Marginal Cost of Electricity Service Study

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TABLE OF CONTENTS

INDEX OF SCHEDULES

Marginal Cost of Electricity Service in Ireland

I. INTRODUCTION

The Commission for Energy Regulation (CER) retained National Economic Research Associates, Inc. (NERA) to prepare an estimate of the marginal costs of supplying electricity in Ireland. NERA worked with the CER staff to develop this study. The analysis encompasses the marginal costs of generation, transmission, distribution and supply costs These estimates will be used in the analysis of alternative tariff structures for the Transmission Use of System charges (TUoS), Distribution Use of System charges (DUoS) and Public Electricity Supply (PES) tariffs, including the review of customer classes. During the course of the analysis, a number of assumptions, including likely changes to the connection policies, were developed. This report describes the assumptions, the methods for estimating the generation, transmission, distribution and supply marginal costs, and presents summary tables of the results. All estimates of marginal costs are expressed in 2005 prices.

What are marginal costs? Marginal cost is defined as the change in total cost with respect to a small change in output. To quantify the marginal costs of electricity service one must ask and answer the question: What are the additional costs that would be incurred with changes in kilowatt-hours of energy, kilowatts of demand and number of customers? Because the cost of additional consumption may differ depending upon the time of the change in output, it is important to estimate time-differentiated marginal costs of electricity.

As the electric power industry structure evolves and competitive wholesale markets develop, the basis for the marginal costs of generation, transmission and ancillary services change. In Ireland, the electricity retail market will be fully open to competition on the 19th of February 2005, and a competitive wholesale market (Market Arrangements for Electricity-MAE) will begin in February 2006. Full legal unbundling of ESB business units (network vs. non-network businesses) is expected in the near future. ESB National Grid (to become Eirgrid) has operational control of transmission lines and is in charge of planning transmission and under the new arrangements will be responsible for administering a real-time market. Our marginal cost estimates take account of these expected changes to the extent possible. As the market develops and more data is available, the marginal cost estimates should be refined.

Our method for estimating marginal costs is based on the system planning process. We determine the marginal cost of electricity by examining the companies' planning processes to determine what drives new investment and purchase decisions and how changes in consumption affect system operations.

Data limitations for this first comprehensive marginal cost study of Ireland's electricity sector required use of proxy information, such as average incremental investment and expense levels in recent years in lieu of forward-looking estimates. As the liberalised market matures and more data become available, the marginal cost estimates will become more precise.

II. COSTING/PRICING PERIODS

Period definitions for use in tariff design can be defined by analysing the patterns of the marginal cost components that vary by time of use (generation, transmission and distribution substation).[1] Ideally, pricing periods should group months and hours with similar marginal costs and separate months and hours with different costs. Practical considerations such as administrative feasibility (including billing system and metering constraints) and customer understanding limit the number of periods and the complexity of their definition. The sections below describe the development of *hourly* marginal cost estimates for a typical Weekday, Saturday and Sunday for each month. Appendix A contains monthly charts showing the patterns of the sum of generation, transmission and distribution substation hourly marginal costs.

To select an efficient set of periods, we used a regression model that computes the average marginal costs for sets of peak, shoulder and off-peak hours in each season, and calculates a measure of 'goodness-of-fit' of the average costs in the chosen periods to the underlying hourly costs (R-square). Use of the model involves testing different period definitions until the set of periods that produces the highest R-square and meets other objectives is found.

Our analysis of the hourly cost pattern suggested that two seasons—Winter (November - February) and Summer (March - October) are appropriate and the wide range of hourly costs in winter months support choice of three weekday diurnal periods—peak, shoulder and off-peak. In summer months two diurnal periods are sufficient. After following the iterative process described above, we settled on the periods below as a reasonable compromise between goodness-of-fit and customer and administrative considerations.

[1] The estimation of these marginal costs and their time differentiation is explained in detail later in this report.

Winter: November – February		Hours in Period
Monday-Friday	Peak Shoulder: Off-Peak:	17.01 – 20:00 08.01 – 17:00 & 20.01 – 21:00 All remaining hours
Saturday	Shoulder Off-Peak	17.01 – 21:00 All remaining hours
Sunday & Holidays	Shoulder Off-Peak	17.01-18:00 All remaining hours
Summer: March - October		
Monday-Friday	Shoulder Off-peak	08.01 – 21.00 All remaining hours
Saturday, Sundays & Holidays	Off-Peak	All hours

Note: Holidays are Jan. 1, Mar. 17, Good Friday and Easter Monday, and Dec. 25-31.

As the chart below illustrates, there is consistency of period definitions across days of the week and seasons that should help customers remember what the periods are.

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

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

The three-period definition illustrated above is suitable for customers with programmable meters than can distinguish three periods per week and treat weekends differently from weekdays.[2] Because of metering limitations for some customer categories in Ireland, a second set of pricing periods was developed for meters that can only distinguish two periods per week. The 2-period definition was based on the same regression approach as described above. As is illustrated in the chart below, the shoulder period (16:01 to 21:00 in Weekdays) is the same in the Winter and the Summer, as these meters cannot differentiate between seasons.

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

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

For illustrative purposes, we have used the three-period definition to summarise the time-differentiated marginal costs in this report. Marginal costs for the two-period definition were computed before the tariff screening stage, for those customers with meter limitations.

[2] All maximum demand customers of PES have three phase time-of-use meters.

III. MARGINAL GENERATION COSTS

A. Conceptual Description

To obtain a marginal kWh in the MAE, a supplier may contract with generation, or other suppliers via CfDs, or procure in the spot market. However, in each case the value of the kWh to a supplier may be the best estimate of marginal energy costs in any given hour. This will depend on a forecast of the hourly market-clearing price.

Under the MAE, the system operator may jointly schedule energy and reserves, and will manage transmission congestion through a centralised real-time bid market. The market clearing prices may take the form of nodal Locational Marginal Prices (LMPs). An ex-ante LMP clearing-market price for a particular half-hour will be used to settle all energy quantities served from (or delivered to) the energy market during that period. Generators will be paid the nodal LMP, while suppliers will pay a weighted average of the nodal prices.

B. Development of marginal generation costs to PES

PES provided a forecast of generation prices for the year 2003, which were developed for internal use. These hourly prices include estimates of VOLL (value of lost load) and LOLP (loss-of-load probability). PES cautions that these prices are not a forecast of the prices expected to prevail under the MAE, and therefore the expected hourly pattern and levels of market prices are only preliminary. In the absence of a forecast of LMP prices, we used this data for our calculation of marginal generation costs.

The PES market price estimates are assumed to be stated at the virtual hub that will be created by the computation of the weighted-average LMPs to be paid by suppliers. Therefore, they already include transmission losses.

According to the proposed arrangements in Ireland, the DSO may be responsible for purchasing the distribution losses. Therefore we are including the marginal distribution energy losses (incurred in moving the energy from the virtual hub through the distribution system) in the Distribution Section of this report.

Normally, an adjustment is required to account for the cost of working capital necessary to finance the lag from the time when the supplier pays its generation bill and to the time when it is reimbursed by its customers. Under current payment policies, PES does not currently have such a lag and we have used a cash working capital requirement of zero in our computations. In examining a CER analysis of ESB business units' working capital utilisation, we found that the absence of a lag in payments was common to all of the ESB business units.[3] While there is currently a requirement for a zero cash working capital requirement, this may change with market opening.

Another element of the marginal generation costs to PES will be the operating reserve costs. According to the proposed MAE rules,[4] each provider will be paid the operating reserve-market clearing price for each half-hour in which its reserve offer is accepted.[5] The detailed rules and mechanisms to recover these operating reserve payments from market participants are currently being developed, and therefore we have not included in this analysis a marginal cost component for operating reserves. One possibility is that some portion of reserve costs will be recovered on the basis of load purchased through the market[6].

In that case each hour's estimate of marginal generation costs will need to include a reserve market price component.

Since we are developing marginal costs for the year 2005, we escalated the generation price estimates provided by PES by using the forecast inflation rate (2.6% for 2004, 3.5% for 2005).[7]

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[3] For ESB transmission, distribution and supply business units, the average delay in payments exceeds the average delay in receipts.

[4] *Market Arrangements for Electricity (MAE). A MAE Consultation by the Commission for Energy Regulation*. CER/03/230. 12 September 2003.

[5] A generators actually called on to generate in response to a contingency will be paid the LMP at its location for the extra electricity it produces, in addition to its regular reserve payment. Interruptible demand will be able to offer reserve in the spot market where appropriately configured. Interruptible load accepted in the reserve market and interrupted in response to a contingency will save the uniform weighted LMP for the energy it would otherwise have consumed and also receive the reserve payment.

[6] One of the expectations of this study is that reserve will be paid for in the market. However, some element of reserve costs may be recovered in TUoS.

[7] Inflation forecast provided by ESB Networks

The marginal generation costs after the adjustments, averaged over the costing periods, are shown below.

Schedule 1. 2005 Time-Differentiated Marginal Generation Costs

Winter Peak	Winter Shoulder	Winter Off-Peak	Summer Shoulder	Summer Off-Peak
(2005 € per kWh)				
€ 0.1932	€ 0.0938	€ 0.0375	€ 0.0717	€ 0.0322

Costing periods are defined as follows:

Summer: March-October.

Shoulder	Monday - Friday, 8 am to 9 pm.
Off-peak:	All remaining hours.

Winter: November - February.

Peak:	Monday - Friday, 5 pm to 8 pm.
Shoulder	Monday - Friday, 8 am to 5 pm and 8 pm to 9 pm Saturday 5 pm to 9 pm Sunday 5 pm to 6 pm
Off-peak:	All remaining hours.

IV. MARGINAL TRANSMISSION COSTS

A. Conceptual discussion

The planning of transmission investment and O&M, and the operation of the transmission system is carried out by the Transmission System Operator (TSO). The Transmission Asset Owner (TAO) owns the system, and carries out most of the repair and maintenance work. The combined TSO and TAO transmission revenue requirement is currently recovered through a combination of up-front connection charges and TUoS tariffs, recovered from all users of the transmission system.

Short-run marginal transmission cost is the added cost of supplying a small increment of transmission service with no addition to transmission capacity. This cost consists of 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.

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 longer-term marginal transmission costs are not reflected in LMPs and therefore should be recovered through the TUoS.

Under the MAE, operating reserves and regulation reserves may be administered by the TSO through an 'integrated bid-based' (co-optimised) market. Costs associated with other ancillary services (i.e., black-start capability and reactive power) could still be recovered through TUoS charges. We estimated the marginal cost of reactive power. Black-start capability is not a marginal cost because the need for this service does not change with marginal changes in electricity consumption.

To summarise, the marginal transmission costs can be categorised as follows:

1) short-run marginal costs of the system (the congestion costs and losses reflected in LMPs)
2) marginal costs associated with general expansion of the transmission network (depreciation, return on investment, operation and maintenance expenses, taxes);
3) marginal costs of reactive power;
4) marginal costs of new connections;
5) TSO's settlement, market operation and administrative costs.

B. Marginal Transmission Costs

1. Transmission Investment Costs

The typical marginal investment in transmission network capacity can be 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 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.[8]

To estimate the marginal transmission investment cost to be recovered through the TUoS, we started by looking at:

a) the (load-growth related) transmission capital expenditure budget over the period 2001-2005, as provided by the TSO;

b) the (actual and expected) annual peak load growth during that period.

We selected the projects that were load-related, and excluded those that were related to connection of specific users, under the assumption that the current transmission connection policy will be revised to require all users upfront payment of 100% of shallow connection costs[9]. Dividing investment in growth-related projects, in constant euros, by expected load growth over the same period, we obtained an average annual investment cost over the period. However, TSO capital expenditures for the budget period included a substantial amount of 'catch-up' investment to comply with international reliability standards. In order not to distort the resulting marginal cost, we expanded the analysis period by including the historic transmission investment and peak load growth for the period 1995-2000.[10]

[8] The TSO noted that transmission investment is largely driven by two factors; peak growth and ustomers' capacity requirements. However, given the difficulty in determining the proportion of transmission investment that is capacity based and the propotion that is energy based, for the purpose of this study it is assumed that transmission network investment is driven by peak growth.

[9] We also excluded DSO-related shallow connection costs. In order to avoid cross-subsidies from users with associated high connection costs to users with lower cost connections, we are recommending a 100% shallow policy for all transmission users (both generators and demand customers).

[10] The historical data available for 1996-2000 was not disaggregated in any level of detail. However, we used a proxy to adjust the historical transmission expansion costs for shallow connection costs over that period. We did apply an adjustment factor to the 1996-2000 capex, in order to exclude an estimate of shallow connection costs. This factor was based on the ratio of 2001-2005 total shallow transmission connection costs to 2001-2005 total transmission Capex (around 8%). Further refining in later exercises should identify the connection vs. load-growth related costs during the historical period.

Schedule 2. Marginal Transmission Investment

(1)	Total Investment in Demand-Related Transmission Facilities, 1996-2005 (Thousands of 2005 Euros)	425,876
(2)	Additions to Peak Load, 1996-2005 (Megawatts)	1,658.00
(3)	Total Marginal Investment in Demand-Related Transmission Facilities per Kilowatt (2005 Euros) (1) / (2)	**256.86**

2. Transmission O&M Expense

The estimation of marginal O&M expenses was based on TAO O&M expenses and TSO network-related O&M costs using historical data (years 2001 and 2002) and forecast expenses for 2003.[11] We evaluated the various transmission-related services from other businesses to ensure that these costs were included in the O&M estimates, and that the TSO did not receive payments outside the TUoS charges for services provided. As the table below shows, we used the resulting 2002 figure as the best estimate of marginal O&M. We believe that this average most closely reflects the level of marginal transmission O&M expense expected to exist in 2005. The large increase between 2001 and 2002 is largely driven by the increase in both TAO and TSO's network repairs and maintenance activity, and the higher professional fees associated with the TSO's O&M responsibilities. These higher levels are assumed to continue.[12]

[11] TAO and TSO's non-capitalised planning and construction costs were also included as part of the transmission O&M. Sources for the TSO historical data were the 2001 and 2002 Outturn from the Revenue Determination for 2003 TUoS and the TSO Revenue Submission for 2004 TUoS. TAO O&M data were provided by ESB. We decided not to use 2003 figures as they are "allowed" figures.

[12] There may be some level of 'catch-up' O&M expenses in the levels shown in 2002. However, it is not assumed that this level will drop in the near term. Source: 2002 Transmission Revenue Determination.

Schedule 3. Marginal Transmission O&M Expenses

	Year	Transmission Operation and Maintenance Expenses ^1	System Peak Demand	Expense Per kW of System Peak Demand	Weighted Labor and Materials Cost Index	Expense Per kW of System Peak Demand
		(Thousand Euros)	(MW)	(Euros) (1) / (2)	(2005=1.0000)	(2005 Euros) (3) / (4)
		(1)	(2)	(3)	(4)	(5)
(1)	2001	13,140	3,909	3.36	0.85	3.94
(2)	2002	22,856	4,238	5.39	0.90	5.97
(4)	Estimated Annual Transmission O&M Expense for the Planning Period ^2					**5.97**

^ 1 Transmission Network-related R&M expenses and Operations, for both TAO and TSO
^ 2 2002 Expense per kW.

3. Derivation of Annual Marginal Transmission Cost

The marginal investment per kilowatt was annualised using an economic carrying charge[13] and adjusted for operating and maintenance (O&M) expenses, administrative and general (A&G) expenses and general plant. The sources and methods used to estimate A&G and General Plant loaders are explained in Section IV.H below.

We also added a revenue requirement for working capital based on an estimate of the materials and spares marginal cost. We estimated the materials and spares marginal cost by calculating the average ratio of transmission stocks to total tangible assets, for the years 2001 and 2002. The revenue requirement for this working capital was developed from our estimate of ESB weighted average cost of capital, plus an income tax component that recognises that the equity portion of return on capital is taxable.[14] Under current payment policies, TAO and TSO have a zero cash working capital requirement; therefore we did not need to include a cash working capital factor.[15]

[13] The economic carrying charges are explained in section VII.

[14] See Section VII.

[15] Based on analysis of all ESB units.

The annualised marginal transmission cost was adjusted for marginal demand losses through the transmission system up to the metering point (110 kV). The computation of the marginal demand losses is explained in Section IV.J below.

Transmission capacity additions are driven largely by growth in the peak on the transmission system (as noted previously, meeting customers' capacity requirements is also a factor). We analysed the hourly system loads for the period 2001-2003 and estimated the probability that a given hour would be the peak hour of the year. We assigned annual marginal transmission capacity costs to hours using the estimated relative probability of peak.

Schedule 4. Derivation of Annual Marginal Transmission Cost

		400-110 kV Lines and Substations (2005 € per kW) (1)
(1)	Marginal Investment per kW	256.86
(2)	With General Plant Loading (1) x 1.0082	258.97
(3)	Annual Economic Carrying Charge Related to Capital Investment	8.74%
(4)	A&G Loading (plant related)	0.08%
(5)	Total Annual Carrying Charge (3) + (4)	8.82%
(6)	Annualized Costs (2) x (5)	22.85
(7)	Demand-Related O&M Expenses	5.97
(8)	With A&G Loading (7) x 1.4668 (Non-plant Related)	8.76
(9)	Demand-Related Cost (6) + (8)	31.60
	Working Capital	
(10)	Material and Supplies (2) x 2.00%	5.18
(11)	Cash Working Capital Allowance (8) x Net Lead/Lag days (%)	0.00
(12)	Total Working Capital (10) + (11)	5.18
(13)	Revenue Requirement for Working Capital (12) x 5.66%	0.29
(14)	Total Annual Marginal Cost per kW (9)+(13)	**31.90**

4. Time-Differentiated Marginal Transmission Costs

The tables below show the time-differentiated marginal transmission costs (a) per kW marginal costs, and (b) per kWh.

Schedule 5. Time-Differentiated Marginal Transmission Cost per kW

		Annual Transmission Cost per kW of System Peak Demand (2005 € per kW)	Period Assignment Factor ^1 %	Seasonal Transmission Cost per kW of System Peak Demand (2005 € per kW) (1) x (2)	Monthly Transmission Cost per kW of System Peak Demand ^2 (2005 € per kW)
		(1)	(2)	(3)	(4)
	Winter				
(1)	Winter Peak	31.90	90.37%	28.83	7.21
(2)	Winter Shoulder	31.90	9.23%	2.94	0.74
(3)	Winter off-Peak	31.90	0.34%	0.11	0.03
	Summer				
(4)	Summer Shoulder	31.90	0.06%	0.02	0.00
(5)	Summer Off-Peak	31.90	0.00%	0.00	0.00

Notes:
^1 The Period Assignment Factors for Transmission are based on a relative probability of system peak analysis.
^2 Monthly Transmission Costs were calculated by dividing the seasonal costs by the number of months in each season (4 months in the Winter, 8 months in the Summer).

Schedule 6. Time-Differentiated Marginal Transmission Cost per kWh

		Winter			Summer	
		Peak	Shoulder	Off-Peak	Shoulder	Off- Peak
		(1)	(2)	(3)	(4)	(5)
(1)	Seasonal Marginal Transmission Cost per kW (2005 € per kW)	28.83	2.94	0.11	0.02	0.00
(2)	Number of Hours in Each period	258	945	1,677	2,275	3,605
(3)	Time-differentiated Cost per kWh (cents/kWh) (1)*100/(2)	11.17	0.31	0.01	0.00	0.00

C. Marginal Cost of Connections

Since we assume a 100% shallow connection payment for purposes of estimating the marginal transmission investment costs, there is no marginal connection cost to be recovered in the TUoS charges.

