ESB Customer Supply

Tariff Methodology Statement

for

Tariff Period

1st October 2009 to 30th September 2010

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Appendices

1. Introduction

The purpose of the Tariff Methodology Statement is to set out clearly the methodology that ESB Customer Supply (ESBCS) uses to set regulated tariffs. This includes information on how costs are allocated to tariffs along with information on proposed changes to existing tariff structures and the formation of new tariffs. The Tariff Methodology Statement is approved by the Commission for Energy Regulation (CER).

1.1 Statutory and Licence Requirements

The functions of the Commission in relation to electricity are set down in Section 9 of the Electricity Regulation Act 1999 as amended by subsequent Statutory Instruments. SI 60 2005 {European Communities(Internal Market in Electricity) Regulations 2005} provides for the amendment of Section 9 of the 1999 Act for the purposes of assigning the Commission with the power to issue directions to ESB as the Public Electricity Supplier (PES) in relation to its costs, including tariffs. The legal basis for retail tariff regulation is also subject to EC Directive 2003/54/EC of the 23rd June 2003 which relates to the liberalisation of European energy markets.

ESB was granted an Interim Public Electricity Supply Licence in April 2006[1] (revised 25th Oct 2007) and ESBCS carries out the role of the PES. Condition three of the interim licence 'Terms of Supply to Final Customers' outlines the obligations on ESBCS in relation to tariffs.

1.2 General Principles

In line with the statutory and Licence obligations in relation to tariff setting, the key principles being applied in setting tariffs are centred around cost recovery, cost reflectivity and non-discrimination across customer groups. The main objectives for ESBCS in setting the tariffs are to :
:

- *Achieve cost reflectivity and non-discrimination across customer tariff groups.*
- *Provide appropriate economic price signals to customers.*
- *Deliver tariffs that are transparent, understandable and can be implemented.*

In setting these tariffs, any necessary revenue correction factors will be applied with due consideration to the impact on retail competition

2 Background Assumptions for Tariff Calculations

This section discusses the approach to arriving at the customer demand forecasts that are used to determine the projected costs and revenues for the tariff period. While such forecasts might be discussed and presented in aggregate annual terms of customer consumption and/or demand growth rates at the retail level, they must be provided to a half-hourly granularity for the purposes of projecting ESBCS costs in the wholesale market.

[1] CER/06/073

Section 3 describes assumptions regarding the cost components associated with satisfying this projected customer demand.

2.1 Demand Forecasting

A combination of 'bottom-up' and 'top-down' forecasting techniques are used with up-to-date inputs from the ESBCS customer billing and market settlement IT systems to provide a reference-case, central scenario.

- The 'bottom-up' approach produces a forecast for each tariff group. These are then summed to arrive at the forecast of ESBCS overall consumption.
- The 'top-down' approach starts with a forecast of total consumption in the market and arrives at the ESBCS forecast by considering ESBCS projected market share. This is used as a "sense" check on the bottom-up forecasts.

With the introduction of the Single Electricity Market (SEM) and half-hourly wholesale pricing, the emphasis is on the "bottom-up" disaggregated approach.

2.1.1 Market Consumption

Total Final Consumption (TFC) in the RoI market comprises ESBCS consumption, independent supplier consumption and the local own-use of CHP or small-scale generation plant. As noted in EIRGRID's Generation Adequacy Review, this own-use or self-generation represents approximately 2% of system demand.

The baseline for projections (currently TFC in 2008) is derived from published system demand and settlement quantities and the estimation of own-use. Forecasts are then produced using established techniques, as discussed below.

The primary driver of electricity demand growth has traditionally been shown to be the performance of the country's economy and it has become standard international practice to use Gross Domestic Product (GDP) as the causal input to the electricity demand forecast model. While this will establish a standard forecast, we must also have regard to the myriad uncertainties which impact on demand and their potential to introduce step changes over the forecast period.

Such uncertainties, affecting electricity usage, include:
- Any change in the relationship of demand drivers (GDP) with final demand
- National economic climate subject to change within a year
- Population growth and house-build
- Structural growth (residential/commercial/industrial)
- Impact of lifestyle changes on customer consumption levels
- Public perception (e.g. environmental & conservation considerations)
- Take-up by customers of new technologies or products
- Impact of fuel availabilities & prices
- Weather and other short-term significant events (e.g. live-TV) which will affect half-hourly demands but are not explicitly catered for in the Pricing timeframe.

These considerations notwithstanding, forecasts of TFC for future years can be derived using a 'top-down' approach with GDP as the main causal input. This is characterised by the application of standard regression analysis to historic pairs of annual TFC and corresponding GDP values to give average annual growth rates over the planning period. Projections of GDP correspond to the ESRI forecast of their most recent 'Medium Term Review'. The resultant demand forecasts are then typically tested for reasonableness by comparison with those provided in the System Operator's most recent Generation Adequacy Review. Where it is judged necessary, the forecast may be adjusted to take account of revised assumptions generated by any of the uncertainties listed above.

