

As shallow connection costs are specific to each individual connecting customer, the connection charge levied on an individual customer will depend on the specific configuration required to connect that customer to the transmission system.

Deep or reinforcement costs associated with demand and generation connections and 50% of the demand customer's shallow connection costs are recovered through the TUoS tariff and spread among all users of the network.

3.3.2 Options

The Commission is considering the following options in relation to the future connection charging policy:

a) *Status Quo*

100% shallow connection for generators, 50% for demand customers.

b) Alignment of Demand and Generation Policies

This alternative option involves a change from the present policy to a 100% shallow connection charging approach for both generation and demand customers.

The options for implementing this are as follows:

- a gradual increase from 50% to 100% for demand customers; or
- an immediate increases from 50% to 100% for demand customers.

3.3.3 Screening/Evaluation

3.3.3.1 Advantages and Disadvantages

a) Status Quo

The status quo socialises new customer costs and provides a cross-subsidy to the DSO's connections and large new demand customers from existing customers. 50% is an arbitrary figure and the recovery of only 50% of costs from new demand customers connecting to the transmission system is not necessarily representative of true cost causation, as a result marginal cost-based signals may not be provided and efficiency of connection decisions may be distorted. However, most new transmission-connected demand customers (and the DSO) may be relatively inelastic regarding their choice of location – i.e. electric connection charges may be a small component of the overall operating costs for large demand customers.

b) 100% shallow policy for all customers

A considerable advantage of moving to a 100% shallow connection charging approach for both generation and demand is that it better aligns responsibility for cost with cost causation. This alternative approach should lead to better long-term economic efficiency to the extent that it influences customer location decisions (e.g. the decision as to how close to the grid exit point a new factory should be built).

In addition, with the absence of cross-subsidies (from the high-connection cost users to low-connection costs) the TUoS charges, that now recover the residual fifty percent of connection costs, should fall over time, and the TUoS revenue requirement should better reflect marginal network costs.

If a 100% shallow policy were implemented, there could be two possible mechanisms:

- *An Immediate Change to 100% Shallow Connection Policy:*

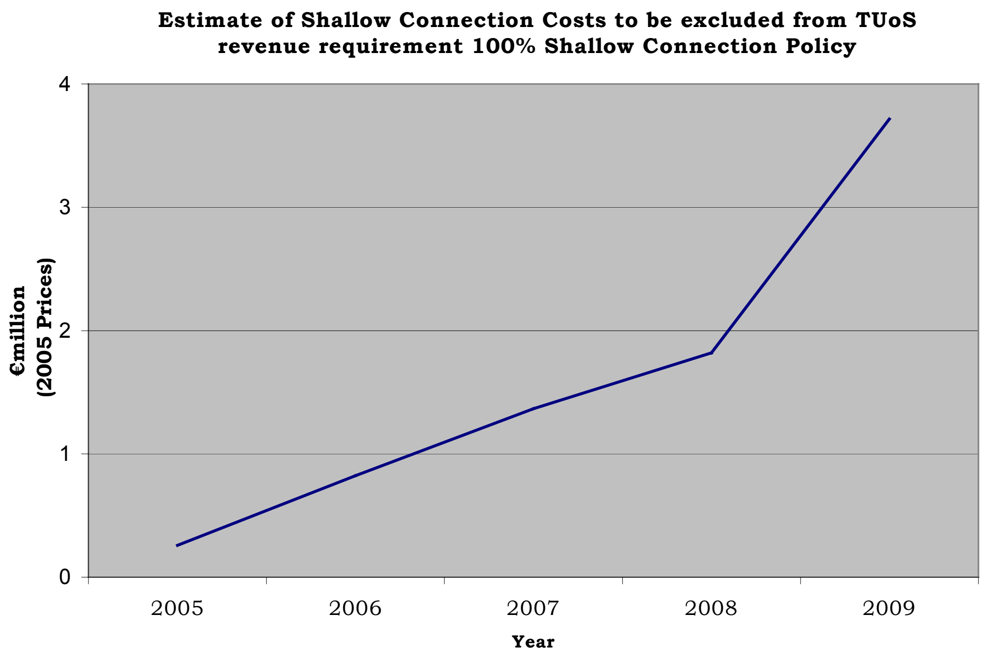
The advantage of an immediate increase from a 50% to a 100% shallow connection charging approach for load is that it would alleviate the efficiency and fairness concerns of the current policy, and the option has no direct rate impact on existing customers who are already connected. The disadvantage of a 100% shallow connection-charging approach to both generation and demand customers is that it may have a large bill impact for potential new transmission-connected customers with high connection costs. However, the expected number of new transmission-connected demand customers is small.

- *Gradual Change to 100% Shallow Connection Policy*

The advantage of a gradual increase from a 50% to a 100% shallow connection charging approach for demand is that the impact would be scaled back and result in a lower financial burden as compared to having to pay all the costs up-front. The disadvantage is that it might add unnecessary complexity and might unnecessarily delay the efficiency and fairness improvements. It might also provide perverse incentives to accelerate connection dates of future projects to fall within the timeframe before the connection charge increases take place.

The effect of changing from 50% shallow to 100% shallow connection charges for demand users is reflected in Table 3.3 below, which shows the estimated reduction in the revenue requirement for TuoS charges over the next 5 years. The increase in demand contributions from transmission customers and the DSO, is based on historical capital expenditures for the years 2001-2005 applied over the period 2005-2009. The higher connection charges should reduce TuoS revenue requirements and this effect will grow over time.

Table 3.3: Effect in Reduction of Connection Cost Recovery through TUoS charges Under a 100% Demand Shallow Connection Policy



3.3.4 Potential Alternative

The subsidy removal effect for other transmission users is likely to result in a small efficiency improvement effect at first, although the effect should grow over time as the cumulative effects of higher connection revenues put downward pressure on the TUoS revenue requirement. The effect is likely to be diluted when spread over all TUoS charges, as the amounts of money involved with connections are likely to be small relative to the total transmission revenue requirement.

Nonetheless given the efficiency, equity and consistency benefits of this change, the Commission favours the adoption of a 100% shallow connection charging policy for demand customers, including the DSO.

The Commission invites comments on the alternative transmission connection charges outlined above.

3.4 Transmission Use of System (TUoS) Tariffs

The TUoS charging regime is designed to recover the total allowed costs of the transmission business (net of connection charges revenue) from all users of the transmission network. The allowed revenues comprise the network and non-network costs of constructing, operating and maintaining the transmission network in Ireland.

3.4.1 <u>Generation/Demand Allocation</u>

Harmonisation of transmission tariffs across Europe, and in particular within European regions, in terms of the generation and load components, is currently being pursued at a European level to promote the internal market in electricity and cross border trade. Ireland, Northern Ireland and England & Wales[17] currently have a similar split in generation and load components of the transmission tariff. In light of Ireland's commitments to work towards the achievement of this goal the Commission does not propose any changes to the present policy, as discussed below.

3.4.1.1 Present Policy

As mentioned in Section 3.1.1.2, in the existing transmission tariff structure the costs of the transmission system are split into two distinct categories: network and non-networks costs.

Of network related costs 25% are recovered from generation and the remaining 75% are recovered from demand users (via suppliers) through both capacity and energy-based charges.

In addition, approximately 99.5% of non-network related costs are recovered from demand users through a System Services Charge. The small proportion of these costs recovered from generation is by means of a generation direct trip charge and fast wind down trip charge.

3.4.1.2 Options Affecting the Split of Costs between Generation and Demand

Notwithstanding the Commission's decision to continue with the existing allocation of network costs among generation and demand users, there may be changes in the specific cost elements defined as "network costs" for which an alternative allocation may be appropriate, or alternative allocations of non-network costs between generation and demand. Alternative options are set out below:

a) <u>Status Quo</u>

The current allocation of transmission costs – a 25%/75% split of network and a 99.5%/0.5% split of non-network costs.

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[17] Refer to Section 2 of CER/04/101 at http://www.cer.ie/CERDocs/cer04101.pdf for international comparisons.

b) *Defining some of the current network costs as "Market-Participant costs", and recovering them through a separate Market Participant Charge.*

This option involves the introduction a separate charge to recover market-participant (generator and supplier) related costs, on a monthly basis. These costs, discussed also in Section 3.1.2.2, are not directly related to the physical network and are considered to vary with the number of market participants (e.g. customer records and billing, settlement, telecoms, participant training costs etc.) A market participant charge should be structured to capture the marginal market-related costs from all participants in an equitable and cost reflective manner.

At present no detailed cost data is available to estimate the portion of these costs that is fixed and the portion that varies with the number of participants. Additional information will be gained as the market develops. Therefore this charge has not been screened at this point.

However, the Commission welcomes comments on the following policy issues:

- What is the appropriate allocation of market participant costs between generation and supply?
- Should all generators be considered market participants or should a *de minimus* threshold be applied?
- Should market participants incur the cost as a fixed or variable charge? For example should it be a fixed standing charge, a fixed capacity charge or a variable energy charge, or some combination thereof?

c) *Allocate part of the network costs related to reactive power equipment to generators through a power factor surcharge.*

This option involves allocating the amount of reactive power costs to generators. This could take the form of a low power factor surcharge, a charge or penalty for the excess amount of reactive power that is consumed. The surcharge or penalty would be designed to recover the marginal cost of reactive power equipment such as Static Var Compensators (SVCs) or capacitors incurred as a result of the absorption of reactive power by generators.

d) *Allocate other non-network costs (in addition to reactive power) to Generators.*

This option looks at an alternative allocation of the remaining non-network costs (under MAE), e.g. Black start, TSO insurance etc.

3.4.1.3 *Evaluation of Alternatives as compared to Status Quo*

a) *Allocation of part of current 'network costs' to generators, through a Market Participant Charge*

The main advantage of recovering market-related operation costs in the same way as other network costs, that is the status quo, is that it is simple. The main disadvantage of the status quo is that some market and system operation costs are inevitably a direct function of the number of participants in the market.

The advantage of setting a separate market participant charge that intends to recover these costs is that it can result in an efficient and fair allocation since it charges the marginal cost of participation

The disadvantage arises if market operation costs are largely fixed[18] (and many of them are: software costs, hardware costs, billing systems, staffing levels, credit costs, and so on) as the average cost per participant is likely to be much higher than the marginal cost per participant. Charging the average cost to each participant would put small participants at a distinct disadvantage which could discourage new entry of small participants an outcome which the Commission is not in favour of. Therefore, any market participant charge would need a rigorous analysis of the incremental costs related to access to the market. This analysis should be possible as the market develops.

b) *Allocation of part of Reactive Power costs to Generators through a Power Factor Surcharge*

It is likely that there is some scope for allocation of certain reactive supply and voltage control costs to generators because generators can be directly responsible for the system operator incurring additional reactive power costs on the margin. Allocation of some reactive power-related costs to generators has precedents in other countries. For example, it is relatively common for the market rules to specify:

- A "leading power factor" and "lagging power factor", which are measures of target production and absorption of reactive power by a generator; and
- Payments that a generator must make whenever it operates outside of these ranges when not instructed to do so. These payments reflect the expectation of extra costs the system operator will have to bear as a result of the generator operating outside of the target range.

c) *Allocation of other non-network costs to generators*

The advantage of the status quo regarding the allocation of non-network costs (approx. 99.5% on demand) is that it is a relatively simple and efficient

[18] Or alternatively, related generally to the size of the market and not the number of participants in the market.

means of allocation, and keeping the status quo would minimize rate impact effects.

In addition, recovery of non-network costs from both demand and generators may only improve efficiency if:

- the costs are a function of participant behaviour;
- the charges are levied on the same basis that they are incurred (i.e., per participant or per kWh or per kVarh) and
- the charges for generators do not exceed the level of marginal cost (e.g., generators' contribution to market operation costs and reactive power costs.)

Other than some of the marginal cost of reactive power, the *Marginal cost study* did not find the costs related with the remaining non-network costs to be marginal with regard to any measurable billing determinant. Some reactive power requirements are caused by demand load and generators, while some are a function of the transmission system design. For the most part, black start and reactive power costs are not directly proportional to the activities of individual participants.

The disadvantage of allocating non-marginal network costs to generators is that it would impose additional fixed cost on them which would be passed through to demand load via the market price in any event. However, such a mechanism could potentially run the risk of changing generator behaviour, and thus distorting dispatch decisions and consequently market prices.

3.4.1.4 Screening

The Commission is minded that non-network costs should continue to be levied on demand users through a System Services Charge. The quantification of this charge and its preferred structure is covered in Section 3.4.3.

In addition to the system services charge, recovery of the market participant-related costs (currently recovered as network costs) would be recovered through a market participant charge through both generators and suppliers, once the appropriate cost levels are assessed. This charge has not been screened at this point.

The Commission invites comment on the allocation of transmission network and non-network costs between generation and demand.

3.4.2 Generation TUoS Categories & Detailed TUoS Structure

3.4.2.1 Present Policy

The TUoS charges applicable to generators are set out in the Generation Transmission Service (GTS) schedule in ESBNG's annual Statement of Charges.[19] The GTS schedule recovers 25% of the annual transmission network costs and recognises two distinct categories of generators:

- Tariff Schedule GTS-T applicable to generators connected directly to the transmission system; and
- Tariff Schedule GTS-D applicable to generators greater than or equal to 10MW connected indirectly to the transmission system via the distribution system.

Generators face TUoS charges on the basis of their contracted Maximum Export Capacity (MEC) and connection location. This charge is referred to as the 'Generation Network Location-Based Capacity Charge' and is calculated using the *Reverse MW-mile approach*.

This approach allocates a share of the annual costs of the network[20] to the generator based on its usage of the transmission system, reflecting the fact that cost depends on the distance and direction that power is being transmitted as well as the level of power being transmitted. The methodology rewards generators that offset network flows and allocates the cost of unused capacity that exists in the network across all users.

The Commission understands that the approach allocates approximately 12% to 15% of network costs to generators. Therefore, there is an uplift required to recover the 25% of costs allocated to generators, meaning that approximately 40% of the generation TUoS charge is non-locational.

Generators under the above schedules also pay a small portion of non-network costs via a direct trip and fast wind-down trip charge. This charge is levied on per MW basis of trip output in excess of 100MW.

3.4.2.2 Options - Categories

The Commission is considering the following options:

a) Status Quo

As discussed in section 3.4.2.1 above – separate categories for transmission-connected generators and one for distribution-connected generators >10MW.

[19] The 2004 Statement of TUoS Charges can be downloaded from: http://www.eirgrid.com/EirGridPortal/uploads/Regulation%20and%20Pricing/TUOS%20-%20statement%20of%20charges%202004.pdf

[20] The Costs include Depreciation, Operations and Maintenance and a Rate of Return.

b) *Combined Generation Category*

Under the current tariff structure the GTS-T schedule and the GTS-D schedule are not substantially different. In fact the single difference is the threshold of 10MW applied to distribution-connected generators. All generators are subject to the same trip charges and reverse MW mile methodology used to derive the capacity charge. Furthermore, a participant-related cost would be incurred by both types of generators. For this reason it may not be necessary to differentiate between categories of transmission and distribution connected generators.

3.4.2.3 Evaluation

Status Quo compared to a combined generation tariff

The marginal cost study assumes that the transmission marginal costs to be recovered through TUoS tariffs are not marginal with regard to generation export capacity, but rather to the growth in system peak demand. Therefore, the nature of the costs charged to generators should not vary with the voltage level they are connected to. A combined generation TUoS class seems appropriate.

The Commission invites comment on the transmission generator categories as outlined above.

3.4.2.4 Options – Generator Structural Components

The Commission is considering the following options in relation to the structure of the Generation Transmission Tariff:

a) *Status Quo*

As discussed in section 3.4.2.1 above - locational tariffs based on MEC, plus trip charges.

b) *Locational Tariff with adjustments*

This option assumes that the existing reverse MW mile based locational tariff remains. In addition to this, the Commission is considering measures to reduce the variability of the annual charge. The Commission is considering three options to implement this:

i) a rolling 4-year average tariff: [21] or
ii) a once-off locational tariff determined by the TSO at the time of connection; or
iii) a cap or ceiling on the change in any one year.

c) *Postalised Charge*

[21] For example, using 2001 to 2004 Generation tariffs to set charges for 2005.

This option involves the introduction of a postalised or flat capacity charge with no geographic, seasonal or time-of-day (TOD) components.

d) *Other elements of the GTS schedule*

These options propose changes to individual elements of the GTS schedule

i) Applicable Threshold
ii) Trip Charges
iii) Unauthorised Usage Charge
iv) Market Participant Charge
v) MEC Administration

3.4.2.5 Evaluation & Screening – Generator Structural Components

a) *Status Quo: Locational Capacity Charge*

One advantage of a maintaining a locational-based tariff is that it preserves the status quo and could therefore minimise regulatory uncertainty on the part of generators.

One disadvantage is that a locational-based tariff based on a dynamic transportation model may be difficult for a generator manage in terms of risk if it varies considerably on a regular basis. If the total (long-run) marginal cost of transmission is also charged, implicitly by virtue of the way the transportation model works, then costs would be double counted. New Zealand has used locational based transmission charging with LMP. Some US regions have intra-regional differences in the load TUoS equivalent, however, these are a legacy of historic costs of vertically integrated utilities. However, implementing a locational approach that gives signals regarding location-related long run marginal costs may be difficult to achieve.

The current policy adjusts the results of the transportation model so that total capacity revenue from generators matches the 25% allocation of network-related TUoS revenue requirement to generators. Given this uplift the result is a somewhat diluted set of locational charges.

b) *Locational Charge with adjustments*

i) Rolling Average: The variability of the locational capacity charge would be spread over 4 years by way of a weighted or simple average. However, even if smoothed as a 4-year rolling average the cost to a generator could change substantially from year to year and the generator could not easily hedge those cost changes.

ii) Once-off Charge: Another variation of the locational option is that the system operator could calculate the charges at the time of connection. Whatever charge that was in place in a location the year a generator was connected at that location would apply for the life of that generator. This would solve the price uncertainty issue.

However, this approach would raise a number of other issues that would need to be considered. For example, the system operator, in setting the locational charge each year, would need to take an expectation of how the locational value would change in *subsequent* years; this in turn would be a function of who builds what, where they build it and when they build it. It would be much as if the system operator was taking a position in the market by guessing how market participants will react to its decisions. Rather than have market participants take locational risks – which is one of the key reasons for competition in the first place– the central planner would be taking these risks, which would result in an inefficient market outcome. Consumers would receive the benefits of good central planning decisions, and consumers (not generators) would pay the cost of bad central planning decisions. Another problem with the once-off setting of capacity charges is what charge to apply to existing generators.

iii) Cap on Increase: Similar to the rolling average method a cap would still expose the generator to some, albeit limited, risk. A cap on percentage increases or one linked to ranges of absolute changes could be used. There may also need to be a floor placed on decreases in applicable tariffs to ensure adequate recovery of transmission revenues. However, the decision on the size of the cap or floor would be necessarily arbitrary. Given the level of detail required this option has not been quantitatively screened.

Table 3.4 shows the impact of adopting options i) and ii) on the existing generation tariff. For the analysis of the rolling average option a weighted average was used, with greater weight placed on the most recent years' tariffs. For the screening of the once-off tariff option 2001 generation tariffs were assumed to represent the once-off locational tariff. For generators who have connected after 2001 the first applicable tariff was used.

c) Postalised Capacity Charge for Generators

The main advantages of a postalised tariff are that it is simple, transparent, and predictable. The postalised generation tariff is also the structure followed in Northern Ireland.

One disadvantage of a postalised tariff is that there would be a difference in approach between Britain's transmission pricing and Ireland's.

The customer currently pays for deep reinforcements on the transmission system but has no control over these costs. This would suggest that there should be a signal providing a disincentive to generation locating in unsuitable (e.g. congested) areas. The removal of such a signal from the TUoS generator charges is another disadvantage, but to the extent that LMPs are able to capture geographical differences, the economic incentives for efficient generation location would be preserved.

Table 3.5 shows a comparison of the annual 2004 locational capacity charges for each Generator (above 10 MW) compared to what the annual capacity charges would be under a postalised capacity charge (all figures in 2005 Prices). The tariff screening exercise resulted in a postage stamp capacity TUoS charge for generators of €751.09. It is important to note that as the locational charges have been variable, a one-year comparison does not provide a complete picture.