D. Marginal Cost of Reactive Power

Currently, reactive power (capability and utilisation) payments are made by the TSO to dispatchable generators.[16] Payments are recovered from the demand users through a per-kWh charge ('system service charge'). To estimate the marginal cost of reactive power, we divided annual reactive power payments by the TSO to generators by energy transmitted at the transmission level in 2001 and 2002,[17] and averaged the two figures.

Schedule 7. Marginal Cost of Reactive Power per kWh

		2001	2002
(1)	Cost (million 2005 Euros)	13.11	14.06
(2)	Energy Transmitted (GWh)	22,247	22,749
(3)	Cost per kWh (1)/(2) (cents/kWh)	0.059	0.062
(4)	Marginal Cost Reactive Power ^1 Cost per kWh (cents/kWh)	0.060	
(5)	Cash Working Capital (3) x 0.00%	0.00	
(6)	Revenue Requirement for Working Capital	0.00	
(7)	Total Cost of Reactive Power (cents/kWh) (4) + (6) (2005 Euros)	0.060	

^1 Average of 2001-2002

16 Transmission Use Of System Revenue Regulatory Submission made by the Transmission System Operator to the CER, 21st December 2000.

17 TSO Revenue Submissions, 2000 and 2003.

E. Market Participant-Related Costs

Some TSO internal costs, such as Customer Records and Billing, vary with the number of market participants (generators and suppliers) who are the direct customers of the TSO. We are of the view that a share of other TSO costs, such as settlement, participant training, telecoms, etc. also vary with the number of market participants. However, no detailed cost data were available to estimate the portion of these costs that varies with the number of participants. Additional insight will likely be gained as the market develops and the MAE is operational.[18]

F. General Plant and A&G Expense Loaders for Transmission

NERA's standard approach to the estimation of incremental overheads uses a regression over a number of years of accounting data. As not enough years of ESB cost data were available to run a regression, we calculated the overheads loaders based on accounting cost ratios, as shown in the tables below.

a) *General Plant loader*: General plant consists of items such as office buildings, warehouses, cars, trucks and other equipment. Generally, when new transmission or distribution capacity is added, the need for general plant increases as well. To estimate the general plant loader for transmission we divided the non-network capex[19] for the period 2001-2002 by network-related capex for the same period. This factor was applied to the marginal transmission investment.

b) *Plant-related A&G loader:* This loader is designed to account for overhead expenses that increase with investment. In the case of the TSO and TAO, these expenses consist of insurance costs. The loader was calculated by dividing the insurance expenditures by an estimate of the transmission reproduction cost.

[18] We asked ESB-TSO for feedback on which components of the TSO internal system and market operation costs could be considered marginal/incremental with the number of market participants. The response indicated that it was too early form a clear view on participant related marginal costs in the current or new market.

[19] TSO Non-network Capital Expenditure, 2001-2003 (TSO Submission for Marginal Cost Study).

This factor was added to the economic carrying charge that was used to annualise the marginal transmission capacity cost.[20]

c) *Non-plant-related A&G loader:* This loader accounts for overhead expenses that vary with transmission O&M. Both the TAO & TSO are assigned by corporate accounting practices a share of corporate costs such as building services, finance, legal, regulatory affairs, human resources, pensions, etc. We analysed these corporate-level accounts to identify expenses likely to vary as transmission O&M expense increases with transmission plant. The loader was derived by dividing these 2002 marginal overhead expenses by total transmission O&M.[21] This loader is applied to the transmission O&M expenses.

Schedule 8. Transmission General Plant Loader

		2001	2002
		(million Euros)	
(1)	A&G non- network capex		
(2)	Fixtures and Fittings	0.00	0.01
(3)	IT (Hardware/Software)	0.60	0.60
(4)	Total Marginal Non-Network Capex (2) +(3)	0.60	0.61
(5)	Network Capex (Load-related)	62.32	89.41
(6)	General Plant Loader (4)/(5)	0.96%	0.68%
(7)	**Average General Plant Loader**	**0.82%**	

[20] Economic carrying charge is explained in Section VII.

[21] Sources: TSO Revenue Determinations for 2002 TUoS and 2001 Transmission Revenue Determination.

Schedule 9. Derivation of Transmission A&G Loader

		2002
		€m
(1)	A&G plant-related operational expenditures	
	Insurance	0.83
(2)	Transmission Reproduction Cost	1,063
(3)	**Plant-related A&G loader (1)/(2)**	**0.08%**
	Non-plant related A&G (TSO)	
(4)	Building Services	2.10
(5)	Finance	0.30
(6)	HR & Payroll	1.72
(7)	Other shared costs ^1	1.67
(8)	Total TSO non-plant related marginal A&G	5.79
(9)	TAO non-plant related marginal A&G	4.88
(10)	Total TSO & TAO marginal A&G (8)+(9)	10.67
(11)	Transmission O&M	22.9
(12)	**Non-plant related A&G Loader (10)/(11)**	**46.7%**

Notes:

^1 Includes other shared corporate services such as Legal, ITS, Chief Executive, Telecoms. It excludes consultancy profesional fees (non-marginal).

G. Transmission and Distribution Demand Losses

The marginal loss calculations in this study are based on estimates of variable and fixed losses at time of system peak at each voltage level for which costs are calculated. Marginal capacity losses reflect the fact that a kW of added load at a customer's meter requires successively larger additions to capacity as you move up the system in order to accommodate both the incremental load imposed by the customer and the losses that occur in moving the power through the system to the customer.

To derive both transmission and distribution losses, we used ESB's Annual *Peak Power Flow* and the Annual *Energy Flow* as forecast for the year 2004. Using ESB estimates of load factor at each service level, we were able to estimate fixed and variable losses by service level. The transmission loss factor estimates are not disaggregated between 400, 220 and 110 kV levels as ESB did not provide load estimates at each level. A summary of the demand losses (including both transmission and distribution) is shown below.

Schedule 10. Transmission and Distribution Demand Loss Factors

Sales Level	LV Network	MV Subs	MV Network	38 kV Stations	38 kV Network	110 kV Stations	400/220/110 kV Network
LV Network	1.0335	1.0501	1.0759	1.0845	1.1013	1.1079	1.1523
MV Subs		1.0160	1.0410	1.0493	1.0656	1.0720	1.1150
MV Network			1.0246	1.0328	1.0488	1.0551	1.0974
38 kV Stations				1.0080	1.0236	1.0297	1.0710
38 kV Network					1.0155	1.0216	1.0625
110 kV Stations						1.0060	1.0464
400/220/110 kV Network							1.0401

V. MARGINAL DISTRIBUTION COSTS

A. DSO System Description

In Ireland, the DSO owns facilities from the point of interconnection with the TSO, through a series of lines and substations of various voltage levels, through local transformers, service drops and meters on customer premises. We include the costs of all of these facilities in our marginal distribution cost analysis, although some are what would normally be called subtransmission.

The substations at which the DSO and TSO are interconnected include: 220/110 kV, 110/38 kV, and 110/MV (20 or 10 kV) stations. No additional 220/110kVA stations are planned, and we have not included costs of such stations in the marginal cost study. In the Dublin area 110 kV lines serve a distribution function. Power transmitted on those lines is stepped down to 38 kV or directly to primary voltage (20 or 10 kV). The ownership of 110 kV lines (and cables) is split between TAO and DSO depending on the type of 110 kV station being supplied. DSO maintains ownership of 110 kV lines and cables supplying tail-fed and Dublin 110 kV stations. Therefore DSO owns a portion of the 110 kV lines outside of the Dublin city area in addition to the 110kV lines/cables within Dublin. For all stations, assets below the HV bushings of the 110kV transformers are DSO assets.

The marginal costs for customers served in Dublin differ from those served outside of Dublin for this reason. We developed separate distribution marginal costs applicable within and outside Dublin, respectively, as well as country-wide estimates.

B. Conceptual Discussion

Most costing practitioners agree that the design of the distribution system is determined by two major factors: (1) the number and location of customers and (2) their demands. Utility cost studies, both marginal and embedded, have traditionally attempted to identify a portion of distribution costs as customer-related and the remaining portion as demand-related. This has led to semantics arguments about the definition of the customer-related and demand-related components. In fact, for most distribution systems, there is no economic reason for this split.

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 of those customers. For example, an area with all-electric homes may have different design standards from an area where the homes are not electrically heated. 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.

Trunkline MV feeders, distribution substations, and higher voltage lines and substations owned by the distribution utility, however, are typically sized based on near-term peak demands. This would normally include all network assets from the interconnection point with the transmission system (220kV/110 kV stations in Ireland) down to and including the trunk feeders out of distribution substations (38kV/MV or 20kV/MV stations in Ireland). Thus these costs are marginal with respect to added loads in hours when load is close to capacity and we refer to them as the demand-related marginal distribution costs.

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

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- in Ireland). 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.

The marginal cost of trunkline feeders and distribution substations, *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 of unique circumstances and information limitations, the standard NERA approach was modified for Ireland. This section explains the assumptions made.

C. Marginal Distribution Substation and Lines Cost

1. Distribution Substation and Line Investment

To estimate the typical marginal demand-related substation, line and trunkline feeder investment per kW of load growth, we asked the DSO to identify the growth-related projects of this type budgeted for the period 2001-2005. Because this budget was not available, we used the 2002 reproduction cost estimates for cables/lines and substations (both 38 kV and 110 kV),[22] available from an updated version of the 2002 DUOS model, and divided the costs by estimates of total peak loads at the various voltage levels, also provided by DSO. [23] We have some concerns about the use of this proxy for marginal investment, particularly since the reproduction costs provided by DSO are significantly higher than earlier estimates of reproduction costs and modern equivalent asset values. Thus, this component of marginal cost should be reviewed before the study is used to set tariffs.

The peak load used for the per-kVA 110-kV lines investment is the sum of load on 110-kV stations connected to the 110-kV lines owned by DSO. For the 110 kV stations, the peak load used is the sum of load on all 110kV stations. The data were provided by DSO.

The unit investment for distribution substations and cables was adjusted by the corresponding CPI inflation factor to convert the 2002 estimate into 2005 Euros.

[22] Although some DSO/TSO interconnections occur at 220/110-kV stations, no additional stations of this size are planned and we did not include costs of such stations in the marginal cost study.

[23] The reproduction cost data provided by DSO did not distinguish between trunk feeder and MV investment. Therefore in this study the distribution facilities include essentially all plant below the 38-kV substation and above the customer's service.

Schedule 11. Marginal 110 kV Substation and 110 kV Lines/Cables Investment

		110 kV Substations	110 kV Cables and Lines
(1)	Reproduction Cost of 110 kV Plant, 2002 (Thousands of 2002 Euros)	€ 311,690	€ 135,342
(2)	Distribution Substation Non-Coincident Load at:		
	- 110 kV stations (MVA)	3,897	
	- 110 kV Stations connected to DSO 110 kV lines 2002 (MVA)		1,173
(3)	Marginal Investment in Load-Related 110 kV Distribution Facilities per kVA of DSO Station Load (2002 Euros) (1) / (2)	€ 80	€ 115
(4)	(2005 Euros)	€ 88	€ 127

The peak load used for the per-kVA 38-kV substations and line investment is load at the 38kV substations as given by DSO, which we assumed to be the equivalent of the sum of the non-coincident peaks on the substations. The 38-kV substation reproduction costs used include indoor and outdoor stations, but not customer stations, as these are considered to vary with design demand and therefore are treated as distribution facilities costs.

In addition to customer stations, the DSO advised that a portion of the 38kV lines and stations is planned on the basis of the expected customer's MIC. This is essentially the local network surrounding a newly connected 38kV customer. Therefore, we adjusted the total 38kV investment in lines and stations to subtract the share of 38kV facilities that varies with MIC. The adjustment factors used to estimate the connection portion of the total reproduction costs of 38kV lines and stations (0.75% for lines and cables, 1% for stations) were based on the typical standard connection charge for a 38kV customer.[24] We treated this portion of the costs as distribution facilities costs, and the rest as demand-related costs.

[24] The CER understands that a typical 38kV customer has a capacity requirement of about 5,482 kVA. The connection charge associated with this typical customer was multiplied by the number of 38kV customers (39) and the result was compared to the reproduction cost of 38kV lines and stations.

Schedule 12. Marginal 38KV Substation and Lines/Cables Investment

		38 kV Substations	38 kV Cables and Lines
(1)	Reproduction Costs of 38 kV Distribution Plant, 2002 (Thousands of 2002 Euros)	€ 571,238	€ 332,715
(2)	38 kV Distribution Substation Non-Coincident Load, 2002 (MVA)	3,423	3,423
(3)	Marginal Investment in Load-Related Distribution Facilities per kVA of Non-Coincident Load (2002 Euros) (1) / (2)	€ 167	€ 97
(4)	(2005 Euros)	€ 183	€ 107

2. Distribution Substation and Line O&M Expenses

Estimates of marginal distribution O&M expenses were developed from detailed prime accounts from the updated 2002 DUoS Model. The O&M for distribution substations was divided by estimates of total peak loads at the various voltage levels, as provided by DSO.

Schedule 13. Marginal 110kV Lines/Cables and 110kV- Substation O&M Expenses

	Year	Operation and Maintenance Expenses ^1 (Thousand Euros) (1)	110 kV Substation NC Peak Load (MVA) (2)	Expense Per kW of Substation NC Peak Load (Euros) (1) / (2) (3)	Weighted Labor and Materials Cost Index (2005=1.0000) (4)	O&M Expense Per kW of Substation NC Peak Load (2005 Euros) (3) / (4) (5)
(1) 110kV Lines	2002	€ 605	1,173 ^2	€ 0.52	0.9051	€ 0.57
(2) 110kV-38kV Station	2002	€ 3,302	3,897 ^3	€ 0.85	0.9051	€ 0.94

^1 from ESB file: "DUoSUpdate(CER)2.xls.
^2 Non-coincident load at DSO-owned 110kV stations
^3 Non-coincident load at all 110kV stations.

Schedule 14. Marginal 38kV Lines and 38kV-MV Substation O&M Expenses

	Year	Operation and Maintenance Expenses ^1	38 KV Substation Non-Coincident Load ^2	Expense Per kW of Subst. NC Peak Load	Weighted Labor and Materials Cost Index	Expense Per kW of Subst. NC Peak Load
		(Thousand Euros)	(MW)	(Euros)	(2005=1.0000)	(2005 Euros)
				(1) / (2)		(3) / (4)
		(1)	(2)	(3)	(4)	(5)
(1) 38kV Lines	2002	€ 7,145	3,423	€ 2.09	0.9051	€ 2.31
(2) 38kV-MV Station	2002	€ 4,677	3,423	€ 1.37	0.9051	€ 1.51

^1 From ESB file: "DUoSUpdate(CER)2.xls, adjusted by 97% and 95% respectively. Percentages taken from "Netwk Cap" worksheet.

^2 Non-Coincident Load at 38 kV stations

3. Derivation of Annual Marginal Distribution Substation and Line Unit Cost

As shown in the two tables below, the investment per-kVA values were adjusted upwards by a general-plant loading factor (described in Section V.G below). We multiplied the resulting figures by the annual economic carrying charge percentage plus the plant-related A&G loading factor to yield the annualised plant costs. To these costs we added the associated O&M and non-plant A&G expenses (described below). We also added a revenue requirement for working capital based on an estimate of the materials and spares marginal cost, calculating the average ratio between distribution stock and total tangible assets, for the year 2001 and 2002. According to our analysis, ESB DSO has a zero marginal cash-working capital requirement.

Schedule 15. Derivation of Annual Marginal 110kV Station and Cable/Lines Unit Costs

		Cables and Lines 110 kV	Station 110-38 kV	Combined 110kV Lines and Station
		------- (2005 Euros per kW) -------		
		(1)	(2)	(3)
(1)	Marginal Investment per kW	126.81	87.91	
(2)	With General Plant Loading (1) x 1.0661	135.19	93.72	
(3)	Annual Economic Carrying Charge Related to Capital Investment	8.74%	8.74%	
(4)	A&G Loading (plant related)	0.08%	0.08%	
(5)	Total Annual Carrying Charge (3) + (4)	8.83%	8.83%	
(6)	Annualized Costs (2) x (5)	11.93	8.27	
(7)	Demand-Related O&M Expenses	0.57	0.94	
(8)	With A&G Loading (7) x 1.1649 (Non-plant Related)	0.66	1.09	
(9)	Demand-Related Cost (6) + (8)	12.60	9.36	
	Working Capital			
(10)	Material and Supplies (2) x 2.50%	3.38	2.34	
(11)	Prepayments (2) x 0.00%	0.00	0.00	
(12)	Cash Working Capital Allowance (8) x 0.00%	0.00	0.00	
(13)	Total Working Capital (10) + (11) + (12)	3.38	2.34	
(14)	Revenue Requirement for Working Capital (13) x 5.66%	0.19	0.13	
(15)	Total Demand-Related Costs (9) + (14)	12.79	9.49	
(16)	Total Annual Marginal Cost per kW	12.79	9.49	22.28

Schedule 16. Derivation of Annual Marginal 38kV Station and Cable/Lines Unit Costs

		Cables and Lines 38 kV	Station 38-20 kV	Combined 38kV Lines and Station
		------- (2005 Euros per kW) -------		
		(1)	(2)	(3)
(1)	Marginal Investment per kW	106.83	183.42	
(2)	With General Plant Loading (1) x 1.0661	113.89	195.54	
(3)	Annual Economic Carrying Charge Related to Capital Investment	8.74%	8.74%	
(4)	A&G Loading (plant related)	0.08%	0.08%	
(5)	Total Annual Carrying Charge (3) + (4)	8.83%	8.83%	
(6)	Annualized Costs (2) x (5)	10.05	17.26	
(7)	Demand-Related O&M Expenses	2.31	1.51	
(8)	With A&G Loading (7) x 1.1649 (Non-plant Related)	2.69	1.76	
(9)	Demand-Related Cost (6) + (8)	12.74	19.02	
	Working Capital			
(10)	Material and Supplies (2) x 2.50%	2.85	4.89	
(11)	Prepayments (2) x 0.00%	0.00	0.00	
(12)	Cash Working Capital Allowance (8) x 0.00%	0.00	0.00	
(13)	Total Working Capital (10) + (11) + (12)	2.85	4.89	
(14)	Revenue Requirement for Working Capital (13) x 5.66%	0.16	0.28	
(15)	Total Demand-Related Costs (9) + (14)	12.90	19.29	
(16)	Total Annual Marginal Cost per kW	12.90	19.29	32.19

The annual marginal costs of the 110-kV system were time-differentiated based on the same statistical analysis of hourly transmission loads used to time-differentiated transmission costs. The 38-kV distribution system costs were time-differentiated using relative probability of peak estimates developed from 2003 hourly load data for three representative 38-kV substations, representing substations in high-density urban, medium-density urban and sparse areas respectively. ESB DSO provided the weights to be applied to each of the representative substations, according to the percent of load served in those three typical areas by voltage level.