In the case of the 2009/10 forecast the rapidly developing recession has required increased reliance on recent actual demand measurements.

2.1.2 ESBCS Market Share

The 'bottom-up' analysis allows us to make explicit assumptions to give a more detailed view. In this 'bottom-up' approach forecasts are produced for each tariff group, which are then summed to arrive at the forecast of ESBCS overall consumption. This entails setting out assumptions with regard to expected customer movements for each customer tariff category taking into account both new connections and movements to and from other suppliers, as well as the appropriate sizing of each of these customer tranches.

A 'top-down' analysis approach can be used to provide an initial global estimate for ESBCS share of this forecast market TFC. Obviously, this share will depend on the activity of independent suppliers in the market, and the primary determinant of this is their access to generation. With the advent of the SEM, assumptions regarding access of suppliers to generation are more difficult to formulate.

The resultant forecasts from the 'top-down' and 'bottom-up' approaches can then be reconciled to give the required central projection of ESBCS customer numbers and consumption for the tariff period. Because of the current continuing significant loss of market share to increased competition in the domestic sector, the "bottom up" or disaggregated approach is the primary basis for the ESBCS demand forecast for the 2009/10 tariff year.

2.1.3 ESBCS Demand Volume and Shape

The above customer consumption forecasts at the retail level are translated into corresponding forecasts of wholesale energy purchase requirements at the half-hourly level. There is therefore a shape element as well as a volume element to the projections.

Since ESBCS's wholesale electricity demand for settlement purposes continues to be derived using the differencing methodology, this will differ from the wholesale demand calculated by application of standard tariff profiles and Distribution Loss Adjustment Factors (DLAFs) to the associated retail consumption (in common with other suppliers). While piecemeal adjustment of selected tariff profiles can be made to achieve a better fit for historic values, this is not the enduring solution which will be provided by the introduction of global aggregation.

Obviously, the shape of our wholesale demand forecasts has become an increasingly important factor with the advent of the SEM, since they essentially determine our optimised portfolio of hedge contracts and pool purchases.

3 Tariff Cost Elements

There are four main tariff cost elements.

1. Wholesale Generation Costs
2. Network Charges
3. Supply Costs
4. Public Service Obligation Levy

3.1 Wholesale Generation costs

Energy is purchased at the wholesale level in the Single Electricity Market (SEM or "pool market") to meet customers' energy demand and the energy losses that occur transporting the energy directly to the customer.

The largest component of Wholesale Costs is the cost of electricity purchased from the Pool at prices which reflect the market value of wholesale electricity (which in turn are expected to reflect the marginal costs of the marginal generator). This component is the System Marginal Price (SMP)[2]. The second largest component of Wholesale costs are the Capacity Charges deriving from the Capacity Payment Mechanism which assigns a fixed cost associated with having generation plant available to provide electricity to the Pool. The other pool-related costs are the Market Operator Charges and Imperfections Charges.[3]

The SMP varies by half-hourly trading interval. In order to stabilise the price of electricity over a period, ESBCS enters into Contracts for Differences (CfDs) with generators. Stabilising the price at which energy is bought from the Pool is known as "hedging" or "contracting" and may bring an additional cost (or produce a discount) relative to the SMP.

Almost all of the energy required to meet ESBCS customer demand and transportation losses is purchased in the Pool. The balance is made up from generators with capacity of less than 10MW.

ESBCS Wholesale Generation Costs can be categorised as follows:

- Pool Energy Costs at (SMP) and Contract Costs (at fixed strike prices)
- Generator Capacity Payment Mechanism Costs
- Market Operator Costs
- Imperfections Costs

Contract types may include :

- Directed Contracts (DCs)
- Non-Directed Contracts (NDCs), including
- Public Service Obligation (PSO) – backed NDCs

Each of these contract types comprises a series of individual contracts with strike prices and volumes.

[2] To help to minimise any possible confusion, this document will use the term SMP when referring to the marginal cost of electricity as purchased from the pool.
[3] This document will refer to Wholesale Pool Price as the "Consolidated Pool Price" (CPP). CPP = SMP + Capacity Payment Price + Market Operator Price + Imperfection Price.

3.1.1 Pool Energy (SMP) Costs

The Trading and Settlement Code defines the market trading rules and procedures for buying or selling wholesale electricity. All energy from generators greater than (>) 10MW is purchased by Suppliers via the Electricity Pool. The Pool facilitates a competitive bidding process between generators that sets the wholesale price paid for electricity for each half hour period of every day and establishes the preferred generation merit order at the day ahead stage. The pool price is known as the "System Marginal Price" (SMP).

The Electricity Pool SMP price is the driver of wholesale electricity costs.