Table 3.4: Locational Capacity Charge with Adjustments

Station	Capacity	Existing Locational Tariff (2005€)	4-Year Rolling Average of Locational Tariff (2005€)	Change from Existing Tariff	Once-off Locational Tariff (2001 Charge*) (2005€)	Change from Existing Tariff
	(MW)	€/MW/Month	€/MW/Month	€/MW/Month	€/MW/Month	€/MW/Month
Aghada	528	672.59	654.99	17.61	715.24	-42.65
Ardnacrusha	85.5	-30.67	-24.93	-5.74	25.99	-56.66
Bellacorick	36.8	9.56	-527.52	537.08	-810.01	819.57
Edenderry	117.6	416.69	536.80	-120.11	551.27	-134.58
Erne	45	78.47	-874.88	953.35	-1312.09	1390.56
Erne	20	112.41	-534.92	647.33	-1278.98	1391.39
Golagh	15	342.45	100.72	241.73	342.45	0.00
Great Island	114	256.07	186.67	69.40	171.81	84.26
Great Island	112	340.58	306.46	34.12	317.60	22.98
Huntstown	352	593.07	324.42	268.65	593.07	0.00
Irishtown	400	800.75	715.99	84.75	625.71	175.03
Lanesboro	128	288.64	-198.30	486.93	-511.53	800.16
Lee	8	434.04	302.50	131.55	304.71	129.34
Lee	19	513.99	340.07	173.92	283.69	230.30
Liffey	30	585.47	551.34	34.13	521.29	64.18
MARIG1	112.3	415.85	398.78	17.07	431.92	-16.07
Moneypoint	862.5	1154.15	1075.29	78.85	1038.74	115.40
Northwall	44	522.49	354.18	168.32	156.16	366.33
Northwall	227	1304.48	1074.74	229.74	804.83	499.65
Poolbeg	486	1077.32	1064.43	12.89	1068.88	8.45
Poolbeg	457	815.99	724.63	91.36	626.03	189.96
Shannonbridge	37	10.69	-71.03	81.72	-93.99	104.68
Shannonbridge	77.5	144.95	11.77	133.18	-36.74	181.69
TARBG1	114	741.51	677.20	64.31	698.04	43.47
TARBG3	481.4	822.05	734.12	87.92	732.57	89.48
Turl_Hil	292	914.18	852.22	61.96	802.40	111.78
Cunghill	23.8	0.00	0.00	0.00	0.00	0.00
Derrybrien	60	277.80	81.71	196.10	69.45	208.35
Meentycat	43.6	250.80	73.76	177.03	62.70	188.10
Seorgus Wind	15	373.99	312.23	61.76	373.99	0.00
Cark Wind	15	156.35	156.35	0.00	156.35	0.00
Culliagh Wind	11.9	156.35	156.35	0.00	156.35	0.00
Carnsore Wind	11.9	72.21	72.21	0.00	72.21	0.00
Arklow Wind	25.5	334.83	334.83	0.00	0.00	334.83
Raheen Barr Wind	18.7	0.00	0.00	0.00	0.00	0.00
Moanmore Wind	12.6	0.00	0.00	0.00	0.00	0.00
Gartnaneane	10.5	42.50	42.50	0.00	10.63	31.88
Beam Hill Wind	14	183.76	183.76	0.00	45.94	137.82
Sorne Hill Wind	31.5	183.76	183.76	0.00	45.94	137.82
Richfield Wind	20.3	72.21	72.21	0.00	18.05	54.16
Aghada	52	675.00	675.00	0.00	675.00	0.00
Tawnaghamore	52	27.11	27.11	0.00	27.11	0.00

* Or year of commissioning if after 2001

Table 3.5: Postalised Capacity Charge for Generators

Station	Capacity	Existing Locational Generation Tariff (2005€)	Proposed Postalised Charge (2005€)	Impact from Postalised Charge	
	(MW)	€/MW/Month	€/MW/Month	(%)	€/MW/Month
Aghada	528	672.59	751.09	11.7%	78.49
Ardnacrusha	86	-30.67	751.09	-2548.9%	781.76
Bellacorick	37	9.56	751.09	7759.5%	741.53
Edenderry	118	416.69	751.09	80.3%	334.40
Erne	45	78.47	751.09	857.2%	672.62
Erne	20	112.41	751.09	568.2%	638.68
Golagh	15	342.45	751.09	119.3%	408.64
Great Island	114	256.07	751.09	193.3%	495.02
Great Island	112	340.58	751.09	120.5%	410.50
Huntstown	352	593.07	751.09	26.6%	158.01
Irishtown	400	800.75	751.09	-6.2%	-49.66
Lanesboro	128	288.64	751.09	160.2%	462.45
Lee	8	434.04	751.09	73.0%	317.04
Lee	19	513.99	751.09	46.1%	237.10
Liffey	30	585.47	751.09	28.3%	165.61
MARIG1	112	415.85	751.09	80.6%	335.23
Moneypoint	863	1154.15	751.09	-34.9%	-403.06
Northwall	44	522.49	751.09	43.8%	228.59
Northwall	227	1304.48	751.09	-42.4%	-553.39
Poolbeg	486	1077.32	751.09	-30.3%	-326.24
Poolbeg	457	815.99	751.09	-8.0%	-64.90
Rhode					
Shannonbridge	37	10.69	751.09	6922.8%	740.39
Shannonbridge	78	144.95	751.09	418.2%	606.14
TARBG1	114	741.51	751.09	1.3%	9.58
TARBG3	481	822.05	751.09	-8.6%	-70.96
Turl_Hil	292	914.18	751.09	-17.8%	-163.09
Cunghill	24	0.00	751.09		751.09
Derrybrien	60	277.80	751.09	170.4%	473.28
Meentycat	44	250.80	751.09	199.5%	500.29
Seorgus Wind	15	373.99	751.09	100.8%	377.10
Cark Wind	15	156.35	751.09	380.4%	594.73
Culliagh Wind	12	156.35	751.09	380.4%	594.73
Carnsore Wind	12	72.21	751.09	940.2%	678.88
Arklow Wind	26	334.83	751.09	124.3%	416.26
Raheen Barr Wind	19	0.00	751.09		751.09
Moanmore Wind	13	0.00	751.09		751.09
Gartnaneane	11	42.50	751.09	1667.1%	708.58
Beam Hill Wind	14	183.76	751.09	308.7%	567.33
Sorne Hill Wind	32	183.76	751.09	308.7%	567.33
Richfield Wind	20	72.21	751.09	940.2%	678.88
Aghada	52	675.00	751.09	11.3%	76.09
Tawnaghamore	52	27.11	751.09	2670.7%	723.98
	5620				

d) Other elements of the GTS schedule

i) Applicable Threshold

TUoS tariffs are not levied on generators connected to the distribution system below 10MW. This option looks at the basis for the 10MW threshold level. This threshold was based on the dispatch threshold of 10MW for generation as set down in the Trading and Settlement Code. [22]

It can be argued that there should be consistent treatment for transmission-connected generators in order to preclude any potential bias towards the distribution system and ensure the equitable treatment of all generators. However, given that distribution connected generators pay deep distribution connection costs (not transmission deep costs) and in most cases make less use of the transmission system for their power output it can be argued that a consistent policy with the transmission system is not necessarily an appropriate one.

It can also be argued that the 10MW threshold should be set at a lower level. This may be a means to recover a greater portion of the deep transmission costs caused by increased penetration of small-scale generation on the distribution system.

An alternative method to ensure recovery of deep transmission costs caused by distribution-connected generators is to charge the Distribution System Operator (DSO) for the associated transmission deep costs. This could in turn be levied on distribution-connected generators through a once off connection charge or Distribution Use of System (DUoS) tariff. Under this scenario distribution-connected generators would not be required to pay separate TUoS tariffs. However, they may be subject to the market participant charge, the merits of which are discussed in section 3.4.1.2(b) and in item iv) below.

ii) Trip Charges

The issues regarding generator trip charge, currently applicable to all generators with a trip output in excess of 100MW, will be considered by the Commission within the MAE process.

iii) Unauthorised Usage Charge (UUC)

Currently demand users (under the DTS-T and the DTS-D1 schedules) are subject to an unauthorised usage charge of €600/MWh of energy transferred in excess of contracted Maximum Import Capacity (MIC). This charge does not currently apply to generators. This option would involve the introduction of an unauthorised usage charge for generators whose maximum output to the network exceeds their contracted MEC.

[22] Paragraph 1.4 Trading and Settlement Code, Version 1.0.

An advantage of this option is that it should encourage generators to choose an appropriate MEC and help the TSO to plan the network efficiently. It is also consistent with the treatment of transmission connected demand users who exceed their MIC.

There are two scenarios in which generators will exceed their MEC. They will be either be instructed by the TSO to do so or they will do so of their own accord. In the former circumstance it would be anticipated that the generator would need to be exempt from the penalty to ensure it is not deterred from providing required additional output, although the MEC should be increased to provide up-to-date information for TSO planners.

Two options are being considered:

a) *Generator UUC*

Under this option the charge would be extended to generators.

b) *MIC UUC* (Similar to Distribution)

A capacity per kVA MIC charge, as opposed to the current energy based charge, would apply to transmission customers. Such a capacity based charge currently applies to distribution-connected customers under the DUoS structure.

iv) Market Participant Charge

Market participant costs are incurred by the TSO in providing billing, scheduling and settlement services. The purpose of a market participant related charge would be to ensure that the marginal market costs of market settlement and billing are recovered on a cost reflective basis. A separate charge to recover market-participant related costs as discussed in section 3.4.1.2(b) would apply to generators (and suppliers) who are responsible for these costs being incurred.

v) MEC Administration

ESBNG's Maximum Import capacity (MIC) administration policy was approved by the Commission in 2003. This allows transmission connected demand customers to reduce their MIC as their requirements reduce over time but incentivises that sufficient notice be given before doing so. This policy is designed to avoid unnecessary stranding of transmission assets by encouraging demand customers to reserve capacity that is legitimately required. The policy also acts as a means of protecting the general TUoS customer from additional costs incurred as a result of MIC reductions.

However, the principles of this policy do not currently apply to generators seeking a reduction in MEC. This option involves extending a similar policy to cover transmission-connected generators.

MEC requirements can change over time and in the absence of a clear mechanism to address changes the need for an MEC administration policy should be addressed. The purpose of implementing a formal policy would be to reduce the exposure of the general TUoS customer from unanticipated revenue under-recoveries which feed through to higher tariffs. The policy would also act to ensure consistency with the treatment of transmission-connected demand customers.

The Commission invites comment on the alternative transmission generator structural components.

3.4.3 Demand TUoS Categories & Structure

3.4.3.1 Present Policy

The TUoS charges applicable to demand users are set out in the Demand Transmission Schedule (DTS) of ESBNG's Statement of Charges. The DTS recovers 75% of the annual network costs and approximately 99.5% of non-network costs. For billing purposes the DTS associated charges are levied directly on suppliers. The DTS schedule has three categories:

- Tariff Schedule DTS-T applied to suppliers serving demand users connected directly to the transmission system;
- Tariff Schedule DTS-D1 applied to suppliers serving demand users connected to the distribution system and having a MIC of 0.5MW or above;
- Tariff Schedule DTS-D2 applied to suppliers serving all other demand users connected to the distribution system not served under DTS-T or DTS-D1.

Demand TUoS charges are levied through capacity and energy charges according to the user's category. Capacity charges are based on the maximum import capacity (MIC) of the demand user (measured in MW), whilst the energy charge relates to actual usage (measured in MWh).

In terms of network cost recovery, suppliers with customers under DTS-DT and DTS-D1 face both a flat capacity charge (the Demand Network Capacity Charge), and an energy based charge (the Demand Network Transfer Charge). The capacity based charge constitutes 60% and energy 40% of the network costs allocated to this group. However, suppliers with customers under DTS-D2 face a pure energy charge as a proxy for an MIC based capacity charge as a result of the absence of MIC values. This charge is based on metered energy consumption during day hours.[23] (68% of distribution delivered energy is transferred during day hours). DTS-D2 is levied based on profiles of demand customers.

The current demand capacity charge contains several elements that recognise that total network capacity will not always be required. This excess capacity is built into the system for contingency purposes to provide security of supply. The following adjustments are made to the capacity determinant of the demand capacity tariff:

- Switching Capacity Surplus There is additional capacity built in at exit points from the transmission system for the purpose of distribution contingency switching. Therefore, this means that the sum of all MICs of distribution-connected demand customers does not equal distribution transformer capacity at the transmission exit points or bulk supply point (BSP). Currently BSP capacity is estimated to be 6813MW for the distribution system. An arbitrary switching factor adjustment of 28% is applied to arrive at 4905MW, the base capacity for which distribution connected demand customers are billed, with two additional adjustment as described below.

[23] 08:00 to 23:00 Hours

- Charging Bandwidth Adjustment: A transmission and distribution demand user reducing its overall demand either temporarily or permanently and thus not using its full MIC will pay lower capacity charges as a result of the structure of network capacity charge which incorporates a bandwidth. The bandwidth rules provide a range of tolerance[24] in respect of the total capacity charges which users are liable to pay under periods where demands are less than their MIC.

- Distribution Diversity Factor: A forecast load or capacity factor is also calculated and used to arrive at the final distribution capacity charge. The factor is calculated by means of the Bary curve which estimates a relationship between a demand user's load factor and its individual maximum demand coincidence with the system maximum demand. The result is a coincidence factor of 0.889, which reduces the base capacity charge.

In terms of non-network cost recovery, suppliers are charged on an energy basis through a System Services Charge (SSC).

In addition, customers under DTS-T are also subject to an unauthorized usage charge. For planning purposes it is important for the TSO to have an accurate estimate of the maximum demands imposed by large customers. This charge provides an incentive for large customers to keep the TSO informed of any growth in their peak demands.

3.4.3.2 Options – Categories

The Commission is considering the following options with respect to demand categories:

a) Status Quo

As discussed above, there is one category for transmission-connected demand users and two for distribution–connected customers, based on metering functionality.

b) Bill DSO and transmission connected demand users as direct demand customers

This option involves treating the DSO as a demand customer of the transmission system for TUoS charging purposes. This would mean that the DSO would be charged directly under the DTS-DT or similar schedule based on the contracted capacity and/or metered energy of each exit point from the transmission system. In turn the DSO would apply this charge to suppliers through DUoS tariffs. Transmission connected demand customers would continue to be charged directly by the TSO.

[24] A demand user whose MIC is less than 20 MW and highest metered demand is less than 80% of their MIC will be charged based on 80% of their MIC. A demand user with an MIC value greater than 20 MW will be charged based on their MIC value minus 4 MW, providing highest metered demand does not exceed this.

c) *Amalgamate DTS-D1 and DTS-D2 Schedules into a single DTS schedule (revision of metering technology required).*

This option would allow all distribution-connected demand users to be charged on a consistent capacity or energy basis.

3.4.3.3 Screening - Customer Categories

a) *Status Quo*

The advantage of maintaining the status quo is that it reduces the cost impact of changes in metering equipment that may be required to implement changes of customer categories. The disadvantage of maintaining the status quo is that the perception of an unnecessarily complex demand tariff structure may remain if capacity charges are in place. In particular, the use of energy charges as a proxy for capacity charges in the case of DTS-D2 users has been highlighted in the Commission's consultation on the existing tariff structure as a source of confusion and unclear price signals. [25]

b) *DSO and transmission connected demand users as direct demand customer for billing purposes*

This option would provide clear signals to the DSO with respect to investment decisions concerning its exits from the transmission system. It would also reduce the administrative burden of TUoS tariffs for small suppliers, which may be of some benefit to suppliers.

The alternative of establishing two categories of demand customers, transmission-connected users and DSO interface points, would also simplify billing from a TSO perspective, but would make it very difficult to effectively pass TSO costs through to the DSO and in turn to suppliers.

c) *Amalgamate DTS-D1 and DTS-D2 Schedules into a single DTS schedule (revision of metering technology required)*

The advantage of this option is that it ensures the consistent treatment of all distribution connected demand users. However, combining the two distribution-connected user categories would either require complex metering (demand metering or some form of TOU metering) of all customers, or would limit the TSO structure options that could be applied to the combined class.

3.4.3.4 Potential Alternative – Categories

In the screening of alternative structures as discussed in section 3.4.3.6 below current demand categories are assumed to continue, with a minor modification. There would be two major TUoS categories:

[25] Refer to *Existing Structure of tariffs in Ireland: Response Paper*, CER/04/100, 09 March 2004. This paper can be downloaded from: http://www.cer.ie/cerdocs/cer04100.pdf

a) *Transmission-connected demand users;* and

b) *Distribution-connected customers* – divided into two sub-categories, depending on the type of metering equipment:

   i. Distribution-connected customers with interval (TOU) energy metering, and

   ii. Distribution-connected customers with no TOU metering capability.

The Commission invites comment on the transmission demand categories outlined.

3.4.3.5 Options – Structure

The Commission is considering the following options with respect to the structure of the demand TUoS Tariff:

Network Charges

a) *Status Quo*

As discussed above, a combination of capacity and energy charges for DTS-T and DTS-D1 customers, and energy-only charges for DTS-D2 customers with no seasonal or time-of-day (ToD) components.

b) *Alternative 1 (T1): Time-differentiated Energy Charges*

This tariff structure would incorporate both seasonal and time of day components in an energy only charge. Customers without TOD metering would pay only seasonally differentiated per-kWh charges. The charges would be based on marginal costs and would signal the relative cost of consumption in the various pricing periods.

c) *Alternative 2 (T2): Time-differentiated Maximum Demand (MD) Charge Tariff*

This tariff structure would incorporate both seasonal and time of day components for Maximum Demand (MD) customers and seasonal and time-of day energy charges (or seasonal-only energy charges) for remaining customers (refer Section 2.4.2.2 (e) for a discussion on demand charges).

d) *Alternative 3 (T3): Maximum Demand and Energy Charges*

This tariff structure would incorporate both seasonal and time-of-day Maximum Demand and Energy charges. An arbitrary split would be required, for example 70% energy/30% demand. In the case of customers with no maximum demand meter, only seasonal and time of day energy charges would apply (refer Section 2.4.2.2 (e) for a discussion on demand charges).

e) *Alternative 4 (T4): Flat Capacity Charge and Time-differentiated Energy Charges*

This tariff structure would incorporate both a flat capacity charge per kW of MIC, and an energy charge with a seasonal and time of day component (or seasonal energy component only for customers with no TOD metering capability). An arbitrary split would be required, for example 70% energy/30% demand.

Non-network Costs

a) *System Services Charge:* This charge is currently designed to recover all non-network costs of the transmission business, including operating reserves and constraints. Under the MAE operating reserves and constraint costs are assumed to be excluded for the purposes of the screening of this tariff. This option assumes that remaining non-network costs continue to be recovered through a flat per kWh charge applicable to all demand users, as in the current TUoS. The System Service charge is shown in Table 3.6 in the screening section below.

b) *Low Power Factor Surcharge:*

This proposed penalty is in addition to the system services charge applicable to transmission-connected demand users. The option examines placing a penalty on transmission-connected demand users when reactive power consumption exceeds a certain level. Currently the DSO levies a low power factor surcharge on distribution-connected demand on a kVArh basis. This option examines a consistent approach for transmission connected demand users.

3.4.3.6 Screening and Evaluation

b), c), d) & e) The four marginal cost-based demand tariff options (T1 to T4)

To quantify the charges applicable to the four proposed demand-user categories under each of the network charge structures described above, the applicable marginal costs were taken as a starting point.[26] The marginal costs were then adjusted to match the various elements of the revenue requirement.

The reactive-power marginal cost per-kWh (system service charge) was raised to recover the revenue requirement related to External Cost, by multiplying the marginal cost by a constant factor across each customer class.[27]

The network-related marginal costs were adjusted to meet the network-related transmission revenue requirement, by making equal adjustments to energy and maximum demand (where they exist) charges, preserving the relative marginal costs for peak, shoulder and off-peak hours and for the winter vs. summer seasons.

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[26] Refer to Section IV of the *Marginal Cost Study*
[27] Net of operating reserves and constraint costs.

It should be noted that, in those screened options where the structure calls for both energy and demand/capacity charges (T3 and T4), it was determined as an ex-ante constraint that 70% of the demand-user revenue requirement would be allocated to classes on the basis of energy, and the remaining 30% would be allocated on the basis of either peak demand (T3) or MIC (T4) charges.

The *Marginal Cost Study* indicated that transmission long-term marginal capacity costs vary across the hours of the day and year. The time-differentiation analysis assigned the costs to each of these hours based on probability of peak. Thus, a marginal cost-based demand TUoS structure that maximises efficiency would be time-differentiated and could recover costs on an energy-only basis.

On the basis of this principle the marginal cost based tariff option T1 could be argued to be the most favoured because it best tracks the marginal cost structure and has comparable effects on each of the demand user classes (all other options have a relatively high bill impact on DTS-D2].

Alternatively, the current combination of MIC/energy charges could be retained, with the 70% energy and 30% capacity split used for Options T3 and T4 improving the marginal price signals as compared with the current 40% energy 60% capacity split.

A summary of both demand and generation options screened is shown in Table 3.8 below. The results from this screening exercise are shown in Tables 3.9 to 3.15. The tables show the tariffs developed under each of the four options, assuming a Market Participant Charge is levied (Options T1 to T4). The generation options are also summarised.

a) *<u>System Service Charge</u>*

A significant proportion of the current non-network costs are assumed to be dealt with outside of TUoS tariffs (mainly, operating reserves[28] and constraint costs, which account for about 70% of the total current non-network costs). Therefore, even without any reallocation of these costs to generators, and keeping the same structure, the screening model assumes that TuoS charges that currently recover the non-network costs recover a smaller amount of required revenue.

The proposed charges would recover the remaining non–network costs such as costs of black start, TAO insurance, and CER Levy currently recovered through the system service charge. For screening purposes non-network costs are assumed to continue to be levied on demand users through a System Services Charge. Table 3.6 below compares the tariffs that would be required to recover the remaining non-network costs (estimated for screening purposes to be €20.5m) to the existing tariff, which recovers all non-network costs (i.e. including operating reserves and constraints approx. €62.6m).

[28] Operating reserve or regulation reserve required as a result of demand loads will continue to be recovered through the TUoS tariff. This has been excluded for tariff screening purposes given that there is no detailed historical data for this figure.

Table 3.6: System Services Charge			
	Existing Non-Network (System Service Charge) (1)		Proposed Non-Network Related Charges (2)
	Day	Night	(no TOU)
	(€ per MWh)		(€ per MWh)
Demand Users	(1)	(2)	(3)
DTS-T	€ 2.476	€ 2.476	€ 0.987
DTS-D1 (MIC >0.5 MW)	€ 2.549	€ 2.538	€ 1.009
DTS-D2	€ 2.712	€ 2.675	€ 1.044

Notes:

(1) Charges for D1 and D2 are adjusted by current day/night Distribution Loss Adjustment Factors

(2) Charges for D1 and D2 are adjusted by distribution losses factor from MC study. These charges are set to recover the 2005 External Cost except for Operating reserves and Constraints.

b) *Low Power Factor Surcharge*

The advantage of this option is that it sends appropriate cost signals for reactive power utilisation. At present there is no signal to transmission-connected demand users (there is for distribution connected customers). Customers connected to the transmission system previously saw a surcharge under old ESB tariffs and maintained their power factor accordingly therefore this charge is not expected to have material bill impacts, given the existing behaviour of transmission-connected demand users.

It would give incentives for appropriate behaviour on behalf of new customers and prevent a deterioration of the current good practice by existing ones. The surcharge would also mean closer alignment with existing DUoS tariffs[29] by providing a Low Power Factor Surcharge to transmission-connected customers thereby eliminating a perverse incentives for choosing a transmission connection.

ESBNG have proposed two options to the Commission in relation to the possible structure of this surcharge:

i) Charge on a trading period basis when Reactive Power exceeds a certain level and demand load exceeds a certain threshold. In other words if the metered kVArh in any trading period is more than

[29] For non-domestic customers, a Low Power Factor Surcharge of 0.699 - 0.574¢/kVArh applies when the metered kVArh is more than one third of the metered kWh in any two month period. The charge is applicable to the kVArh in excess of one third of the kWh.