The schedules below show separately the distribution marginal costs applicable within and outside Dublin respectively, and for the country as a whole. In Dublin area, the DSO owns all the 110kV lines. Thus, for the Dublin area, costs were estimated as 100% of the 110-kV station and lines costs. Outside Dublin, about 5% of the load uses DSO-owned 100kV lines, as a result the non-Dublin 110kV costs were estimated as 5% of the 110-kV line costs. For the entire country, the combined cost reflects 30% of the 110 kV lines, as the total 110kV load served from DSO-owned lines is approximately 30% of the total 110kV load in the country. A distinction was also made with regard to the 38kV facilities costs within and outside Dublin. MV and LV customers within Dublin get allocated 93% of the 38-kV station and lines unit costs, while outside Dublin 95% of these costs are allocated. This reflects the fact that about 7% of the load (in Dublin) and 5% (outside Dublin) never moves over 38 kV facilities, rather it flows through 110kV/MV (10 or 20 kV) substations.

Schedule 17. Summary of Time-Differentiated Marginal Distribution Costs by Voltage Level (Dublin)

			Annual Cost	Annual Cost ^2			Period	Seasonal Cost		
		Weighting Factors ^1	110 kV Service	38 kV Service	MV Service	LV Service	Assignment Factor ^3	38 kV Service	Primary Service	Secondary Service
			--------- (2005 Euros per Kilowatt) --------				- (Percent) -	--------- (2005 Euros per Kilowatt) --------		
								(1) x (4)	(2) x (4)	(3) x (4)
			(1)	(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Winter Peak Period									
(1)	110 kV lines	1.00	13.30	13.59	14.03	14.73	90.40%	12.28	12.68	13.32
(2)	110-38/20 kV stations	1.00	---	9.70	10.02	10.52	90.40%	8.77	9.06	9.51
(3)	38 kV lines	0.93 ^4	---	13.10	12.57	13.20	30.70%	4.02	3.86	4.05
(4)	38 kV-MV stations	0.93	---	---	18.52	19.45	30.70%	0.00	5.69	5.97
	Winter Shoulder Peak Period									
(5)	110 kV lines	1.00	13.30	13.59	14.03	14.73	9.20%	1.25	1.29	1.36
(6)	110-38/20 kV stations	1.00	---	9.70	10.02	10.52	9.20%	0.89	0.92	0.97
(7)	38 kV lines	0.93 ^4	---	13.10	12.57	13.20	17.30%	2.27	2.18	2.28
(8)	38 kV-MV stations	0.93	---	---	18.52	19.45	17.30%	0.00	3.20	3.36
	Winter Off-Peak Period									
(9)	110 kV lines	1.00	13.30	13.59	14.03	14.73	0.30%	0.04	0.04	0.04
(10)	110-38/20 kV stations	1.00	---	9.70	10.02	10.52	0.30%	0.03	0.03	0.03
(11)	38 kV lines	0.93 ^4	---	13.10	12.57	13.20	17.50%	2.29	2.20	2.31
(12)	38 kV-MV stations	0.93	---	---	18.52	19.45	17.50%	0.00	3.24	3.40
	Summer Shoulder Period									
(13)	110 kV lines	1.00	13.30	13.59	14.03	14.73	0.10%	0.01	0.01	0.01
(14)	110-38/20 kV stations	1.00	---	9.70	10.02	10.52	0.10%	0.01	0.01	0.01
(15)	38 kV lines	0.93 ^4	---	13.10	12.57	13.20	33.00%	4.32	4.15	4.36
(16)	38 kV-MV stations	0.93	---	---	18.52	19.45	33.00%	0.00	6.11	6.42
	Summer Off-Peak Period									
(17)	110 kV lines	1.00	13.30	13.59	14.03	14.73	0.00%	0.00	0.00	0.00
(18)	110-38/20 kV stations	1.00	---	9.70	10.02	10.52	0.00%	0.00	0.00	0.00
(19)	38 kV lines	0.93 ^4	---	13.10	12.57	13.20	1.50%	0.20	0.19	0.20
(20)	38 kV-MV stations	0.93	---	---	18.52	19.45	1.50%	0.00	0.28	0.29

Note: For costing period definition see Section II.

^1 Weighted in proportion to load using that plant based on DSO reponse to 8Jan04 Updated data request, response 4d.

^2 The annual costs from Schedules 17 and 18, line 16, were adjusted by demand loss factors. The loss factors used are shown on Schedule 12.

^3 The Period Assignment Factors for 110 kV facilities are based on a relative probability of system peak analysis. The factors for Distribution are based on an analysis of hourly 38 kV substation loads.

^4 This factor only applies to MV and LV service levels.

Schedule 18. Summary of Time-Differentiated Marginal Distribution Costs by Voltage Level (Outside Dublin)

		Weighting Factors ^1		Annual Cost ^2 38 kV Service	Annual Cost ^2 MV Service	Annual Cost ^2 LV Service	Period Assignment Factor ^3	Seasonal Cost 38 kV Service	Seasonal Cost Primary Service	Seasonal Cost Secondary Service
				--------- (2005 Euros per Kilowatt) --------			- (Percent) -	--------- (2005 Euros per Kilowatt) --------		
								(1) x (4)	(2) x (4)	(3) x (4)
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Winter Peak Period									
(1)	110 kV	0.05		0.73	0.75	0.79	90.40%	0.66	0.68	0.71
(2)	110-38/20 kV	1.00		9.70	10.02	10.52	90.40%	8.77	9.06	9.51
(3)	38 kV	0.95	^4	13.10	12.85	13.49	30.70%	4.02	3.95	4.14
(4)	38 kV-MV	0.95		---	18.93	19.88	30.70%	0.00	5.81	6.10
	Winter Shoulder Peak Period									
(5)	110 kV	0.05		0.73	0.75	0.79	9.20%	0.07	0.07	0.07
(6)	110-38/20 kV	1.00		9.70	10.02	10.52	9.20%	0.89	0.92	0.97
(7)	38 kV	0.95	^4	13.10	12.85	13.49	17.30%	2.27	2.22	2.33
(8)	38 kV-MV	0.95		---	18.93	19.88	17.30%	0.00	3.27	3.44
	Winter Off-Peak Period									
(9)	110 kV	0.05		0.73	0.75	0.79	0.30%	0.00	0.00	0.00
(10)	110-38/20 kV	1.00		9.70	10.02	10.52	0.30%	0.03	0.03	0.03
(11)	38 kV	0.95	^4	13.10	12.85	13.49	17.50%	2.29	2.25	2.36
(12)	38 kV-MV	0.95		---	18.93	19.88	17.50%	0.00	3.31	3.48
	Summer Shoulder Period									
(13)	110 kV	0.05		0.73	0.75	0.79	0.10%	0.00	0.00	0.00
(14)	110-38/20 kV	1.00		9.70	10.02	10.52	0.10%	0.01	0.01	0.01
(15)	38 kV	0.95	^4	13.10	12.85	13.49	33.00%	4.32	4.24	4.45
(16)	38 kV-MV	0.95		---	18.93	19.88	33.00%	0.00	6.25	6.56
	Summer Off-Peak Period									
(17)	110 kV	0.05		0.73	0.75	0.79	0.00%	0.00	0.00	0.00
(18)	110-38/20 kV	1.00		9.70	10.02	10.52	0.00%	0.00	0.00	0.00
(19)	38 kV	0.95	^4	13.10	12.85	13.49	1.50%	0.20	0.19	0.20
(20)	38 kV-MV	0.95		---	18.93	19.88	1.50%	0.00	0.28	0.30

Note: For costing period definition see Section II.
^1 Weighted in proportion to load using that plant based on DSO reponse to 8Jan04 Updated data request, response 4d.
^2 The annual costs from Schedules 17 and 18, line 16, were adjusted by demand loss factors. The loss factors used are shown on Schedule 12.
^3 The Period Assignment Factors for 110 kV facilities are based on a relative probability of system peak analysis. The factors for Distribution are based on an analysis of hourly 38 kV substation loads.
^4 This factor only applies to MV and LV service levels.

Schedule 19. Summary of Time-Differentiated Marginal Distribution Costs by Voltage Level (Entire Country)

		Weighting Factors	^1	Annual Cost ^2 110 kV Service	38 kV Service	MV Service	LV Service	Period Assignment Factor	^3	Seasonal Cost 38 kV Service	Primary Service	Secondary Service
				--------- (2005 Euros per Kilowatt) --------				- (Percent) -		--------- (2005 Euros per Kilowatt) --------		
										(1) x (4)	(2) x (4)	(3) x (4)
				(1)	(1)	(2)	(3)	(4)		(5)	(6)	(7)
	Winter Peak Period											
(1)	110 kV	0.30		4.00	4.09	4.22	4.43	90.40%		3.70	3.82	4.01
(2)	110-38/20 kV	1.00		---	9.70	10.02	10.52	90.40%		8.77	9.06	9.51
(3)	38 kV	0.93	^4	---	13.10	12.53	13.15	30.70%		4.02	3.85	4.04
(4)	38 kV-MV	0.93		---	---	18.45	19.37	30.70%		0.00	5.66	5.95
	Winter Shoulder Peak Period											
(5)	110 kV	0.30		4.00	4.09	4.22	4.43	9.20%		0.38	0.39	0.41
(6)	110-38/20 kV	1.00		---	9.70	10.02	10.52	9.20%		0.89	0.92	0.97
(7)	38 kV	0.93	^4	---	13.10	12.53	13.15	17.30%		2.27	2.17	2.28
(8)	38 kV-MV	0.93		---	---	18.45	19.37	17.30%		0.00	3.19	3.35
	Winter Off-Peak Period											
(9)	110 kV	0.30		4.00	4.09	4.22	4.43	0.30%		0.01	0.01	0.01
(10)	110-38/20 kV	1.00		---	9.70	10.02	10.52	0.30%		0.03	0.03	0.03
(11)	38 kV	0.93	^4	---	13.10	12.53	13.15	17.50%		2.29	2.19	2.30
(12)	38 kV-MV	0.93		---	---	18.45	19.37	17.50%		0.00	3.23	3.39
	Summer Shoulder Period											
(13)	110 kV	0.30		4.00	4.09	4.22	4.43	0.10%		0.00	0.00	0.00
(14)	110-38/20 kV	1.00		---	9.70	10.02	10.52	0.10%		0.01	0.01	0.01
(15)	38 kV	0.93	^4	---	13.10	12.53	13.15	33.00%		4.32	4.13	4.34
(16)	38 kV-MV	0.93		---	---	18.45	19.37	33.00%		0.00	6.09	6.39
	Summer Off-Peak Period											
(17)	110 kV	0.30		4.00	4.09	4.22	4.43	0.00%		0.00	0.00	0.00
(18)	110-38/20 kV	1.00		---	9.70	10.02	10.52	0.00%		0.00	0.00	0.00
(19)	38 kV	0.93	^4	---	13.10	12.53	13.15	1.50%		0.20	0.19	0.20
(20)	38 kV-MV	0.93		---	---	18.45	19.37	1.50%		0.00	0.28	0.29

Note: For costing period definition see Section II.
^1 Weighted in proportion to load using that plant based on DSO reponse to 8Jan04 Updated data request, response 4d.
^2 The annual costs from Schedules 17 and 18, line 16, were adjusted by demand loss factors. The loss factors used are shown on Schedule 12.
^3 The Period Assignment Factors for 110 kV facilities are based on a relative probability of system peak analysis. The factors for Distribution are based on an analysis of hourly 38 kV substation loads.
^4 This factor only applies to MV and LV service levels.

The tables below are summaries of monthly time-differentiated marginal distribution substation and demand-related costs by voltage level, for Dublin, outside Dublin, and for the entire country, respectively.

Schedule 20. Summary of Monthly Time-Differentiated Marginal Distribution Costs by Voltage Level for Dublin

	Winter			Summer	
	Peak	Shoulder	Off-Peak	Shoulder	Off-Peak
	(1)	(2)	(3)	(4)	(5)
LV Service					
Monthly Costs per Kilowatt					
(2005 Euros per Kilowatt)					
110 kV lines	3.33	0.34	0.01	0.00	0.00
110-38/20 kV stations	2.38	0.24	0.01	0.00	0.00
38 kV lines	1.01	0.57	0.58	0.54	0.02
38 kV-MV stations	1.49	0.84	0.85	0.80	0.04
Total Capacity Costs	8.21	1.99	1.45	1.34	0.06
MV Service					
Monthly Costs per Kilowatt					
(2005 Euros per Kilowatt)					
110 kV lines	3.17	0.32	0.01	0.00	0.00
110-38/20 kV stations	2.26	0.23	0.01	0.00	0.00
38 kV lines	0.97	0.54	0.55	0.52	0.02
38 kV-MV stations	1.42	0.80	0.81	0.76	0.03
Total Capacity Costs	7.82	1.89	1.38	1.28	0.05
38 kV Service					
Monthly Costs per Kilowatt					
(2005 Euros per Kilowatt)					
110 kV lines	3.07	0.31	0.01	0.00	0.00
110-38/20 kV stations	2.19	0.22	0.01	0.00	0.00
38 kV lines	1.01	0.57	0.57	0.54	0.02
Total Capacity Costs	6.27	1.10	0.59	0.54	0.02

Schedule 21. Summary of Monthly Time-Differentiated Marginal Distribution Costs by Voltage Level for Outside Dublin

	Winter			Summer	
	Peak	Shoulder	Off-Peak	Shoulder	Off-Peak
	(1)	(2)	(3)	(4)	(5)
LV Service					
Monthly Costs per Kilowatt					
(2005 Euros per Kilowatt)					
110 kV lines	0.18	0.02	0.00	0.00	0.00
110-38/20 kV stations	2.38	0.24	0.01	0.00	0.00
38 kV lines	1.04	0.58	0.59	0.56	0.03
38 kV-MV stations	1.53	0.86	0.87	0.82	0.04
Total Capacity Costs	5.13	1.70	1.47	1.38	0.07
MV Service					
Monthly Costs per Kilowatt					
(2005 Euros per Kilowatt)					
110 kV lines	0.17	0.02	0.00	0.00	0.00
110-38/20 kV stations	2.26	0.23	0.01	0.00	0.00
38 kV lines	0.99	0.56	0.56	0.53	0.02
38 kV-MV stations	1.45	0.82	0.83	0.78	0.04
Total Capacity Costs	4.87	1.63	1.40	1.31	0.06
38 kV Service					
Monthly Costs per Kilowatt					
(2005 Euros per Kilowatt)					
110 kV lines	0.16	0.02	0.00	0.00	0.00
110-38/20 kV stations	2.19	0.22	0.01	0.00	0.00
38 kV lines	1.01	0.57	0.57	0.54	0.02
Total Capacity Costs	3.36	0.81	0.58	0.54	0.02

Schedule 22. Summary of Monthly Time-Differentiated Marginal Distribution Costs by Voltage Level for Entire Country

	Winter			Summer	
	Peak	Shoulder	Off-Peak	Shoulder	Off-Peak
	(1)	(2)	(3)	(4)	(5)
LV Service					
Monthly Costs per Kilowatt					
(2005 Euros per Kilowatt)					
110 kV lines	1.00	0.10	0.00	0.00	0.00
110-38/20 kV stations	2.38	0.24	0.01	0.00	0.00
38 kV lines	1.01	0.57	0.58	0.54	0.02
38 kV-MV stations	1.49	0.84	0.85	0.80	0.04
Total Capacity Costs	5.88	1.75	1.44	1.34	0.06
MV Service					
Monthly Costs per Kilowatt					
(2005 Euros per Kilowatt)					
110 kV lines	0.95	0.10	0.00	0.00	0.00
110-38/20 kV stations	2.26	0.23	0.01	0.00	0.00
38 kV lines	0.96	0.54	0.55	0.52	0.02
38 kV-MV stations	1.42	0.80	0.81	0.76	0.03
Total Capacity Costs	5.59	1.67	1.37	1.28	0.05
38 kV Service					
Monthly Costs per Kilowatt					
(2005 Euros per Kilowatt)					
110 kV lines	0.92	0.09	0.00	0.00	0.00
110-38/20 kV stations	2.19	0.22	0.01	0.00	0.00
38 kV lines	1.01	0.57	0.57	0.54	0.02
Total Capacity Costs	4.12	0.88	0.58	0.54	0.02

D. Marginal Distribution Facility Cost

Marginal costs of MV and LV networks were developed from customer numbers, MV/LV transformer capacity and 2004 reproduction costs for three sample feeders – dense urban underground, mix of urban underground and rural overhead, and rural overhead, as provided by the DSO. We adjusted the reproduction costs of the feeders to credit for the up-front customer contributions through a connection charge (50% of connection costs). This approximates the marginal distribution costs that would need to be recovered in DUoS assuming that the current connection policy continues.

Circuit reproduction costs were separated into MV and LV components, each of which was divided by the sum of the estimated design demands of the connected customers, as explained below.[25]

Ideally, we would use the MIC of the LV and MV customers on the sample circuits to compute distribution facilities cost per kVA of MIC. However, this approach produced costs per kVA that seemed too high, as compared to the EU standard of 12 kVA connection. As an alternative, we took the capacity of the feeders (provided by DSO), as the installed capacity of MV/LV transformers and MV connections, along with a diversity factor for LV load to estimate the design demands.[26] This takes into account the fact that because of the diversity of LV loads, less MV capacity is needed to serve a kVA of LV customer MIC than a kVA of MV customer MIC.

We took the MV/LV station capacity and subtracted an estimate of the MIC of the MV customers. We then multiplied this LV share of the station capacity by the diversity factor to estimate the diversified LV loads that LV facilities are designed to serve. The MV costs were then divided by the sum of the estimated MV capacity to produce a per kVA marginal distribution facilities costs for the MV level. This cost was adjusted by the diversity-adjusted LV demands on the MV facilities to provide an estimate of MV cost per kVA of LV MIC. The LV feeder costs were divided by this same diversity-adjusted LV MIC estimate.

Unit investments through the MV and LV levels were calculated for each of the three feeders (see Line 1 in Schedules 23 and 24). The marginal unit investments (for LV and MV customers) were annualised using first-year economic carrying charges. We added the marginal distribution facilities O&M expenses (explained in Section D.2. below), General Plant and Administrative and General (A&G) loaders[27] and working capital adjustments to the annualised marginal investments, in order to produce the marginal distribution costs per kW of installed capacity at the MV and LV levels.

[25] Customers served at MV only contribute to the capacity built into the MV segment, while requirements of customers served at LV contribute to the capacity built into both LV and MV.

[26] We used a diversity factor of 1.3 for MV/LV transformation. This estimate was advised by PB Power, based on analysis of range of various MV/LV network types.

Schedule 23. LV Annual Distribution Facilities Unit Costs

		LV Unit Cost
		------------ (2005 Euros per kVa) -----------
		(5)
(1)	Marginal Investment per kVa	276.97
(2)	With General Plant Loading (1) x 1.0000	295.27
(3)	Annual Economic Carrying Charge Related to Capital Investment	9.43%
(4)	A&G Loading (plant-related)	0.08%
(5)	Total Annual Carrying Charge (3) + (4) (non-plant related)	9.51%
(6)	Annualized Costs (2) x (5)	28.09
(7)	Demand-Related O&M Expenses	7.89
(8)	With A&G Loading (7) x 1.0000	9.19
(9)	Demand-Related Cost (6) + (8)	37.28
	Working Capital	
(10)	Material and Supplies (2) x 0.00%	7.38
(11)	Prepayments (2) x 0.00%	0.00
(12)	Cash Working Capital Allowance (8) x 0.00%	0.00
(13)	Total Working Capital (10) + (11) + (12)	7.38
(14)	Revenue Requirement for Working Capital (13) x 0.00%	0.42
(15)	Total Demand-Related Costs per kVa (9) + (14)	37.70
(16)	Total Annual Marginal Cost per kVa	37.70
(17)	Total Annual Marginal Cost per kVa per month	3.14

[27] The computation of General Plant and A&G loaders is described in Section V.F.