Because the SMP varies and can be volatile, suppliers and generators can enter financial contracts (hedges) to fix or stabilise the cost of the energy transfers between them. There may be premiums or discounts relative to the (forecast) pool price that arise from hedging. These should be relatively small given the existence of a separate capacity payment for generators and the desire for both suppliers and generators to have certainty about costs and revenues over the contracting period.

As ESBCS offers regulated fixed tariffs, it has, as a key objective, to hedge its exposure to the variable SMP (i.e. fix its input energy costs). This is achieved in accordance with a Hedging Policy and Methodology approved by CER in the context of the PES Economic Purchase Obligation (EPO).

In each half-hourly trading period, where ESBCS is "under-hedged" it buys electricity from the pool at the pool price to meet its aggregate customer demand requirement. When ESBCS is "over-hedged" it effectively "sells" electricity back to the pool at the pool price. The forecast SMP which inputs to the tariff calculations is generated by the Industry standard modelling software (PLEXOS) using forward fuel price estimates close to tariff setting time.

3.1.1.1Contract Costs

The effective cost of each contract type is the agreed strike price multiplied by the contracted volume. This cost is made up of two payment types, firstly a payment to the Market Operator at the outturn SMP and secondly a "difference payment" to the contract counterparty (usually a generator) which is the difference between the agreed strike price and the outturn SMP.

There are three different types of contracts that ESBCS has entered into for the period 1st October 2009 to 30th September 2010 based on the nature of the contract and the counterparty.

(1) Directed Contract (DC) Costs

Each year since the start of the SEM, the Regulatory Authorities have put in place a suite of DCs as part of a market power mitigation strategy on the incumbent generators (ESB Power Generation and NIE Energy Power Procurement Business). In common with all eligible suppliers in the market, ESBCS is allocated a volume of DCs according to its retail market share. For tariff year 2009/10, these CfDs were purchased in May/June 2009 at prices determined by regulatory formula.

The Directed Contracts are defined standard contracts with the following characteristics:

- Quarterly contracts with equal MW volumes in each month of the Quarter
- In the form of the standard Base-load, Mid-Merit 1 or Peak "block" contracts.

(2) Non-Directed Contract (NDC) Costs

These contracts are, similarly, Contracts for Differences (CfDs) entered into with ESBPG and NIEEPPB through the auction process held over the period from mid-May through July 2009.

(3) Public Service Obligation (PSO) Contract Costs

The Public Service Obligation (PSO) is a legislative requirement to support the purchase of electricity from specified sources including sustainable, renewable, and indigenous sources. PSO-backed contracts are also made available to the market through the NDC auction process and all suppliers, including ESBCS, can bid for them. The auction took place over six auction days in late June& early July

It is worth noting that contract costs may also have exchange risks that need to be hedged separately.

3.1.2 Capacity Charges

The Capacity Payments Mechanism under the Single Electricity Market (SEM) is a mechanism which allocates an amount of money (the Annual Capacity Payment Sum[4]) determined prior to the start of each year into monthly amounts and is paid to generators based on their availability in each half-hour.

These capacity payments are recovered via capacity charges levied on each supplier according to their demand. Capacity charges are allocated to all ESBCS customers, regardless of tariff category, on the same €/MWh basis (at the trading point) in each trading period.

The overall capacity charge for each customer will depend on the overall demand profile for that customer i.e. the level of demand and the coincidence between the customer's demand and the system demand.

As with the SMP costs, the actual cost of capacity in each trading period (in €/MWh) is not finalised until ex-post, and ESBCS forecasts the cost curve for input to tariff-setting.

3.1.3 Other Energy Market Costs

Market Operator Charges (the costs of operating the pool market) and Imperfections Charges (which include transmission congestion charges and currency charges) are other market costs that will be included in the final retail tariffs. These costs apply to all suppliers in the market will be fixed for the tariff year 1st October 2009 to 30th September 2010 and will be allocated to customers on a demand (i.e. per MWh) basis.

[4] Determination of the annual sum is based on the product of two numbers:
• A volume element (the Capacity Requirement) - the quantity of capacity required to just meet an all-island adequacy standard; and
• A price element – the fixed costs of a Best New Entrant (BNE) peaking plant.

3.2 Network Charges

These are the energy transportation costs or the "toll" associated with transporting energy from the point of purchase (trading point) to point of sale (customer point). Costs arising from the use of the transmission and distribution networks follow from the regulatory approved tariffs i.e. the Transmission Use of System Charges (TUoS) and the Distribution Use of System Charges (DUoS) which are published annually in advance of tariff setting.

