Commission for Energy Regulation

An Coimisiún um Rialáil Fuinnimh

2006-2010 ESB Price Control Review

CER Decision Paper on Distribution System Operator Revenues

CER 05/138

9th September 2005

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Appendices

1. OUTLINE OF THE DECISION PAPER

This document details the Commission's decision on the price control for ESB's Distribution business for the period 2006 to 2010. It is structured as follows:

- Introduction - provides context for the price control review, explaining the Commission's relevant powers, its objectives, assumptions and the incentives that it has applied.
- Approach - outlines the components of the price review, the steps undertaken and the types of analysis used for the price control. An overview of the benchmarking used for assessing the capital expenditure and operational expenditure is also provided here.
- The asset base - the valuation of the regulatory asset base upon which return on capital employed and depreciation is based and a discussion of the key issues relating to the valuation.
- Assessment of the network's performance - based upon international measures of distribution system performance, distribution losses and performance against the Customer Charter.
- Capital Expenditure and Operational Expenditure for 2006 to 2010 - assesses historical expenditure against international distribution companies, provides observations from the Commission's review of the network's assets and investment processes and controls, and provides justification for expenditure for the next price control period.
- Price control - outlines the overall form of the price control and how the base and subsequent year's revenues have been determined. Also sets out the control formulae to be used and the Commission's decision on allowed revenues for 2006-10.

There are also a number of appendices to this document that address the following issues;

- Appendix A sets out the underlying assumptions used in the analysis;
- Appendix B describes the background to the benchmarking that has been carried out and appendix C sets out the opex and capex measures used in the benchmarking;
- Appendix D describes the components of non network capex;
- Appendix E sets out the formulae for the calculation of annual depreciation on the regulatory asset base, including the calculation of customer contributions;
- Appendix F contains a technical analysis of reinforcement capex.

2. *EXECUTIVE SUMMARY*

The Commission for Energy Regulation (CER) is the independent body responsible for overseeing the liberalisation of Ireland's energy sector. Under Section 35 of the Electricity Regulation Act 1999 the Commission may direct ESB on the basis for charges for connection to, and use of, the distribution system. This document sets out the Commission's decision on ESB Networks Distribution System Operator ("DSO") allowed revenues for the five-year period from 2006 to 2010. It also examines the DSO's performance against the revenues allowed in the first price control covering the period 2001 to 2005.

During the initial price control period the Irish electricity system has seen substantial load growth as the economy has continued to expand. The distribution network has been extended and reinforced to accommodate rising demand and new connections and a substantial proportion of the distribution system has also been renovated through the Network Renewal Programme. The Commission is satisfied that the previous price control has been successful in providing the basis for system expansion and renewal. Significant improvements have been achieved in addressing the effects of the historical lack of investment in the distribution system, with good progress made in increasing reliability and safety.

The purpose of this second price review has been to determine an appropriate level of allowed revenue for the DSO over the next five years. In deciding on the level of approved revenues the CER has been mindful of the need to: meet customers' service quality expectations; ensure that the ESB can attract appropriate capital investment to support future investment plans; ensure that the DSO's investment plans provide value for money for customers; and encourage the DSO to improve its efficiency and pass savings on to consumers where appropriate.

Undertaking a review of a complex business such as the DSO necessarily requires a very detailed and flexible analytical approach. The CER and its consultants have used a range of top-down and bottom-up approaches to analysing the various data provided by the DSO. The review has included an analysis of historic and forecast capital expenditure ("capex") and operational expenditure ("opex") to assess the efficiency of both capital investments and opex improvements. The DSO's capex and opex were also benchmarked against comparable utilities. The review has established the value of the DSO's regulatory asset base, decided on a cost of capital appropriate to the DSO business, and determined the allowed regulatory revenue for 2006 to 2010.

The Commission's proposals are summarised below.

- ***The Regulatory Asset Base***

The majority of the DSO's allowed revenues relate to the depreciation of network assets and a return on the capital employed in the network. In determining the regulatory asset base ("RAB") the Commission has applied a value to the underlying assets, investigated the appropriate useful lives of these assets, decided on a suitable depreciation methodology and a rate of return related to those assets.

In deciding on an approach to valuing the RAB the Commission has been wary of the need to ensure that ESB is able to fund new investments. The RAB should therefore be capable of providing sufficient revenue when applying the cost of capital to fund such investments.