32.87% [i.e. pf lower than 0.95) of the metered kWh and energy consumption is greater than 50% of MIC then apply LPFS of 0.32 c/kVarh on the kVarh in excess of one third of the kWh.

This is consistent in structure with the Grid Code which states that a Grid Connected Customer shall ensure that at any load above 50% of Maximum Import Capacity the aggregate power factor as determined at the Connection Point in any half-hour period shall be within the range 0.90 lagging to unity. While the Grid Code provides an absolute technical limit to power factor, it is appropriate for the tariff (which is designed to be cost reflective and not punitive) to commence at the level of 0.95 as this is the assumed power factor when converting parties MICs from MVA to MW.

ii) Adopt similar methodology as DSO for the Low Power Factor Surcharge. This would ensure consistency. The low power factor surcharge applies when the metered kVarh is more than 32.87% [i.e. average pf lower than 0.95) of the metered kWh in any monthly period [DSO use 2 monthly period]. The charge is applicable to the kVarh in excess of one third of the kWh

MVars are currently provided by a variety of sources including network components and generators. ESBNG makes payments to generators for leading and lagging MVars as required and makes capital investment in reactive devices such as SVCs[30] [and capacitors.

When the payment schedule to generators was originally formulated the cost of providing MVarh from static devices was used as the basis for the cost.

The resulting charge is shown in Table 3.7 and could be described as follows: If MVArh > MWh*0.3287 then apply LPFS of 0.30 c/kVarh to the kVarh in excess of 32.87% of the kWh.

Table 3.7: Low Power Factor Surcharge

Reactive Power Surcharge	2005 Prices
Reactive Power payments to generators (€million)	13.8
Total MVarh	4.3
€/MVarh	3.2
Cent/Mvarh	0.32

[30] Static Var Compensators

Table 3.8: Summary of Alternative TUoS Tariffs
▪ TUoS Demand Options - T1: Energy Charge only (seasonal and TOD) - T2: Max *Demand* Charge only (seasonal and TOD) for MD customers; (Seasonal and TOD Energy charge for the rest) - T3: Split between Seasonal and TOD Energy Charge and Seasonal and TOD Demand Charge (for those with no demand meter: Seasonal and TOD Energy Charges) - T4: Split between Seasonal and TOD Energy Charge and flat Capacity (MIC) Charge (no TOD) ▪ TUoS Generation Options Flat capacity charge (MEC) – same all year round

The tables below shows the charges developed under each of the four options (Options T1, T2, T3 and T4). Although a specific market-participant charge was not screened, a proxy for the annual market-related costs (€1.15) was used that would be separately recovered through market participant charges.[31]

The generation options are also summarized.

[31] The proxy for annual market-participant costs was based on the 2002 TSO "Customers Records and Billing", plus a portion of administrative overheads, converted to 2005 prices.

Table 3.9: Option T1

Customer Category	System Service Charge (no TOU)	Network-Related Charges: WINTER P	WINTER S	WINTER Off	WINTER Seasonal-Equivalent	SUMMER S	SUMMER Off	SUMMER Seasonal-Equivalent
	PROPOSED TUOS CHARGES OPTION T1 (100% Energy allocation for Network-related costs)							
	(€/ MWh)	(€ per MWh)						
Demand Users								
DTS-T	€ 0.99	€ 117.950	€ 4.994	€ 1.873	€ 12.380	€ 1.778	€ 1.769	€ 1.774
DTS-D1 (MIC >0.5 MW)	€ 1.01	€ 122.400	€ 5.117	€ 1.877	€ 12.787	€ 1.779	€ 1.769	€ 1.774
DTS-D2	€ 1.04	€ 130.483	€ 5.342	€ 1.885	€ 16.504	€ 1.779	€ 1.769	€ 1.774

Table 3.10: Option T2

Customer Category	System Service Charge (no TOU)	Network-Related Charges: Charges per MWh, WINTER P	WINTER S	WINTER Off	WINTER Seasonal-Equivalent	SUMMER S	SUMMER Off	SUMMER Seasonal-Equivalent	Charges per MW, WINTER P	WINTER S	WINTER O	WINTER Seasonal
	PROPOSED TUOS CHARGES OPTION T2 (100% Demand allocation for Network-related costs)											
	(€/ MWh)	(€ per MWh)							(€ per MW of Max Demand)			
Demand Users												
DTS-T	0.99	-	-	-	-	-	-	-	7,308.35	578.01	-	6,230.17
DTS-D1 (MIC >0.5 MW)	1.01	-	-	-	-	-	-	-	7,595.52	607.34	-	6,481.58
									-	-	-	-
DTS-D2	1.04	200.886	5.575	0.180	22.996	0.015	-	0.007	-	-	-	-

Note: Charges per MW of Max Demand are zero in the Summer.

Table 3.11: Option T3

Customer Category	PROPOSED TUOS CHARGES OPTION T3 Split of Max Demand Charge and Energy Charge (70% Energy allocation for Network-related costs)											
	System Service Charge (no TOU)	Network-Related Charges										
		Charges per MWh							Charges per MW			
		WINTER				SUMMER			WINTER			
		P	S	Off	Seasonal-Equiv.	S	Off	Seasonal-Equiv.	P	S	O	Seasonal-Equiv.
	(€/ MWh)	----------------- (€ per MWh) ---------------							----- (€ per MW of Max Demand) -----			
Demand Users												
DTS-T	€ 0.99	€ 114.826	€ 1.870	€ 0.000	€ 9.912	-	-	-	€ 1,871.53	€ 0.000	€ 0.000	€ 1,447.41
DTS-D1 (MIC >0.5 MW)	€ 1.01	€ 119.277	€ 1.994	€ 0.000	€ 10.317	-	-	-	€ 2,158.69	€ 0.000	€ 0.000	€ 1,669.50
DTS-D2	€ 1.04	€ 184.883	€ 5.131	€ 0.166	€ 21.164	0.014	€ 0.000	0.006	-	-	-	-

Note: Charges per MW of Max Demand are zero in the Summer.

Table 3.12: Option T4

Customer Category	PROPOSED TUOS CHARGES OPTION T4 Split of MIC and Energy (70% Energy allocation for Network)					
	System Service Charge (no TOU)	Network-Related Charges				
		Charges per MWh				
		WINTER				Monthly Non-TOU MIC charge
		P	S	Off	Seasonal-Equivalent	
	(€/ MWh)	------------------- (€ per MWh) ------------------------				(€ / MW)
Demand Users						
DTS-T	€ 0.987	€ 114.826	€ 1.870	€ 0.000	€ 9.912	€ 280.27
DTS-D1 (MIC >0.5 MW)	€ 1.009	€ 119.277	€ 1.994	€ 0.000	€ 10.317	€ 302.67
DTS-D2	€ 1.044	€ 127.359	€ 2.218	€ 0.000	€ 14.046	€ 322.95

Note: Charges per MWh are zero in the Summer.

Table 3.13 below shows the revenue the various alternative tariff structures would generate from each tariff group and the percentage change as compared with current revenues. One important consideration in evaluating these changes is that all demand users see a negative percentage change in their TUoS bills as a result of the removal of operating and constraint costs to be recovered from TUoS charges. The average percentage change in TUoS revenues under all scenarios results in -24% for demand users and –9.3% for generators.

Table 3.13: TUoS Alternatives – Impacts by Category

	OPTION T1		OPTION T2		OPTION T3		OPTION T4	
	REV. FROM PROPOSED CHARGES (2005 €000)	% CHANGE IN TUOS REVENUES BY CLASS	REV. FROM PROPOSED CHARGES (2005 €000)	% CHANGE IN TUOS REVENUES BY CLASS	REV. FROM PROPOSED CHARGES (2005 €000)	% CHANGE IN TUOS REVENUES BY CLASS	REV. FROM PROPOSED CHARGES (2005 €000)	% CHANGE IN TUOS REVENUES BY CLASS
Demand Users								
DTS-T	13,866	-22.13%	8,700	-48.88%	11,210.1	-35.94%	10,900	-37.51%
DTS-D1 (MIC >0.5 MW)	38,594	-34.32%	24,458	-58.08%	32,026.1	-45.39%	32,781	-44.10%
DTS-D2	122,630	-20.09%	141,931	-7.59%	131,853.4	-14.09%	131,409	-14.40%
Generator User								
GTS-T	48,626	-9.80%	48,626	-9.80%	48,626	-9.80%	48,626	-9.80%
GTS-D	1,013	2.91%	1,013	2.91%	1,013.0	2.91%	1,013	2.91%
Autoprod. & CHP								
ATS-T (as Gen.)	-	-	-	-	-	-	-	-
ATS-D (as Gen.)	1,013	2.91%	1,013	2.91%	1,013	2.91%	1,013	2.91%
Overall Change	**225,742**	**-21.39%**	**225,742**	**-21.39%**	**225,742**	**-21.39%**	**225,742**	**-21.39%**

Table 3.14 below shows the change in annual TUoS revenues by user category after excluding the effect of the change in overall revenue requirement. Therefore the revenue impacts reflect the effect of a change in TUoS structure under each alternative and the proposed change in the current connection policy for demand users (100% up-front payment, as opposed to 50%). The overall TUoS revenue change from the revision of the connection policy is estimated as -1.52%.

Table 3.14: TUoS Alternatives – Impacts by Category

	OPTION T1	OPTION T2	OPTION T3	OPTION T4
	% CHANGE IN TUOS REVENUES BY CLASS	% CHANGE IN TUOS REVENUES BY CLASS	% CHANGE IN TUOS REVENUES BY CLASS	% CHANGE IN TUOS REVENUES BY CLASS
Demand Users				
DTS-T	-1.62%	-3.57%	-2.62%	-2.74%
DTS-D1 (MIC >0.5 MW)	-2.51%	-4.24%	-3.31%	-3.22%
DTS-D2	-1.47%	-0.55%	-1.03%	-1.05%
Generator User				
GTS-T	-0.67%	-0.67%	-0.67%	-0.67%
GTS-D	0.20%	0.20%	0.20%	0.20%
Autoprod. & CHP				
ATS-T (as Generation)	-	-	-	-
ATS-D (as Generation)	0.20%	0.20%	0.20%	0.20%
Overall Revenue Change	**-1.52%**	**-1.52%**	**-1.52%**	**-1.52%**

Finally, the bill impacts under each TUoS option assuming that the current connection policy continues are shown in Table 3.15 below.

Table 3.15: TUoS Alternatives – Impacts by Category (Present Connection Policy)

	OPTION T1	OPTION T2	OPTION T3	OPTION T4
	% CHANGE IN TUOS REVENUES BY CLASS	% CHANGE IN TUOS REVENUES BY CLASS	% CHANGE IN TUOS REVENUES BY CLASS	% CHANGE IN TUOS REVENUES BY CLASS
Demand Users				
DTS-T	-0.29%	-0.65%	-0.48%	-0.50%
DTS-D1 (MIC >0.5 MW)	-0.46%	-0.77%	-0.60%	-0.59%
DTS-D2	-0.27%	-0.10%	-0.19%	-0.19%
Generator User				
GTS-T	1.36%	1.36%	1.36%	1.36%
GTS-D	-0.40%	-0.40%	-0.40%	-0.40%
Autoprod. & CHP				
ATS-T (as Generation)	-	-	-	-
ATS-D (as Generation)	-0.40%	-0.40%	-0.40%	-0.40%
Overall Revenue Change	**0.00%**	**0.00%**	**0.00%**	**0.00%**

A comparison of bill impacts of alternative TUoS structures for a range of customers within each customer category was not attempted because the impact on customer bills depends upon the structures adopted for all cost elements, not just TUoS.

The section on PES tariffs below provides information on bill impacts at the individual customer level.

4 DISTRIBUTION CHARGING

4.1 Introduction

The distribution system supplies electricity to over 1,800,000 customers connected at voltage levels ranging from low voltage to 110kV.

This section on distribution charging:

- describes the DSO's role in relation to tariffs;
- briefly outlines network and non-network costs faced by the DSO;
- documents existing connection as well as Use of System charges; and
- identifies potential alternative charges, including customer categorisation and individual tariff components;
- presents screening results/impacts of these alternative tariffs in comparison with existing structures

4.1.1 Role of the Distribution System Operator (DSO)

ESB Networks as Distribution System Operator is the owner and operator of the Irish Distribution system, the network that connects most customers to the transmission system.

As per S.I. 445, the DSO's functions are 'to operate and ensure the maintenance of and develop, as necessary, a safe, secure, reliable, economical and efficient electricity distribution system, taking into account exchanges with other interconnected systems, with a view to ensuring that all reasonable demands for electricity are met and having due regard for the environment'. Duties include security of supply, the offering of connection to all applicants in line with existing legislation[32], accountability for distribution losses; metering, meter reading and meter data transfer; and with suppliers and customers, responsibility for meter revenue protection[33].

4.1.2 Distribution Revenue & Costs

The DSO recoups most of the costs of fulfilling these duties via distribution connection charges and use-of system (DUoS) charges. The Commission determines revenue requirements (normally for 5-year periods) for the DSO at regular intervals based on the level of anticipated capital and operational expenditure required in distribution networks. This five-year revenue requirement, approved and adjusted on an annual basis for applicability each January 1st, feeds through to annual DUoS tariffs.

Connection costs, or a portion thereof, are recovered via up-front charges. There were over 76,000 new connections to the distribution system made in 2003, most of these at LV level. DUoS charges apply to all customers connected to the distribution system.

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[32] For a more comprehensive account of the various DSO roles and responsibilities please see DSO Performance Reports for 2001 and 2002.
[33] The TAO is also responsible for the provision and maintenance of transmission connected metering equipment.

The distribution allowed revenue for 2004 amounted to €549 million. This translates into a distribution use-of-system charge that accounts for approximately 35% of the domestic customer tariff and 15% of the final retail tariff for MV customers.

4.2 *Distribution Revenue Requirement & DUoS Marginal Costs*

As described in section 2, for purposes of evaluating alternative DUoS structures, distribution marginal costs were estimated and adjusted to match estimated 2005 revenue requirements.

4.2.1 Distribution Marginal Costs

Distribution tariff structures should reflect the underlying structure of the cost of providing distribution service. There are three distinct components of the distribution system which require separate marginal cost analysis[34]:

- Local Marginal Facilities Costs (LV/MV);
- Demand-Related Marginal Costs (38kV/110kV);
- Customer Related Marginal Costs (Meters/Administration)

In addition, if the DSO is required to purchase energy to cover distribution losses, there will be a fourth component of distribution marginal cost:

- Distribution energy losses

4.2.1.1 'Local' Marginal Distribution Costs

Local distribution systems (from the customer's meter up to the feeder coming from the distribution substation) are typically built using engineering design standards that take into consideration the number of customers and the expected maximum loads (MIC) of those customers.

In short, the local distribution system is designed based on the *design load* of the customers to be served, not specifically on the number of customers or their actual loads at any given moment.

Because the local marginal distribution costs are incurred based on the *design load* of the customer, and do not vary with the customer's actual peak load from month to month, it makes sense to recover these marginal distribution costs in a fixed monthly charge imposed on the customer's design load, or maximum import capacity (MIC). Likewise, since these costs are not saved if a customer chooses to invest in a demand-side management device or a more efficient appliance, it is important to keep these costs out of the usage-sensitive components of marginal or avoided cost estimates.

Estimates of local distribution facilities marginal costs were estimated using *reproduction costs* for three typical MV 3-phase feeders, provided by DSO. The three feeders represent dense urban underground development, a mix of urban underground and rural overhead, and rural overhead. The marginal cost estimates used for evaluation of tariff structures in this report include only 50% of the cost of distribution facilities. This approximates the marginal distribution costs that need to be recovered in DUoS if a policy of recovering 50% of distribution facility costs in upfront connection charges is in place.

[34] The methodology used to calculate these components is contained in the *Marginal Cost Study*.

4.2.1.2 ‘Demand-Related’ Marginal Substation and Sub-Transmission Costs

MV 3-phase (‘Trunkline’) feeders, distribution substations (38kV and above), and higher voltage lines owned by the DSO are typically sized based on expected near-term peak demands. Thus these costs are marginal with respect to added loads in hours when load is close to capacity and are referred to as the demand-related marginal distribution costs. These costs in the Dublin region are somewhat different from the costs in other parts of Ireland because of the different voltages used for distribution in the Dublin region. In the case of DSO, it was not possible to separate trunkline feeders from other primary feeders, so the trunkline feeders are included in the distribution facilities component of marginal distribution cost.

The marginal cost of distribution substations and the lines and cables that feed them, *does* belong in the usage portion of rates. If a customer uses more in an hour when its distribution substation is peaking, additional capacity will likely be required. If the customer reduces usage in such an hour, capacity is freed up for use by other customers.

Because detailed budgets were not available, to estimate the marginal investment in substations and high voltage lines and cables, we used the reproduction cost estimates for cables/lines and substations (both 38 kV and 110 kV), and divided the costs by estimates of total peak loads at the various voltage levels. The estimates of marginal investment must then be annualised and assigned to hours or periods within the year based on a probability of peak analysis that determines each hour’s likelihood of being the peak hour.

4.2.1.3 Marginal Customer Costs

Meters and service drops, and related expenses, are dedicated to a single customer (or building) and are treated as marginal customer costs.

DSO provided the 2002 installed cost of a typical meter and service investment and the relative cost of meter reading and other customer-related expenses for each customer category. The investments were annualised using the same approach for other types of plant. Only 50% of the meter and service drop investment was included in the marginal customer cost estimates, consistent with a 50% connection charge policy.

4.2.1.4 Marginal Distribution Losses

If the DSO is given responsibility for acquiring energy to cover losses on the distribution system, it will need to purchase energy for this purpose. The marginal cost study includes an estimate of these marginal energy loss costs; however, since the current DSO revenue requirement does not include these costs, the illustrative tariffs developed for this review do not include an energy loss component of the DUoS. The cost of distribution losses is included in the marginal generation costs incorporated in the illustrative PES tariffs.

The Commission has recently published a draft decision on this issue outlining its proposed approach, which indicates the intention to continue the present arrangements with regards to distribution losses. Assuming the present arrangements continue, losses will not form part of distribution revenues and therefore will not have to be accommodated within the DUOS tariff.

4.2.1.5 Summary of DSO Marginal Costs

The plant-related marginal costs must be adjusted by peak demand losses to convert a marginal cost at, for example, the distribution substation, to a marginal cost at a customer's primary or secondary meter. Furthermore, customers served at primary voltage do not use transformers and secondary lines that secondary customers require. Thus, the marginal distribution costs vary by voltage level of service.

The tables below summarise the substation and high voltage lines/cables marginal costs by voltage level of service and costing period. The first table expresses the costs in terms of cents/kWh. The second expresses the same costs in terms of monthly peak demand by voltage level and time period.

Table 4.1: Distribution HV kWh Costs (allocated to lower voltages)

High Voltage Distribution Lines & Station Marginal Costs
2005 cents per kWh

Voltage	Winter			Summer	
	Peak	Shoulder	Off-Peak	Shoulder	Off-Peak
LV	9.12	0.74	0.34	0.47	0.01
MV	6.71	0.71	0.33	0.45	0.01
38kV	6.37	0.37	0.14	0.19	0.01

Table 4.2: Distribution HV per month kW costs (allocated to lower voltages)

High Voltage Distribution Lines & Station Marginal Costs
2005 cents per kW

Voltage	Winter			Summer	
	Peak	Shoulder	Off-Peak	Shoulder	Off-Peak
LV	5.88	1.75	1.43	1.34	0.06
MV	5.60	1.67	1.37	1.28	0.06
38kV	4.12	0.88	0.58	0.54	0.02

The two tables below summarise marginal distribution facilities costs (i) per kVA and (ii) per customer as applied to a typical customer in each category. Rural customers are not differentiated from urban customers.

Table 4.3: Distribution Facilities per kVA per month

Marginal Distribution Facilities Cost
2005 € per kVA of MIC per month

DG1	Urban Domestic	3.14
DG2	Rural Domestic	3.14
DG3	Public Lighting	3.14
DG4	Unmetered	3.14
	LV FR Meters	
DG5	LV Non-Domestic - DT & GP Meter	3.14
	All MD Meters	
DG6	LV Non-Domestic Max Demand	3.14
DG7	MV Max Demand	1.23
DG8	38kV Looped	0.53
DG9	38kV Tailed	0.53

Table 4.4: Distribution Facilities using Deemed kVA per connection

Distribution Facilities kVA per Customer

Urban Domestic	3.75
Urban Domestic D/N	5
Rural Domestic	3.75
Rural Domestic NightSaver	5
Public Lighting	28
C&I GP	10
C&I GP NightSaver	35
LVMD	127
MV MD	1395
38 kV MD	5482

The table below summarises marginal customer-related costs for each customer category.

Table 4.5: Distribution Customer Cost per month

Marginal Distribution Customer Cost
2005 € per customer per month

DG1	Urban Domestic GP Meter (& Services)	2.46
	Urban Domestic DT Meter	2.90
DG2	Rural Domestic GP Meter	3.00
	Rural Domestic DT Meter	3.80
DG3	Public Lighting (per connection)	1.70
DG4	Unmetered	n/a
	LV FR Meters	
DG5	LV Non-Domestic - GP Meter - 1-phase	4.41
	LV Non-Domestic - DT Meter - 1-phase	5.26
	LV Non-Domestic - GP Meter - 3-phase	5.90
	LV Non-Domestic - DT Meter - 3-phase	7.46
	All MD Meters	
DG6	LV Non-Domestic Max Demand	28.85
DG7	MV Max Demand	28.35
DG8	38kV Looped	72.19
DG9	38kV Tailed	72.19

There is one more element of marginal cost included in the distribution marginal costs. The market rules may require the DSO to purchase energy to cover both technical and commercial losses on the distribution system. In this case energy losses are a component of distribution service and will need to be recovered in the DUoS. Marginal energy losses increase at each successively lower voltage level. In addition at any given voltage level losses increase with system load. Thus there is a different energy loss adjustment factor for each hour and for each voltage level of service. Hourly losses were calculated by means of an approximation of quadratic losses based on variable losses at system peak load and a forecast of 2004 hourly loads.

4.2.2 DSO Revenue Requirement & Marginal Cost Revenue Gap

The starting point for the DSO revenue requirement used in the tariff screening process was the 2004 DUoS charges multiplied by the 2004 billing determinants. The 2004 DUoS charges were escalated to 2005 euros by application of an inflation factor of 3.5%.