3.3 Public Electricity Supply (PES) Costs & Margin

ESBCS is the licensed PES in the Republic of Ireland. ESBCS costs & margin have been approved by the Commission in the 2006-2010 ESB Price Control Review - Public Electricity Supply ref CER/05/164. The allowed revenue comprises operating expenditure (opex), depreciation charges on capital expenditure (derived from the allowable capex) as well as the allowed margin. Allowed revenue also reflects a customer service incentive payment or penalty linked to the performance of the Customer Contact Centre. Operating expenditure was approved under specified headings including payroll, bad debt provision, shared service costs, contact centre operations, etc.[5]

The approach taken by the Commission in approving the allowed costs for the period 2006 – 2010 was to set allowed costs for a base year and thereafter to link changes in allowed costs to inflation.

3.4 Public Service Obligation Levy Costs

The PSO was first imposed by the Minister for Communications, Marine and Natural Resources on the Electricity Supply Board (ESB) on 1st January 2003 and has been amended from time to time since. It requires ESB to purchase power from specified sources, including, but not limited to, peat, renewable and other sustainable sources. The Act specifies four areas which the PSO can cover:

(a) security of supply,
(b) regularity, quality and price of supplies,
(c) environmental protection, and
(d) use of indigenous energy sources.

The Commission for Energy Regulation (CER) is required to calculate and notify all relevant parties of the level of the Public Service Obligation (PSO) levy each year in accordance with section 39 of the Electricity Regulation Act 1999 (the Act), (Public Service Obligations) Order 2002 (SI 217 of 2002) as amended.

For domestic customers, the PSO levy is a fixed charge per customer basis
For small commercial customers with an MIC < 30kVA, the PSO Levy is charged on a fixed cost per customer basis.
For medium and large customers with an MIC > 30kVA, the PSO Levy is charged per kVA.

[5] Further detailed information on the allowed revenue is available in the published document CER/05/164, Table 3.2 Opex Allowed Decision.

For 2009/2010 the CER has set the PSO Levy to zero.

3.5 Existing Tariffs for 2008/9

The CER Price determination (CER/08/246) of December 1st 2008 set prices to apply for the period 1st January 2009 to 30th September 2009. This implemented a price reduction of less than 1% on average to ESBCS customers on fixed tariffs. The determination stated that “there would be no further change in tariffs for the regulated tariff classes for the remainder of the 2008/09 tariff year to 30th September 2009.

However, in February 2009, in response to a request from the Minister for Communications, Energy and Natural Resources, the Commission undertook an in-depth look at the electricity retail market followed by an examination of the options available for the reduction of tariffs in the short term.

In considering the case for an immediate reduction in prices, CER examined the level of tariffs in place. This review showed that ESBCS tariffs were cost reflective and did not warrant a price reduction. It also showed that, based on fuel market trends, there was likely to be scope for a tariff reduction from October 2009. The Commission brought this price reduction forward through a mechanism of re-profiling network charges in the period May through September 2009, issuing a decision paper on 9th April 2009 (CER/09/053) which resulted in a reduction of the order of 10% in electricity prices for all customers (regardless of supplier).

4 Customer Groupings

4.1 Tariff Groups

The grouping of customers for tariff purposes was fundamentally based on customer type; Domestic, Small Commercial and Large Commercial & Industrial Customer. Historically, this classification was the obvious one because each customer type had a different consumption level range and thus metering arrangement, a different service level expectation and an appropriate tariff complexity level.

Within each of these Customer type groupings, there are different sub-tariff categories.

The main Tariff Groups and Sub-Tariffs are as follows:

Regulated tariffs

There are 4 regulated tariff groups :

Domestic tariffs: Urban 24 Hour, Urban Nightsaver, Rural 24 Hour, Rural Nightsaver

General Purpose (GP) Tariffs : GP 24 Hour, GP Nightsaver, Residential Business Premises (RBP) 24 Hour, RBP Nightsaver

Low Voltage Max Demand (LVMD) Tariffs : Low Load Factor, LVMD

Public Lighting (PL) Tariffs : PL Unmetered 24-hour, Dusk to Midnight, Dusk to Dawn, Single Point

Consistent with licence obligations, it is an objective of ESBCS in formulating tariffs to achieve cost reflectivity and non-discrimination across these tariff groups. For each of these groups the proposed tariffs will reflect the costs associated with the group.

Unregulated tariffs

Large Energy User (LEU) Tariffs: Large Energy Users are customers supplied at voltages of 10kV, 20kV, 38kV & 110kV. Since 1st March 2008 these customers are supplied on one of two variants of a Pool Price Pass Through (PPPT[6]) tariff in accordance with the Commission's direction in CER/07/191. The two variants are:

1) Individual PPPT
2) Group PPPT

More details of ESBCS's tariff groupings are set out in Appendix 1 and Appendix 2.

[6] A PPPT tariff is a variable tariff where the energy cost component of the tariff is related to the forecasted Day ahead System Marginal Price (SMP) of electricity in the All Island Electricity Pool Market. The forecasted SMP is variable on a half-hourly trading period.