The Commission has decided to continue using a Replacement Cost approach to valuing the RAB indexing its historic value by CPI. However, two important adjustments to this methodology have been made:

- Revaluation of the 2001 opening RAB in accordance with "FRS 15 Tangible Fixed Assets"; and
- Extension of the network asset lives from 40 to 45 years. Any extension of asset lives should not affect assets that have already been fully depreciated – i.e. these should not be brought back into the RAB as a result of a change in the regulatory depreciation policy.

Using this approach the CER has determined an opening RAB valuation of €3,370m for 2006, compared with the DSO's proposed opening RAB of €3,709m.

- ***Cost of Capital***

The DSO's cost of capital is a critical element of the price control, as it determines the allowed return on its asset base. The CER has decided to continue with the weighted average cost of capital methodology ("WACC") to determine the DSO's cost of capital. The Commission recognises that there is an element of subjectivity involved in setting the cost of capital for a regulated utility. Having taken a balanced approach to evaluating the individual components of WACC the CER has arrived at a range for the pre-tax WACC of 3.26% to 6.85%.

The Commission has decided that the appropriate cost of capital to apply to the DSO is 5.63%.

- ***System Performance***

The CER has reviewed the DSO's historic and proposed future performance in terms of customer interruptions, distribution losses and performance against the Customer Charter.

<u>Customer Minutes Lost</u>

With respect to Customer Minutes Lost ("CML") Ireland's network performance was benchmarked against over 40 comparable US utilities. The results show that Ireland's network performance is at an acceptable level. CML has improved from 371 in 2001 to an expected 275 in 2005 (i.e. a 26% improvement) reflecting the significant investment that has been made to the network during that period. The Low Voltage ("LV") network has shown the greatest improvement. Whilst the significant historical investment in the MV network has improved system performance, the Commission was expecting to see system performance improve even further than the DSO has forecast, due to the MV network being a key contributor to customer minutes lost.

With regard to future system performance, CER believes that the DSO's customer interruption forecasts, leading to a CML target of 201 in 2010, are achievable and will be adopting these as the requirements for the next review.

Distribution Losses

Internationally, it is felt that 7.5% to 8.5% is an "optimal" range for distribution losses. However it is recognised that every system has a unique mix of geographic, economic, historic and technical factors that influence the optimum level. Over the period between 1979 and 2003, losses have reduced from over 10% of sales to the current level of around 8%. In the Commission's view, the DSO's distribution losses are currently at an acceptable level considering Ireland's unique network characteristics.

If the present calculation of DSO losses as a proportion of energy received (from TSO and embedded generators) is approximately 8%, CER believes that a reduction to 7.5% during the period 2006-10 is achievable, even with the cuts in reinforcement and rehabilitation Capex (see below). This corresponds closely with the DSO proposal for cutting the aggregate Distribution Loss Factor from 1.080 to 1.076 over the period.

Customer Charter

The DSO's performance against the Customer Charter shows that the majority of performance levels were not met. For example, against a 100% target for responding to requests for a site visit from Commercial customers within three hours, DSO achieved 89% with 902 responses outside the charter timescale. The Commission has reduced the 2006 allowed revenue to reflect these underpayments. The Commission will be requiring the DSO to compensate all customers who have not received the required level of service; the introduction of an improved automated compensation system which can be fully audited should ensure that this occurs

Turning to future Customer Charter performance, as an additional incentive towards improvement, the Commission has decided that performance against the Customer Charter will be incorporated into the price control formula for 2006-2010.

- ***Review of Capital Expenditure Programme***

The Commission reviewed the DSO's historic and forecast capex programmes. Capex is categorised as follows:

- New business capex (which includes new connections);
- Network reinforcement to cater for load growth;
- Non load related network capex – e.g. Refurbishing existing infrastructure;
- Non network capex – e.g. IT systems.

Historic Capex

The review of historic capex compared actual against approved capex and compared the work program delivered against the agreed deliverables. The benefits to the system, and the customer, of the capex incurred were analysed and the review also benchmarked capex against comparable utilities (this benchmarking extended to the forecasted capex review).

The historic review includes an examination of an additional €71m of New Business capex, incurred purely due to new connection volumes being greater than expected. This capex overspend has been allowed into the RAB by the Commission.