The table below shows the deemed 2005 DSO revenue requirement (for the purpose of this review), and marginal cost revenues that would result if all consumers paid the marginal cost of distribution service (net of connection costs) for each element of distribution service, and the marginal cost revenue gap. Note that charging marginal cost would not produce revenue sufficient to cover the allowed revenue level.

Table 4.6: Distribution Revenue 'Gap'

DUoS Revenue Requirement Used[35]	Marginal Cost Revenues	Estimated Revenue Gap	Percent Gap
2005 €000	**2005 €000**	**2005 €000**	**%**
566,223	590,346	-24,123	4.2

[35] The figures used for 2005 should not prejudice and are simply uplifted from 2004 by projected inflation.

4.3 Distribution Connection Charges

The existing distribution connection charging policy differentiates demand customers and (embedded) generator customers – generators pay 100% deep connection charges while demand customers pay 50% of the *attributable*[36] cost of connecting to the distribution system.

4.3.1 Generator (Embedded) Connections

Connection policy for embedded generators is complicated because of the different ways these generators use the distribution system. Distribution connected or Embedded generation may be categorised as follows:

- *Stand-alone Embedded Generation*: The term *embedded generators* typically refers to generators that are largely stand-alone generators and that, except for some small energy imports for station service when the generator is not operating, use the distribution system only to deliver energy to the network.

- *(Exporting) Autoproducers*[37]: Other embedded generators primarily serve on-site load and deliver excess energy to the network. These generators use the distribution system for those deliveries and to import energy when the generator is out of service.

- *Stand-by Generation*: In another configuration, the embedded generator supplies a portion of on-site load requirements, imports additional energy in most hours, and imports all on-site load requirements when the generator is out of service.

4.3.1.1 Present Policy

Under the present charging methodology, embedded generators pay on the basis of:

- 100% Deep Connection Costs;
- Ongoing Payments:
  - On-going O&M charges on their connection facilities;
  - No DUoS charges for exports

4.3.1.2 Potential Alternatives

All embedded generators, as outlined, have been obliged to pay 100% deep connection costs. This provides a locational signal which encourages embedded generation to connect to existing distribution facilities in economically efficient locations.

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[36] The *Attributable Cost* is a proxy for the incremental cost of connecting a new customer or group of customers to the networks, including network reinforcement costs. The attributable cost is the estimated cost of the portion of the network that has to be built or existing capacity expanded to provide capacity to the connecting customer.

[37] As discussed in the first consultation paper of this review, *Existing Tariff Structures*, exporting autoproducers are so defined as having a contracted MEC greater than contracted MIC.

One alternative is to switch to a 100% shallow connection charge policy for embedded generators. However, any move to shallow connection charging for generation would reduce the locational signal.

Charging some fraction of deep connection costs less than 100% would, in most cases, represent less of a distortion in the locational signal than a shift to 100% shallow connection costs. A less-than-100% deep connection policy could be combined with the introduction of DUoS payments for exports by generators. Without this addition, a portion of the costs of deep reinforcement would fall on DUoS demand customers. However, the amount of the cost shifts would be small if deep connection costs are small and/or the number of new embedded generators is small. Presently deep connection costs represent a small portion[38] of generator connection charges.

Any move away from 100% deep generator connection costs could be accompanied by the incorporation of ongoing O&M charges into a generator DUOS export charge. However there would be transitional issues related to imposing these on-going charges on generators who have already paid 100% deep connection costs. It should also be noted that moving to 100% shallow connection charges, while introducing DUOS export charges to embedded generators, would put such generators on a similar footing to Transmission connected generators. However, the costs of deep reinforcements to embedded generators are relatively small compared to transmission-connected customers, although by their nature embedded generators are relatively small in size compared to transmission-connected generators. In addition, embedded generators may require less network investment at higher voltages due to their embedded nature. Therefore, on balance, adopting an alternative connection charging policy where embedded generators pay less in connection charges may result in higher long-term costs for embedded generators. Two options being considered are to:

- continue with the 100% deep connection policy, in addition to the ongoing O&M charge.
- apply a 100% shallow connection policy with an ongoing O&M charge that applies only to the shallow facilities and introduce an associated DUoS charge for embedded generators.

The Commission is considering some means of addressing the benefits of embedded generation, insofar as energy delivered to the network by these generators may lead to reduced network investment at higher voltages. This is discussed later in the document.

The Commission invites comment on the alternative distribution generator connection charging policies outlined above.

[38] This issue has not been examined in detail for a period of two years, however in 2002 deep reinforcement costs to embedded generators consisted of 6% of total connection costs. This was based on a sample of connections at that time.

4.3.2 <u>Demand Customer Connections</u>

4.3.2.1 Present Policy

Demand customers are categorised as being domestic or business in nature. Domestic connections are divided into non-scheme (single home) and scheme (residential subdivision). In general demand customers pay semi-shallow connection charges based on average connection costs; however, there are some exceptions. The connection policy is summarised hereunder:

- *Cost:*
  - 50% of standard dedicated connection costs, determined by an analysis of the "least cost technically acceptable solution" (LCTAS) or the minimum possible cost of a typical connection for domestic, farm and business categories;
  - Supplemental charges for very long network additions (with "very long" defined differently for each type of customer);
  - For customers with MIC above 500 kVA, a charge per kVA for reinforcement of the existing system. In general the customer is obliged to pay 50% of the attributable cost of the connection.

- *Refunds:*
  - Individual customers are entitled to a refund of part of the connection costs (excluding the standard charge) if a new customer connects to the same line extension within 5 years. The amount of the refund is based on the relative capacities of the users. The refund amount is included in the connection charge of the new user.

4.3.2.2 Potential Alternatives

The recovery of only part of the connection costs in upfront charges means that customers with high-cost connections may be subsidised by customers with low-cost connections, as the remaining connection costs are recovered from all customers through the DUoS. Alternatives include:

a) <u>*Distribution Connection Allowance*</u>

One alternative to this cross-subsidy is to introduce a system of *allowances* based on the standard cost of connection within any given (connection) category of customer. These should be consistent with DUoS categories.

This *Connection Allowance* could take the form of a specific monetary amount computed each year on the basis of the current installed cost (materials, labour, transport, etc.) of the typical connection of that type and size. The allowance may be 50% of the connection cost which would maintain the status quo, or alternatively the allowance could be reduced, thereby increasing the contribution made by customers.

Upfront payments would recover the difference between the actual costs of the connection in excess of the standard allowances. Refunds would reimburse the original customer for new users connecting to the same beyond-allowance extension. Refunds would be computed as a pro-rata share (either based on MIC or per meter of line used) of the original contribution for the shared facilities, which is similar to the present approach for business customers.

b) *No Connection Charge*

The transfer of connection costs to DUoS charges. This option would increase cross-subsidies from customers with below-average connection costs per kVA to customers with above-average connection costs per kVA. This option may encourage inefficiencies, as the connecting party would have no incentive to reduce the size of connection unless the DUOS incorporated a capacity charge per kVA of MIC.

c) *Revenue Test*

A third option would be to charge customers the difference between the present value of the *expected* DUoS revenue (net of the cost associated with non-connection costs) received over the lifetime of the connection and the *actual cost* of the connection. While this may be equitable, the uncertainties faced by the network operator would mean that there may be a higher risk of cost shifting. In addition, this method would add a level of administrative burden.

d) *Gradual Increase to 100% Deep Connection Policy*

Up-front payments for connection could be increased from the present 50% policy to 100%. The primary benefit of this would be to decrease ongoing DUoS charges for customers. Any policy introducing higher contributions (>50%) would have to be considered in greater detail at implementation stage to ensure equity between existing and new customers.

e) *100% Shallow Connection Policy*

A move to fully shallow charging might simplify the formulation of charges; however, it would not be as equitable as a deeper policy. However, the level of deep costs in distribution connections is small relative to shallow costs.

f) *100% Deep Connection Policy*

While the present policy recovers 50% of attributable costs, attributable costs are based on standard connection costs and do not include all deep costs. The introduction of deep charging for demand customers would be more equitable, but would add administrative burden in setting charges, as ‘deep’ would have to be clearly defined and measurable. The present approach is a practical compromise with respect to the determination of “semi-deep” costs, which resolves some of the difficulties of determining the true deep costs of demand customers.

Any change in connection policy would affect how refunds are administered and will require consideration of some the risk of cross-subsidies between existing and future customers.

4.3.3 Screening/Evaluation

Apart from the obvious changes in upfront charges for new connections, a change in distribution connection policy would affect the amount of revenue to be recovered in the DUoS. The effect would grow over time. The combination of depreciation and return on capital expenditure under the present regulatory model would result in the following reductions in DUOS revenue were the connection charging policy of 100% upfront payments to be adopted. These figures assume the present level of connections continues over the coming five years.

Table 4.7: 100% Demand Connection Charging & DSO Revenue

Year	2005	2006	2007	2008	2009
Reduction in €M Revenue	7	14	21	28	35

These figures are indicative, based on the current depreciation policy and allowing a rate of return of 6.5%.

4.3.4 Proposed Alternative

While the Commission sees the benefits of moving to **100% semi-shallow upfront connection fees** from a customer's perspective this alternative does raise a number of issues including:

- It presents a risk of cross-subsidies between new and existing customers;
- It doubles the upfront connection fees if the policy is immediately changed to 100% semi-shallow.);

The use of a **connection allowance approach** has the following advantages:

- It eliminates cross-subsidies because all consumers pay for the same amount of connection costs in their DUoS charges, and any additional connection costs upfront.
- It gives efficient locational signals because all consumers pay, one way or another, for the cost of their connections.
- It minimises the risk of cross-subsidisation while allowing the option of a gradual move to 100% connection charging if required at a future date.

While some of the above options are being given serious consideration, it should also be borne in mind that separate connection allowance policies may be implemented for different categories of customers. The screening of

DUoS alternatives, described below, assumes that the 50% connection policy is in place.

The Commission invites comment on the alternative distribution demand connection charging policies outlined above.

4.4 Distribution Use of System (DUoS) Charges

The DUoS tariff recovers most of the costs faced by the DSO, having taken contributions for connection costs[39] into account.

4.4.1 Generator/Demand Allocation

4.4.1.1 Present Policy

While transmission network costs are apportioned 75%/25% between demand and generators, no such arrangement exists for the treatment of distribution network costs. There are two reasons for this. First, generators connecting to the distribution system already pay 100% deep connection charges and therefore are exempt from on-going DUoS charges for exports to the network. Second, the 75%/25% division is used by Transmission System Operators across the European Union for reasons associated with interconnection and the cross-border trade in electricity that do not apply at the distribution level. The Commission does not favour the introduction of an arbitrary generator/demand apportionment for DUoS.

4.4.2 DUoS Customer Categories

DUoS charges vary by customer category. DUoS tariff categories are defined by type of customer, type of meter (maximum demand or not; standard or day/night), voltage level, and location on the network (looped or tailed; rural or urban). The categories, by-and-large, follow the voltage level at which the customer is connected. However, categories also take account of metering constraints at LV level. For this reason, smaller LV customers are charged under a non-MD category while larger LV customers whose size warrants the installation of a MD or MFM interval meter are categorised as LVMD customers. All tariff categories, with the exception of unmetered supplies, include charges for day and night time periods, applicable to customers with the appropriate meter.

For more information on existing DUOS categories please refer to the ESB Networks published schedule of charges.

Several tariff categories are sub-divided into demand customer and autoproducer customer groups to reflect the fact that autoproducers and CHP generator customers with MEC>MIC use electricity networks in a different way from conventional customers. These customers, *exporting* autoproducers, do not face fixed or capacity charges and are treated in a similar way to generators with respect to DUOS and connection charges. (Net) Importing Autoproducers (MEC<MIC) are categorised as other demand customers and face fixed and capacity charges, where levied.

4.4.2.1 Alternative DUoS Categories

[39] Refer to 2001-2005 Distribution Revenue Requirement for further information on ESB Networks revenue recovery.

The Commission is of the view that the current categories are adequate and do not require alteration. There are, however, some changes that could be made that may or may not require new categories. Among these are the following:

a) *Embedded Generation*

Embedded generation is addressed as two separate categories, generators and autoproducers. For the purposes of this discussion, we consider a generator as someone who is producing electricity for the purpose of export onto the system. Autoproducers on the other hand may be producing electricity for consumption on site, or a combination of consumption onsite and export onto the system.

While significant embedded generation exists, much of it is installed by customers for standby purposes in the event of power failure. It seems reasonable that such standby generation, if it were economic to do so, should be running at peak times. In considering such generation standby generator are considered as autoproducers. While a move to reflect true peak time prices with the use of time-of-use tariffs would encourage such use, it may be argued that even this approach does not reflect the true value of embedded generation where such generation is stand-alone as opposed to autoproducing generators. It has been noted that autoproducers may avail of the benefits of time of use tariffs, however a normal embedded generator is not afforded any commercial advantage which in theory should accrue to them as a result of avoided network costs at higher voltage levels. E.g. a generator exporting onto the medium voltage network at peak times will lead to reductions in network investment at high voltage levels. This assumes that such generation is actually generating at system peak times and does in fact result in reduced network investment.

A number of other jurisdictions consider that distribution-connected, or embedded, generation may help to defer or avoid future investment in transmission and higher voltage distribution networks because they deliver energy to meet loads of other consumers without using the higher voltage facilities. At present most embedded generators do not pay TUoS because they fall below the 10 MW criterion. However, avoided distribution network investment could potentially occur at 110kV (Distribution), 38kV and 3-phase MV voltage levels.

The Commission is, in principle, in favour of some means of recognising the benefits of such generation, such as a rebate. Just as customers connected at 38kV or 110kV voltage do not cause and therefore do not face MV or LV-associated charges, embedded generation connected at, say, 38kV voltage and delivering energy to demand users nearby should not have to pay for 110kV investment if it is not using that network. Of course embedded generators do not pay DUOS as a result of their 100% connection charging policy, therefore it may be argued that this should be sufficient incentive. However this on its own does not reflect the avoided network investment at higher voltages. This avoided network cost could accrue to an embedded generator in the following ways:

a) *Rebate to embedded generators in the form of a payment per kWh of energy exported to the network during peak hours.*) The rebate could be based on the full avoided cost of demand-related distribution as identified in the Marginal Cost Study, or alternatively, a percentage of this avoided cost. Ideally, the rebates should vary by location, although the avoided costs by sub-region might be difficult to estimate.

b) *End-of-year rebate*: based on actual peak usage. This rebate could, for instance, be based on how often an embedded generation customer produced its full MEC at system peak.

The design of an appropriate rebate for embedded generation must consider a number of factors:

- Firstly, the production of an embedded generator must be consistent or reliable in order for it to help defer or avoid network investment;

- Secondly, this production should be at times of peak demand on the affected facilities. If sites with embedded generators are exporting, say, 80% of the time while importing at times of peak, there are no savings in network investment vis-à-vis a demand customer.

The problem of unpredictability of embedded generation exporting at peak times would be eased by making the rebates on a time-differentiated per-kWh basis.

b) *<u>Prepayment Domestic Customer Category</u>*

As discussed in section 2.5, the introduction and the availability of prepayment metering, as has occurred in Northern Ireland and Britain, will require either a new category for domestic customers or a different standing charge to reflect the higher meter investment and lower meter reading and bad debt costs associated with these meters.

In addition, modern prepayment meters are considered capable of measuring usage at several intervals during the day – i.e. are capable of measuring time-of-use. A prepayment tariff could have energy charges (kWh) varying by peak, shoulder and off-peak.

The Commission has recently issued a consultation paper on this issue and will review the role of prepayment metering over the next year.

c) *<u>LV Customer 3-Phase/ 1-phase Sub-Categories</u>*

Low voltage customers pay tariffs on the basis of economic criteria (business, domestic etc.) or on meter type (MFM or simple electromechanical) regardless of whether they have a single-phase or three-phase connection.

The extra costs of supplying three-phase are primarily as a result of the need for extra capacity. However, under the current tariff there is no such differentiation.

As there is little reason why this cost should be shared, the Commission therefore proposes the introduction of 3-phase and 1-phase sub-categories.

The C above.

4.4.3 DUoS Structural Components

As described in section 2.3 of this paper, the tariff components should reflect the structure of the cost of service – i.e., costs that are fixed in nature (metering costs and connection costs not recovered via connection charges) should be collected through fixed charges, while variable costs such as those caused by kWh use which in turn contribute to investment to cover system use at certain times should be charged on a by-use basis.

4.4.3.1 Present DUoS Structural Components

Existing customer DUoS categories include some or all of the following types of charges:

a) *Fixed 'Standing' Charge based on Customer & Capacity Costs (DG5 and below)*

This current standing charge includes customer or meter charges and an implicit capacity charge for all general purpose or dual tariff customers (DG5 or below), although it may be argued that such costs are not accurately reflected in the tariffs.

b) *Energy charge per kWh based on Demand-related Costs (All DGs except Unmetered connections – DG4)*

Under present structures, energy charges that recover costs that vary with peak demand apply to all customer categories at different rates and are time-differentiated (but not seasonally-differentiated) into day/night periods for customers with Dual Tariff (day/night) meters, maximum demand meters and MFM interval meters.

c) *Explicit Capacity charge per kVA of MIC*[40]

Larger customers with contracted (as opposed to deemed) MIC are charged per kVA of MIC.

d) *MIC penalty - when metered demand exceeds contracted MIC (DG6 and above)*

[40] Or MEC for Autoproducers with MEC>MIC

Customers with contracted MIC pay a MIC penalty, in the event that MIC is exceeded, to discourage breach of contracted MIC levels. Metering in place measures maximum demand on a 15-minute basis.

e) *<u>Low (Reactive) power charge (per excess kVARh)</u>*

Larger customers with a low power factor are penalised as an incentive to keep power factor above 0.95.

4.4.3.2 Alternative Structural Components

The *Marginal Cost Study* undertaken as part of the tariff structure review identified potential alternative DUoS charges based on marginal costs. These consist of the following:

a) *<u>Customer Charges based on Meter- and Service-related Costs</u> (All Categories)*

As these occur on a customer-by-customer basis and do not relate to the demand of the customer it is proposed that these should continue to be recovered in the standing charge.

b) *<u>MIC-derived Capacity Charge based on Local Network Costs</u> (All Categories)*

The study determined that local LV and single-phase MV networks[41] are *designed* on the basis of aggregate MIC of customers – these do not vary with peak demand. Therefore these costs are incurred on the basis of *design* demand (MIC or MEC, whichever is the larger).

c) *<u>Time-Differentiated Energy kWh Charge based on 3-phase MV line, 38kV-MV substation, as well as Higher Voltage Costs</u> (All Categories for seasonal charging; All Categories with ToD metering for TOD charges)*

Another premise of the study is that that networks above and including 3-phase MV 'trunk' lines are built to cater for peak demand. Therefore these charges would recover costs of investing in networks to cater for peak and could be recovered either through time-differentiated per kWh or per metered kW charges (depending on metering). (See item (d) below)

Going forward, it is anticipated that all Low Voltage Maximum Demand (LVMD) customers will have MFM meters, offline or on-line[42].

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41 Distribution facilities for commercial and industrial customers are generally designed on a case-by-case basis, given the expected peak load of the customer. In short, the local distribution system is designed based on the design load of the customers to be served, not specifically on the number of customers or their actual loads at any given moment. We refer to these costs as marginal distribution facilities costs, since the costs are both customer- and (design) demand-related.

42 As stated in Section 2.5 almost all MV customers have on-line MFM or profile meters capable of communicating meter data to the DSO via GSM. Those customers with off-line MFM meters, i.e. those MFM meters that have to be read at the meter, are mainly installed at LVMD customers' premises.

This means that all maximum demand customers will have MFM metering capable of recording time-of-use kWh data[43]. In other words, LVMD customers, indeed all maximum demand customers, may be charged on the basis of kWh used at particular times of the day; e.g., that time-differentiated kWh charges levied say at peak, shoulder and off-peak periods would have the same or a similar effect to charging for capacity demanded at peak. Moreover, a time-differentiated per-kWh charge would have an advantage in that it would measure more time-periods than the two peak hours (17.00-19.00) measured at present (in winter) by MD meters. In other words a time-differentiated kWh should replace the MD charge.

d) *Maximum Demand Related Charges (kW)*

An alternative to per-kWh charges for demand-related costs would be to charge on maximum kW demand. The disadvantages, however, are that (i) the customer's maximum demand may not coincide with the most critical hours within the pricing period and (ii) once a customer has reached what he/she expects to be the peak demand for the month, there is little incentive to control demand because such control will not reduce the bill.

e) *MIC penalty - when metered demand exceeds contracted MIC (DG6 and above)*

MIC penalties, used to discourage customers from exceeding their MIC and measured on the basis of MD, may continue.

The first alternative structure considered follows this marginal cost structure (using per-kWh charges for substation and higher voltage costs). It must be modified to fit the metering capability of some customer categories. Deemed MIC can be used in place of a specific contracted MIC for customers without MD meters. Seasonal energy and/or maximum demand charges can be used for customers with no TOD capability. Customers whose meters can handle only two day periods instead of the three used in the marginal cost study can be charged energy charges that are recalculated for the two periods. This alternative tracks cost causation most closely and would lead to the most efficient DUoS tariffs.

Another alternative (shown in the table below) was considered. This second alternative evaluated keeps the standing charge, but uses a different combination of other charges, thereby sacrificing some efficiency of price signal. Both alternatives were tested with two approaches to closing the marginal cost revenue gap.

[43] This would be subject to both the reconfiguration of existing MFM meters and the amount of data an MFM can hold before being read – in cases where a meter reader must visit the site this could be anything up to 13 months after the units are used.

Table 4.8: DUoS Alternatives

DUoS Base Structure Options

	Charges
DU 1:	Seasonal and ToD Energy charge MIC charge Standing charge
DU 2:	Seasonal and ToD Energy charge Seasonal and ToD Max D charge MIC charge Standing charge

Revenue Reconciliation Options

(a):	Adjust usage charges only
(b):	Adjust fixed charges only

For instance, a DUoS tariff structure, D-1 (a), would translate into a tariff, based on marginal cost, with a time-of-use kWh charge, a fixed customer charge, a fixed per kVA charge, with the difference between marginal revenue and the revenue requirement accounted for by adjusting the time-of-use kWh charge.