Schedule 24. MV Annual Distribution Facilities Unit Costs

		MV Unit Costs
		------------(2005 Euros per kW)-------------
(1)	Marginal Investment per kVa	98.03
(2)	With General Plant Loading (1) x 1.0661	104.51
(3)	Annual Economic Carrying Charge Related to Capital Investment	9.43%
(4)	A&G Loading (plant-related)	0.08%
(5)	Total Annual Carrying Charge (3) + (4) (non-plant related)	9.51%
(6)	Annualized Costs (2) x (5)	9.94
(7)	Demand-Related O&M Expenses	3.60
(8)	With A&G Loading (7) x 1.1649	4.20
(9)	Demand-Related Cost (6) + (8)	14.14
	Working Capital	
(10)	Material and Supplies (2) x 2.50%	2.61
(11)	Prepayments (2) x 0.00%	0.00
(12)	Cash Working Capital Allowance (8) x 0.00%	0.00
(13)	Total Working Capital (10) + (11) + (12)	2.61
(14)	Revenue Requirement for Working Capital (13) x 5.66%	0.15
(15)	Total Demand-Related Costs per kVa (9) + (14)	14.29
(16)	Total Annual Marginal Cost per kVa	14.29
(17)	Total Annual Marginal Cost per kVa per month	1.19
(18)	Total Annual Marginal Cost per kVa for MV Customers	1.23

As explained above, a portion of the 38kV lines and stations is planned on the basis of the expected customer's MIC (0.75% for lines and cables, 1% for stations) and therefore we treated this share of costs as distribution facility costs, together with the customer station costs. The 38kV distribution facilities costs were adjusted for the 50% upfront customer contributions, and divided by the sum of MIC for DG-8 and DG-9 customers to compute a unit distribution facility investment cost. As for MV and LV cost, the marginal unit investment was annualised using economic carrying charges. We then added the corresponding share of 38kV O&M expenses (explained in Section D.2. below), General Plant and Administrative and General (A&G) loaders and working capital adjustments to the annualised marginal investments, in order to produce the marginal distribution costs per kW of installed capacity at the 38kV level. The schedule below shows this process.

Schedule 25. 38 kV Annual Distribution Facilities Cost

		38kV Distribution Facility Cost (2005 Euros per kW) (1)
(1)	Marginal Investment per kVa	47.76
(2)	With General Plant Loading (1) x 1.0661	50.91
(3)	Annual Economic Carrying Charge Related to Capital Investment	9.43%
(4)	A&G Loading (plant-related)	0.08%
(5)	Total Annual Carrying Charge (3) + (4) (non-plant related)	9.51%
(6)	Annualized Costs (2) x (5)	4.84
(7)	Demand-Related O&M Expenses	1.22
(8)	With A&G Loading (7) x 1.1649	1.42
(9)	Demand-Related Cost (6) + (8)	6.26
	Working Capital	
(10)	Material and Supplies (2) x 2.50%	1.27
(11)	Prepayments (2) x 0.00%	0.00
(12)	Cash Working Capital Allowance (8) x 0.00%	0.00
(13)	Total Working Capital (10) + (11) + (12)	1.27
(14)	Revenue Requirement for Working Capital (13) x 5.66%	0.07
(15)	Total Demand-Related Costs per kVa (9) + (14)	6.33
(16)	Total Annual Marginal Cost per kVa of MIC for Customers Served at 38kV Level.	6.33

1. Distribution Facilities Operation and Maintenance Expenses

Marginal distribution facilities O&M costs were estimated for the MV and LV levels by using 2002 data from the updated 2002 DUoS model. We used diversity factors to recognise the degree to which peak LV loads exceed those at the 38 kV voltage substation. The O&M for distribution facilities cost was divided by appropriate measures of capacity.

Schedule 26. LV Distribution Facilities O&M Expenses per kVa of MIC

	Year	LV Distribution Facilities O&M Expenses ^1	Substation Load	O&M Expense Per kVa of Design Demand	Weighted Labor and Materials Cost Index	O&M Expense Per kW of Design Demand LV
		--(1000 Euros)--	-- (KVA) --	---- (Euros) ---- (1) / (2) / 1.57 ^2	(2005=1)	(2005 Euros) (3) / (4)
		(1)	(2)	(3)	(4)	(5)
(1)	2002	23,520	3,423,000	4.38	0.9051	4.84
(2)	Estimated Annual Distribution Facilities O&M Expenses for the Planning Period (2005 Euros / kVa)					4.84
(3)	Loss Adjustment Factors to Adjust Expenses Per kVa as Measured at the 38 kV substation to Expenses per kVa as Measured at the LV Customer Level					1.085
(4)	Loss Adjusted Estimated Annual Distribution Facilities O&M Expenses for the Planning Period Line (2) / Line (3)					4.46
(5)	Estimated Distribution Facilities O&M for a Secondary Customer:					7.89

Schedule 27. MV Distribution Facilities O&M Expenses per KVA of MIC

	Year	MV Distribution Facilities O&M Expenses ^1	Substation Load	O&M Expense Per kVa of Design Demand	Weighted Labor and Materials Cost Index	O&M Expense Per kW of Design Demand MV
		--(1000 Euros)--	-- (KVA) --	---- (Euros) ---- (1) / (2) / 1.18 ^2	(2005=1)	(2005 Euros) (3) / (4)
		(1)	(2)	(3)	(4)	(5)
(1)	2002	13,588	3,423,000	3.36	0.9051	3.72

(2)	Estimated Annual Distribution Facilities O&M Expenses for the Planning Period (2005 Euros / kVa)	3.72
(3)	Loss Adjustment Factors to Adjust Expenses Per kVa as Measured at the 38kV Substation to Expenses per kVa as Measured at the MV Customer Level	1.033
(4)	Loss Adjusted Estimated Annual Distribution Facilities O&M Expenses for the Planning Period Line (2) / Line (3)	3.60

^1 Total MV expenses are LV operation and maintenance expenses taken from file" DUOS calculationV10wfr.xls (sheet: Omalloc(2))" or the corresponding files with imputs for years prior to 2002.

^2 Rural-Uban unweighted average based on diversity factors between 38kV stations and MV outlet based on B.Redden e-mail of 10 March 2004.

Schedule 28. 38 kV Distribution Facilities O&M Expenses per KVA of MIC

	Year	38 kV Distribution Facilities O&M Expense ^1	Sum of MIC 38 kV ^2	Dist. Facilities O&M Cost per kVA of MIC	Weighted Labor and Materials Cost Index	O&M Expense Per kW of Design Demand 38 kV
		--(1000 Euros)--	-- (KVA) --	---- (Euros) ---- (1)*1000 / (2)	(2005=1)	(2005 Euros) (3) / (4)
		(1)	(2)	(3)	(4)	(5)
(1)	2002	236	213,800	1.10	0.9051	1.22

^1 Includes the 38kV Customer Station O&M expenses plus the portion of the 38kV cables and station O&M that is considered related to distribution facilities (0.75% for lines and cables, 1% for stations).
^2 Sum of MIC values for DG-8 & DG-9, taken from 2002 DUoS Model.

E. Customer-Related Marginal Distribution Costs

DSO provided the 2002 installed cost of a typical meter and service investment and the relative cost of meter reading and other related costs for each DG customer category.[28] The three categories of expenses are meter-reading, checking (which only applies to the demand-metered and interval metered customers) and meter notification. The installed cost of a typical meter and service was adjusted by 50% to account for customer contributions.

Annual meter-related expenses from 2002 were divided by weighted customers to obtain an expense per-weighted customer. The weighted number of customers was derived by multiplying the number of customers in each class by a factor reflecting the relative cost responsibility of each class for activity, such as the number of times the meter is read, the relative cost of metering and other factors. The weights were obtained from the 2002 DUoS model.

[28] The customer-related investment - services and meters – and O&M related expenses was taken from the updated 2002 reproduction costs intended as inputs for the DUoS pricing model.

Schedule 29. Installed Cost of a Typical Meter and Service per Customer (Public Lighting excluded)

	Rate	Description	2002 Installed Meter Cost (2005 Euros) (1) x (2) (3)
(1)	DG-1	U Dom. GP, 1-Phase	€ 155
(2)	DG-1	U Dom. DT, 1-Phase	191
(3)	DG-2	R Dom. GP, 1-Phase	182
(4)	DG-2	R Dom. DT, 1-Phase	247
(5)	DG-3	Public Light	0
(6)	DG-4	Unmetered	0
(7)	DG-5	LV Non-Dom. GP, 1-Phase	178
(8)	DG-5	LV Non-Dom. GP, 3-Phase	294
(9)	DG-5	LV Non-Dom. DT, 1-Phase	244
(10)	DG-5	LV Non-Dom. DT, 3-Phase	417
(11)	DG-6	LV Non-Dom. Max Demand	1,117
(12)	DG-7	MV, Max Demand	6,482
(13)	DG-8	38kV Looped	2,973
(14)	DG-9	38kV Tailed	2,973

The tables below show the derivation of marginal meter and service O&M expenses, based on expense data from the 2002 DUoS model, and the weighting factors applicable to each class. The relative cost by DG category included two sets of allocation factors meter-reading and a general meter category. Additionally, the DUoS pricing model sheets indicated where a class of cost applied only to a subset of DUoS categories, e.g., meter checking only involved DG-7 and above. Finally, other customer costs, which covers payments made to PES for billing functions, was spread equally to all classes.

Schedule 30. Meter and Service O&M Expense by Customer Class

	Rate	Class	Weighting Factor	Annual Meter and Service O&M Expense Per Customer (2005 €)
			(1)	(2)
		Domestic Meters		(1) x 6.86 ^1
(1)	DG-1	U Dom. GP, 1-Phase	1.00	6.86
(2)	DG-1	U Dom. DT, 1-Phase	1.23	8.44
(3)	DG-2	R Dom. GP, 1-Phase	1.17	8.03
(4)	DG-2	R Dom. DT, 1-Phase	1.59	10.91
(5)	DG-3	Public Light	0.85	5.83
(6)	DG-4	Unmetered	0.00	0.00
		LV FR Meters		(1) x 7.73 ^2
(7)	DG-5	LV Non-Dom. GP, 1-Phase	1.00	7.73
(8)	DG-5	LV Non-Dom. GP, 3-Phase	1.65	12.75
(9)	DG-5	LV Non-Dom. DT, 1-Phase	1.37	10.59
(10)	DG-5	LV Non-Dom. DT, 3-Phase	2.33	18.01
		All MD Meters		(1) x 78.43 ^3
(11)	DG-6	LV Non-Dom. Max Demand	1.00	78.43
(12)	DG-7	MV, Max Demand	1.00	78.43
(13)	DG-8	38kV Looped	3.86	302.74
(14)	DG-9	38kV Tailed	3.86	302.74

Schedule 31. Meter Reading Expense by Customer Class

	Rate	Class	Weighting Factor	Annual Customer Accounts Expense Per Customer (2005 Euros)
				(1) x 1.58
			(1)	(2)
(1)	DG-1	U Dom. GP, 1-Phase	1.00	1.58
(2)	DG-1	U Dom. DT, 1-Phase	1.00	1.58
(3)	DG-2	R Dom. GP, 1-Phase	2.33	3.69
(4)	DG-2	R Dom. DT, 1-Phase	2.33	3.69
(5)	DG-3	Public Light	0.00	0.00
(6)	DG-4	Unmetered	0.00	0.00
		LV FR Meters		
(7)	DG-5	LV Non-Dom. GP, 1-Phase	8.15	12.87
(8)	DG-5	LV Non-Dom. GP, 3-Phase	8.15	12.87
(9)	DG-5	LV Non-Dom. DT, 1-Phase	8.15	12.87
(10)	DG-5	LV Non-Dom. DT, 3-Phase	8.15	12.87
		All MD Meters		
(11)	DG-6	LV Non-Dom. Max Demand	40.38	63.81
(12)	DG-7	MV, Max Demand	40.38	63.81
(13)	DG-8	38kV Looped	40.38	63.81
(14)	DG-9	38kV Tailed	40.38	63.81

Schedule 32. Meter Notification Expense by Customer Class

	Rate	Class	Weighting Factor	Annual Customer Notification Expense Per Customer
				(2005 Euros)
				(1) x 3.14
			(1)	(2)
(1)	DG-1	U Dom. GP, 1-Phase	1.00	3.14
(2)	DG-1	U Dom. DT, 1-Phase	1.00	3.14
(3)	DG-2	R Dom. GP, 1-Phase	1.00	3.14
(4)	DG-2	R Dom. DT, 1-Phase	1.00	3.14
(5)	DG-3	Public Light	0.00	0.00
(6)	DG-4	Unmetered	0.00	0.00
		LV FR Meters		
(7)	DG-5	LV Non-Dom. GP, 1-Phase	1.20	3.77
(8)	DG-5	LV Non-Dom. GP, 3-Phase	1.20	3.77
(9)	DG-5	LV Non-Dom. DT, 1-Phase	1.20	3.77
(10)	DG-5	LV Non-Dom. DT, 3-Phase	1.20	3.77
		All MD Meters		
(11)	DG-6	LV Non-Dom. Max Demand	5.00	15.70
(12)	DG-7	MV, Max Demand	10.00	31.40
(13)	DG-8	38kV Looped	50.00	157.00
(14)	DG-9	38kV Tailed	50.00	157.00

Schedule 33. Meter Checking Expense by Customer Class

	Rate	Class	Weighting Factor	Annual Customer Accounts Expense Per Customer (2005 Euros) (1) x 7.54
			(1)	(2)
		All MD Meters		
(1)	DG-6	LV Non-Dom. Max Demand	5.00	37.70
(2)	DG-7	MV, Max Demand	10.00	75.40
(3)	DG-8	38kV Looped	50.00	377.00
(4)	DG-9	38kV Tailed	50.00	377.00

The annualisation of unit costs for meters, services and meter-related expenses was developed using a procedure similar to that for the other types of plant. The results are presented by customer category below.

Schedule 34a. Customer-Related Marginal Distribution Cost

		DG1 GP-1Phase Urban Domestic	DG1 DT-1Phase Urban Domestic	DG2 GP-1Phase Rural Domestic	DG2 DT-1Phase Rural Domestic	DG3 Public Light
		(2005 Euros)				
		(1)	(2)	(3)	(4)	(5)
(1)	Meter Investment	155.00	191.00	182.00	247.00	0.00
(2)	With General Plant Loading (1) x 1.066	165.24	203.62	194.03	263.33	0.00
(3)	Annual Economic Charge Related to Capital Investment	8.74%	8.74%	8.74%	8.74%	8.74%
(4)	A&G Loading (Plant Related)	0.08%	0.08%	0.08%	0.08%	0.08%
(5)	Total (3) + (4)	8.83%	8.83%	8.83%	8.83%	8.83%
(6)	Annualized Costs (2) x (5)	14.58	17.97	17.12	23.24	0.00
(7)	Meter O&M Expenses	6.86	8.44	8.03	10.91	5.83
(8)	Meter Reading Expenses	1.58	1.58	3.69	3.69	0.00
(9)	Meter Checking Expenses	0.00	0.00	0.00	0.00	0.00
(10)	Meter Notification	3.14	3.14	3.14	3.14	0.00
(11)	Other Customer Expenses	0.81	0.81	0.81	0.81	0.81
(12)	With A&G Loading [(7)+(8)+(9)+(10)+(11)] x 1.1649 (Non-plant Related)	14.43	16.27	18.25	21.61	7.74
(13)	Customer-Related Cost (6) + (12)	29.02	34.25	35.38	44.85	7.74
	Working Capital					
(14)	Materials and Supplies (2) x 2.50%	4.13	5.09	4.85	6.58	0.00
(15)	Prepayments (2) x 0.000%	0.00	0.00	0.00	0.00	0.00
(16)	Cash Working Capital (12) x 0.00%	0.00	0.00	0.00	0.00	0.00
(17)	Revenue Requirement for Working Capital [(14)+(15)+(16)] x 5.66%	0.23	0.29	0.27	0.37	0.00
(18)	Total Customer-Related Costs (13) + (17)	29.25	34.53	35.65	45.22	7.74
(19)	Total Annual Marginal Unit Cost	29.25	34.53	35.65	45.22	7.74

Schedule 34b. Customer-Related Marginal Distribution Cost

		DG4 Unmetered	DG5 GP-1Phase LV Non-Dom. Non-Max Demand	DG5 GP-3Phase LV Non-Dom. Non-Max Demand	DG5 DT-1Phase LV Non-Dom. Non-Max Demand	DG5 DT-3Phase LV Non-Dom. Non-Max Demand
		----------	----------	(2005 Euros)	----------	----------
		(1)	(2)	(3)	(4)	(5)
(1)	Meter Investment	0.00	178.00	294.00	244.00	417.00
(2)	With General Plant Loading (1) x 1.066	0.00	189.77	313.43	260.13	444.56
(3)	Annual Economic Charge Related to Capital Investment	9.43%	9.43%	9.43%	9.43%	9.43%
(4)	A&G Loading (Plant Related)	0.08%	0.08%	0.08%	0.08%	0.08%
(5)	Total (3) + (4)	9.51%	9.51%	9.51%	9.51%	9.51%
(6)	Annualized Costs (2) x (5)	0.00	18.05	29.82	24.75	42.30
(7)	O&M Expenses	0.00	7.73	12.75	10.59	18.01
(8)	Meter Reading Expenses	0.00	12.87	12.87	12.87	12.87
(9)	Meter Checking Expenses	0.00	3.77	3.77	3.77	3.77
(10)	Meter Notification	0.00	3.77	3.77	3.77	3.77
(11)	Other Customer Expenses	0.81	0.81	0.81	0.81	0.81
(12)	With A&G Loading [(7)+(8)+(9)+(10)+(11)] x 1.1649 (Non-plant Related)	0.94	33.73	39.57	37.06	45.70
(13)	Customer-Related Cost (6) + (12)	0.94	51.78	69.39	61.81	88.00
	Working Capital					
(14)	Materials and Supplies (2) x 2.50%	0.00	4.74	7.84	6.50	11.11
(15)	Prepayments (2) x 0.000%	0.00	0.00	0.00	0.00	0.00
(16)	Cash Working Capital (12) x 0.00%	0.00	0.00	0.00	0.00	0.00
(17)	Revenue Requirement for Working Capital [(14)+(15)+(16)] x 5.66%	0.00	0.27	0.44	0.37	0.63
(18)	Total Customer-Related Costs (13) + (17)	0.94	52.05	69.84	62.17	88.63
(19)	Total Annual Marginal Unit Cost	0.94	52.05	69.84	62.17	88.63

Schedule 34c. Customer-Related Marginal Distribution Cost

		DG6	DG7	DG8	DG9
		LV Non-Dom. Max Demand	MV Max Demand	38 kV Looped Max Demand	38 kV Tailed Max Demand
		(2005 Euros)			
		(1)	(2)	(3)	(4)
(1)	Meter Investment	1,117.00	769.00	2,973.00	2,973.00
(2)	With General Plant Loading (1) x 1.066	1,190.83	819.83	3,169.51	3,169.51
(3)	Annual Economic Charge Related to Capital Investment	11.36%	11.36%	11.36%	11.36%
(4)	A&G Loading (Plant Related)	0.08%	0.08%	0.08%	0.08%
(5)	Total (3) + (4)	11.44%	11.44%	11.44%	11.44%
(6)	Annualized Costs (2) x (5)	136.23	93.79	362.60	362.60
(7)	O&M Expenses	78.43	78.43	302.74	302.74
(8)	Meter Reading Expenses	63.81	63.81	63.81	63.81
(9)	Meter Checking Expenses	15.70	31.40	157.00	157.00
(10)	Meter Notification	15.70	31.40	157.00	157.00
(11)	Other Customer Expenses	0.81	0.81	0.81	0.81
(12)	With A&G Loading [(7)+(8)+(9)+(10)+(11)] x 1.1649 (Non-plant Related)	203.22	239.80	793.75	793.75
(13)	Customer-Related Cost (6) + (12)	339.46	333.59	1,156.35	1,156.35
	Working Capital				
(14)	Materials and Supplies (2) x 2.50%	29.77	20.50	79.24	79.24
(15)	Prepayments (2) x 0.000%	0.00	0.00	0.00	0.00
(16)	Cash Working Capital (12) x 0.00%	0.00	0.00	0.00	0.00
(17)	Revenue Requirement for Working Capital [(14)+(15)+(16)] x 5.66%	1.69	1.16	4.48	4.48
(18)	Total Customer-Related Costs (13) + (17)	341.14	334.75	1,160.83	1,160.83
(19)	Total Annual Marginal Unit Cost	341.14	334.75	1,160.83	1,160.83

The table below summarises the monthly marginal customer costs by customer class.