A number of additional key overspend areas will also be allowed into the RAB, where this overspend has been justified to the Commission's satisfaction:

- The DSO has overspent €89.1m on domestic new connections due to higher unit costs. The Commission has approved €41.9m of this;

- The MV Network Renewal Programme has recorded an over-spend of €77m. The Commission has critically examined the justification provided by the DSO and has approved €50m of this amount.

Forecast Capex

In making its assessment of future capex requirements the Commission considered a number of important issues such as maintaining adequate safety standards, improving security of supply and reducing losses.

In relation to Network Capex (New Business and Reinforcement capex), benchmarking has shown that the DSO is significantly above industry norms. The DSO is forecasting an upward trend in new business capex, despite historic falls in connection costs in some areas. CER believes that the new connection capex on a per new customer basis should show improvement over time.

On Network Load-related capex, the DSO expenditure level is above average reflecting the significant investment during the first price control period. The following table summarises the DSO's proposed capex allowance and the Commission's final allowed figures:

	€ (2004, m)			
Capex component	**DSO**	**CER**	**Reduction**	
New business	908	854	54	6%
Reinforcements	618	530	88	14%
Network non-load related	981	755	226	23%
Non-Network	154	139	15	10%
Total capex	**2,661**	**2,278**	**383**	**14.4%**

Whilst the Commission has accepted some of the historic increase in domestic and industrial connection costs, for the next review period, the DSO is expected to improve connection costs so that the network load related capex is better aligned with the benchmarking data.

The Commission believes that the DSO can reduce its reinforcement capex by 14% to a Commission approved level of €530m. This should be delivered for example by prudent and economically appropriate application of planning standards – deferring projects with marginal customer benefits and cancelling unnecessary projects.

In relation to Network non-load related capex, the majority of the elements of the plan are allowed, but with general efficiency and contracting savings (in addition to cuts in the HV line and meter refurbishment as discussed above). The three largest components of the proposed programme (NRP2) are believed by the Commission not to be fully justified in their scale and scope and have therefore been reduced.

With respect to Non Networks capex, the Commission believes that there is a risk that works will progress more slowly than planned and the expenditure will not be realised. The first year will be principally taken up in initiating the projects, including developing user requirement definitions, establishing plans and identifying staff resources from the business and internal IS to effect the work. In subsequent years it should be possible to progress the work through suppliers and the use of contract staff. The Commission has approved a reduced non-network capex of €139m.

- ***Review of Operational Expenditure***

Historic Opex

The Commission's objective in setting an allowed opex is to ensure that efficiency improvements continue to be made, to the benefit of customers. This should result in setting the DSO challenging but realistic and achievable targets and incentives. The review of both historic and forecast opex: (1) assessed historic trends in opex; (2) compared actual against allowed opex; (3) benchmarked DSO opex against international comparators; (4) evaluated future required opex; and (5) assessed the impact of the capex programme on opex requirements.

The following table summarises actual operating expenditures made by the DSO against the Commission approved operating expenditures, taking account of all adjustments that were allowed in the annual revenue calculations over the control period.

CER determination 2001:	2001 € m	2002 € m	2003 € m	2004 € m	2005 € m
Allowed cash opex (real 2000)	193.0	181.2	178.7	182.6	187.5
Allowed cash opex (€ 2004)	224.0	210.3	207.4	211.9	217.7
Total Adjustments (€ 2004)	2.0	11.9	18.2	16.3	41.7
Total CER allowed (€ 2004)	**226.0**	**222.2**	**225.5**	**228.3**	**259.4**
ESB Networks net cash opex (€ 2004)	**243.1**	**231.1**	**238.4**	**243.4**	**260.5**
Overspend vs allowed opex (€ 2004)	**17.1**	**8.9**	**12.9**	**15.1**	**1.2**

While it can be seen that the DSO exceeded its allowed expenditure, which included efficiency targets, by 2005 the gap had been reduced compared to earlier years. It is also important to note that the DUoS tariffs over the period were based only on the allowed expenditures.

Opex Benchmarking

The Commission undertook a benchmarking exercise of the DSO's controllable and non-controllable opex using US utilities. This has shown that DSO's opex is high in comparison with the utilities benchmarked. In addition, the DSO's own benchmarking against UK utilities also highlighted the DSO as above average in terms of opex expenditure.