The Commission invites comment on the alternative DUOS structural compo

4.4.3.3 Screening of DUoS Alternatives

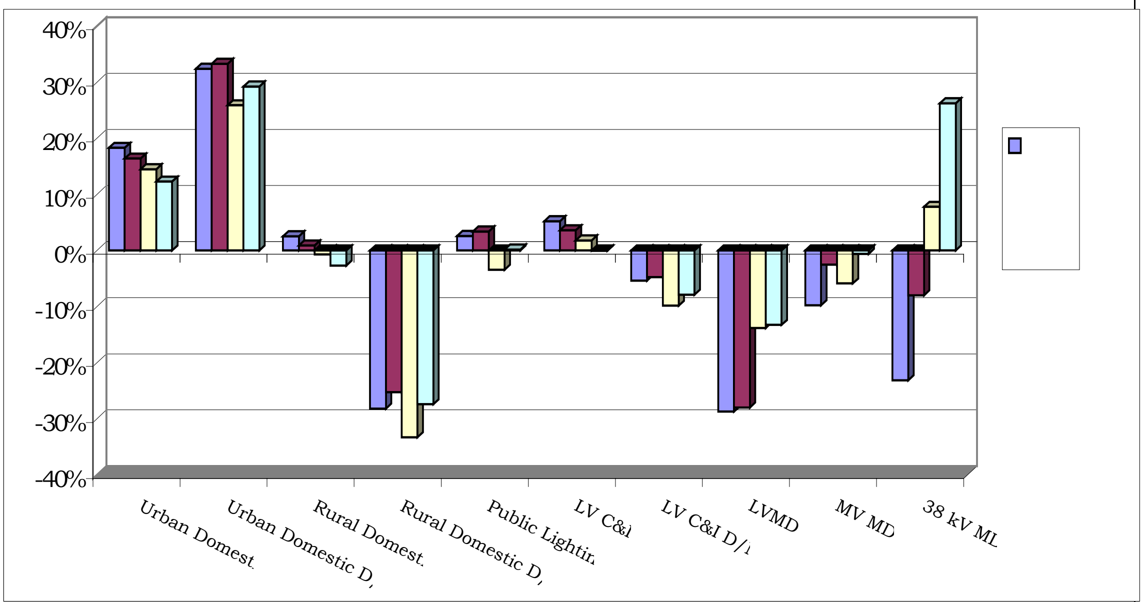
Each of the alternatives used marginal costs as the basis for the charges. Two approaches were used to close the marginal cost revenue gap: making proportional reductions to standing and MIC (where they exist) charges; and making equal adjustments to energy and maximum demand (where they exist) charges. Adjusting the fixed charges is more efficient because it leaves the charges related to usage closer to marginal cost. In cases where fixed charges set above marginal cost would create unacceptable bill impacts on small customers, adjustments to usage charges can be a second-best solution. In the other approach, making comparable adjustments to all the usage charges preserves the relative marginal costs for peak, shoulder and off-peak hours and for the winter vs. summer seasons. Of course combinations of adjustments to fixed and usage charges are also possible, but were not tested for this study.

The table below shows the impact of the alternative structures and alternative methods for closing the revenue gap on class revenue requirements. Evaluation of selected alternatives' effects on individual customers is considered in the section on PES tariffs below. Revenue and Customer impacts of the alternative tariffs are presented in the appendices.

Table 4.9: DUoS Alternatives – Bill Impacts by Category

	DUoS Customer Category	D-1a Change in Revenues By Class %	D-1b Change in Revenues By Class %	D-2a Change in Revenues By Class %	D-2b Change in Revenues By Class %
DG1	**Urban Domestic Customers**				
	Standard Meter	18.3%	16.4%	14.5%	12.3%
	Day & Night	32.4%	33.3%	25.9%	29.2%
DG2	**Rural Domestic Customers**				
	Standard Meter	2.5%	0.9%	-0.7%	-2.7%
	Day & Night	-28.2%	-25.3%	-33.3%	-27.4%
DG3	**Public Lighting**	2.6%	3.4%	-3.5%	0.2%
DG4	**Unmetered Conenctions**	n/a	n/a	n/a	n/a
DG5	**Commercial and Industrial General Purpose**				
	Standard Meter	5.2%	3.6%	1.8%	0.0%
	Day & Night	-5.4%	-4.7%	-9.8%	-7.9%
DG6	**Low Voltage (Metered Demand)**	-28.7%	-28.0%	-13.8%	-13.3%
DG7	**Medium Voltage (Metered Demand)**	-9.8%	-2.5%	-5.9%	-0.6%
DG8 & 9	**38 kV (Metered Demand)**	-23.2%	-8.0%	7.8%	26.2%

Figure 4.10: DUoS Alternatives: Bill Impacts by Category



Overall, resulting alternative DUoS revenues, when applied to current customer categories, decline for most commercial categories, with LV Max Demand revenues showing the greatest fall. It should noted that the decline in rural domestic day/night tariffs and the corresponding increases in urban domestic charges are mainly due to the use, for the sake of simplicity, of the same per kVA figure as for urban and rural customers. In reality the kVA marginal cost figure, and hence the kVA charge, for rural customers should be higher (and lower for urban domestics) reflecting the larger network per head required for rural customers.

4.4.3.4 Proposed Alternative

The Commission is of the view that an alternative should include an explicit capacity charge per kVA of MIC. Customers are already paying such charges (directly or indirectly) and recovering local facilities costs in usage charges exaggerates the price signal applicable to marginal consumption or peak demand.

Therefore there are merits in an alternative DUoS tariff structure for customers with basic metering such as **D1 (b) - Combination of Seasonal & TOD Energy Charge (kWh) with flat (deemed) MIC Charge (with fixed uplift).**

This option provides clear signals to consumers as to the value of both seasonal and peak time costs that they are ultimately imposing on the system.

On balance any alternative tariff should also take full advantage of the time-of-day capabilities of existing (or proposed) metering. Thus, all customers with interval meters could face DUoS charges that are differentiated by time of day as well as by season.

Time-differentiated per kWh charges give more efficient price signals than time-differentiated maximum demand charges, and so the per kWh structure for substation and higher voltage cost recovery should be preferred.

The Commission has a preference for a DUoS tariff that reflects the true marginal cost structure and is of the view that the **fixed charge adjustment** method for closing the revenue gap provides a better reflection of such an approach. The alternative method might be appropriate if the revenue gap required charging significantly more than marginal cost.

The Commission invites comment on the proposal outlined above.

5. PES SUPPLY

5.1 Introduction

As well as setting network tariffs, the Commission sets tariffs for the Public Electricity Supplier (PES) on an annual basis. Regulation 31 of S.I. 445 of 2001 requires that the Commission set regulated supply tariffs for customers of the ESB PES.

The Commission approves PES tariffs for various customer categories and publishes these every October for application from January 1st the following year. In so doing the Commission has to consider the impact that the level of PES tariffs has on independent suppliers.

5.1.1 Role of PES

5.1.1.1 Current Role

The role of the PES at present is to operate as a Universal Service Provider. The purpose of this role is to ensure that customers have all reasonable requests for an electricity supply fulfilled by at least one supplier. The role of universal service provider means that PES offers supply to customers on the basis of a set of regulated tariffs.

In other countries, this role is fulfilled by former integrated monopolies. In states where competition has been introduced for a number of years, such as Britain, New Zealand and Australia to name a few, this obligation, in full or in part, has fallen away as a result of the proliferation of supply offerings available to customers.

Since initial market opening in 2000 this role of universal service provider has applied to PES in its servicing of both eligible customers, customers by law allowed to choose their electricity supplier, and franchise customers, customers served by the ESB PES or by suppliers procuring energy from renewable or CHP sources.

5.1.1.2 Future Role of PES (with Full Market Opening)

PES' role as provider of a universal supply service is anticipated to continue with full market opening when all customers will become eligible to choose their electricity supplier.

As universal service provider, the tariff charged by the PES tariff will set the benchmark against which other suppliers must compete. To this end the PES tariff should be cost reflective and should reflect the underlying transmission and distribution charging policy. This would have the effect of facilitating retail competition, firstly, by increasing the transparency of the cost inputs that make up the PES tariff, and secondly, by allowing for cost reflectivity and recovery of costs caused by the use of a particular customer category.

This policy translates into, on the one hand, maintaining the time-of-use and other economic price signals that are inherent in the Transmission and Distribution charges while, on the other hand, facilitating retail competition from other suppliers vis-à-vis PES tariff offerings.

Overall, it is the view of the Commission that PES tariffs should be set at levels and with structures that best achieve the objectives of the Commission – facilitation of retail competition, encouragement of energy efficiency, the pass-through of proper network and generation price signals, and the protection of final customers.

5.2 PES Retail Revenue Requirement & Retail Marginal Costs

As with all suppliers, most costs faced by PES are 'pass-through' of DUoS, TUoS and generation costs. In addition the Public Service Obligation (PSO) levy, as well as capacity margin payments to ESB Power Generation, are added to the PES tariff faced by customers.

Therefore the marginal costs of the PES business itself are made up of the following:

- PES Marginal Customer Cost;
- PES Retail Margin

5.2.1 PES Marginal Retail Costs

5.2.1.1 Customer Costs

PES' marginal customer-related supply costs consist of the costs that vary with the number of customers on the system, independent of the customer's consumption. These include billing, revenue collection, customer service and administrative costs, etc.

The *Marginal Cost Study* identified marginal customer-related expenses from a detailed analysis of PES accounting data and assumed that appropriately identified accounting costs would make a good proxy for marginal customer expense. Each element of these accounts was assessed to determine if it is likely to be marginal with respect to number of customers or load, and to determine if it should be treated as a primary element of marginal cost or as an overhead that is applicable to both marginal and non-marginal expense categories.

PES writes off some bad debt each year. The study assumed that bad debt is marginal with respect to revenue; i.e., as PES sells more or less service, its bad debts will change proportionally.

5.2.1.2 PES Retail/ Supply Margin

Under Commission policy, PES is allowed a profit margin to mirror the profits required by other suppliers to make them willing to enter the electricity supply business in Ireland. The current formula for PES revenue expresses this margin in terms of euros/MWh because the appropriate margin is assumed to vary with the level of PES' supply business. Thus the margin was treated as a revenue-related marginal cost.

5.2.1.3 Summary of PES Marginal Costs

No marginal plant requirements were identified for PES, which has some computer assets, but no significant expectation to invest in any further plant and equipment. As a consequence, there is no capital component in the PES marginal costs.

The table below summarises PES marginal customer-related and revenue-related marginal costs:

Table 5.1 PES Customer & Revenue related Costs

	Tariff	Category	Monthly Cost Per Customer (2005 €) (1)	Marginal Revenue-Related Cost (%) ^1 (2)
-1	UrbDom	Urban Domestic	2.59	1.35%
-2	RurDom	Rural Domestic	2.59	1.36%
-3	Com GPT	Commercial General Purpose	3.75	1.21%
-4	Ind GPT	Industrial General Purpose	3.75	1.21%
-5	PL	Public Light	7.14	1.21%
-6	Com LVMD	Commercial MD (LV)	11.07	1.21%
-7	Ind LVMD	Industrial MD (LV)	11.07	1.21%
-8	Com 10kV	Commercial MD 10 kV	11.07	1.21%
-9	Ind 10 kV	Industrial MD 10kV	11.07	1.21%
-10	110kv	Maximum Demand 110kV	11.07	1.21%
-11	38kV	Maximum Demand 38 kV	11.07	1.21%
-12	CEU	CEU	11.07	1.21%

Notes
1 Percent of Generation, TUoS, DUoS and other PES charges

Source:
PES MARGINAL COST Study March 11 04.XLS.
Tab: PES Marginal Cost Allocation

5.2.1.4 PES Generation Costs

The *Marginal Cost Study* used as the basis for PES alternative tariffs uses a forecast of generation prices that include estimates of VOLL (value of lost load) and LOLP (loss-of-load probability) in the absence of a forecast of market prices.

5.2.2 PES Revenue Requirement & Marginal Cost Revenue Gap

In an actual PES tariff review, the PES tariffs would be set to recover TUoS and DUoS charges and generation costs, all of which would be marginal costs for PES, on a pass-through basis. The only element of marginal cost revenue gap would be the difference between PES's own total costs and marginal costs. As a result, there would be very little gap to close. For purposes of analysing alternative PES tariff structures, we used the revenue produced by the 2004 tariffs and the assumed billing determinants for 2005. The current PES revenue requirement includes PES' allowed generation costs, which may be quite different from market prices PES will face in the future. As there is no generation component specifically identified in each of the PES tariffs, no adjustment for this mismatch was possible. In addition, changes in TUoS and DUoS that would result from new policies for these tariffs would change those elements of PES' costs. Since the generation component of PES revenue requirement is very uncertain, no effort was made to modify the total PES revenue requirement assumed in the tariff screening process.

In the development of the alternative PES tariffs, the difference between the total PES revenue under current tariffs and the marginal cost revenue (including marginal generation costs, TUoS charges and DUoS charges) was spread proportionally to all tariffs and all tariff components to avoid introducing a distortion that would affect the evaluation of the alternative structures.

5.3 *PES Tariffs*

As stated above in section 5.1 above, the Commission is of the view that PES tariff categories and structural components should reflect underlying DUoS and TuoS tariff characteristics. Moreover PES tariffs should also reflect the underlying costs of the relevant TUoS and DUoS categories, adjusted to include generation costs, supply margin, supply costs and the PSO.[44]

5.3.1 <u>Present PES Categories & Structure</u>

5.3.1.1 Present Policy – Categories

Current PES tariff categories are divided by location (urban/rural), end use, type of metering (standard, day/night, maximum demand/interval metering) and voltage level. NightSaver service is optional for low voltage customers with day/night meters but no demand meters. Urban domestic customers without day/night meters pay the night price for energy used by night storage heating devices on timers.

As a rule-of-thumb PES customer categories broadly follow underlying DUoS customer categories. Categories in use at present are as follows:

- <u>*Urban Domestic & Rural Domestic (Standard, Night Saver, Night Storage)*</u>

  These categories are based on the same criteria as the equivalent DUoS customer categories. NightSaver tariffs apply to customers with a Dual Tariff meter and measure day consumption between 08.00 and 23.00 in winter and 09.00 and 24.00 in summer (see section 2). Night storage applies to customers who have electrical equipment that stores electricity at night to use during the day.

  As with DUoS, only domestic customers are charged based on a rural/urban divide. The basis for the difference is the larger fixed costs of rural network.

- <u>*Residential Business Premises (Standard, Night Saver)*</u>

  Residential Business charges are mixed premise-use customers and therefore combine the application of both the domestic rate and the commercial & industrial GP rate (below). At present, customers pay for 1,500 units at domestic rate and the remainder of their 2-month usage at the General Purpose business rate.

- <u>*Commercial and Industrial General Purpose (Standard, Night Saver, Night Storage) & Commercial and Industrial MD (LV)*</u>

  PES Commercial & Industrial General Purpose tariffs apply to customers in DUoS category DG5. PES Commercial & Industrial MD tariffs apply to PES customers in DUoS category DG6.

[44] Because the PSO would apply to all tariff alternatives, it has not been included in the screening analysis.

- *Maximum Demand (MV), Maximum Demand (38 kV) & Maximum Demand (110 kV)*

  As the category titles suggest, PES customers connected above the LV level are charged maximum demand charges.

- *Public Lighting and Unmetered Supplies*

  This category amalgamates DUoS categories DG3 and DG4 and applies to unmetered connections such as public lights, kiosks, shelters etc.

5.3.1.2 Present Policy – Structure

PES customers are billed customer charges, network demand-related (kW or kWh) charges and network capacity (or MIC) charges, but the charges do not always reflect underlying network costs that PES pays to TuoS, DUoS or the market cost of generation. PES customers also pay for generation costs (kWh) based on bulk power purchasing arrangements PES has with ESB Power Generation and other contracted stations.

Currently PES charges do not mirror TUoS or DUoS charges. Any increment in customer usage imposes a financial marginal cost to PES, reflected in the TUoS and DUoS charges that PES is subject to. Therefore, PES charges should mirror as close as possible the structure in TUoS and DUoS charges. Currently, this is not the case for some categories. For example, DUoS DG6 (LV Non-Domestic Customers, Maximum Demand) are subject to a monthly MIC charge, while the PES MD LV customers pay seasonally-differentiated metered demand charges and load-factor based energy charges.

Where the supply tariff deviates from underlying cost structure is principally in the following areas:

- *Energy Day/Night (kWh) charges*

  While the day rates of the day/night domestic DUoS tariffs (DG1 and DG2) are higher than the unrestricted 24-hour domestic rate, the PES domestic day rates are the same as the 24-hour rate. The equivalent night rate for PES domestics is a fraction of the day rate. In addition, the current TOD differentiation (day/night) in tariffs does not allow customers to know in which hours their marginal usage imposes the highest cost on generation, transmission and distribution systems; a uniform average charge across 15 daily hours does not encourage customers to make efficient electricity consumption decisions. Price signals would improve with a clearer peak period definition.

- *Seasonal Differentiation*

  Seasonal differentiation (Winter/Summer) only applies to Maximum Demand classes. No seasonal differentiation for the remaining customers. Price signals would improve if the underlying differences in the marginal costs of usage in Summer and Winter were reflected in tariffs for all users.

- *Maximum Demand Related Charges (kW) (LVMD and above)*

  Traditionally maximum demand charges have been applied to all PES customers with MD meters for use at peak periods. This metered demand acts as a proxy for any given customer's contribution to peak demand related investment. The problem with such a charge is that once a customer breaches its normal MD, there is little incentive to reduce usage at peak times.

- *Energy Block (kWh)*

  The PES applies an energy (kWh) block to General Purpose business customers. This energy block is a declining block as the first 8,000 units used are charged a higher rate than all subsequent units. The purpose of this energy block is to encourage customers to use more units.

- *Capacity Block (kW)*

  The capacity block applies to Low Voltage Maximum Demand customers and is based on the maximum capacity used by the customer in any given 15 minutes between 17.00 and 19.00 in any given month. This capacity block is charged on the basis of kWh per kW maximum demand metered as described above.

5.3.2 Alternative PES Categories & Structure

5.3.2.1 Potential Alternatives – Categories

As discussed in section 2.4 there are many possibilities that may be considered when designing supply categories. These possibilities include alternative tariff categories for prepayment customers, embedded generation and for LV customers based on connection type similar to those discussed in section 4.4.2.1.

One of the impacts of the costing methodology employed during this review is the resulting reflection of underlying costs of serving customers at a given voltage level. As such, the differentiation between Domestics and General Purpose customers for example may be reduced if the costs of serving these customers are similar. This would in turn impact on the need for a Residential Business Category.

Overall the Commission is satisfied with the number and nature of current customer categories on offer.

The Commission invites comment on the continuation of existing PES customer catego

5.3.2.2 Potential Alternatives – Structure

As explained in previous sections on DUoS and TUoS, the *marginal cost study* undertaken as part of the tariff structure review identified potential alternative charges based on marginal costs. These should also apply to PES tariffs as below:

a) *Customer Charges (Costs based on customer numbers)*

PES customers pay these at present. The fixed customer cost should only reflect customer costs.

b) *Capacity Charge (MIC Charge based on Local Network Costs)*

This will require the introduction of deemed or actual capacity on all customers including domestics and general purpose.

c) *Time-Differentiated Energy (kWh) Charge*

The Commission is of the view that costs that vary with usage would be passed through as time-differentiated charges reflecting when they occur. These should apply to network costs in the first instance. The pass-through of generation costs will be considered during the implementation phase of this review.

d) *Maximum Demand Related Charges (kW)*

Alternatively time-differentiated charges could be based on maximum kW demand.

e) *MIC penalty*

The MIC penalty present in the DUoS 'Maximum Demand' charges could also applied to PES MD tariffs.

f) *Declining Energy & Capacity Blocks*

The purpose of both blocks is to encourage efficient use of kWh units. Therefore the introduction of efficiently priced time-differentiated (kWh or kW) energy charges should remove the need for a capacity or energy block in PES business charges.

Nevertheless as suggested in section 2, a declining or increasing energy block may be used to reconcile marginal cost revenues with the revenue requirement as such a block would not distort the marginal price signal charged to customers.

g) *Interruptible Tariff*

In the first consultation paper of this review, the Commission put forward proposals for an interruptible tariff. An interruptible tariff is a tariff that has a price reflecting the ceiling value of the electricity to the customer. If the price goes over a certain limit, the price is higher than the value associated with it by the customer. Hence the supply can be reduced or foregone by the customer at these times. While this issue is being addressed as part of the MAE as part of demand side bidding, it should be noted that ESB PES tariffs are likely to include a component of interruptible tariff to facilitate demand side bidding options.

h) *Mid Year Adjustment*

In the first consultation paper of this review, the Commission put forward proposals for PES tariff *mid-year generation element adjustments* to reflect changes in MAE prices.

The Commission is of the view that, in order to foster competition, the PES tariff level should be reviewed in line with typical contracts issued by independent suppliers. This review did not look at mid-year reviews of PES tariffs. A variation on mid-year reviews is to include an index component in tariffs, e.g., a fuel or a market price index. However this does present issues as to what extent a particular fuel's price change has affected PES generation costs/ index component. This would allow ESB PES to pass through increases/ reductions in fuel price within year. This has the added benefit of avoiding large price correction transferring from one year to another, promoting efficient demand response and encouraging retail competition. In addition it would more accurately reflect the costs that independent suppliers may face in the market.

The Commission invites comment on the alternative PES structural components outlined above.

5.3.3 Screening of PES Alternatives

In developing alternative PES tariffs for screening, we started with PES marginal cost components (including generation, transmission and distribution, PES customer-related costs and PES revenue factor adjustments). In the case of transmission and distribution costs, these are simply the TUoS and DUoS charges which PES pays. Because of the large number of TUoS and DUoS alternatives, only the most promising combinations were screened quantitatively. The table below shows the TUoS and DUoS combinations screened for each scenario.