4.2 Load Profiles

The forecast energy demand profiles used to forecast demand shape (load shape), which is the determinant of energy and Transmission network costs, for the different customer groups are as follows:

Tariff Rate Type	Forecast Demand Profile to be used
Urban Domestic 24-Hour Customers	Industry Standard profile (LP1) – adjusted for settlement
Urban Domestic Nightsaver Customers	Industry Standard Profile (LP2) – adjusted for settlement
Rural Domestic 24-Hour Customers	Industry Standard Profile (LP3) – adjusted for settlement
Rural Domestic Nightsaver Customers	Industry Standard Profile (LP4) – adjusted for settlement
General Purpose 24 Hour	Industry Standard Profile (LP5)
General Purpose Nightsaver	Industry Standard Profile (LP6)
Residential Business Premises 24 Hour	Industry Standard Profile (LP5)
Residential Business Premises Nightsaver	Industry Standard Profile (LP6)
Low Voltage Maximum Demand	Sampled Actual Customer Profiles and Industry Std LP7, LP8 & LP9
Low Load Factor	Industry Standard Profile, (LP7) LF < 30%
Public Lighting (4 variants)	Industry Standard PL Profiles

- The industry standard profiles are provided by Retail Market Design Centre (www.rmdservice .com) and are updated annually.

4.3 Metering Arrangements

The metering employed for different customer classes is determined at present by ESB Networks. The present criteria for the installation of QH meters is:

- Customer annual consumption > 300MWh
- Existing Customers with MIC > 100kVA
- All new customers > 50kVA

The QH meter functionality by tariff group is as follows:

	Quarter Hourly Meter
Domestic 24 hour Customers	0%
Domestic Dual Tariff Customers	0%
General Purpose Customers	0%
General Purpose Dual Tariff Customers	<1%
LV Maximum Demand Customers	35% approx.
10kV / 20kV Customers (STOD)	100%
38kV Customers (STOD)	100%
110kV Customers (STOD)	100%

5 Tariff Formulation

5.1 Cost Attribution to different Customer Categories

5.1.1 Allocation of Wholesale Generation Costs

1. Fixed Tariff Customers (i.e. all Customers supplied at Low Voltage – residential and small business customers).
ESBCS enters into hedge contracts for the majority of the energy for these customers and will purchase any residual amount of energy required to meet their demand directly from the pool. The energy contracts for these customers will include PSO Contracts, Directed Contracts and Non-Directed Contracts. ESBCS aims to optimise the mix of contracts and pool purchases so as to minimise cost and provide maximum cost stability.

Allocation of Wholesale Pool Energy Costs for Fixed Tariff Customers

Energy purchases are optimised on a portfolio basis for fixed tariff customers i.e. the purchase of hedges is optimised for the overall demand of all fixed tariffs together rather than for any tariff individually.

In order to reflect pool market energy cost signals in its tariffs, flat contract costs are profiled to provide day/night & seasonal price signals to customers.

This means that the SMP cost signal is reflected with minimum distortion in the generation costs allocated to each tariff and therefore in the final tariff price (affects day/night and seasonal relativities).

2. LEU Customers (Customers supplied at 10kV and above)

ESBCS charges these customers monthly, transparently based on the Day-Ahead (D-1) SMP and the Month plus 3 Working Days (M+3WD) ex-post Capacity Price Demand Payment costs. These customers will be on a “Pool Price Pass through Pricing Structure” and will be exposed to the SMP in each half-hour trading period.

Energy losses will be allocated according to published Distribution Loss Adjustment Factors (DLAFs) depending on the voltage level at which customers are supplied.

5.1.2 Allocation of Capacity Payment Mechanism Costs

As defined in the SEM Trading and Settlement code, Capacity charges to suppliers are settlement period specific (monthly pots), will be in €/MWh at the trading point and will be calculated separately for each trading period i.e. CPM supplier costs can be represented by a forward cost curve proportional to demand.

The CPM cost in €/MWh in any trading period = [[Monthly System CPM Pot] * Demand Scaling factor (for the period) * Price Scaling Factor(for the period] / System Demand (for the period)

Essentially the monthly CPM cost is profiled over trading period in the month by a demand scaling factor which allocates the cost over the trading periods according to a "peakier" version of the system demand profile. However, the price scaling factor dampens CPM costs during trading periods when SMP prices become exceptionally high.

The CPM cost (in €/MWh) in each half-hour trading period is the same for all suppliers and all customers. Obviously the aggregated Capacity cost depends on the aggregation of demand.
The overall CPM costs for each customer will depend on the overall demand profile for that customer i.e. the level of demand and the coincidence between the customer's demand and the system demand.

The actual CPM cost in each trading period (in €/MWh) is not finalised until ex-post.

The formulae for calculation of Supplier CPM charges are given in Section 4 of the Trading & Settlement Code.