While the Commission accepts that there is no optimal way to compare opex across different networks, the above results, using two different approaches and different companies, show that the DSO's comparable opex is considerably higher than average.

Forecast Opex

In reviewing the DSO's proposed 2006-2010 opex submission, the Commission noted that the proposals would not result in any significant reduction in opex levels by 2010. It is the view of the Commission that the DSO's opex levels in 2010 should be in line with efficient comparable companies and to this end is proposing reductions in most areas of the DSO's opex.

The DSO's and the Commission's proposals for required opex for the period 2006-2010 fall under the following headings:

Opex Areas	DSO	CER	Reduction €	%
Capital Driven Opex	**107.8**	**95.1**	13	12%
Network Operations & Maintenance	**480**	**427.2**	53	11%
Asset Management	**57**	**52.3**	4	8%
Metering	**99**	**90.9**	8	8%
Customer Service	**102**	**98.1**	4	4%
Provision of information	**129**	**111.4**	17	13%
Commercial	**86**	**81.2**	5	6%
Corporate	**77**	**76.6**	0	0%
Other (Non-Controllable):				
Network Depreciation	**955**	**653.1**	302	32%
Rates, Insurance and Pension	**179**	**179.3**	0	0%
Other (Controllable)	**42**	**38.9**	3	7%
Total	***2312***	***1904***	***408***	***17.7%***
Non-Controllable Opex	**1278**	**964**	**314**	**24.6%**
Controllable Opex	**1034**	**940**	**94**	**9.1%**

By 2010, the allowed controllable opex will be significantly lower (by approximately 15%) than DSO's proposed position, with a gradual cost reduction path followed to arrive at this point.[1]

- ***Price Control***

In setting the price control the CER has been conscious of the need to ensure that the DSO can finance its planned investment, operating costs, financing costs and taxation liabilities. The Commission has therefore developed a cash-flow model for the DSO designed to ensure the compatibility of the price control with these objectives. The Commission also has the objective of improving the DSO's efficiency over time so that it more closely matches the performance of its peers. Therefore, the Commission has included a set of incentives linked to key performance indicators within the price control formula to encourage the required improvements. The Commission has implemented a number of changes to the price control formula to incorporate new incentives for the DSO.

- ***Impact of the Commission's Decision***

The table below summarises the calculation of the allowed revenues using the revised price control formula.

Profile for the DSO's allowed revenues based on the Commission's decision:

		2006	2007	2008	2009	2010	Total
Operating Costs	[€m]	225.8	223.7	221.6	217.2	214.8	1,103.1
Deferrals / K factor	[€m]	-19.7	-5.3	0.0	0.0	0.0	-25.0
Depreciation	[€m]	127.4	132.9	138.3	144.4	150.2	693.2
Cost of Capital	[€m]	201.4	216.2	228.8	240.3	250.3	1,137.0
Total DUoS Required	**[€m]**	**535.0**	**567.4**	**588.7**	**601.8**	**615.4**	**2,908.4**

[1] Figures represent total opex less opex on market opening, call centres, rates, network depreciation, insurance and pension. Opex on line diversions is included, but dismantling is excluded, as this will be defined as Capex.

ESB's proposed profile for the DSO's allowed revenues

		2006	2007	2008	2009	2010	Total
Operating Costs	[€m]	267.3	277.0	277.8	280.1	275.3	1,377.6
Deferrals / K factor	[€m]	44.0	0.0	0.0	0.0	0.0	44.0
Depreciation	[€m]	184.1	191.5	196.3	200.1	201.9	973.8
Cost of Capital	[€m]	146.8	237.7	302.8	373.1	459.6	1,520.0
Total DUoS Required	**[€m]**	**642.2**	**706.2**	**776.9**	**853.3**	**936.8**	**3,915.4**

The Commission's review has resulted in a reduction of over €1billion in DSO revenues over the next five years.

Based on the allowed revenues outlined in this paper, the Average Unit Price (AUP) of distribution services for 2006 will be in the region of 2.40 cent/kWh (2005 prices). This compares to a 2005 AUP of 2.71 cent/kWh, representing a reduction of 11.5%.