Schedule 35. Summary of Monthly Customer-Related Marginal Distribution Cost

	Rate	Class	Monthly Cost Per Customer (2005 Euros) (1)
(1)	DG-1	U Dom. GP, 1-Phase	2.44
(2)	DG-1	U Dom. DT, 1-Phase	2.88
(3)	DG-2	R Dom. GP, 1-Phase	2.97
(4)	DG-2	R Dom. DT, 1-Phase	3.77
(5)	DG-3	Public Light	0.64
(6)	DG-4	Unmetered	0.08
		LV FR Meters	
(7)	DG-5	LV Non-Dom. GP, 1-Phase	4.34
(8)	DG-5	LV Non-Dom. GP, 3-Phase	5.82
(9)	DG-5	LV Non-Dom. DT, 1-Phase	5.18
(10)	DG-5	LV Non-Dom. DT, 3-Phase	7.39
		All MD Meters	
(11)	DG-6	LV Non-Dom. Max Demand	28.43
(12)	DG-7	MV, Max Demand	27.90
(13)	DG-8	38kV Looped	96.74
(14)	DG-9	38kV Tailed	96.74

F. General Plant and A&G Expense Loaders for Distribution

Our marginal cost estimates include a loader for general plant (e.g., land, vehicles, fixtures. We estimated this loader by dividing the average level of these expenditures (from 2002 Distribution Regulatory Accounts) over 2001/02 by average total network expenditures over the same period.

Schedule 36. Derivation of Distribution General Plant Loader

	Item	2001	2002	Average
		Euros		
(1)	Land	1	0.9	
(2)	Vehicles	11.7	7.2	
(3)	Fixtures	0.3	0.2	
(4)	IT (ex. MO)	4.8	9.6	
(5)	Tools	4.3	5.5	
(6)	Other	0	0.1	
(7)	**Total Non-Network Exp**	**22.1**	**23.5**	**22.8**
	Load Related Expenditure			
	New Business:			
(8)	Subtotal	131.2	143.8	
	Reinforcements:			
(9)	Subtotal	118.0	131.5	
(10)	**Total Load Related Exp**	249.2	275.3	**262.3**
	Non-Load Related Expenditure			
(11)	Rural LV Refurbish	5.0	9.5	
(12)	Rural MV Refurbish	14.4	92.0	
(13)	Urban LV	2.0	3.3	
(14)	UG Cable and Minipillars	0.1	4.1	
(15)	Meters plus ancillary	2.6	3.8	
(16)	SCADA	0.0	0.2	
(17)	Automation	0.1	0.6	
(18)	Interval Metering	0.6	1.2	
(19)	Quality of Supply	9.4	7.5	
(25)	Replacement sub-total	3.0	6.0	
(26)	Subtotal	**37.2**	**128.2**	**82.7**
(27)	**Total Network Expenditure**	286.4	403.5	**345.0**
(28)	**General Plant Loader (7)/(27)**			**6.61%**

The marginal cost estimates also include loaders for A&G expenses related to marginal plant (insurance and services provided by Power Gen and ESBI) and marginal O&M (allocations of commercial costs, pensions, human resources, chief executive office; and charges for services provided by PES, Telecoms and ITS). The plant-related loader was developed by dividing the plant-related A&G expenses by the average asset reproduction costs over the period 2001-2002. The on-plant related A&G loader was developed by dividing the average of non-plant related A&G by average payroll plus O&M over the period 2001-2001. The calculation of loaders and the specific categories of expenses that were considered marginal A&G are shown below.

Schedule 37. Derivation of Distribution Plant-Related A&G Loader

	2001	2002	Av 2001/2002
		€m	
(1) Insurance	0.6	0.8	
Average 01/02			0.70
Misc. Revenue Charges			
(2) Power Gen	0.2	0.2	0.2
(3) ESBI	1.4	4	2.7
(4) Subtotal Average 01/02	1.6	4.2	2.9
(5) **Total Marginal A&G**			
Average 01/02			3.60
(6) **Reproduction Asset Cost**	4342	4541.47	
Average 01/02			4442
(7) **Plant A&G Loader (5)/(6)**			**0.08%**

Schedule 38. Derivation of Distribution Non-Plant-Related A&G Loader

	Item	2001	2002	Av. 01/02
			€m	
	Non-Plant			
(1)	Commercial	1.2	2.5	
(2)	Pensions	0.4	0.9	
(3)	Group HR	1.1	2.5	
(4)	Chief Executive	4	2.9	
(5)	**Subtotal**	**6.7**	**8.8**	**7.75**
	Misc. Revenue Charges			
(6)	PES	7.7	11.5	
(7)	Telecoms	4.9	7.1	
(8)	ITS	16.9	12.5	
(9)	**Subtotal**	**29.5**	**31.1**	**32.2**
(10)	**Total (5)+(9)**			**39.95**
(11)	Payroll		99.8	
(12)	O+M		142.4	
(13)	**Total (11)+(12)**		**242.2**	
(14)	**Non-Plant Loader (10)/(13)**		**16.49%**	

G. Distribution Losses

The demand losses for distribution were computed from the information on load flows provided by ESB, as indicated in Section IV.J above. All 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. The distribution demand loss factors shown on Section II.J were applied to the 110- and 38-kV distribution 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 load. Thus there is a different energy loss adjustment factor for each hour and for each voltage level of service. We calculated hourly losses by means of an approximation of quadratic losses based on variable losses at system peak load and a forecast of 2004 hourly loads. The table below shows the variable loss factors at time of peak by service level (includes both transmission and distribution). These factors are an input to the calculation of marginal energy losses, which vary with loads.

Schedule 39. Marginal Energy Losses by Service Level

Sales Level	LV Network	MV Subs	MV Network	38 kV Stations	38 kV Network	110 kV Stations	400/220/110 kV Network
LV Network	1.0245	1.0245	1.0448	1.0448	1.0579	1.0579	1.0891
MV Subs		1.0000	1.0198	1.0198	1.0326	1.0326	1.0631
MV Network			1.0198	1.0198	1.0326	1.0326	1.0631
38 kV Stations				1.0000	1.0125	1.0125	1.0424
38 kV Network					1.0125	1.0125	1.0424
110 kV Stations						1.0000	1.0295
400/220/110 kV Network							1.0295

The table below shows the marginal distribution energy losses by the defined costing periods. Commercial losses are assumed to be non-marginal.

Schedule 40. Time-Differentiated Marginal Distribution Energy Losses by Service Level

	Winter Peak	Winter Shoulder	Winter Off-Peak	Summer Shoulder	Summer Off-Peak
38 kV	8.37%	7.36%	5.78%	6.62%	4.94%
MV	12.99%	11.36%	8.86%	10.18%	7.53%
LV	19.38%	16.83%	12.99%	15.01%	10.99%

VI. PES MARGINAL COSTS

A. Conceptual Discussion

In addition to the generation, transmission and distribution marginal costs described above, PES supply tariffs must recover the marginal costs of supply. 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. In Ireland these costs do not include meter investment or meter reading because the metering function is included in the DUoS. Our study identified marginal customer-related expenses from a detailed analysis of PES accounting data. As in the case of other functions, we assumed that appropriately identified accounting costs would make a good proxy for marginal customer expense.

Estimates of PES supply costs were developed from an analysis of 2002 regulatory accounts, the most recent year for which audited results are available. 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. We 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. Under CER policies, 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 we have treated the margin as a revenue-related marginal cost.[29]

We did not identify any marginal plant requirements 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.[30]

[29] PES Revenue Draft Decision. September 2001.

[30] Although PES is investing in a new billing system, the costs are not considered to be marginal with respect to number of customers.

B. Cost Categories

The PES regulatory accounts provide only a single figure for payroll. We used relationships in the 2004 PES Allowed Costs to split the total payroll into the following categories:

- Trading
- Advertising & Marketing (further split into energy efficiency, communications, Elcom, technical services and special promotions in customer care)
- Customers records, service and billing
- Revenue collection, and
- Contact centre.

In addition to payroll, PES has costs in the following categories:

- Material and Goods for resale
- Transport & communications
- Establishment costs
- Computer costs
- Selling and advertising
- Professional services, and
- Other

PES currently incurs certain costs associated with services or obligations provided by other ESB business units. For example, PES pays transmission for capacity margin, although this will be discontinued in the new market and we have excluded this cost from the marginal cost study. PES currently pays distribution for collections from customers about to be disconnected. This practice is also scheduled to be discontinued, although we have assumed that PES will still incur these costs in one form or another. Other services provided by ESB business units include telecoms, contracts, ITS, retail (discounts on appliances sold to employees), and shared services. Each of these costs was evaluated as described above for the PES expenses.

In addition to paying other ESB business units for services, PES is also compensated for services it provides to other ESB business units. We categorised these services and credited the revenues to the corresponding expense categories before computing PES marginal customer- and revenue-related marginal costs.

PES is assigned by corporate accounting practices a share of corporate costs such as finance, legal, regulatory affairs, human resources, pensions, etc. We analysed these corporate-level costs to exclude them if they are not marginal. The remainder were treated as overheads and included in the A&G loader.

C. Calculation of PES A&G loaders

The overheads were divided by applicable (marginal and non-marginal) expenses to produce a percentage administrative and general (A&G) expenses loader that was then applied to the primary cost elements. The table below summarises the elements of expense used to determine the A&G loader.

Schedule 41. PES Non-Plant related A&G

		2002
		€m
	Marginal A&G	
(1)	Transport & communications	3.2
(2)	Computer costs	0.1
(3)	Other	4.7
(4)	Group Finance	0.9
(5)	Commercial	0.8
(6)	Pensions	0.2
(7)	Group Human Resources	0.4
(8)	Chief Executive	0.9
(9)	Shared Services	7.7
(10)	Telecoms	1.1
(11)	ITS (marginal)^1	3.35
(12)	Retail	0.6
(13)	Telecoms & ITS from other business units	1.2
(14)	**Total Marginal A&G**	**25.15**
	Applicable Expenses	
(15)	Trading	0.4
(16)	Energy Efficiency	1.0
(17)	Comm. and Marketing & Special Promotions	1.5
(18)	Elcom and Technical Services	0.3
(19)	Customer Records Service & Billing	5.5
(20)	Revenue Collection	15.2
(21)	Contact Centre	1.9
(22)	Material and Goods for Resale	0.9
(23)	Establishment costs	1.3
(24)	Selling and advertising	3.5
(25)	Professional & Legal Services	2.9
(26)	Regulatory & Corporate Affairs	1.0
(27)	Misc charges from trans. & distrib.	8.5
(28)	Other ITS	3.35
(29)	Contracts	0.1
(30)	**TOTAL**	**47.35**
(31)	**Non-plant related A&G loader (15)/(36)**	**53.1%**

Notes

^1 Half of ITS cost is assumed to be marginal A&G

D. Calculation of PES Marginal Costs

Bad debts and the PES profit margin were treated as revenue-related marginal costs, with allocations to customer categories based on category revenues (excluding PES costs to avoid circularity). The remaining marginal cost elements were treated as customer-related and allocated to customer categories using numbers of customers or bills, as in the existing PES supply cost model. All costs were escalated to year 2005 euros, using PES-provided estimates of inflation from 2002 to 2005.

Normally there is a cash working capital requirement to finance the lag between when a company pays its bills and is reimbursed by its customers. Under current payment policies, PES does not have such a lag and we have used a cash working capital requirement of zero in our computations. The tables below show the allocation factors used to apportion the marginal costs to customer categories, the actual apportionment, and the total marginal customer- and revenue-related PES costs, escalated to 2005 euros. The customer-related numbers are annual costs per customer for each category. The revenue-related costs are percentage adders that would be applied to generation, TUoS, DUoS and PES costs other than bad debt and margin.

Schedule 42. Derivation of Allocation Factors for PES Marginal Supply Costs

PES Allocation Factors for Marginal Supply Costs (using 2002 RAGs)

		Customer Categories												
	Allocation Factors	**UrbDom**	**RurDom**	**Com GPT**	**Ind GPT**	**PL**	**Com LVMD**	**Ind LVMD**	**Com 10kv**	**Ind 10 kv**	**110kv**	**38kV**	**CEU**	**Total**
(1)	**Customer Numbers1**	931,693	661,107	119,719	3,605	2,619	6,371	1,262	65	160	7	3	1	1,726,612
(2)		0.5396	0.3829	0.0693	0.0021	0.0015	0.0037	0.0007	0.0000	0.0001	0.0000	0.0000	0.0000	
(3)	MD Customers						0.8096	0.1604	0.0083	0.0203	0.0009	0.0004	0.0001	
(4)	**Electricity Units**	4,202	3,229	2,084	259	205	1,987	514	73	265	59	53	406	13,336
(5)		0.3151	0.2421	0.1563	0.0194	0.0154	0.1490	0.0386	0.0055	0.0199	0.0044	0.0040	0.0305	
(6)	**Total Revenue**	493	400	247	25	13	169	40	5	18	4	4	21	1,439
(7)		0.3427	0.2781	0.1719	0.0171	0.0092	0.1172	0.0281	0.0033	0.0122	0.0026	0.0029	0.0144	
(8)	Domestic	0.5521	0.4479											
(9)	Non-Domestic			0.4535	0.0452	0.0244	0.3092	0.0741	0.0088	0.0323	0.0070	0.0076	0.0380	
	Total 2005 Revenue less PES supply revenue	442	364	237	24	13	166	40	5	17	4	4	21	1,337
		0.3308	0.2721	0.1774	0.0182	0.0097	0.1242	0.0298	0.0035	0.0130	0.0028	0.0031	0.0154	
	Domestic	0.5487												
	Non-Domestic			0.4467	0.0457	0.0245	0.3127	0.0751	0.0089	0.0328	0.0071	0.0078	0.0387	
(10)	**Bills Issued**	6	6	6	6	12	12	12	12	12	12	12	12	
(11)	**Total No. of Bills issued p.a.**	5,590,158	3,966,642	718,314	21,630	31,428	76,452	15,144	780	1,920	84	36	12	10,422,600
(12)		0.5363	0.3806	0.0689	0.0021	0.0030	0.0073	0.0015	0.0001	0.0002	0.0000	0.0000	0.0000	
(13)	Domestic	0.5849	0.4151											
(14)	Non-Domestic			0.8297	0.0250	0.0363	0.0883	0.0175	0.0009	0.0022	0.0001	0.0000	0.0000	865,800
(15)	**For customer records, service, billing: MD staff costs as % of total**						0.5%							
(16)	**For Revenue Collection, collection as % of total**													7.4%
(17)	Collection	80%		20%										
(18)	For Bad Debts	44%		56%										

Schedule 43. Derivation of PES Marginal Customer-related Costs

PES Marginal Supply Costs (using 2002 RAGs)

	Marginal Cost Categories		**Customer Categories**											
			UrbDom	**RurDom**	**Com GPT**	**Ind GPT**	**PL**	**Com LVMD**	**Ind LVMD**	**Com 10kv**	**Ind 10 kv**	**110kv**	**38kV**	**CEU**
		€m	----------	----------	----------	----------	----------	€	----------	----------	----------	----------	----------	----------
	Advertising & Marketing													
(1)	- Energy Efficiency	1.01	547,036	388,164	70,292	2,117	1,538	3,741	741	38	94	4	2	1
(2)	*No of Customers*													
(3)	- Communications	1.37	737,561	523,356	94,774	2,854	2,073	5,044	999	51	127	6	2	1
(4)	*No of Customers*													
(5)	- Technical Services (WDRI & PowerSave)	0.19						155,579	30,818	1,587	3,907	171	73	24
(6)	*No of MD Customers*													
(7)	- Special Promotions in Customer Care	0.18	95,715	67,917	12,299	370	269	655	130	7	16	1	0	0
(8)	*No of Customers*													
(9)	**Customer Records Service & Billing**	5.49												
(10)	*MD Staff (No of MD Customers)*	0.03						22,912	4,539	234	575	25	11	4
(11)	*Remainder (No of Bills Issued)*	5.46	2,930,705	2,079,558	376,584	11,340	16,476	40,081	7,939	409	1,007	44	19	6
(12)	**Revenue Collection**	15.18												
(13)	*Collection (80% Domestic); then no of bil*	0.90	527,618	374,385										
(14)	*Collection (20% Non Dom); then no of bil*	0.23			187,087	5,634	8,186	19,912	3,944	203	500	22	9	3
(15)	*Receipting (No of Bills Issued)*	14.06	7,539,040	5,349,522	968,738	29,171	42,385	103,105	20,424	1,052	2,589	113	49	16
(16)	**Contact Centre**	1.87	1,009,659	716,430	129,737	3,907	2,838	6,904	1,368	70	173	8	3	1
	No of Customers													
	Charges to PES by other ESB business units													
(17)	Distribution	8.2												
(18)	*Collection (80% Domestic); then no of bil*	6.56	3,837,209	2,722,791										
(19)	*Collection (20% Non Dom); then no of bil*	1.64			1360632	40972	59531	144816	28686	1477	3637	159	68	23
(20)	SubTotal	33.50	17,224,543	12,222,122	3,200,144	96,363	133,296	502,748	99,587	5,129	12,626	552	237	79
(21)	Administrative and General Expense Loade	53.1%												
(22)	Allocated Expenses (incl A&G) (20) x (21)		26,373,376	18,713,915	4,899,903	147,547	204,096	769,784	152,483	7,854	19,332	846	362	121
(23)	Cash working capital		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(24)	Revenue requirement for cash working capital (23) x 5.95%		0	0	0	0	0	0	0	0	0	0	0	0
(25)	Allocated expenses with cash working capital allowance (22) + (24)		26,373,376	18,713,915	4,899,903	147,547	204,096	769,784	152,483	7,854	19,332	846	362	121
	Marginal Customer-Related PES Costs													
(26)	*2002 euros per customer per annum*		28.31	28.31	40.93	40.93	77.93	120.83	120.83	120.83	120.83	120.83	120.83	120.83
(27)	*2005 euros per customer per annum*	esc. Rate5 1.099	**31.11**	**31.11**	**44.98**	**44.98**	**85.65**	**132.80**	**132.80**	**132.80**	**132.80**	**132.80**	**132.80**	**132.80**

Schedule 44. Derivation of PES Marginal Revenue-related Costs

PES Marginal Revenue-Related Supply Costs (using 2002 RAGs)

			Customer Categories										
			UrbDom	**RurDom**	**Com GPT**	**Ind GPT**	**PL**	**Com LVMD**	**Ind LVMD**	**Com 10kv**	**Ind 10 kv**	**110kv**	**38kV**
(28) Bad Debts (don't apply a loader) mEur	3												
(29) *Domestic Share - % of Revenue*		1,309,091	718,313	586,393									
(30) *Non-Domestic Share - % of Revenue*		1,690,909			766,767	76,430	41,214	522,840	125,292	14,839	54,591	11,815	12,886
(31) Marginal Costs including Bad Debt			27,091,689	19,300,308	5,666,670	223,976	245,310	1,292,624	277,774	22,693	73,923	12,660	13,248
(32) Margin (projected for 2005) mEur6 *Allocated on the basis of Total Revenue*	17.15		5,876,486	4,768,153	2,947,954	293,845	158,452	2,010,140	481,703	57,053	209,883	45,423	49,542
(33) **Total allocated PES Costs (49) + (50)**			32,968,175	24,068,461	8,614,624	517,821	403,761	3,302,764	759,478	79,746	283,806	58,084	62,790
(34) **Marginal Revenue-Related PES Costs** *percent of Generation, TUoS, DUoS and other PES Charges*			**1.35%**	**1.36%**	**1.21%**	**1.21%**	**1.21%**	**1.21%**	**1.21%**	**1.21%**	**1.21%**	**1.21%**	**1.21%**

VII. COMPUTATION OF ECONOMIC CARRYING CHARGES

To be useful in ratemaking and other marginal cost applications, the marginal investment in new plant must be converted into annual costs using an economic carrying charge (ECC). These annual charges reflect the revenue requirement associated with incremental plant: return to stockholders and bondholders, depreciation, and income taxes.