Table 5.2: PES Alternatives

TUoS Base Structure Options

T1:
- Energy charge
- Market Participant Charge

T4
- Energy charge
- MIC charge
- Market Participant Charge

\+

DUoS Base Structure Options

D-1:
- Seasonal and ToD Energy charge
- MIC charge
- Standing charge

D-2:
- Seasonal and ToD Energy charge
- Seasonal and ToD Max D charge
- MIC charge
- Standing charge

DUoS Rev. Reconc. Options
- **(a):** Adjust usage charges only
- **(b):** Adjust fixed charges only

Because the total PES revenue requirement used as a target for each set of tariffs is not a precise figure, each PES marginal cost element was scaled up proportionally to determine the charges under each combination of TUoS and DUoS structures.

The series of charts below illustrate the effect of the alternative PES structures on revenue allocation to the various customer categories. Also shown in Appendix C is the share of the class' revenue recovered in standing charges, capacity charges, energy charges, etc. All of the computations ignore PSO costs, which are common to all tariff structures. The specific charges that make up the illustrative tariffs are shown below.

Table 5.3: PES Category Revenue Impacts – Options D1 and D2 combined with T1

PES Customer Category	T-A1 & D-1a Change in Revenues By Class %	T-A1 & D-1b Change in Revenues By Class %	T-A1 & D-2a Change in Revenues By Class %	T-A1 & D-2b Change in Revenues By Class %
Urban Domestic Customers				
Standard Tariff	6.0%	5.5%	5.3%	4.0%
Nightsaver Tariff	25.4%	25.8%	24.1%	24.3%
Rural Domestic Customers				
Standard Tariff	0.7%	0.2%	0.1%	-1.3%
Nightsaver Tariff	-4.3%	-3.4%	-12.5%	-4.0%
Commercial and Industrial General Purpose				
Standard Tariff	-8.1%	-8.6%	-8.7%	-10.1%
Nightsaver Tariff	-1.1%	-1.1%	-7.5%	-1.8%
Public Lighting	193.7%	198.0%	189.1%	196.1%
Maximum Demand (MD)				
MD Low Voltage	-10.9%	-10.6%	-6.3%	-6.9%
MD Medium Voltage	-5.0%	-4.1%	-0.6%	-0.4%
MD 38 kV	-7.6%	-6.1%	-4.7%	-3.7%
MD 110 kV	-3.2%	-1.8%	0.8%	2.0%

Figure 5.1 PES Category Revenue Impacts – Options D1 and D2 combined with T1

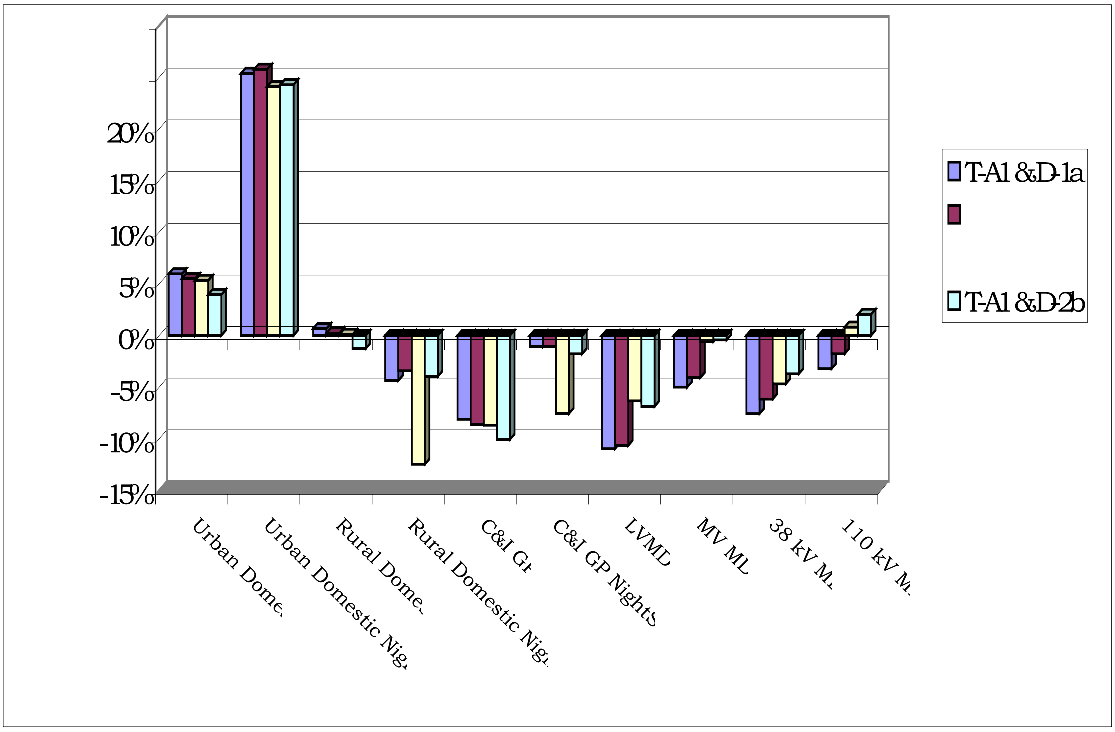
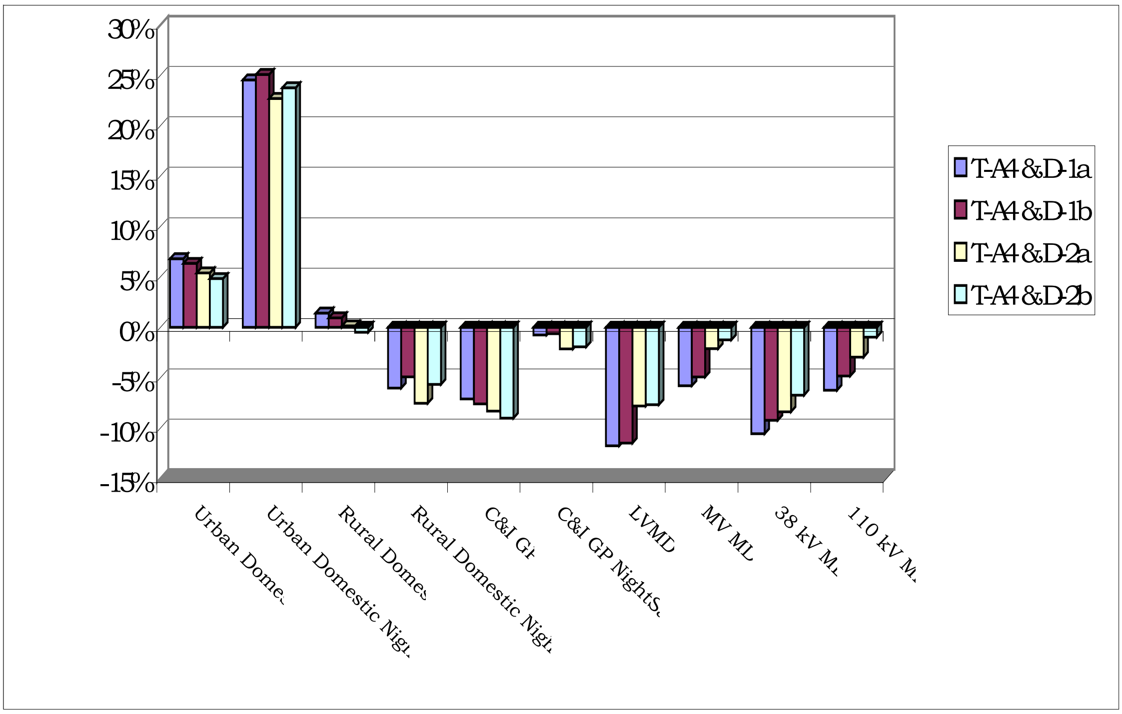


Table 5.4: PES Category Revenue Impacts – Options D1 and D2 combined with T4

PES Customer Category	T-A4 & D-1a Change in Revenues By Class %	T-A4 & D-1b Change in Revenues By Class %	T-A4 & D-2a Change in Revenues By Class %	T-A4 & D-2b Change in Revenues By Class %
Urban Domestic Customers				
Standard Tariff	6.8%	6.3%	5.4%	4.8%
Nightsaver Tariff	24.5%	25.1%	22.7%	23.8%
Rural Domestic Customers				
Standard Tariff	1.4%	0.9%	0.1%	-0.5%
Nightsaver Tariff	-6.0%	-4.9%	-7.5%	-5.7%
Commercial and Industrial General Purpose				
Standard Tariff	-7.1%	-7.6%	-8.3%	-9.0%
Nightsaver Tariff	-0.8%	-0.6%	-2.1%	-1.9%
Public Lighting	188.1%	192.3%	181.5%	190.6%
Maximum Demand (MD)				
MD Low Voltage	-11.8%	-11.5%	-7.8%	-7.7%
MD Medium Voltage	-5.8%	-4.9%	-2.1%	-1.2%
MD 38 kV	-10.6%	-9.2%	-8.4%	-6.7%
MD 110 kV	-6.2%	-4.8%	-2.9%	-1.0%

Figure 5.2 PES Category Revenue Impacts – Options D1 and D2 combined with T4



Overall, PES revenues, reflecting DUoS revenues somewhat, decline for low voltage (LV) commercial categories, with LV Max Demand revenues showing the greatest fall. It should noted that the decline in rural domestic day/night tariffs and the corresponding increases in urban domestic charges are mainly due to the use, for the sake of simplicity, of the same per kVA marginal cost figure as for urban and rural customers. In reality the kVA marginal cost, and hence the kVA charge, for rural customers should be higher (and lower for urban domestics) reflecting the larger network per head required for rural customers.

The Commission invites comment on the above results.

6. TARIFF STRUCTURE IMPLEMENTATION PROCESS

Over the next number of months the Commission will publish a draft decision on tariffs and will subsequently look at how best to implement this decision.

The implementation phase of the review, and the speed at which the implementation takes place, will be guided by the potential impacts that the alternative tariff structures proposed in this paper will have on all customer categories.

In this light the Commission will be publishing an implementation plan in later in 2004 and will discuss which new structures will be applied, if any, from January 2005 and which will be applied a year later for 2006.

The timetable for alternatives proposed in this paper is:

- End June: Consultation Paper
- End July: Consultation Deadline & Receipt of Comments
- Mid-August:
  - Draft Decision on Alternative Tariff Structures
  - Publication of Comments
  - Publication of Implementation Plan

APPENDICES – CONTENTS

The tables and figures presented here further demonstrate the results of screening of distribution and PES supply alternative tariffs described in the main document. For the purpose of comparison existing tariffs are also included. However, caution should be taken when comparing existing tariffs with alternatives screened as the costing methodology, cost components and time periods differ entirely.

The following information is contained below:

A. DUoS existing & alternative tariffs structure Components;
B. PES existing & alternative tariff structural components;
C. Annual PES revenues by revenues by customer category under existing & alternative tariffs;

It should be noted that the alternatives tariffs presented here are illustrative, and the resulting bill impacts are only approximate. More detailed analysis is required if tariffs are actually set on these models. This analysis will be undertaken during the implementation stage of this review.

APPENDIX A: DUoS – EXISTING & ALTERNATIVE TARIFF STRUCTURAL COMPONENTS

The tables below show the DUoS charges for Options D1 (a) and D1(b), also shown in the main body of the text, as well as Options D2 (a) and D2 (b).

Table 1: DUoS Summary of Alternatives

DUoS Base Structure Options

- **DU 1:**
  - Seasonal and ToD Energy charge
  - MIC charge
  - Standing charge
- **DU 2:**
  - Seasonal and ToD Energy charge
  - Seasonal and ToD Max D charge
  - MIC charge
  - Standing charge

Revenue Reconciliation Options

- **(a):** Adjust usage charges only
- **(b):** Adjust fixed charges only

Table 2: DUoS Existing Structural Components

Existing Tariff Category	*Components*		**Existing Tariff**
DG -1 (Urban Domestic)	**Customer (€/month)**	Standing Charge 24hr	3.41
		Standing Charge Peak/Off-	3.96
	Capacity (€/kVA)	kVA (MIC)	
	Energy (€/kWh)	24-hour Day Night	2.792 3.424 0.438
DG -2 (Rural Domestic)	**Customer (€/month)**	Standing Charge 24hr	5.48
		Standing Charge Peak/Off-	6.01
	Capacity (€/kVA)	kVA (MIC)	
	(€/kVA)	24-hour Day Night	2.792 3.424 0.438
DG -3 (Public Lighting)	**(€/kVA)**	Flat	2.628
DG-4	**Customer**	Standing Charge	268.27
DG -5 (LV non-MD)	**Customer**	Standing Charge	6.08
		Standing Charge Peak/Off-Peak (D/N)	6.80
	Capacity	kVA (MIC)	
	Energy (kWh)	24-hour Day Night	3.465 4.052 0.496
	Other	Low Power Factor	0.765

DG-6 to DG-9

Existing Tariff Category	*Components*		**Existing Tariff**
DG –6 (LV MD)	**Customer**	Standing Charge	58.27
	Capacity	kVA (MIC)	2.18
	Energy (kWh)	Day Night	2.062 2.400
	Other	Low Power Factor	0.699
DG –7 (MV MD)	**Customer**	Standing Charge	185.84
	Capacity	kVA (MIC)	1.36
	Energy (kWh)	Day Night	0.648 0.096
	Other	Low Power Factor	0.616
DG –8 & DG9 (38 kV)	**Customer**	Standing Charge (Looped)	3,155
		Standing Charge (Tailed)	887
	Capacity	kVA (MIC)	0.67
	Energy (kWh)	Day Night	0.141 0.010
	Other	Low Power Factor	0.616

Table 3 (Non-MD & MD): DUoS Alternative D1

DG-1 to DG-5

				Alternative Tariff D-1	
Existing Tariff Category	***Components***			**Usage Charge Adjusted D-1(a)**	**Fixed Charge Adjusted D-1(b)**
DG -1 (Urban Domestic)	**Customer (€/month)**	**Standing Charge 24hr**		2.46	2.33
		Standing Charge Peak/Off-Peak		2.90	2.75
	Capacity (€/kVA)	**kVA (MIC)**		3.14	2.98
	Energy (cent/kWh)	**WINTER**	Flat (St. meter)	1.12	1.26
			Peak	5.91	6.13
			Off-Peak	0.25	0.40
		SUMMER	Flat (St. meter)	0.05	0.19
			Peak	0.31	0.47
			Off-Peak	0.00	0.14
DG -2 (Rural Domestic)	**Customer (€/month)**	**Standing Charge 24hr**		3.00	2.85
		Standing Charge Peak/Off-Peak (D/N)		3.80	3.61
	Capacity (€/kVA)	**kVA (MIC)**		3.14	2.98
	Energy (cent/kWh)	**WINTER**	Flat (St. meter)	1.12	1.26
			Peak	5.91	6.13
			Off-Peak	0.25	0.4
		SUMMER	Flat (St. meter)	0.05	0.19
			Peak	0.31	0.47
			Off-Peak	0.00	0.14
DG -3 (Public Lighting)	**Customer (€/month)**	**Standing Charge**		1.70	1.61
	Capacity (€/kVA)	**kVA (MIC)**		1.77	2.98
	Energy (cent/kWh)	**WINTER**	Seasonal	1.12	1.26
		SUMMER	Seasonal	0.05	0.19
DG -5 (LV non-MD)	**Customer (€/month)**	**Standing Charge**		5.16	4.89
		Standing Charge Peak/Off-Peak (D/N)		6.36	6.03
	Capacity (€/kVA)	**kVA (MIC)**		3.14	2.98
	Energy (cent/kWh)	**WINTER**	Flat	1.12	1.26
			Peak	5.99	6.13
			Off-Peak	0.27	0.4
		SUMMER	Flat	0.05	0.19
			Peak	0.33	0.47
			Off-Peak	0.00	0.14

DG-6 to DG-9

				Alternative Tariff D-1	
Existing Tariff Category	***Components***			**Usage Charge Adjusted D-1(a)**	**Fixed Charge Adjusted D-1(b)**
DG –6 (LV MD)	**Customer (€/month)**	**Standing Charge**		28.85	27.37
	Capacity (€/kVA)	**kVA (MIC)**		3.14	2.98
	Energy (cent/kWh)	**WINTER**	Peak	8.98	9.12
			Shoulder	0.60	0.74
			Off-Peak	0.21	0.34
		SUMMER	Shoulder	0.33	0.47
			Off-Peak	0.00	0.01
DG –7 (MV MD)	**Customer**	**Standing Charge**		28.35	27.37
	Capacity	**kVA (MIC)**		1.23	1.17
	Energy (cent/kWh)	**WINTER**	Peak	8.53	8.67
			Shoulder	0.57	0.71
			Off-Peak	0.19	0.33
		SUMMER	Shoulder	0.31	0.45
			Off-Peak	0.00	0.01
DG –8 & DG9 (38 kV)	**Customer**	**Standing Charge**		72.19	68.5
	Capacity (€/kVA)	**kVA (MIC)**		0.53	0.50
	Energy (cent/kWh)	**WINTER**	Peak	6.25	6.39
			Shoulder	0.23	0.37
			Off-Peak	0.00	0.14
		SUMMER	Shoulder	0.05	0.19
			Off-Peak	0.00	0.00

Table 4 (Non-MD & MD): DUoS Alternative D2

DG-1 to DG-5

				Alternative Tariff D-2	
Existing Tariff Category	***Components***			**Usage Charges Adjusted D-2(a)**	**Fixed Charge Adjusted D-2(b)**
DG -1 (Urban Domestic)	**Customer (€/month)**	**Standing Charge 24hr**		2.46	2.24
		Standing Charge Peak/Off-Peak		2.90	2.64
	Capacity (€/kVA)	**kVA (MIC)**		3.14	2.86
	Energy (cent/kWh)	**WINTER**	Flat (St. meter)	0.82	1.26
			Peak	5.60	6.13
			Off-Peak	0.00	0.40
		SUMMER	Flat (St. meter)	0.00	0.19
			Peak	0.00	0.47
			Off-Peak	0.00	0.14
DG -2 (Rural Domestic)	**Customer (€/month)**	**Standing Charge 24hr**		3.00	2.73
		Standing Charge Peak/Off-Peak (D/N)		3.80	3.46
	Capacity (€/kVA)	**kVA (MIC)**		3.14	2.86
	Energy (cent/kWh)	**WINTER**	Flat (St. meter)	0.82	1.26
			Peak	5.60	6.13
			Off-Peak	0.00	0.40
		SUMMER	Flat (St. meter)	0.00	0.19
			Peak	0.00	0.47
			Off-Peak	0.00	0.14
DG -3 (Public Lighting)	**Customer (€/month)**	**Standing Charge**		1.70	1.55
	Capacity (€/kVA)	**kVA (MIC)**		1.77	2.86
	Energy (cent/kWh)	**WINTER**	Seasonal	0.82	1.26
		SUMMER	Seasonal	0.00	0.19
DG -5 (LV non-MD)	**Customer (€/month)**	**Standing Charge**		5.16	4.69
		Standing Charge Peak/Off-Peak (D/N)		6.36	5.79
	Capacity (€/kVA)	**kVA (MIC)**		3.14	2.86
	Energy (cent/kWh)	**WINTER**	Flat	0.82	1.26
			Peak	5.69	6.13
			Off-Peak	0.00	0.40
		SUMMER	Flat	0.00	0.19
			Shoulder	0.02	0.47
			Off-Peak	0.00	0.14

DG-6 to DG-9					
				Alternative Tariff **D-2**	
Existing Tariff Category	***Components***			**Usage Charge Adjusted D-2(a)**	**Fixed Charge Adjusted D-2(b)**
DG –6 (LV MD)	**Customer (€/month)**	**Standing Charge**		28.85	26.26
	Capacity (€/kVA)	**kVA (MIC)**		3.14	2.86
	Energy (cent/kWh)	**WINTER**	Peak	0.00	0.00
			Shoulder	0.00	0.00
			Off-Peak	0.00	0.00
		SUMMER			
			Shoulder	0.00	0.00
			Off-Peak	0.00	0.00
	Max Demand (€/kW)	**WINTER**	Peak	5.59	5.88
			Shoulder	1.46	1.75
			Off-Peak	1.15	1.44
		SUMMER			
			Shoulder	1.05	1.34
			Off-Peak	0.00	0.06
DG –7 (MV MD)	**Customer (€/month)**	**Standing Charge**		28.35	25.81
	Capacity (€/kVA)	**kVA (MIC)**		1.23	1.12
	Energy (cent/kWh)	**WINTER**	Peak	0.00	0.00
			Shoulder	0.00	0.00
			Off-Peak	0.00	0.00
		SUMMER			
			Shoulder	0.00	0.00
			Off-Peak	0.00	0.00
	Max Demand (€/kW)	**WINTER**	Peak	5.30	5.59
			Shoulder	1.38	1.67
			Off-Peak	1.08	1.37
		SUMMER			
			Shoulder	0.99	1.28
			Off-Peak	0.00	0.05
DG –8 & DG9 (38 kV)	**Customer (€/month)**	**Standing Charge**		72.19	65.71
	Capacity (€/kVA)	**kVA (MIC)**		0.53	0.48
	Energy (cent/kWh)	**WINTER**	Peak	0.00	0.00
			Shoulder	0.00	0.00
			Off-Peak	0.00	0.00
		SUMMER			
			Shoulder	0.00	0.00
			Off-Peak	0.00	0.00
	Max Demand (€/kW)	**WINTER**	Peak	3.83	4.12
			Shoulder	0.59	0.88
			Off-Peak	0.29	0.58
		SUMMER			
			Shoulder	0.25	0.54
			Off-Peak	0.00	0.02

APPENDIX B: PES – EXISTING & ALTERNATIVE TARIFF STRUCTURAL COMPONENTS

Existing and alternative PES tariffs are presented in this section. PES tariffs combine TUoS, DUoS, supply charges as well as PES generation costs. The table below shows all the alternative PES tariffs tested.

It should be noted that while existing components are listed here, no direct comparison should be made with alternatives due to the fact that time periods as well tariff structural components are entirely different.

Table 1: PES Summary of Alternatives

TUoS Base Structure Options			DUoS Base Structure Options		DUoS Rev. Reconc. Options
T1:	Energy charge Market Participant Charge	+	**D-1:**	Seasonal and ToD Energy charge MIC charge Standing charge	**(a):** Adjust usage charges only **(b):** Adjust fixed charges only
T4	Energy charge MIC charge Market Participant Charge		**D-2:**	Seasonal and ToD Energy charge Seasonal and ToD Max D charge MIC charge Standing charge	

The overall revenue impacts of alternative tariffs are documented and illustrated in Section 5.3.3 of the main document. Transmission options T2 and T3 are screened in Section 3 on transmission charges and tariffs.