3. INTRODUCTION

This section sets out the:

- Powers under which the Commission determines the price control
- Context of the price control
- Commission's objectives for the price control in the period 2006 to 2010
- Incentives that the Commission has applied to the Distribution business
- Key assumptions underpinning the review

3.1 THE COMMISSION'S RELEVANT POWERS

Under Section 35 of the Electricity Regulation Act 1999 ("the Act") the Commission may direct ESB on the basis for charges for connection to and use of the distribution system. In accordance with Section 35 of the Act, the Commission, in this document, has determined the DSO's allowed revenues for the period from 2006 to 2010 in the amounts set out in section 9 below. The rationale for the Commission's decision is explained in detail in the remainder of this paper.

3.2 CONTEXT OF THE PRICE REVIEW

The current price control period – 2000 to 2005 - has seen many fundamental changes in the Irish electricity system. Load growth has continued apace as the economy has expanded. The distribution network has been extended and reinforced to accommodate rising demand and new connections. A substantial proportion of the distribution system has also been renovated through the Network Renewal Programme approved as part of the previous price control.

Against this background, the Commission set a price control and associated tariffs in 2001 intended to support the substantial new investment required while at the same time incentivising efficiency improvements in the business. At a general level, the Commission believes that the previous price control has been successful in providing the basis for system expansion and renewal. Significant improvements have been achieved in addressing the effects of the historical lack of investment in the distribution system, with good progress made in increasing reliability and safety.

During the coming price control period, the DSO will face a new set of challenges. These will include:

- The need for the DSO to continue to improve its performance in terms of operation and investment efficiency to provide best value for money to Irish electricity consumers
- Continuing to develop the system to support future load growth
- Ensuring that the scale of future network renewal is fully justified on economic grounds

3.3 THE COMMISSION'S OBJECTIVES FOR THE PRICE REVIEW

The purpose of this review was to determine an appropriate level of allowed revenue for the DSO over the next five years. The Commission's objectives were to ensure that:

- ESB is able to maintain the distribution network to an adequate standard to meet customers' expectations.

- The interests of final customers are protected, in the short and long term, in terms of containing tariffs to the maximum extent possible and delivering efficient network investment;

- The ESB is able attract the necessary level of capital investment to support the approved level of renewal and extension of the network. In doing so, the Commission wishes to ensure that the DSO's investment plans provide value for money for customers in terms of the benefits they add.

- Appropriate incentives are provided for the DSO to improve its efficiency where possible and that as much as possible of these savings are passed through to consumers. The Commission has set incentives that are challenging but achievable.

- The day-to-day intervention by the Commission in the DSO's business is kept to a minimum.

In order to achieve these objectives, the Commission has reviewed historical data to evaluate the DSO's performance during the first control period, and reviewed the DSO submission for expenditure for this control period. Broadly speaking, these reviews were in terms of operational efficiencies, the delivery and requirements for capital investment, and improvements in the network. This review, technical, economic and financial in nature, has included top-down and bottom-up analyses. This approach led to an assessment of what the DSO's efficient base year (2006) costs should be, and how these are to be adjusted in line with an appropriate work program.

To ensure that the appropriate balance is achieved among the objectives listed above, and that the price control develops as fairly as intended for all parties involved, the Commission will undertake an intermediate review of the distribution price control during the coming 5-year review period.

3.4 THE DSO'S INCENTIVES

The Commission has reviewed the incentives that applied during the current regulatory period and considered the ways in which they should be refined for the period 2006 to 2010. In later sections of this document, the form of the incentives is set out in detail. In summary, the Commission has provided incentives to:

- Improve overall opex and capex efficiency

- Reduce distribution system losses, continuing the approach applied in the current regulation

- Reduce customer minutes lost and the number of supply interruptions

- Improve the quality of service provided to customers through call centre interactions
- Meet Customer Charter requirements.

3.5 KEY ASSUMPTIONS

Inevitably, given the five-year scope of the review, it has been necessary to make a number of assumptions regarding the environment within which the DSO will operate for the price control period. The key assumptions made by the Commission are as follows:

- The distribution network will continue to remain as a Semi-State enterprise for the duration of the review and that there will be no substantial changes made to its structure;
- Any changes and associated costs required as a result of the implementation of the Single Electricity Market (SEM) lies outside the scope of this review; and
- Acceptance of the underlying assumptions submitted by the DSO regarding customer growth and maximum demand. See Appendix A for further details.