For use in a marginal cost study, the appropriate stream of annual charges is a stream that rises at the rate of inflation net of technical progress and yields the total present value of all costs over the life of the investment. In such a stream, the first year's charge represents the cost in today's euros of having the plant or equipment for a year. It also represents the rental rate for such an investment in a competitive market.

ECCs were developed from CER estimates of cost of capital components, and our review of tax and accounting regulations. In the cost of equity calculation we used a new risk-free rate based on the CER's computation of BGE's cost of capital,[31] and made a slight adjustment for the different capital structures in BGE and ESB.[32] The economic carrying charges reflect a cost of a cost of equity relevered to 50-50 debt-equity of 6.5 percent, and 3.9 percent for debt. Although the capital costs are the same for all types of plant, the carrying charges can vary because of differences such as service lives, and depreciation rules. In the carrying charge computation there is provision for a term to incorporate the cost of having to replace assets that fail before their average service life, and delay replacement of assets that last longer. We did not have the information necessary to include this "dispersed retirements" component in this study.

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[31] Commission's Proposals on Transmission Use of System Revenue Requirement and Tariff Structure. October 2003-September 2007; page 11.

[32] For all of the ESB businesses, the allowed revenues determination foresees financing of incremental investment through 50% sales of common stock and 50% debt over the study period. BGE's equity cost assumed a structure of 50% equity and 55% debt.

Schedule 45. Economic Carrying Charge for Transmission and Distribution

		Transmission and Other Distribution	Distribution Meters LVFR	Distribution Meters LVMD
		(1)	(2)	(3)
(1)	Present Value of Revenue Requirements Related to Incremental 1,000 Euro Investment	1,509.53	1,335.35	1,182.54
(2)	Present Value Cost of Replacing Dispersed Retirements Related to Incremental 1,000 Euro Investment	0.00	0.00	0.00
(3)	Total Present Value Cost Related to Incremental 1,000 Euro Investment (1)+(2)	1,509.53	1,335.35	1,182.54
(4)	First-Year Annual Economic Charge Related to Incremental 1,000Euro Investment ^1	87.45	94.33	113.59
(5)	First-Year Annual Economic Charge Related to Incremental Investment [(4)/1,000]	8.74%	9.43%	11.36%

^1 The appropriate charge is the first-year charge which rises annually at the rate of inflation net of technological progress. The first-year charge is calculated using the following formula:

$$AC(T) = K\,(R - J)\,(1 + J)^{T-1} \left(\frac{1}{1 - \left(\frac{1+J}{1+R} \right)^{N}} \right)$$

where:

AC(T) = Annual Charge in Year T

T = Year Index

K = Total PV of Revenue Requirement for Original Investment [line (3)]

R = Discount Rate (After-tax incremental cost of capital)

J = Inflation Rate Net of Technical Progress

N = Book Life

VIII. SUMMARY TABLES

This section summarises the marginal cost estimates of generation, transmission, distribution and supply activities in Ireland.

A. Summary of Time-Differentiated Marginal Costs

Schedules below provide estimates of the time-differentiated marginal generation, transmission and distribution substation costs by pricing period and voltage level, for Dublin, Outside Dublin, and a combined summary for the entire country. The marginal cost of reactive power shown in Schedule 7 above has been included in the marginal generation cost estimates, also adjusted by losses. The time-differentiated marginal costs of transmission and distribution substations & lines have been converted into per-kWh marginal cost estimates.

Schedule 46. Summary of Time-Differentiated Marginal Costs per kWh by Voltage Level, Dublin, 2005

Service Voltage Level		Winter Season			Summer Season	
		Peak	Shoulder	Off-Peak	Shoulder	Off-Peak
		(1)	(2)	(3)	(4)	(5)
LV Service						
	Generation Marginal Cost (cent/kWh) ^1	**21.67**	**10.41**	**4.12**	**7.91**	**3.50**
	Transmission Lines and St. (cent/kWh)					
	400-220/110 kV	12.88	0.36	0.01	0.00	0.00
	Distribution Lines and St. (cent/kWh)					
	110 kV	1.29	0.04	0.00	0.00	0.00
	110-38/20 kV	0.92	0.03	0.00	0.00	0.00
	38 kV	0.39	0.06	0.03	0.02	0.00
	38 kV-MV	0.58	0.09	0.05	0.04	0.00
	Total Dist. Lines & Subst	3.18	0.21	0.09	0.06	0.00
	Total time-differentiated T&D costs (cent/kWh)	**16.06**	**0.57**	**0.09**	**0.06**	**0.00**
	Total time-differentiated G, T&D costs (cent/kWh)	**37.72**	**10.98**	**4.21**	**7.96**	**3.50**
MV Service						
	Generation Marginal Cost (cent/kWh) ^1	**20.60**	**9.96**	**3.98**	**7.60**	**3.40**
	Transmission Lines and St. (cent/kWh)	12.26	0.34	0.01	0.00	0.00
	400-220/110 kV					
	Distribution Lines and St. (cent/kWh)					
	110 kV	1.23	0.03	0.00	0.00	0.00
	110-38/20 kV	0.88	0.02	0.00	0.00	0.00
	38 kV	0.38	0.06	0.03	0.02	0.00
	38 kV-MV	0.55	0.08	0.05	0.03	0.00
	Total Dist. Lines & Subst	3.03	0.20	0.08	0.06	0.00
	Total time-differentiated T&D costs (cent/kWh)	**15.29**	**0.54**	**0.09**	**0.06**	**0.00**
	Total time-differentiated G, T&D costs (cent/kWh)	**35.90**	**10.50**	**4.07**	**7.65**	**3.40**
38 kV Service						
	Generation Marginal Cost (cent/kWh) ^1	**19.83**	**9.63**	**3.87**	**7.37**	**3.32**
	Transmission Lines and St. (cent/kWh)	11.87	0.33	0.01	0.00	0.00
	400-220/110 kV					
	Distribution Lines and St. (cent/kWh)					
	110 kV	1.19	0.03	0.00	0.00	0.00
	110-38/20 kV	0.85	0.02	0.00	0.00	0.00
	38 kV	0.39	0.06	0.03	0.02	0.00
	Total Dist. Lines & Subst	2.43	0.12	0.04	0.02	0.00
	Total time-differentiated T&D costs (cent/kWh)	**14.30**	**0.45**	**0.04**	**0.02**	**0.00**
	Total time-differentiated G, T&D costs (cent/kWh)	**34.13**	**10.08**	**3.92**	**7.39**	**3.32**
110 kV Service						
	Generation Marginal Cost (cent/kWh) ^1	**19.38**	**9.44**	**3.81**	**7.23**	**3.28**
	Transmission Lines and St. (cent/kWh)	11.69	0.33	0.01	0.00	0.00
	400-220/110 kV					
	Distribution Lines and St. (cent/kWh)					
	110 kV	1.17	0.03	0.00	0.00	0.00
	Total time-differentiated T&D costs (cent/kWh)	**12.86**	**0.36**	**0.01**	**0.00**	**0.00**
	Total time-differentiated G, T&D costs (cent/kWh)	**32.24**	**9.80**	**3.82**	**7.24**	**3.28**

Notes:
1 Marginal generation cost includes estimate of marginal cost of reactive power (0.060 cent/kWh) adjusted by losses.

Schedule 47. Summary of Time-Differentiated Marginal Costs per kWh by Voltage Level, Outside Dublin, 2005

Service Voltage Level		Winter Season Peak	Winter Season Shoulder	Winter Season Off-Peak	Summer Season Shoulder	Summer Season Off-Peak
		(1)	(2)	(3)	(4)	(5)
LV Service						
	Generation Marginal Cost (cent/kWh) ^1	**21.67**	**10.41**	**4.12**	**7.91**	**3.50**
	Transmission Lines and St. (cent/kWh)					
	400-220/110 kV	12.88	0.36	0.01	0.00	0.00
	Distribution Lines and St. (cent/kWh)					
	110-38/20 kV	0.92	0.03	0.00	0.00	0.00
	38 kV	0.40	0.06	0.04	0.02	0.00
	38 kV-MV	0.59	0.09	0.05	0.04	0.00
	Total Dist. Lines & Subst	1.92	0.18	0.09	0.06	0.00
	Total time-differentiated T&D costs (cent/kWh)	**14.79**	**0.54**	**0.10**	**0.06**	**0.00**
	Total time-differentiated G, T&D costs (cent/kWh)	**36.46**	**10.95**	**4.21**	**7.97**	**3.51**
MV Service						
	Generation Marginal Cost (cent/kWh) ^1	**20.60**	**9.96**	**3.98**	**7.60**	**3.40**
	Transmission Lines and St. (cent/kWh)	12.26	0.34	0.01	0.00	0.00
	400-220/110 kV					
	Distribution Lines and St. (cent/kWh)					
	110-38/20 kV	0.88	0.02	0.00	0.00	0.00
	38 kV	0.38	0.06	0.03	0.02	0.00
	38 kV-MV	0.56	0.09	0.05	0.03	0.00
	Total Dist. Lines & Subst	1.82	0.17	0.08	0.06	0.00
	Total time-differentiated T&D costs (cent/kWh)	**14.08**	**0.51**	**0.09**	**0.06**	**0.00**
	Total time-differentiated G, T&D costs (cent/kWh)	**34.69**	**10.47**	**4.07**	**7.66**	**3.40**
38 kV Service						
	Generation Marginal Cost (cent/kWh) ^1	**19.83**	**9.63**	**3.87**	**7.37**	**3.32**
	Transmission Lines and St. (cent/kWh)	11.87	0.33	0.01	0.00	0.00
	400-220/110 kV					
	Distribution Lines and St. (cent/kWh)					
	110-38/20 kV	0.85	0.02	0.00	0.00	0.00
	38 kV	0.39	0.06	0.03	0.02	0.00
	Total Dist. Lines & Subst	1.24	0.08	0.03	0.02	0.00
	Total time-differentiated T&D costs (cent/kWh)	**13.11**	**0.41**	**0.04**	**0.02**	**0.00**
	Total time-differentiated G, T&D costs (cent/kWh)	**32.94**	**10.05**	**3.91**	**7.39**	**3.32**
110 kV Service						
	Generation Marginal Cost (cent/kWh) ^1	**19.38**	**9.44**	**3.81**	**7.23**	**3.28**
	Transmission Lines and St. (cent/kWh)	11.69	0.33	0.01	0.00	0.00
	400-220/110 kV					
	Distribution Lines and St. (cent/kWh)					
	110 kV	0.06	0.00	0.00	0.00	0.00
	Total time-differentiated T&D costs (cent/kWh)	**11.75**	**0.33**	**0.01**	**0.00**	**0.00**
	Total time-differentiated G, T&D costs (cent/kWh)	**31.13**	**9.76**	**3.82**	**7.24**	**3.28**

Notes:

1 Marginal generation cost includes estimate of marginal cost of reactive power (0.060 cent/kWh) adjusted by losses.

Schedule 48. Summary of Time-Differentiated Marginal Costs per kWh by Voltage Level, For Entire Country, 2005

Service Voltage Level		Winter Season			Summer Season	
		Peak	Shoulder	Off-Peak	Shoulder	Off-Peak
		(1)	(2)	(3)	(4)	(5)
LV Service						
	Generation Marginal Cost (cent/kWh) ^1	**21.67**	**10.41**	**4.12**	**7.91**	**3.50**
	Transmission Lines and St. (cent/kWh)					
	400-220/110 kV	12.88	0.36	0.01	0.00	0.00
	Distribution Lines and St. (cent/kWh)					
	110 kV	0.39	0.01	0.00	0.00	0.00
	110-38/20 kV	0.92	0.03	0.00	0.00	0.00
	38 kV	0.39	0.06	0.03	0.02	0.00
	38 kV-MV	0.58	0.09	0.05	0.04	0.00
	Total Dist. Lines & Subst	2.28	0.18	0.09	0.06	0.00
	Total time-differentiated T&D costs (cent/kWh)	**15.15**	**0.54**	**0.09**	**0.06**	**0.00**
	Total time-differentiated G, T&D costs (cent/kWh)	**36.82**	**10.95**	**4.21**	**7.96**	**3.50**
MV Service						
	Generation Marginal Cost (cent/kWh) ^1	**20.60**	**9.96**	**3.98**	**7.60**	**3.40**
	Transmission Lines and St. (cent/kWh)	12.26	0.34	0.01	0.00	0.00
	400-220/110 kV					
	Distribution Lines and St. (cent/kWh)					
	110 kV	0.37	0.01	0.00	0.00	0.00
	110-38/20 kV	0.88	0.02	0.00	0.00	0.00
	38 kV	0.37	0.06	0.03	0.02	0.00
	38 kV-MV	0.55	0.08	0.05	0.03	0.00
	Total Dist. Lines & Subst	2.17	0.18	0.08	0.06	0.00
	Total time-differentiated T&D costs (cent/kWh)	**14.43**	**0.52**	**0.09**	**0.06**	**0.00**
	Total time-differentiated G, T&D costs (cent/kWh)	**35.03**	**10.48**	**4.07**	**7.65**	**3.40**
38 kV Service						
	Generation Marginal Cost (cent/kWh) ^1	**19.83**	**9.63**	**3.87**	**7.37**	**3.32**
	Transmission Lines and St. (cent/kWh)	11.87	0.33	0.01	0.00	0.00
	400-220/110 kV					
	Distribution Lines and St. (cent/kWh)					
	110 kV	0.36	0.01	0.00	0.00	0.00
	110-38/20 kV	0.85	0.02	0.00	0.00	0.00
	38 kV	0.39	0.06	0.03	0.02	0.00
	Total Dist. Lines & Subst	1.60	0.09	0.03	0.02	0.00
	Total time-differentiated T&D costs (cent/kWh)	**13.47**	**0.42**	**0.04**	**0.02**	**0.00**
	Total time-differentiated G, T&D costs (cent/kWh)	**33.30**	**10.06**	**3.91**	**7.39**	**3.32**
110 kV Service						
	Generation Marginal Cost (cent/kWh) ^1	**19.38**	**9.44**	**3.81**	**7.23**	**3.28**
	Transmission Lines and St. (cent/kWh)	11.69	0.33	0.01	0.00	0.00
	400-220/110 kV					
	Distribution Lines and St. (cent/kWh)					
	110 kV	0.35	0.01	0.00	0.00	0.00
	Total time-differentiated T&D costs (cent/kWh)	**12.04**	**0.34**	**0.01**	**0.00**	**0.00**
	Total time-differentiated G, T&D costs (cent/kWh)	**31.42**	**9.77**	**3.82**	**7.24**	**3.28**

Notes:
1 Marginal generation cost includes estimate of marginal cost of reactive power (0.060 cent/kWh) adjusted by losses.

Schedules below provide estimates of the time-differentiated marginal transmission and distribution substation costs per-kW of maximum demand, by pricing period and voltage level, for Dublin, Outside Dublin, and combined estimates for the entire country.