CPM costs are allocated to all ESBCS customers, regardless of tariff category, on the same €/MWh basis (at the trading point) in each trading period.

5.1.3 Allocation of Other Market Costs

Market Operator Charges and Imperfections Charges (which include transmission congestion charges and currency charges) are other market costs that will be included in the final retail tariffs. These costs are set ex-ante and are published by the Commission in advance of tariff setting. They will be allocated to customers on a demand (i.e. per MWh) basis.

5.1.4 Allocation of Network Charges

Costs arising from the use of the transmission and distribution networks follow from the regulatory approved tariffs i.e. the Transmission Use of System Charges (TUoS) and the Distribution Use of System Charges (DUoS) which are published annually in advance of tariff setting.

Network Charges have a number of components; some or all of the following depending on the DUoS or TUoS Group:

Fixed charge / customer; kWh; kW(Contracted Maximum Import Capacity), kW (Excess Contracted MIC), Excess kVARh. All quantities are metered at the customer's terminals.

DUoS charges are allocated across day/night based on ESBCS historical billing data for each customer class.

TUoS charges are allocated across day/night based on the Standard Customer Load Profiles (per section 4.2)

5.1.5 Allocation of Allowed Supply Costs

ESBCS allowed costs and associated margin is set by CER for a 5 year period (2006-2010). Supply costs and margin are attributed to each tariff category in accordance with factors derived using a cost to serve model. The factors are agreed as part of the 5 year control and remain unchanged throughout the course of the period (2006 -2010).

The ESBCS cost to serve model attributes the overhead of doing business per customer into different customer categories taking account of the different operational aspects of serving the various customer categories.

In allocating supply costs across tariffs the following factors are use for each customer type: Domestic €73, General Purpose €99.6, Public Lighting €99.6 and LVMD €483.

The ESBCS Allowed Margin on regulated tariffs is set at 1.3% of total revenue in accordance with the Commission's determination (AIP/SEM/304/07) and remains unchanged throughout the course of the control period (2006-2010). The margin is allocated to different customer categories based on the following factors: Domestic 1.3%, General Purpose 1.2%, Public Lighting 1.0% and LVMD 0.6%.

5.1.6 Allocation of Public Service Obligation Levy Costs

The Commission for Energy Regulation (CER) is required to calculate and notify all relevant parties of the level of the Public Service Obligation (PSO) levy each year in accordance with section 39 of the Electricity Regulation Act 1999 (the Act), (Public Service Obligations) Order 2002 (SI 217 of 2002) as amended.

These costs are calculated and specified by CER and levied on all electricity customers in the Republic of Ireland. (The same levy is charged & collected by all suppliers).

For 2009/10 the CER has set the PSO Levy to zero.

5.2 Revenue Correction Mechanism

While ESBCS is committed to ensuring compliance with best practice hedging and forecasting methodology, ESBCS will continue to have variances between the forecast costs and the actual costs due to changes in customer demand and/or variances in costs. In order to address this situation an Ex-post Revenue Correction Mechanism will be applied as follows:-

- For customers other than LEU customers, if forecast variances between costs included in the tariffs and revised forecast costs during the year exceed a threshold, the tariffs will be reviewed. Where tariff rates are to be revised, they will be revised for the remainder of the tariff year to reduce the end-of-year variance. Over and above this, cost variances below the threshold will be catered for in a year-end adjustment and consequently, incorporated into the tariffs for the following year. ESBCS will implement any such carry-over adjustment with due consideration to any possible impact on retail competition.

- For LEU customers (10kV, 20kV, 38kV & 110kV) where the PPPT pricing structure will apply a minimal revenue correction mechanism will be required as these customers will be charged based on SMP (D-1) Energy Costs and Capacity Price Demand Payments (M + 4Working Days) + tariff for non-energy charges. ESBCS will implement any such carry-over adjustment with due consideration to any possible impact on retail competition.

5.3 Tariff Structures

The existing tariff structure and any tariff changes are approved annually by CER as part of the CER's annual price determination.

Electricity tariffs should be reflective of underlying costs in accordance with statutory duties and so as to encourage economic efficiency in the use of electricity. The advent of the SEM means that costs are predominantly linked to the time of use. However present metering arrangements provide little scope for accurate reflection of costs in this manner for most customers.

ESBCS has introduced with approval of CER several modifications and innovations in recent years to improve tariff cost reflectivity and encourage energy efficient behaviour by the users. For the tariff period commencing 1st October 2009 ESBCS proposes to amend the structure of the GP tariff over two years so as to remove the 2-block structure that applies to the day energy rates in the tariff. For 2009/10 the differential between the 2 block structure rates will be reduced by 50%

The Commission conducted a public consultation on this and other proposals [ref CER/08/046]. In a decision published on 22nd May 2008 [ref CER/08/088] CER indicated that it had approved the proposal.