****It should be noted that kVA figures are per month and refer to deemed facilities cost rather than contracted customer MIC****.

Table 2: Existing PES Tariff Components

Existing Tariff Category	*Components*			**Existing Tariff**
Urban Domestic	**Customer (€/month)**	Standing Charge 24hr		6.44
		Standing Charge Nightsaver		16.26
	Energy (cent/kWh)	24-hour		11.07
		Day		11.07
		Night		4.90
Rural Domestic	**Customer (€/month)**	Standing Charge 24hr		11.76
		Standing Charge Nightsaver		23.22
	Energy (cent/kWh)	24-hour		11.07
		Day		11.07
		Night		4.90
Commercial & Industrial	**Customer (€/month)**	Standing Charge 24hr		15.76
		Standing Charge Nightsaver		20.17
	Energy (cent/kWh)	24 hour	First 8000kWh/2 mths	12.97
			Remaining Units	11.05
		Day Unit	First 8000kWh/2 mths	13.81
			Remaining Units	11.05
		Night		4.90

Maximum Demand Customers

Existing Tariff Category	*Components*			**Existing Tariff**
MD LV	**Customer (€/month)**	Standing Charge 24hr		145
	Service Capacity (€/per kVA of MIC)	kVA (MIC)		4.35
	Demand Charge	WINTER		€ 6.70
		SUMMER		€ 5.60
	Energy (cent/kWh)	WINTER	Day Unit Rate 1st 350kWh per kW of MD per Winter period (2 months)	11.17
			Balance of kWh per Winter period (2 months)	7.26
		SUMMER	Day Unit Rate 1st 350kWh per kW of MD per Summer period (2 months)	10.02
			Balance of kWh per Summer period (2 months)	6.86
			Night unit rates	4.60

Table 3: PES Alternative T1 D1

Non-Maximum Demand Customers

				Alternative Tariff T-1 D-1	
Existing Tariff Category	***Components***			**Usage Adjusted T-1 D-1a**	**Fixed Charge Adjusted T-1 D-1b**
Urban Domestic	**Customer (€/month)**	**Standing Charge 24hr**		5.12	5.00
		Standing Charge Nightsaver		5.57	5.43
	Capacity (€/kVA)	**kVA (MIC)**		3.18	3.03
	Energy (cent/kWh)	**WINTER**	Flat (St. meter)	0.11	0.12
			Peak	0.32	0.33
			Off-Peak	0.06	0.06
		SUMMER	Flat (St. meter)	0.05	0.06
			Peak	0.08	0.08
			Off-Peak	0.05	0.05
Rural Domestic	**Customer (€/month)**	**Standing Charge 24hr**		5.67	5.52
		Standing Charge Nightsaver		6.48	6.29
	Capacity (€/kVA)	**kVA (MIC)**		3.18	3.03
	Energy (cent/kWh)	**WINTER**	Flat (St. meter)	0.12	0.12
			Peak	0.32	0.33
			Off-Peak	0.06	0.06
		SUMMER	Flat (St. meter)	0.06	0.06
			Peak	0.08	0.08
			Off-Peak	0.05	0.05
Commercial & Industrial	**Customer (€/month)**	**Standing Charge 24hr**		9.01	8.76
		Standing Charge Nightsaver		10.23	9.92
	Capacity (€/kVA)	**kVA (MIC)**		3.18	3.02
	Energy (cent/kWh)	**WINTER**	Flat (St. meter)	0.10	0.11
			Peak	0.32	0.33
			Off-Peak	0.06	0.06
		SUMMER	Flat (St. meter)	0.06	0.06
			Peak	0.08	0.08
			Off-Peak	0.05	0.05

Maximum Demand Customers					
				Alternative Tariff T-1 D-1	
Existing Tariff Category	*Components*			Usage Adjusted T-1 D-1a	Fixed Charge Adjusted T-1 D-1b
MD LV	**Customer (€/month)**	**Standing Charge 24hr**		40.40	38.98
	Capacity (€/kVA)	**kVA (MIC)**		3.18	3.02
	Energy (cent/kWh)	**WINTER**	Peak Shoulder Off-Peak	0.43 0.11 0.04	0.43 0.11 0.05
		SUMMER	Shoulder Off-Peak	0.08 0.04 0.00	0.08 0.04 0.00
MD MV	**Customer (€/month)**	**Standing Charge 24hr**		39.89	38.50
	Capacity (€/kVA)	**kVA (MIC)**		1.24	1.18
	Energy (cent/kWh)	**WINTER**	Peak Shoulder Off-Peak	0.41 0.11 0.04	0.41 0.11 0.04
		SUMMER	Shoulder Off-Peak	0.08 0.03	0.08 0.03
MD 38kV	**Customer (€/month)**	**Standing Charge 24hr**		84.26	80.68
	Capacity (€/kVA)	**kVA (MIC)**		0.53	0.51
	Energy (cent/kWh)	**WINTER**	Peak Shoulder Off-Peak	0.38 0.10 0.04	0.38 0.10 0.04
		SUMMER	Shoulder Off-Peak	0.07 0.03	0.07 0.03
MD 110kV	**Customer (€/month)**	**Standing Charge 24hr**		84.26	80.68
	Capacity (€/kVA)	**kVA (MIC)**		0.53 0.00	0.51 0.00
	Energy (cent/kWh)	**WINTER**	Peak Shoulder Off-Peak	0.37 0.10 0.04	0.37 0.10 0.04
		SUMMER	Shoulder Off-Peak	0.07 0.03	0.07 0.03

Table 4: PES Alternative T1 D2

Non-Maximum Demand Customers

Existing Tariff Category	*Components*			Alternative Tariff T-1 D-2: Usage Charges Adjusted T-1 D-2a	Alternative Tariff T-1 D-2: Fixed Charge Adjusted T-1 D-2b
Urban Domestic	**Customer (€/month)**	**Standing Charge 24hr**		5.15	4.90
		Standing Charge Nightsaver		5.60	5.30
	Capacity (€/kVA)	**kVA (MIC)**		3.20	2.90
	Energy (cent/kWh)	**WINTER**	Flat (St. meter)	0.11	0.12
			Peak	0.32	0.33
			Off-Peak	0.06	0.06
		SUMMER	Flat (St. meter)	0.05	0.06
			Peak	0.07	0.08
			Off-Peak	0.05	0.05
Rural Domestic	**Customer (€/month)**	**Standing Charge 24hr**		5.70	5.40
		Standing Charge Nightsaver		6.52	6.13
	Capacity (€/kVA)	**kVA (MIC)**		3.20	2.90
	Energy (cent/kWh)	**WINTER**	Flat (St. meter)	0.11	0.12
			Peak	0.23	0.28
			Off-Peak	0.06	0.07
		SUMMER	Flat (St. meter)	0.06	0.06
			Peak	0.07	0.08
			Off-Peak	0.05	0.05
Commercial & Industrial	**Customer (€/month)**	**Standing Charge 24hr**		9.06	8.54
		Standing Charge Nightsaver		10.29	9.65
	Capacity (€/kVA)	**kVA (MIC)**		3.20	2.89
	Energy (cent/kWh)	**WINTER**	Flat (St. meter)	0.10	0.11
			Peak	0.23	0.28
			Off-Peak	0.06	0.07
		SUMMER	Flat (St. meter)	0.06	0.06
			Peak	0.07	0.08
			Off-Peak	0.05	0.05

Maximum Demand Customers					
				Alternative Tariff T-1 D-2	
Existing Tariff Category	***Components***			**Usage Charges Adjusted T-1 D-2a**	**Fixed Charge Adjusted T-1 D-2b**
MD LV	**Customer (€/month)**	**Standing Charge 24hr**		40.64	37.78
	Capacity (€/kVA)	**kVA (MIC)**		3.20	2.89
	Energy (cent/kWh)	**WINTER**	Peak Shoulder Off-Peak	0.34 0.11 0.04	0.34 0.11 0.04
		SUMMER	Shoulder Off-Peak	0.08 0.04	0.08 0.04
	Max Demand (€/kW)	**WINTER**	Peak Shoulder Off-Peak	5.70 1.49 1.18	5.95 1.77 1.46
		SUMMER	Shoulder Off-Peak	1.07 0.00	1.36 0.06
MD MV	**Customer (€/month)**	**Standing Charge 24hr**		40.13	37.31
	Capacity (€/kVA)	**kVA (MIC)**		1.25	1.13
	Energy (cent/kWh)	**WINTER**	Peak Shoulder Off-Peak	0.32 0.10 0.04	0.32 0.10 0.04
		SUMMER	Shoulder Off-Peak	0.08 0.03	0.07 0.03
	Max Demand (€/kW)	**WINTER**	Peak Shoulder Off-Peak	5.40 1.41 1.10	5.66 1.69 1.39
		SUMMER	Shoulder Off-Peak	1.01 0.00	1.30 0.05
MD 38kV	**Customer (€/month)**	**Standing Charge 24hr**		84.76	77.70
	Capacity (€/kVA)	**kVA (MIC)**		0.54	0.49
	Energy (cent/kWh)	**WINTER**	Peak Shoulder Off-Peak	0.32 0.10 0.04	0.31 0.10 0.04
		SUMMER	Shoulder Off-Peak	0.07 0.03	0.07 0.03
	Max Demand (€/kW)	**WINTER**	Peak Shoulder Off-Peak	3.90 0.60 0.30	4.17 0.89 0.59
		SUMMER	Shoulder Off-Peak	0.26 0.00	0.55 0.02

MD 110kV	**Customer (€/month)**	**Standing Charge 24hr**		84.76	77.70
	Capacity (€/kVA)	**kVA (MIC)**		0.54	0.49
	Energy (cent/kWh)	**WINTER**	Peak	0.31	0.30
			Shoulder	0.10	0.10
			Off-Peak	0.04	0.04
		SUMMER	Shoulder	0.07	0.07
			Off-Peak	0.03	0.03
	Max Demand (€/kW)	**WINTER**	Peak	3.90	4.17
			Shoulder	0.60	0.89
			Off-Peak	0.30	0.59
		SUMMER	Shoulder	0.26	0.55
			Off-Peak	0.00	0.02

Table 5: PES Alternative T4 D1

Non-Maximum Demand Customers

				Alternative Tariff T-4 D-1	
Existing Tariff Category	***Components***			**Usage Charges Adjusted T-4 D-1a**	**Fixed Charge Adjusted T-4 D-1b**
Urban Domestic	**Customer (€/month)**	**Standing Charge 24hr**		5.10	4.98
		Standing Charge Nightsaver		5.55	5.40
	Capacity (€/kVA)	**kVA (MIC)**		3.50	3.34
	Energy (cent/kWh)	**WINTER**	Flat (St. meter)	0.11	0.11
			Peak	0.31	0.32
			Off-Peak	0.06	0.06
		SUMMER	Flat (St. meter)	0.05	0.05
			Peak	0.08	0.08
			Off-Peak	0.05	0.05
Rural Domestic	**Customer (€/month)**	**Standing Charge 24hr**		5.65	5.50
		Standing Charge Nightsaver		6.45	6.27
	Capacity (€/kVA)	**kVA (MIC)**		3.50	3.34
	Energy (cent/kWh)	**WINTER**	Flat (St. meter)	0.11	0.11
			Peak	0.31	0.32
			Off-Peak	0.06	0.06
		SUMMER	Flat (St. meter)	0.05	0.05
			Peak	0.08	0.08
			Off-Peak	0.05	0.05
Commercial & Industrial	**Customer (€/month)**	**Standing Charge 24hr**		8.98	8.72
		Standing Charge Nightsaver		10.19	9.88
	Capacity (€/kVA)	**kVA (MIC)**		3.49	3.33
	Energy (cent/kWh)	**WINTER**	Flat (St. meter)	0.10	0.10
			Peak	0.31	0.32
			Off-Peak	0.06	0.06
		SUMMER	Flat (St. meter)	0.06	0.06
			Peak	0.07	0.08
			Off-Peak	0.05	0.05

Maximum Demand Customers

Existing Tariff Category	*Components*			Alternative Tariff T-4 D-1: Usage Charges Adjusted T-4 D-1a	Alternative Tariff T-4 D-1: Fixed Charge Adjusted T-4 D-1b
MD LV	**Customer (€/month)**	**Standing Charge 24hr**		40.24	38.81
	Capacity (€/kVA)	**kVA (MIC)**		3.49	3.33
	Energy (cent/kWh)	**WINTER**	Peak	0.42	0.43
			Shoulder	0.11	0.11
			Off-Peak	0.04	0.04
		SUMMER	Shoulder	0.08	0.08
			Off-Peak	0.03	0.03
MD MV	**Customer (€/month)**	**Standing Charge 24hr**		39.74	38.34
	Capacity (€/kVA)	**kVA (MIC)**		1.55	1.48
	Energy (cent/kWh)	**WINTER**	Peak	0.40	0.40
			Shoulder	0.10	0.10
			Off-Peak	0.04	0.04
		SUMMER	Shoulder	0.08	0.08
			Off-Peak	0.03	0.03
MD 38kV	**Customer (€/month)**	**Standing Charge 24hr**		83.93	80.34
	Capacity (€/kVA)	**kVA (MIC)**		0.84	0.81
	Energy (cent/kWh)	**WINTER**	Peak	0.37	0.37
			Shoulder	0.10	0.10
			Off-Peak	0.04	0.04
		SUMMER	Shoulder	0.07	0.07
			Off-Peak	0.03	0.03
MD 110kV	**Customer (€/month)**	**Standing Charge 24hr**		83.93	80.34
	Capacity (€/kVA)	**kVA (MIC)**		0.81	0.79
	Energy (cent/kWh)	**WINTER**	Peak	0.36	0.37
			Shoulder	0.09	0.10
			Off-Peak	0.04	0.04
		SUMMER	Shoulder	0.07	0.07
			Off-Peak	0.03	0.03

Table 6: PES Alternative T4 D2

Non-Maximum Demand Customers

<table>
<tr><th colspan="4"></th><th colspan="2">Alternative Tariff
T-4 D-2</th></tr>
<tr><th>Existing Tariff Category</th><th colspan="3">Components</th><th>Usage Charges Adjusted
T-4 D-2a</th><th>Fixed Charge Adjusted
T-4 D-2b</th></tr>
<tr><td rowspan="10">Urban Domestic</td><td rowspan="2">Customer (€/month)</td><td colspan="2">Standing Charge 24hr</td><td>5.09</td><td>4.88</td></tr>
<tr><td colspan="2">Standing Charge Nightsaver</td><td>5.54</td><td>5.28</td></tr>
<tr><td>Capacity (€/kVA)</td><td colspan="2">kVA (MIC)</td><td>3.49</td><td>3.21</td></tr>
<tr><td rowspan="6">Energy (cent/kWh)</td><td rowspan="3">WINTER</td><td>Flat (St. meter)</td><td>0.11</td><td>0.11</td></tr>
<tr><td>Peak</td><td>0.31</td><td>0.32</td></tr>
<tr><td>Off-Peak</td><td>0.06</td><td>0.06</td></tr>
<tr><td rowspan="3">SUMMER</td><td>Flat (St. meter)</td><td>0.05</td><td>0.05</td></tr>
<tr><td>Peak</td><td>0.07</td><td>0.08</td></tr>
<tr><td>Off-Peak</td><td>0.05</td><td>0.05</td></tr>
<tr><td colspan="5"></td></tr>
<tr><td rowspan="9">Rural Domestic</td><td rowspan="2">Customer (€/month)</td><td colspan="2">Standing Charge 24hr</td><td>5.64</td><td>5.38</td></tr>
<tr><td colspan="2">Standing Charge Nightsaver</td><td>6.45</td><td>6.11</td></tr>
<tr><td>Capacity (€/kVA)</td><td colspan="2">kVA (MIC)</td><td>3.49</td><td>3.21</td></tr>
<tr><td rowspan="6">Energy (cent/kWh)</td><td rowspan="3">WINTER</td><td>Flat (St. meter)</td><td>0.11</td><td>0.11</td></tr>
<tr><td>Peak</td><td>0.31</td><td>0.32</td></tr>
<tr><td>Off-Peak</td><td>0.06</td><td>0.06</td></tr>
<tr><td rowspan="3">SUMMER</td><td>Flat (St. meter)</td><td>0.05</td><td>0.05</td></tr>
<tr><td>Peak</td><td>0.07</td><td>0.08</td></tr>
<tr><td>Off-Peak</td><td>0.05</td><td>0.05</td></tr>
<tr><td rowspan="9">Commercial & Industrial</td><td rowspan="2">Customer (€/month)</td><td colspan="2">Standing Charge 24hr</td><td>8.96</td><td>8.51</td></tr>
<tr><td colspan="2">Standing Charge Nightsaver</td><td>10.18</td><td>9.62</td></tr>
<tr><td>Capacity (€/kVA)</td><td colspan="2">kVA (MIC)</td><td>3.49</td><td>3.21</td></tr>
<tr><td rowspan="6">Energy (cent/kWh)</td><td rowspan="3">WINTER</td><td>Flat (St. meter)</td><td>0.10</td><td>0.10</td></tr>
<tr><td>Peak</td><td>0.31</td><td>0.32</td></tr>
<tr><td>Off-Peak</td><td>0.06</td><td>0.06</td></tr>
<tr><td rowspan="3">SUMMER</td><td>Flat (St. meter)</td><td>0.05</td><td>0.06</td></tr>
<tr><td>Peak</td><td>0.07</td><td>0.08</td></tr>
<tr><td>Off-Peak</td><td>0.05</td><td>0.05</td></tr>
</table>

Maximum Demand Customers

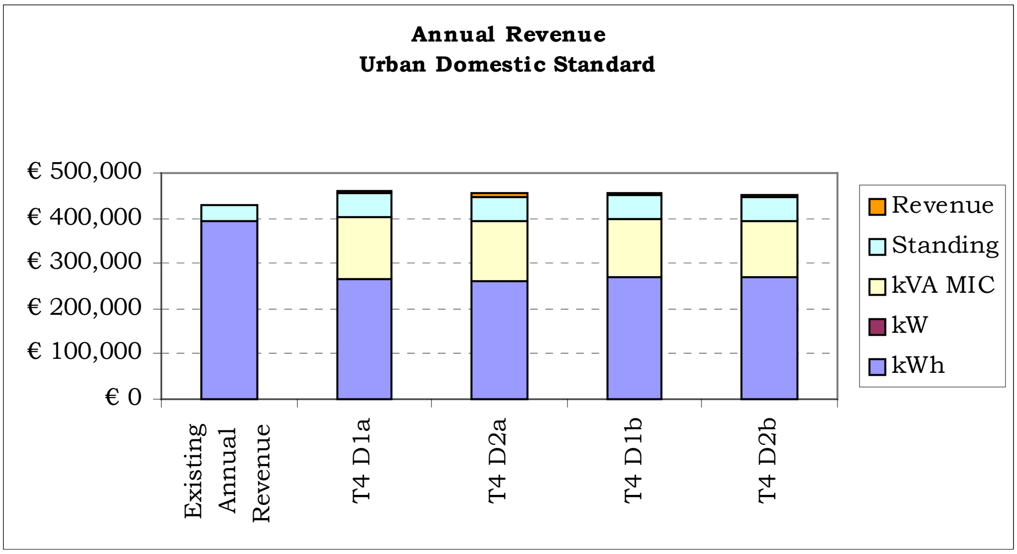
				Alternative Tariff T-4 D-2	
Existing Tariff Category	***Components***			**Usage Charges Adjusted T-4 D-2a**	**Fixed Charge Adjusted T-4 D-2b**
MD LV	**Customer (€/month)**	**Standing Charge 24hr**		40.19	37.64
	Capacity (€/kVA)	**kVA (MIC)**		3.49	3.21
	Energy (cent/kWh)	**WINTER**	Peak	0.33	0.33
			Shoulder	0.10	0.10
			Off-Peak	0.04	0.04
		SUMMER	Shoulder	0.08	0.08
			Off-Peak	0.03	0.03
	Max Demand (€/kW)	**WINTER**	Peak	5.63	5.93
			Shoulder	1.47	1.76
			Off-Peak	1.16	1.45
		SUMMER	Shoulder	1.06	1.35
			Off-Peak	0.00	0.06
MD MV	**Customer (€/month)**	**Standing Charge 24hr**		39.69	37.18
	Capacity (€/kVA)	**kVA (MIC)**		1.54	1.43
	Energy (cent/kWh)	**WINTER**	Peak	0.32	0.32
			Shoulder	0.10	0.10
			Off-Peak	0.04	0.04
		SUMMER	Shoulder	0.07	0.07
			Off-Peak	0.03	0.03
	Max Demand (€/kW)	**WINTER**	Peak	5.34	5.64
			Shoulder	1.39	1.68
			Off-Peak	1.09	1.38
		SUMMER	Shoulder	1.00	1.29
			Off-Peak	0.00	0.05
MD 38kV	**Customer (€/month)**	**Standing Charge 24hr**		83.83	77.41
	Capacity (€/kVA)	**kVA (MIC)**		0.84	0.79
	Energy (cent/kWh)	**WINTER**	Peak	0.31	0.31
			Shoulder	0.09	0.09
			Off-Peak	0.04	0.04
		SUMMER	Shoulder	0.07	0.07
			Off-Peak	0.03	0.03
	Max Demand (€/kW)	**WINTER**	Peak	3.86	4.15
			Shoulder	0.60	0.89
			Off-Peak	0.30	0.58
		SUMMER	Shoulder	0.26	0.54
			Off-Peak	0.00	0.02