Schedule 49. Summary of Time-Differentiated Per-kW Transmission and Distribution Marginal Costs by Voltage Level in Dublin, 2005

Service Voltage Level		Winter Season Peak	Winter Season Shoulder	Winter Season Off-Peak	Summer Season Shoulder	Summer Season Off-Peak
		(1)	(2)	(3)	(4)	(5)
LV Service						
	Transmission Lines and St. (€/kW)					
	400-220/110 kV	8.30	0.85	0.03	0.00	0.00
	Distribution Lines and St. (€/kW)					
	110 kV	3.33	0.34	0.01	0.00	0.00
	110-38/20 kV	2.38	0.24	0.01	0.00	0.00
	38 kV	1.01	0.57	0.58	0.54	0.02
	38 kV-MV	1.49	0.84	0.85	0.80	0.04
	Total Distibution	8.21	1.99	1.45	1.34	0.06
	Total time-differentiated T&D costs (€/kW)	**16.51**	**2.84**	**1.48**	**1.34**	**0.06**
MV Service						
	Transmission Lines and St. (€/kW)					
	400-220/110 kV	7.91	0.81	0.03	0.00	0.00
	Distribution Lines and St. (€/kW)					
	110 kV	3.17	0.32	0.01	0.00	0.00
	110-38/20 kV	2.26	0.23	0.01	0.00	0.00
	38 kV	0.97	0.54	0.55	0.52	0.02
	38 kV-MV	1.42	0.80	0.81	0.76	0.03
	Total Dist. Lines & Subst	7.82	1.89	1.38	1.28	0.05
	Total time-differentiated T&D costs (€/kW)	**15.73**	**2.70**	**1.41**	**1.28**	**0.05**
38 kV Service						
	Transmission Lines and St. (€/kW)					
	400-220/110 kV	7.66	0.78	0.03	0.00	0.00
	Distribution Lines and St. (€/kW)					
	110 kV	3.07	0.31	0.01	0.00	0.00
	110-38/20 kV	2.19	0.22	0.01	0.00	0.00
	38 kV	1.01	0.57	0.57	0.54	0.02
	Total Dist. Lines & Subst	6.27	1.10	0.59	0.54	0.02
	Total time-differentiated T&D costs (€/kW)	**13.93**	**1.88**	**0.62**	**0.54**	**0.02**
110 kV Service						
	Transmission Lines and St. (€/kW)					
	400-220/110 kV	7.54	0.77	0.03	0.00	0.00
	Distribution Lines and St. (€/kW)					
	110 kV	3.01	0.31	0.01	0.00	0.00
	Total time-differentiated T&D costs (€/kW)	**10.55**	**1.08**	**0.04**	**0.00**	**0.00**

Schedule 50. Summary of Time-Differentiated Per-kW Transmission and Distribution Marginal Costs by Voltage Level, Outside Dublin, 2005

Service Voltage Level		Winter Season			Summer Season	
		Peak	Shoulder	Off-Peak	Shoulder	Off-Peak
		(1)	(2)	(3)	(4)	(5)
LV Service						
	Transmission Lines and St. (€/kW)					
	400-220/110 kV	8.30	0.85	0.03	0.00	0.00
	Distribution Lines and St. (€/kW)					
	110-38/20 kV	2.38	0.24	0.01	0.00	0.00
	38 kV	1.04	0.58	0.59	0.56	0.03
	38 kV-MV	1.53	0.86	0.87	0.82	0.04
	Total Dist. Lines & Subst	4.95	1.68	1.47	1.38	0.07
	Total time-differentiated T&D costs (€/kW)	**13.25**	**2.53**	**1.50**	**1.38**	**0.07**
MV Service						
	Transmission Lines and St. (€/kW)					
	400-220/110 kV	7.91	0.81	0.03	0.00	0.00
	Distribution Lines and St. (€/kW)					
	110-38/20 kV	2.26	0.23	0.01	0.00	0.00
	38 kV	0.99	0.56	0.56	0.53	0.02
	38 kV-MV	1.45	0.82	0.83	0.78	0.04
	Total Dist. Lines & Subst	4.70	1.61	1.40	1.31	0.06
	Total time-differentiated T&D costs (€/kW)	**12.61**	**2.42**	**1.43**	**1.31**	**0.06**
38 kV Service						
	Transmission Lines and St. (€/kW)					
	400-220/110 kV	7.66	0.78	0.03	0.00	0.00
	Distribution Lines and St. (€/kW)					
	110-38/20 kV	2.19	0.22	0.01	0.00	0.00
	38 kV	1.01	0.57	0.57	0.54	0.02
	Total Dist. Lines & Subst	3.20	0.79	0.58	0.54	0.02
	Total time-differentiated T&D costs (€/kW)	**10.86**	**1.57**	**0.61**	**0.54**	**0.02**
110 kV Service						
	Transmission Lines and St. (€/kW)					
	400-220/110 kV	7.54	0.77	0.03	0.00	0.00
	Distribution Lines and St. (€/kW)					
	110 kV	0.16	0.02	0.00	0.00	0.00
	Total time-differentiated T&D costs (€/kW)	**7.70**	**0.79**	**0.03**	**0.00**	**0.00**

Schedule 51. Summary of Time-Differentiated Per-kW Transmission and Distribution Marginal Costs by Voltage Level for the Entire Country, 2005

Service Voltage Level		Winter Season			Summer Season	
		Peak	Shoulder	Off-Peak	Shoulder	Off-Peak
		(1)	(2)	(3)	(4)	(5)
LV Service						
	Transmission Lines and St. (€/kW)					
	400-220/110 kV	8.30	0.85	0.03	0.00	0.00
	Distribution Lines and St. (€/kW)					
	110 kV	1.00	0.10	0.00	0.00	0.00
	110-38/20 kV	2.38	0.24	0.01	0.00	0.00
	38 kV	1.01	0.57	0.58	0.54	0.02
	38 kV-MV	1.49	0.84	0.85	0.80	0.04
	Total Distibution	5.88	1.75	1.43	1.34	0.06
	Total time-differentiated T&D costs (€/kW)	**14.18**	**2.60**	**1.47**	**1.35**	**0.06**
MV Service						
	Transmission Lines and St. (€/kW)					
	400-220/110 kV	7.91	0.81	0.03	0.00	0.00
	Distribution Lines and St. (€/kW)					
	110 kV	0.95	0.10	0.00	0.00	0.00
	110-38/20 kV	2.26	0.23	0.01	0.00	0.00
	38 kV	0.96	0.54	0.55	0.52	0.02
	38 kV-MV	1.42	0.80	0.81	0.76	0.03
	Total Dist. Lines & Subst	5.60	1.67	1.37	1.28	0.06
	Total time-differentiated T&D costs (€/kW)	**13.50**	**2.47**	**1.40**	**1.28**	**0.06**
38 kV Service						
	Transmission Lines and St. (€/kW)					
	400-220/110 kV	7.66	0.78	0.03	0.00	0.00
	Distribution Lines and St. (€/kW)					
	110 kV	0.92	0.09	0.00	0.00	0.00
	110-38/20 kV	2.19	0.22	0.01	0.00	0.00
	38 kV	1.01	0.57	0.57	0.54	0.02
	Total Dist. Lines & Subst	4.12	0.88	0.58	0.54	0.02
	Total time-differentiated T&D costs (€/kW)	**11.78**	**1.67**	**0.61**	**0.55**	**0.02**
110 kV Service						
	Transmission Lines and St. (€/kW)					
	400-220/110 kV	7.54	0.77	0.03	0.00	0.00
	Distribution Lines and St. (€/kW)					
	110 kV	0.90	0.09	0.00	0.00	0.00
	Total time-differentiated T&D costs (€/kW)	**8.45**	**0.86**	**0.03**	**0.00**	**0.00**

B. Summary of Distribution Facilities & Distribution Customer-Related Costs

A summary of the monthly distribution customer-related and facilities cost by customer class is provided below. A weighted average of the rural and mixed feeder costs was used to calculate the marginal distribution facilities cost for rural domestic customers. A weighted average of the mixed and urban feeder costs was used for non-rural domestic customers. A weighted average of all three feeders was used for non-domestic customers.

Schedule 52. Summary of Monthly Marginal Distribution Customer-Related Costs and Distribution Facilities by class, 2005

	Rate	Class	Monthly Cost Per Customer	Monthly Distribution Facilities Cost per kVA
			(2005 €)	(2005 € per kVa)
			(1)	(2)
(1)	DG-1	U Dom. GP, 1-Phase	2.44	3.14
(2)	DG-1	U Dom. DT, 1-Phase	2.88	3.14
(3)	DG-2	R Dom. GP, 1-Phase	2.97	3.14
(4)	DG-2	R Dom. DT, 1-Phase	3.77	3.14
(5)	DG-3	Public Light	0.64	3.14
(6)	DG-4	Unmetered	0.08	3.14
		LV FR Meters		
(7)	DG-5	LV Non-Dom. GP, 1-Phase	4.34	3.14
(8)	DG-5	LV Non-Dom. GP, 3-Phase	5.82	3.14
(9)	DG-5	LV Non-Dom. DT, 1-Phase	5.18	3.14
(10)	DG-5	LV Non-Dom. DT, 3-Phase	7.39	3.14
		All MD Meters		
(11)	DG-6	LV Non-Dom. Max Demand	28.43	3.14
(12)	DG-7	MV, Max Demand	27.90	1.23
(13)	DG-8	38kV Looped	96.74	0.53
(14)	DG-9	38kV Tailed	96.74	0.53

C. Summary of PES Customer and Revenue-Related Marginal Costs

Schedule 53. Summary of Monthly PES Marginal Customer Costs and Marginal Revenue-Related Cost

	Rate	Class	Monthly Cost Per Customer	Marginal Revenue-Related Cost
			(2005 €)	(%) ^1
			(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%

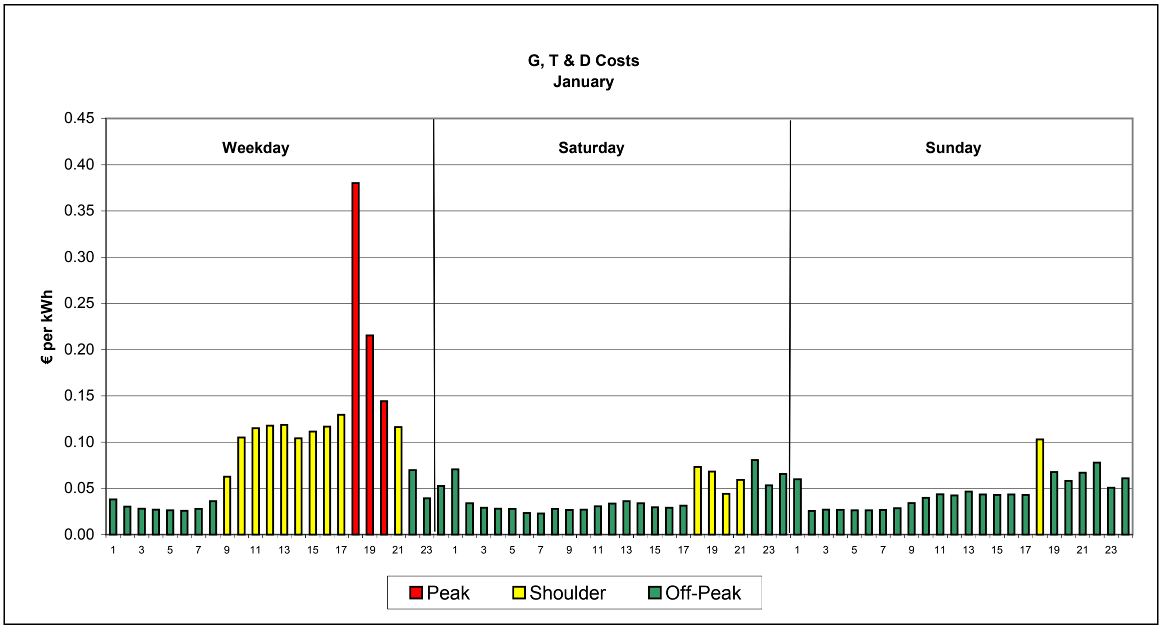
Notes

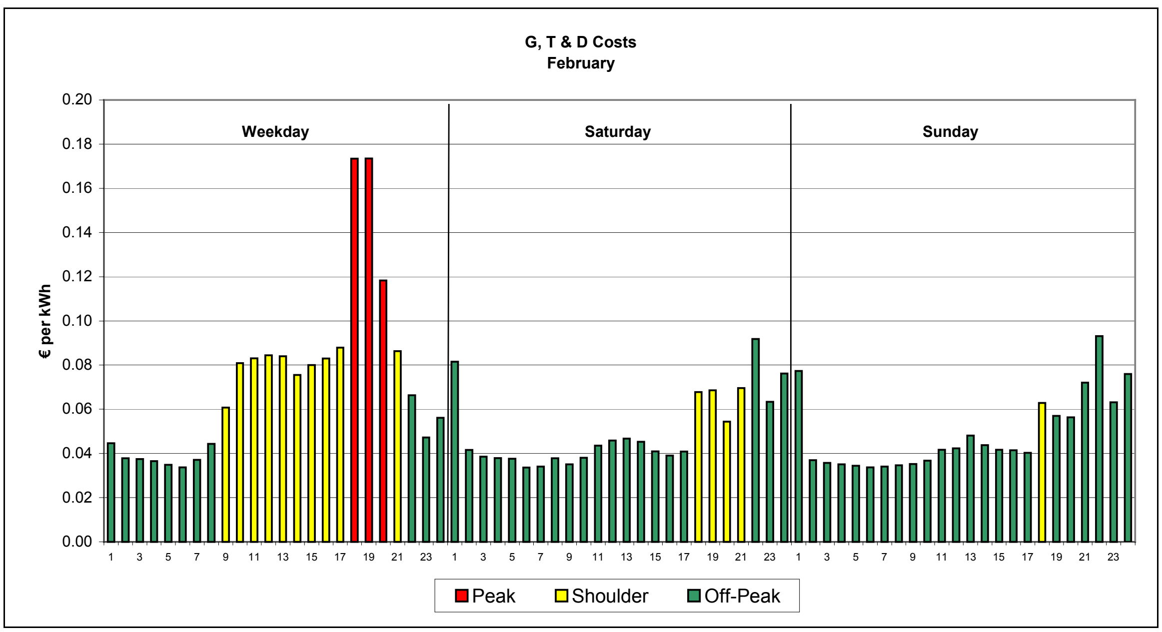
1 Percent of Generation, TUoS, DUoS and other PES charges

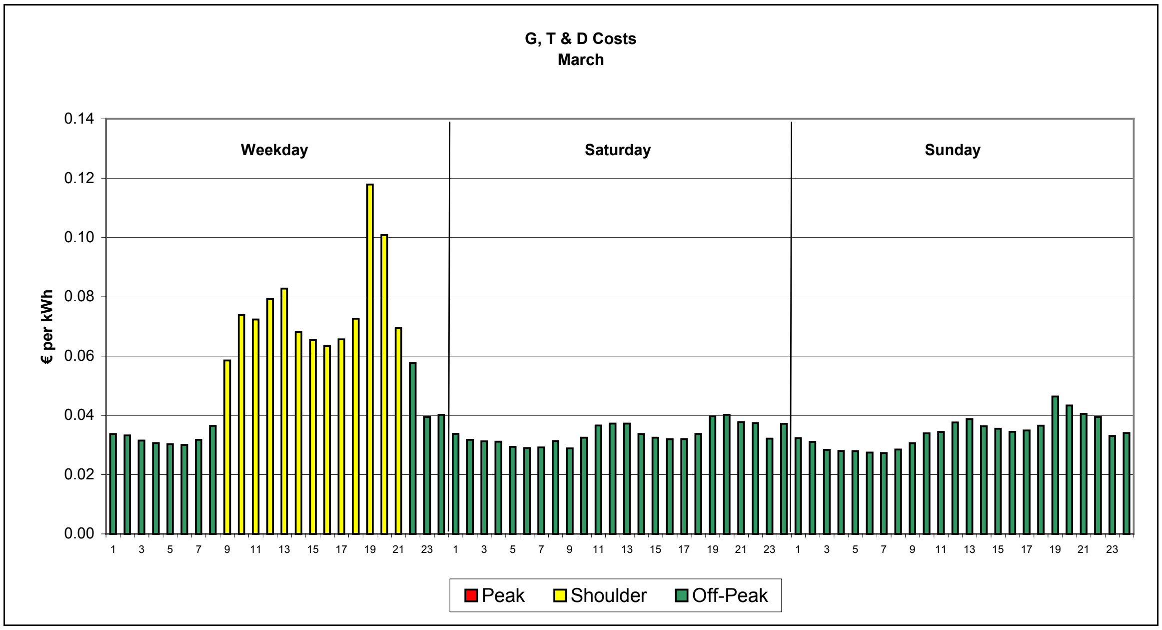
APPENDIX A

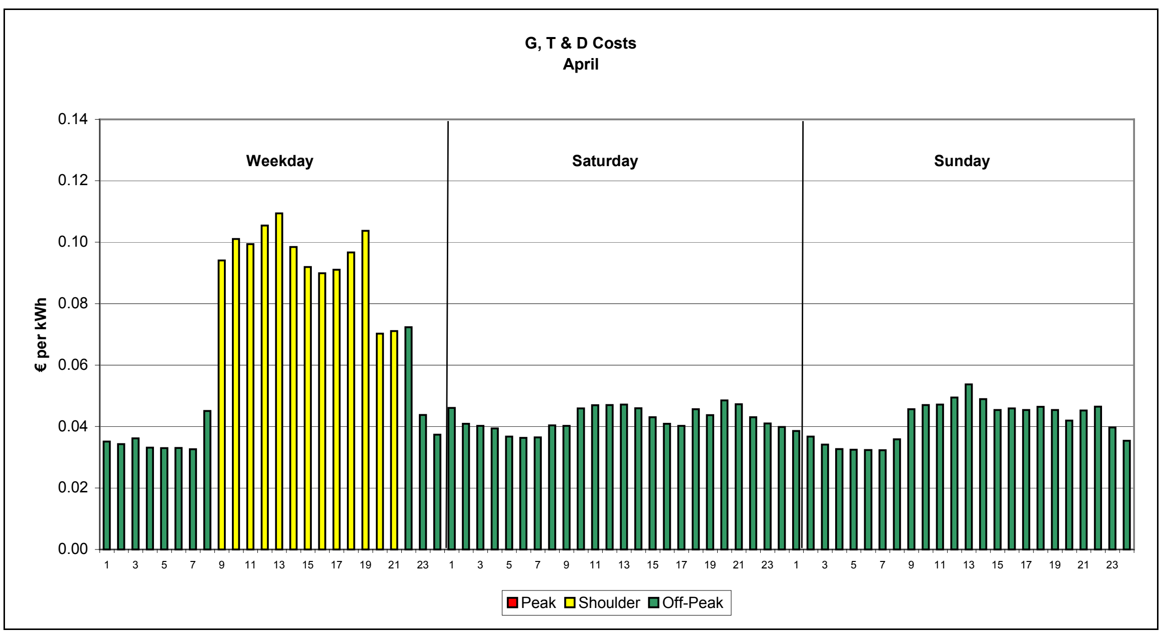
Hourly Marginal Generation, Transmission and Distribution Substation Costs for Weekdays, Saturdays and Sundays in Each Month

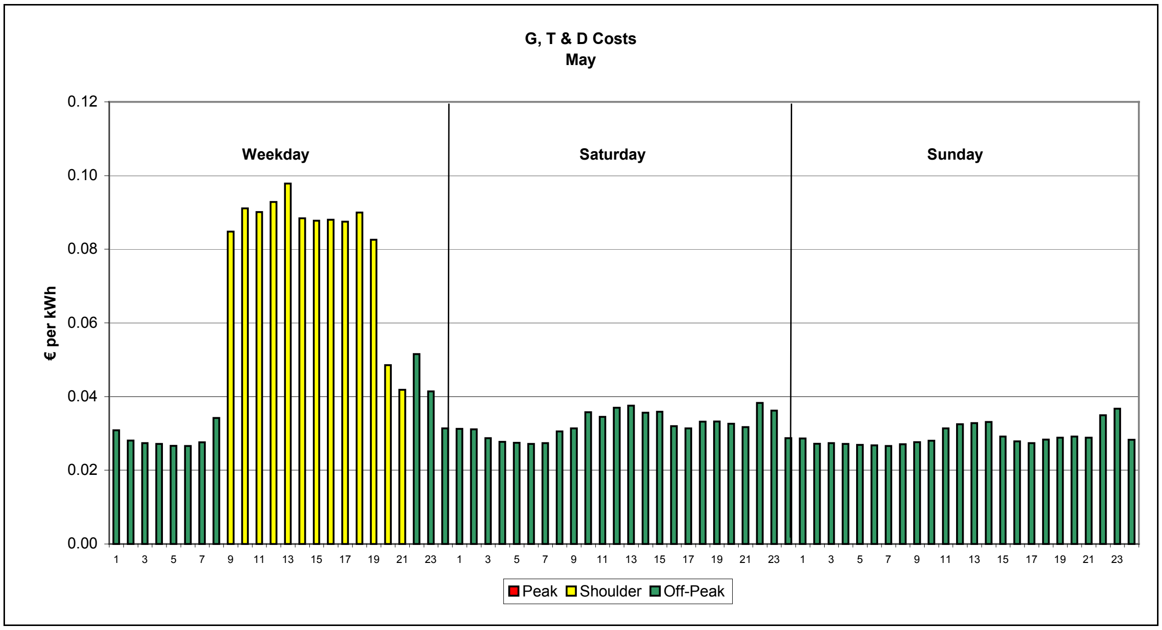
(€ 2005)