6 PES Obligations & Innovative Tariffs

The objective in setting the tariffs has been to comply with the conditions set out in ESBCS's supply licence in relation to tariff setting. Licence obligations also extend to other areas and these are summarised in the following section along with current tariff innovations.

6.1 Supplier of last resort

The Commission's decision on the Supplier of Last Resort in Electricity ref CER/06/006 sets out the appointment of ESBCS as the supplier of last resort (SoLR). Section 2 and Section 7 of this decision paper contain the duties of the SoLR and the relevant points regarding cost recovery. In respect of tariffs the key points which are to be taken into account by ESBCS are from Section 2 & Section 7:

From Section 2:

- (d) to maintain normal conditions of supply for 6 months after the SoLR event for customers on the SoLR tariff or until customers are registered on a different tariff or to a different supplier.
- (f) after 6 months transfer the remaining SoLR customers from the SoLR tariff onto a regular tariff that is appropriate to their customer category.

From Section 7:

- Non-energy costs (for inclusion in the SoLR tariff) will be agreed and included ex-ante and energy costs will be estimated ex-ante and adjusted ex-post

- The ex-post adjustment which will include energy and non-energy costs and subject to Commission approval will be made via the TUoS charge
- The structure and level of the SoLR tariff will correspond to the standard (regulated) tariff for the customer category.

In its decision CER also stated that the SoLR is required to advise CER of its plans to procure energy for the SoLR customers and that separate books of account are to be kept for SoLR customers.

ESBCS understands that it follows from this decision that SoLR customers will be charged tariffs that directly reflect the cost of supplying them and that correspond to the normal tariff for their customer category. For example, the SoLR tariff structure for domestic customers would be the same as the current domestic tariff and for MVMD (SoLR) customers it would be the pool price pass through tariff. It also follows from the CER decision that it will be necessary to capture SoLR costs separately and to allocate them directly to the SoLR customers.

ESBCS would propose to follow the same methodology in the allocation of SoLR costs to SoLR customer tariff categories as for non-SoLR customers. The only differences being that:

- different costs are used e.g. ex-ante estimates of both energy and non-energy costs which are driven by the SoLR event
- there is a specified mechanism for recovery of the difference between the ex-ante estimate and the ex-post actual costs.

6.2 Universal Supply Obligation

The legal basis for the Universal Service Obligation (USO) is set out in Section 18 of SI 60 of 2005 which states that *"the public electricity supplier shall meet all reasonable requests to supply electricity"* and that *"the Commission may specify the terms and conditions under which a request to supply electricity may, as respects a customer or a group or class of customers, be considered to be unreasonable".* Condition 8 of the PES Interim Licence further confirms this obligation.

In practice this obligation means that ESBCS has a duty to meet all requests for supply on the tariffs and standard terms and conditions approved by the Commission under the PES Interim Licence. In so far as ESBCS will continue to be regulated with the continuation of the USO in mind, we do not envisage that there needs to be a change in this approach i.e. tariffs are developed and approved in the knowledge that ESBCS has this universal service obligation and that the costs arising from meeting this are recoverable through the tariffs or an alternative mechanism to be agreed with CER.

6.3 Domestic Micro Generation Export Tariff

In response to a request from CER and following public consultation ESBCS became the first electricity supplier to introduce a Domestic Micro-generation export tariff in February 2009. The tariff rate is set at 9.00 cent per kWh for all verified metered units exported to the network, and reflects the average energy component at wholesale level for the tariff year. This initial tariff was developed to give the customer value for exported units, and to enable the collection of research data on the impact of Micro Generation on the export profile and altered demand profile of Micro Generation customers with a view to better informing the economic appraisal of exported units. To-date ESBCS has received almost 100 applications for this tariff.

6.4 Energy Efficiency & Smart Metering

Traditionally, retail tariffs have been designed to give appropriate price signals to incentivise customers to shift demand from expensive consumption periods to less expensive consumption periods. In particular, ESBCS provides domestic and general purpose "nightsaver" options whereby customers who pay a higher standing charge can benefit from lower night rate electricity prices. The application of PPPT tariffs to LEU customers is giving clear price signals to these customers to encourage load shifting from peak times.

Energy efficiency tariff options are largely determined by the metering available and the introduction of smart metering for domestic and small business customers will facilitate further pricing incentives to encourage load management at peak times.

ESBCS is a participant in the current Smart Metering Project together with representatives from The RAs, the Department of Communications, Energy & Natural Resources (DCENR), Sustainable Energy Ireland (SEI), and other industry players. Customer behaviour trials will be undertaken with Domestic & SME customers in 2010 to ascertain the potential for smart metering =enabled energy efficiency initiatives to effect measurable change in customer behaviour in terms of reductions in peak electricity demand and overall energy use. Time-of-use prices to be used in trials will be calculated based on the prevailing standard domestic tariff as at 1st October 2009. CER is currently working with the industry via the Smart Metering forums to agree methodology & principles to be used in calculating the Time-of-use tariff prices to apply in 2010.