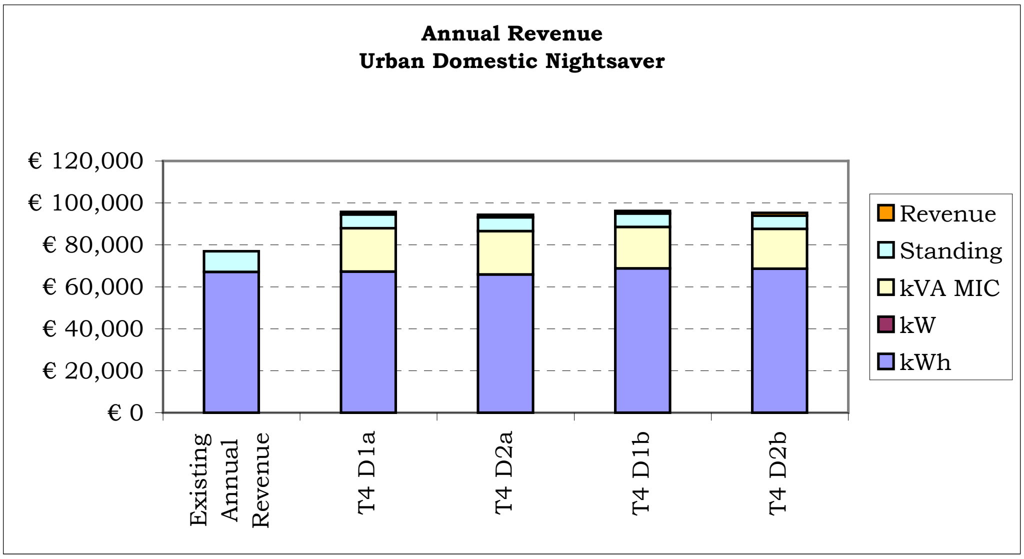
MD 110kV	**Customer (€/month)**	**Standing Charge 24hr**		83.83	77.41
	Capacity (€/kVA)	**kVA (MIC)**		0.81	0.77
	Energy (cent/kWh)	**WINTER**	Peak	0.30	0.30
			Shoulder	0.09	0.09
			Off-Peak	0.04	0.04
		SUMMER	Shoulder	0.07	0.07
			Off-Peak	0.03	0.03
	Max Demand (€/kW)	**WINTER**	Peak	3.86	4.15
			Shoulder	0.60	0.89
			Off-Peak	0.30	0.58
		SUMMER	Shoulder	0.26	0.54
			Off-Peak	0.00	0.02

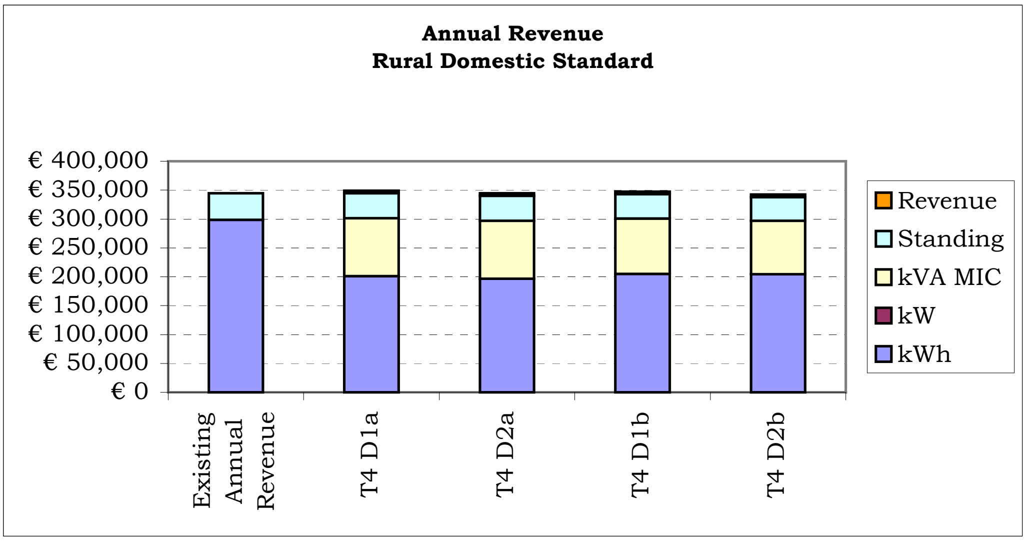
APPENDIX C: ANNUAL PES REVENUES BY CUSTOMER CATEGORY UNDER EXISTING AND ALTERNATIVE TARIFF STRUCTURES

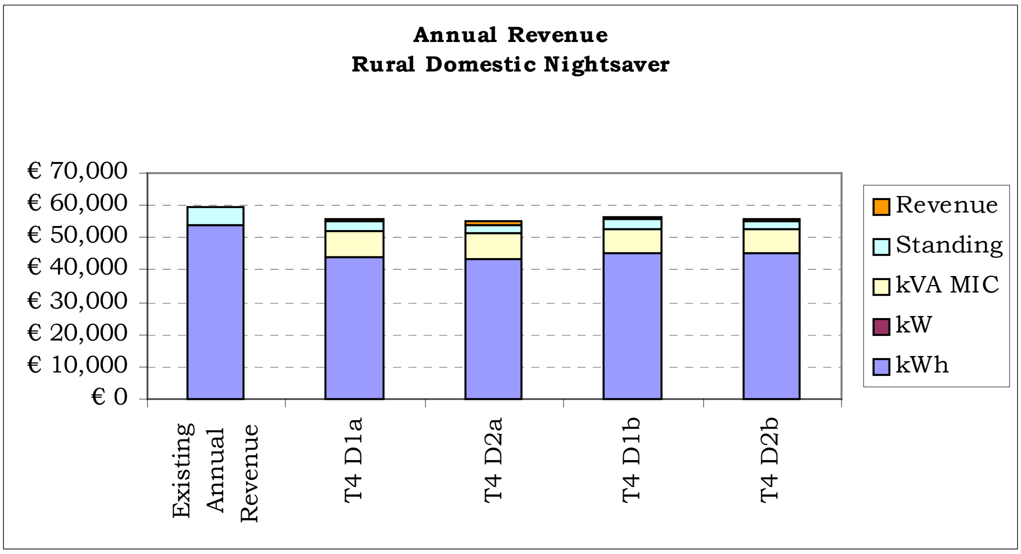
The bar charts below show the composition of the annual revenues in terms of tariff components for selected PES tariffs using TUoS option T4 (see section 3 of the paper). Note that the segment of the bars labelled “revenue” is the portion of PES costs recovered on the basis of revenue.

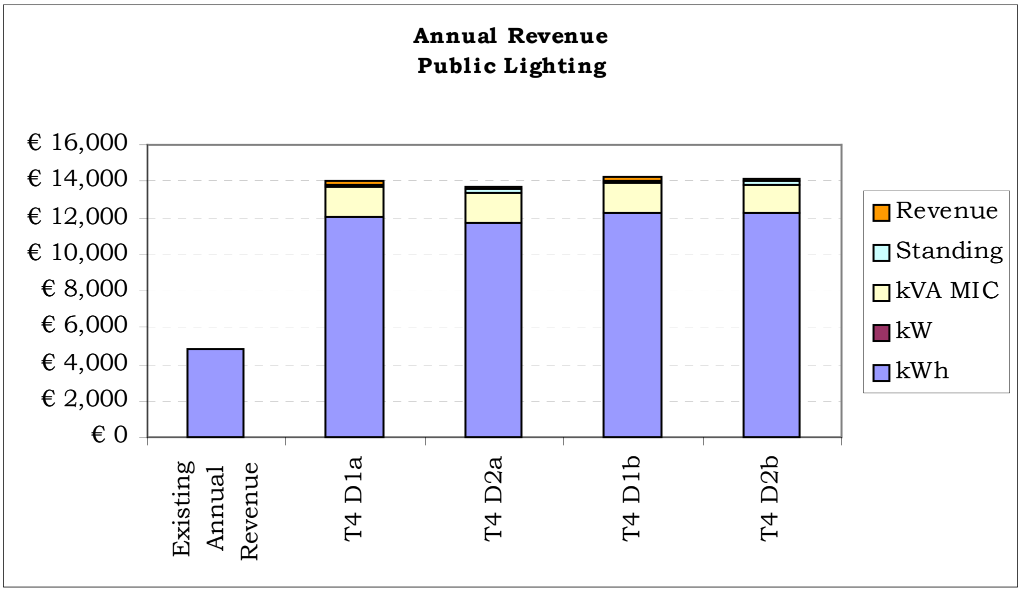
Note also that the diagrams are scaled to denote actual revenue changes and not percentage changes.

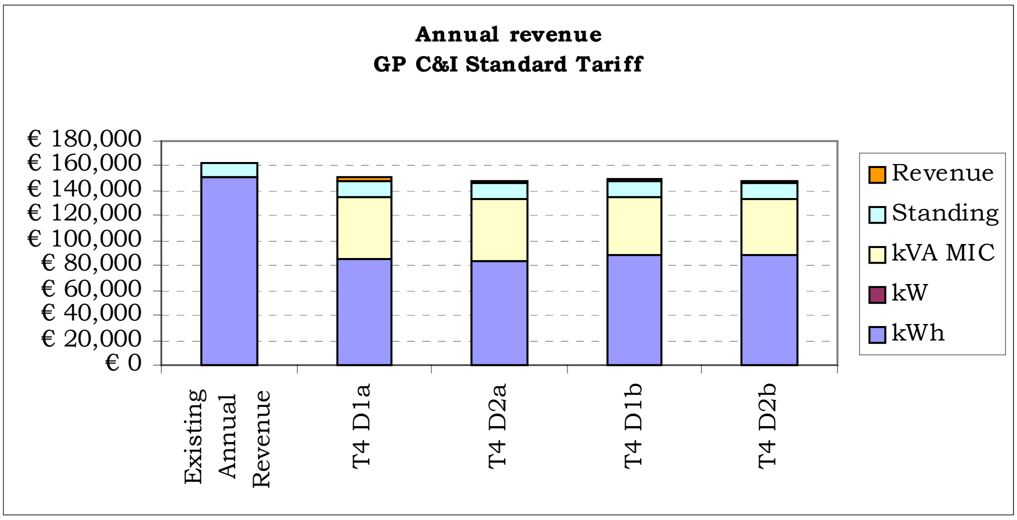


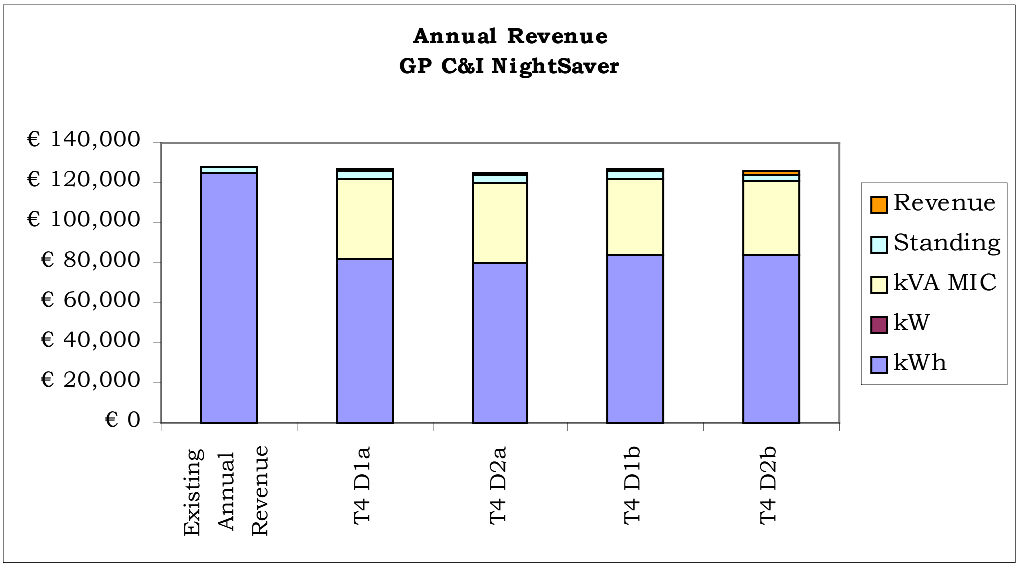


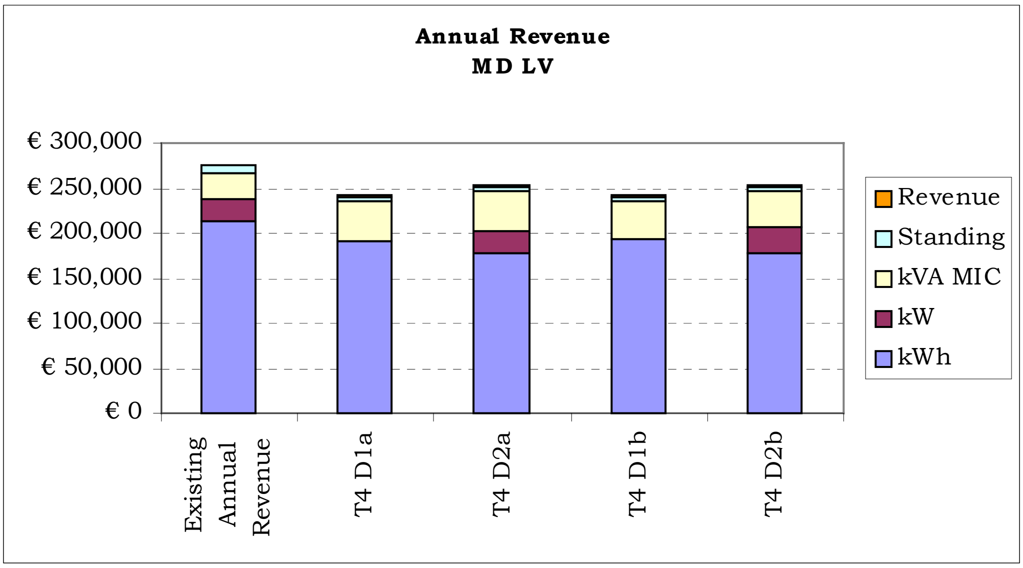

Annual Revenue
Rural Domestic Standard
€ 400,000
€ 350,000
€ 300,000
€ 250,000
€ 200,000
€ 150,000
€ 100,000
€ 50,000
€ 0
Existing Annual Revenue
T4 D1a
T4 D2a
T4 D1b
T4 D2b
Revenue
Standing
kVA MIC
kW
kWh

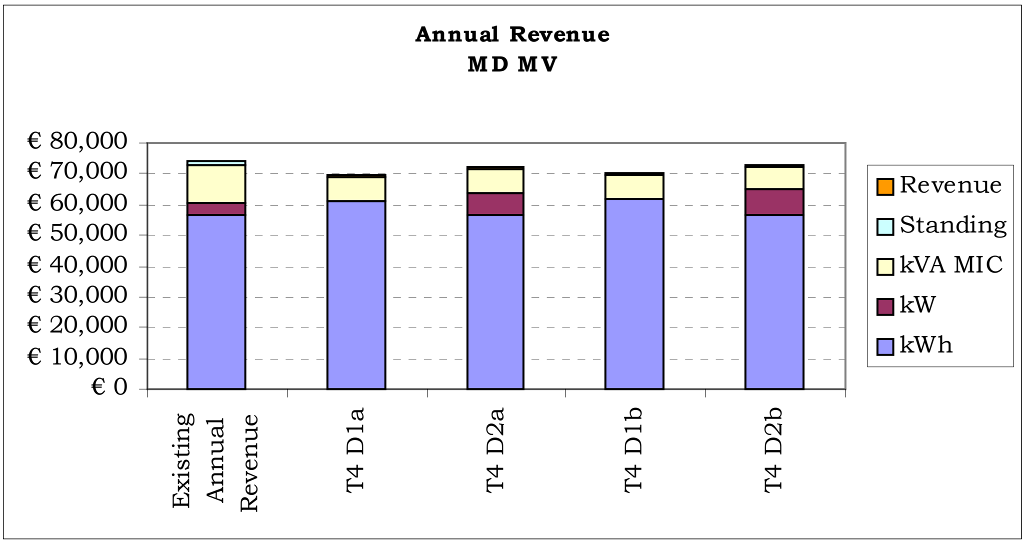

Annual Revenue
Rural Domestic Nightsaver
€ 70,000
€ 60,000
€ 50,000
€ 40,000
€ 30,000
€ 20,000
€ 10,000
€ 0
Existing Annual Revenue
T4 D1a
T4 D2a
T4 D1b
T4 D2b
Revenue
Standing
kVA MIC
kW
kWh

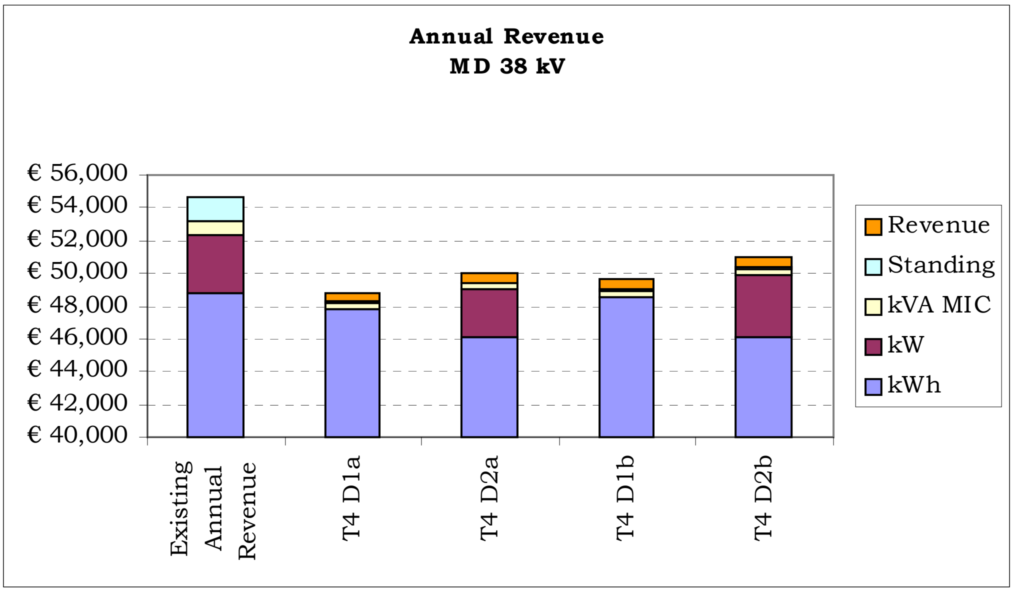

Annual Revenue
Public Lighting
€ 16,000
€ 14,000
€ 12,000
€ 10,000
€ 8,000
€ 6,000
€ 4,000
€ 2,000
€ 0
Existing Annual Revenue
T4 D1a
T4 D2a
T4 D1b
T4 D2b
Revenue
Standing
kVA MIC
kW
kWh

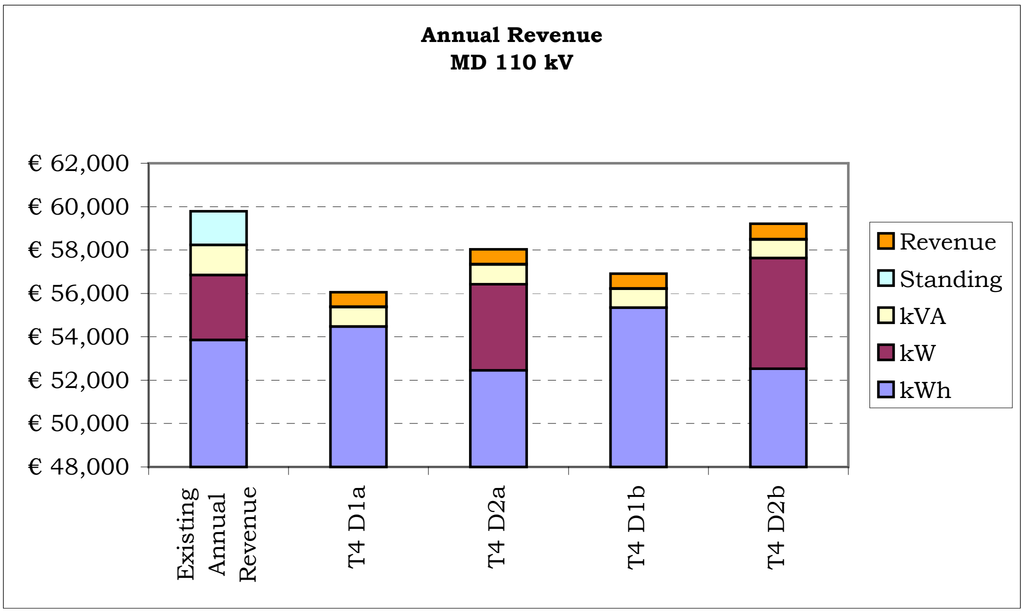

Annual revenue
GP C&I Standard Tariff
€ 180,000
€ 160,000
€ 140,000
€ 120,000
€ 100,000
€ 80,000
€ 60,000
€ 40,000
€ 20,000
€ 0
Existing Annual Revenue
T4 D1a
T4 D2a
T4 D1b
T4 D2b
Revenue
Standing
kVA MIC
kW
kWh


Annual Revenue
GP C&I NightSaver
€ 140,000
€ 120,000
€ 100,000
€ 80,000
€ 60,000
€ 40,000
€ 20,000
€ 0
Existing Annual Revenue
T4 D1a
T4 D2a
T4 D1b
T4 D2b
Revenue
Standing
kVA MIC
kW
kWh


Annual Revenue
MD LV
€ 300,000
€ 250,000
€ 200,000
€ 150,000
€ 100,000
€ 50,000
€ 0
Existing Annual Revenue
T4 D1a
T4 D2a
T4 D1b
T4 D2b
Revenue
Standing
kVA MIC
kW
kWh


Annual Revenue
MD MV
€ 80,000
€ 70,000
€ 60,000
€ 50,000
€ 40,000
€ 30,000
€ 20,000
€ 10,000
€ 0
Existing Annual Revenue
T4 D1a
T4 D2a
T4 D1b
T4 D2b
Revenue
Standing
kVA MIC
kW
kWh


Annual Revenue
MD 38 kV
€ 56,000
€ 54,000
€ 52,000
€ 50,000
€ 48,000
€ 46,000
€ 44,000
€ 42,000
€ 40,000
Existing Annual Revenue
T4 D1a
T4 D2a
T4 D1b
T4 D2b
Revenue
Standing
kVA MIC
kW
kWh


Annual Revenue
MD 110 kV
€ 62,000
€ 60,000
€ 58,000
€ 56,000
€ 54,000
€ 52,000
€ 50,000
€ 48,000
Existing Annual Revenue
T4 D1a
T4 D2a
T4 D1b
T4 D2b
Revenue
Standing
kVA
kW
kWh