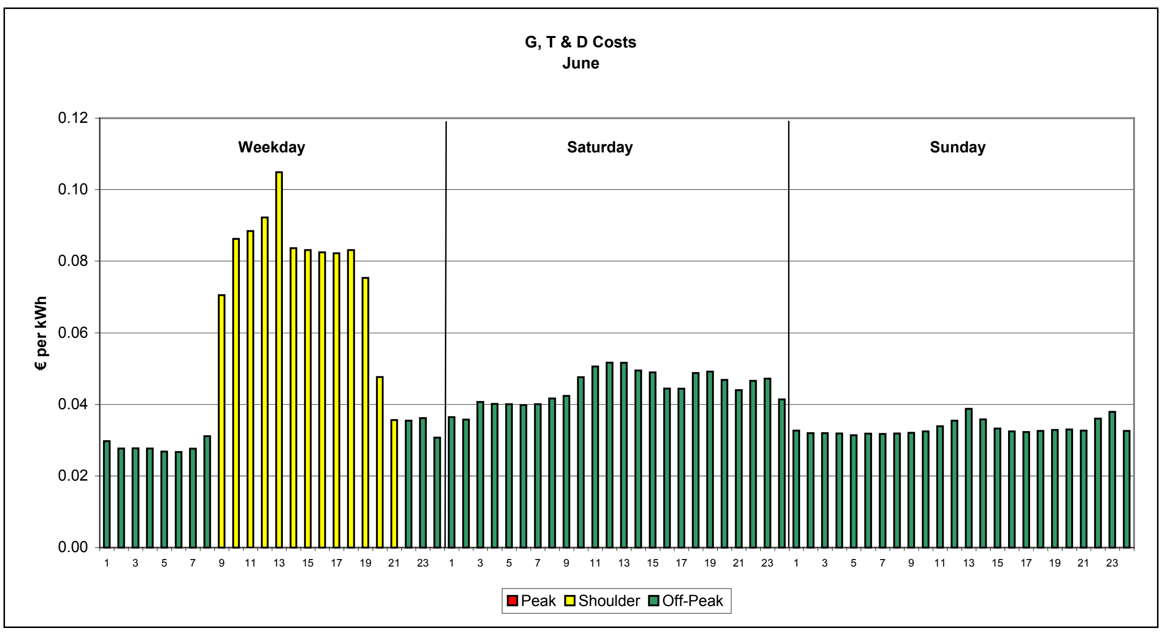

G, T & D Costs
January
Weekday
Saturday
Sunday
€ per kWh
Peak
Shoulder
Off-Peak

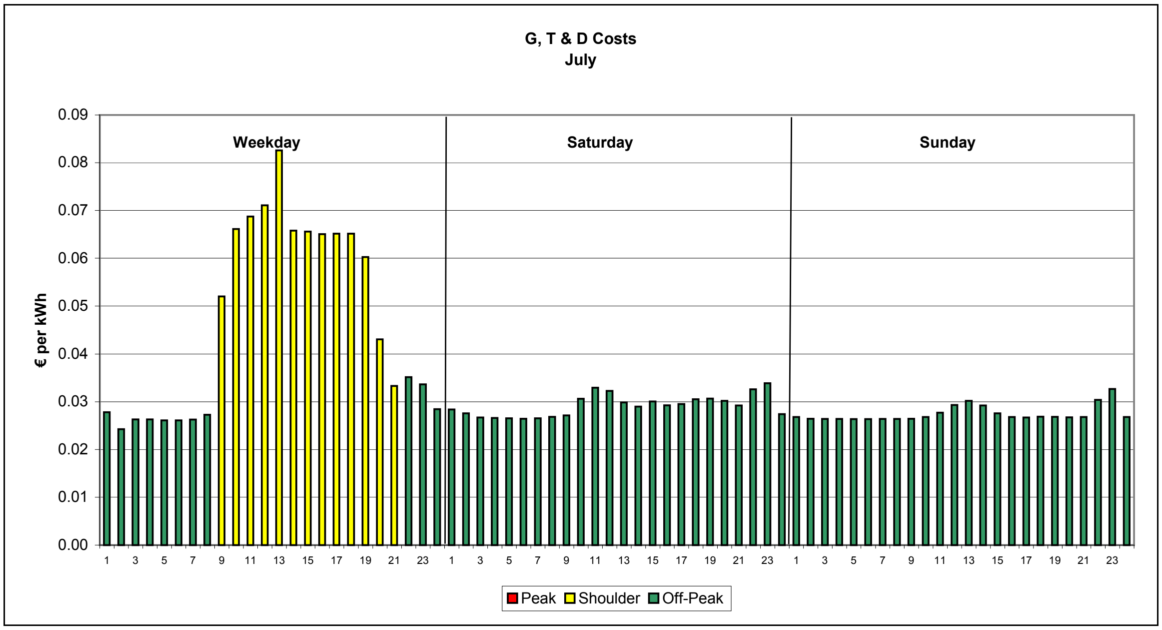

G, T & D Costs
February
Weekday
Saturday
Sunday
€ per kWh
Peak
Shoulder
Off-Peak

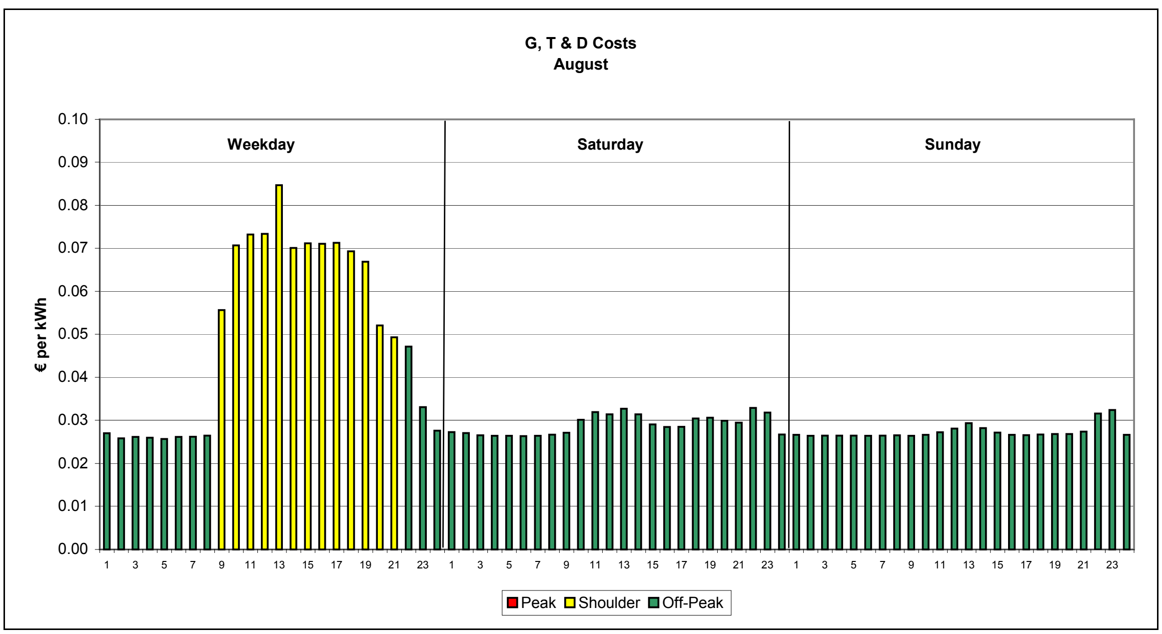

G, T & D Costs
March
€ per kWh
Weekday
Saturday
Sunday
Peak
Shoulder
Off-Peak

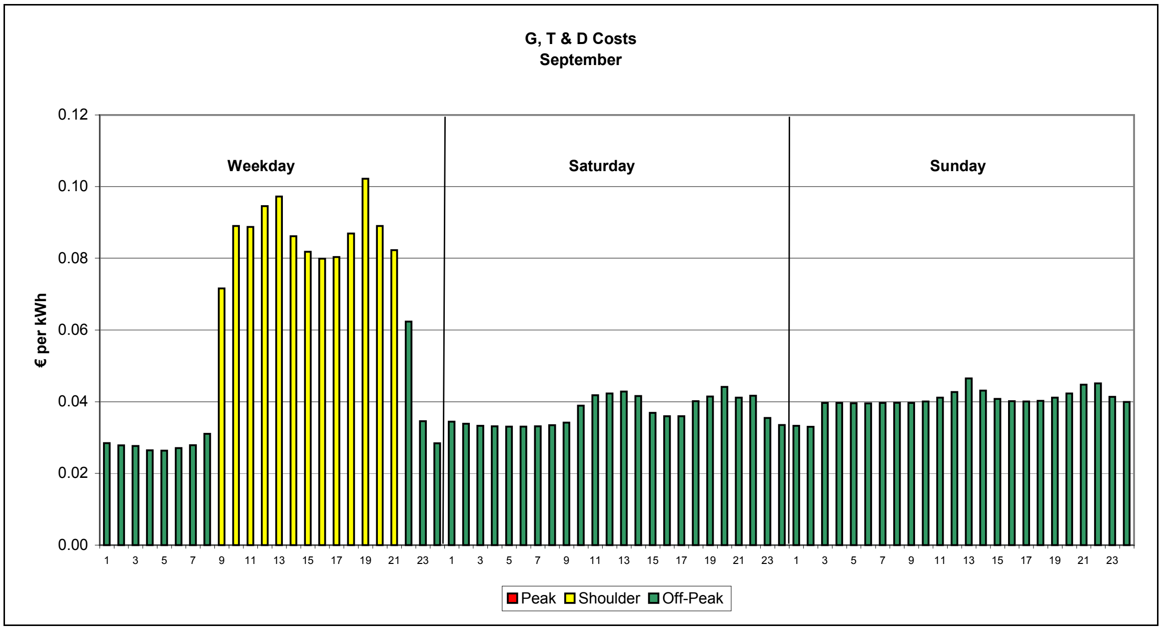

G, T & D Costs
April
€ per kWh
Weekday
Saturday
Sunday
Peak
Shoulder
Off-Peak

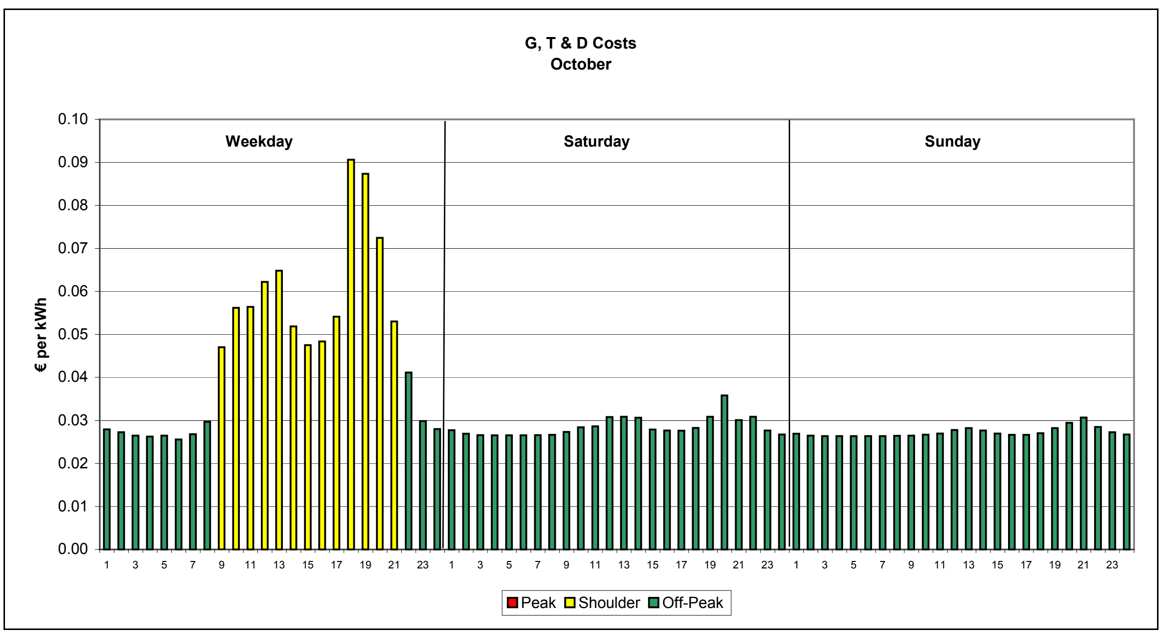

G, T & D Costs
May
Weekday
Saturday
Sunday
€ per kWh
0.12
0.10
0.08
0.06
0.04
0.02
0.00
Peak
Shoulder
Off-Peak

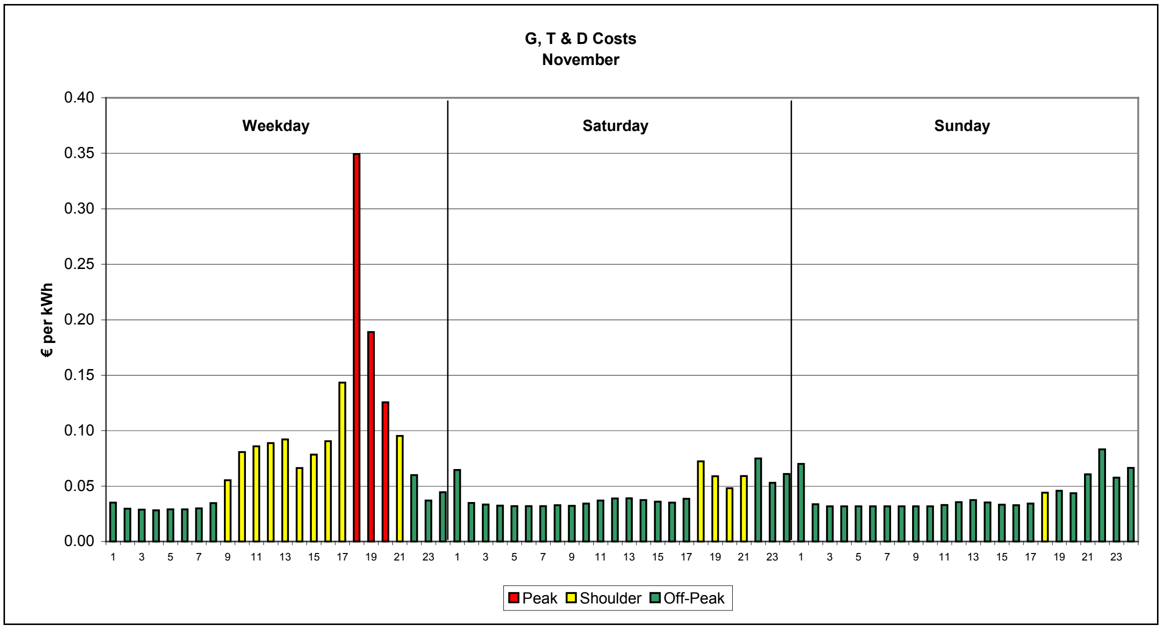

G, T & D Costs
June
Weekday
Saturday
Sunday
€ per kWh
0.12
0.10
0.08
0.06
0.04
0.02
0.00
Peak
Shoulder
Off-Peak

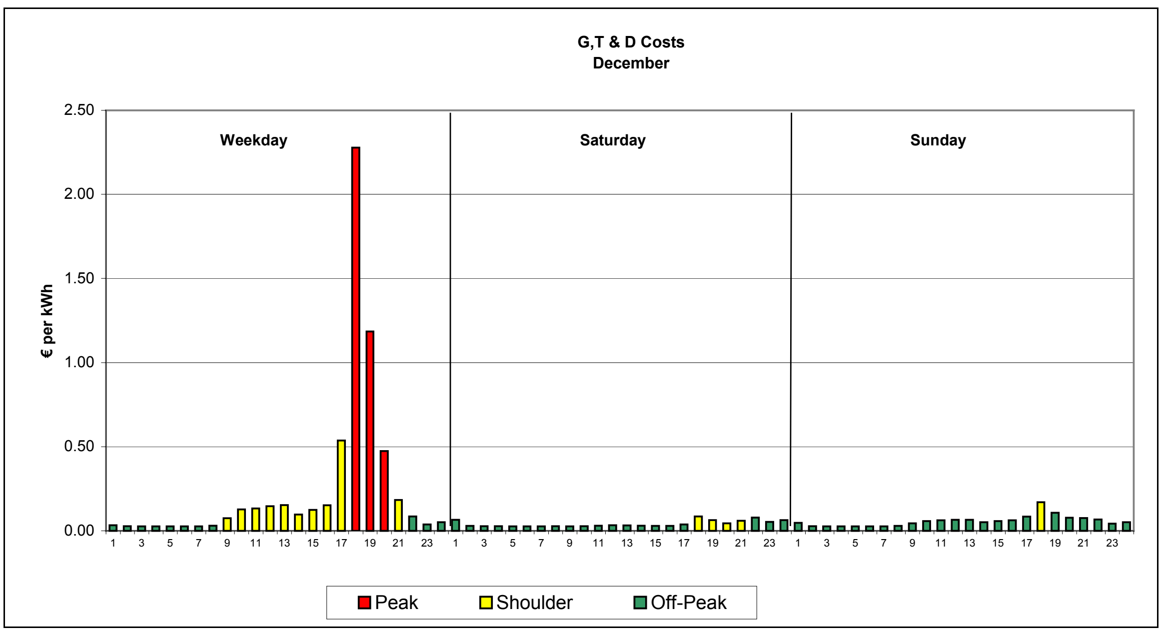

G, T & D Costs
July
€ per kWh
0.00
0.01
0.02
0.03
0.04
0.05
0.06
0.07
0.08
0.09
Weekday
Saturday
Sunday
1 3 5 7 9 11 13 15 17 19 21 23
Peak
Shoulder
Off-Peak


G, T & D Costs
August
€ per kWh
0.00
0.01
0.02
0.03
0.04
0.05
0.06
0.07
0.08
0.09
0.10
Weekday
Saturday
Sunday
1 3 5 7 9 11 13 15 17 19 21 23
Peak
Shoulder
Off-Peak


G, T & D Costs
September
Weekday
Saturday
Sunday
€ per kWh
0.12
0.10
0.08
0.06
0.04
0.02
0.00
1 3 5 7 9 11 13 15 17 19 21 23 1 3 5 7 9 11 13 15 17 19 21 23 1 3 5 7 9 11 13 15 17 19 21 23
Peak
Shoulder
Off-Peak


G, T & D Costs
October
Weekday
Saturday
Sunday
€ per kWh
0.10
0.09
0.08
0.07
0.06
0.05
0.04
0.03
0.02
0.01
0.00
1 3 5 7 9 11 13 15 17 19 21 23 1 3 5 7 9 11 13 15 17 19 21 23 1 3 5 7 9 11 13 15 17 19 21 23
Peak
Shoulder
Off-Peak


G, T & D Costs
November
€ per kWh
Weekday
Saturday
Sunday
0.00
0.05
0.10
0.15
0.20
0.25
0.30
0.35
0.40
1 3 5 7 9 11 13 15 17 19 21 23 1 3 5 7 9 11 13 15 17 19 21 23 1 3 5 7 9 11 13 15 17 19 21 23
Peak
Shoulder
Off-Peak


G,T & D Costs
December
€ per kWh
Weekday
Saturday
Sunday
0.00
0.50
1.00
1.50
2.00
2.50
1 3 5 7 9 11 13 15 17 19 21 23 1 3 5 7 9 11 13 15 17 19 21 23 1 3 5 7 9 11 13 15 17 19 21 23
Peak
Shoulder
Off-Peak