Appendix 1

ESB Customer Supply - Customer Tariff Categories

Customer Category	Main Tariff Category	Tariffs
DOMESTIC	Domestic Rural Domestic Urban	Domestic Urban 24Hr Domestic Urban N/S Domestic Rural 24Hr Domestic Rural N/S
SMALL BUSINESS	Residential Business Premises General Purpose	Res Bus Prem 24Hr Res Bus Prem N/S GP 24Hr NQH GP N/S NQH GP 24h QH GP N/S QH
MEDIUM ENTERPRISES	Low Voltage Max Demand Low Load Factor	LVMD (NQH & QH) LLF (NQH & QH)
PUBLIC LIGHTING & Miscellaneous Supplies	Unmetered Public Lighting Unmetered Single Point	Public Lighting - Unmetered PL - 24 Hour Public Lighting - Unmetered PL - Dusk to Midnight Public Lighting - Unmetered PL - Dusk to Dawn Unmetered Single Point
LARGE ENERGY USERS (LEUs)	10kV/20kV (MV) 38kV Looped 38kV Tailed 110kV	Pool Price Pass Through (PPPT) Individual & Group variants

Appendix 2 : ESBCS Tariff Structures

Rate Category	Standing Charge	MD	MIC/ MIC Excess	Flat Price/KWh **Seasonal Y/N**	Block 1 Price/KWh **Seasonal Y/N**	Block 2 Price/KWh **Seasonal Y/N**	Night Price/KWH 23:00 to 08:00 GMT **Seasonal Y/N**	Night Heating Standing Charge	Night Heating Price/KWh 23:00 to 08:00 GMT **Seasonal Y/N**	Low PF (KVARh)	PSO
<u>Residential:</u> Domestic Urban 24 Hr.	✓			✓ **N**			No	✓	✓ **N**		✓
Domestic Urban Nightsaver	✓			✓ **N**			✓ **N**	✓	✓ **N**		✓
Domestic Rural 24 Hr	✓			✓ **N**			No	✓	✓ **N**		✓
Domestic Rural Nightsaver	✓			✓ **N**			✓ **N**	✓	✓ **N**		✓
Residential Business 24 Hr.	✓				✓ **N**	✓ **N**		✓	✓ **N**	✓	✓
Residential Business Nightsaver	✓				✓ **N**	✓ **N**	✓ **N**	✓	✓ **N**	✓	✓
<u>Commercial/Industrial:</u> General Purpose 24 Hr.	✓				✓ **N**	✓ **N**		✓	✓ **N**	✓	✓
General Purpose Nightsaver	✓				✓ **N**	✓ **N**	✓ **N**	✓	✓ **N**	✓	✓
Low Load Factor	✓		✓	✓ **Y**			✓ **N**			✓	✓
Low Voltage MD	✓	✓	✓	✓ **Y**			✓ **N**			✓	✓
<u>Public Lighting:</u> Public Lighting Unmetered – Dusk to Dawn, Dusk to Midnight, 24 Hours.				✓ **N**							✓
Unmetered Single Point				✓ **N**							✓
<u>LEUs:</u> MV , 38kV, 110kV Individual PPPT and Group PPPT	✓		✓	Half-hour variable price			Half-hour Variable price			✓	✓

Appendix 3

Retail Tariff Categories mapped to DUoS & TUoS categories

ESBNetworks	EIRGRID	ESBCS
DUoS Group (DG)	Demand Transmission Service (DTS)	Rate Category (Tariff)
DG1	DTS-D2	Domestic Urban – 24 Hr. Domestic Urban – Nightsaver (NS)
DG2	DTS-D2	Domestic Rural – 24 Hr. Domestic Rural – NS.
DG3	DTS-D2	Public Lighting – Unmetered Unmetered Single Point Connections
DG4 -Unused		Unused
DG5	DTS –D1(=>500KVA) DTS-D2	General Purpose Commercial – 24 Hr. General Purpose Commercial – NS. General Purpose Industrial – 24 Hr. General Purpose Industrial – NS Residential Business (Restricted Tariff) – 24 Hr. Residential Business (Restricted Tariff) – NS. Metered Public Lighting (Restricted Tariff).
DG6	DTS –D1(=>500KVA) DTS-D2	LV Maximum Demand Commercial. LV Maximum Demand Industrial. LV Low Load Factor.
DG7	DTS –D1(=>500KVA) DTS-D2	10kV/20kV (MV)
DG8	DTS –D1(=>500KVA) DTS-D2	38 KV Looped
DG9	DTS –D1(=>500KVA) DTS-D2	38 KV Tailed
DG10	DTS –D1(=>500KVA) DTS-D2	110 KV – Distribution Connected
TCON	DTS-T	110 KV – Transmission Connected