4. APPROACH

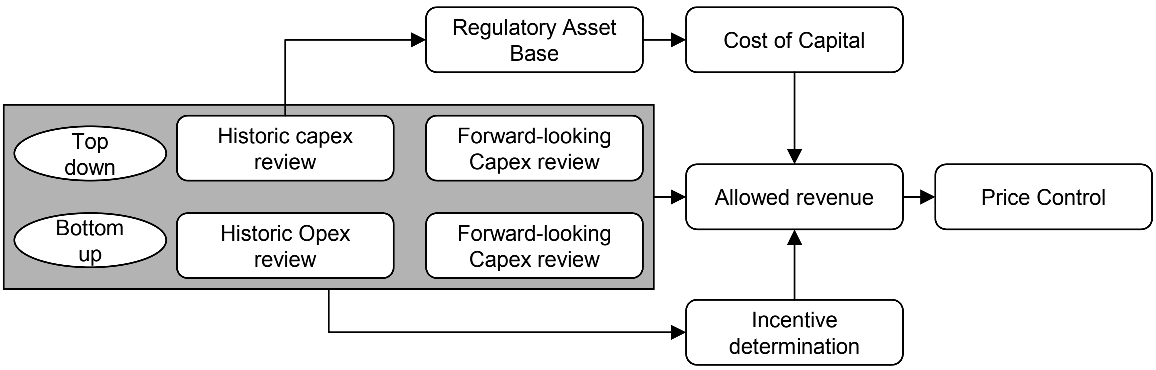
This section includes the following:

- An overview of the components that are used for the Commission's approach to the regulatory review;
- The steps undertaken for the review;
- The types of analysis used for the review;
- A summary of the benchmarking data used; and
- A summary of the expertise used for the review.

4.1 OVERVIEW

Figure 4.1 below summarises the general approach the Commission has adopted to determining the DSO's regulatory revenue.

Figure 4.1: Overview of the review process



The key components of the approach have been as follows:

- Reviewing historic capex, assessing the appropriateness and efficiency of the investments made during the current regulatory review period. A key element of this expenditure has been the Network Renewal Programme. This analysis has included an assessment of actual versus planned capital expenditure over the review period, both in terms of the volume and unit cost of investment.
- Reviewing historic opex, assessing the improvements in efficiency made by the DSO during the current review period.
- Reviewing of forecast opex and capex for the period 2006 to 2010, with particular focus on ensuring value for money from capex and efficiency improvements in opex.
- Determining the value of the regulatory asset base, focusing on the accounting treatment and economic value to be applied.

- Setting the appropriate depreciation policy, indexation approach and asset lifetimes to apply to the RAB and to new investments and hence setting the value of the RAB in 2006.
- Evaluating the appropriate cost of capital to be applied to the regulatory asset base, reflecting the risk to which the DSO will be exposed.
- Based on the output of this analysis, determining the regulatory revenue for the base year and subsequent years.

4.2 SCOPE OF THE REVIEW

This review was focused on the regulated aspects of the DSO's activities. However, it forms part of a wider review process in which each of ESB's regulated businesses have been assessed. With relevance to the current review, the Commission has taken into account:

- Transfers of costs and revenue between businesses, for example in respect of the customer call centre;
- The allocation of corporate centre costs and overheads to the regulated businesses; and
- Additional expenditure required to fund IT systems needed to support the newly-opened market. (Full market opening occurred on 19 February 2005.)

Certain elements subject to substantial uncertainty have been excluded from the review. Principally, these relate to the development of the All-Island Market.

4.3 CONDUCT OF THE REVIEW PROCESS

The review process has been carried out in as transparent a manner as possible so as to ensure that there is clarity as to the underlying data and assumptions as well as the analysis itself. The review has entailed the following steps:

- Following discussion with the DSO on the feasibility and form in which data could be provided, a detailed questionnaire was prepared and issued to the DSO. The questionnaire set out the technical, economic and financial data required by the Commission along with agreed deadlines for provision of responses;
- The DSO then completed the questionnaire in two stages: providing historic data first and then progressing to forecast information. There was a period during which clarifications and further information were sought from the DSO;
- The Commission and its consultants then analysed the final data set provided to determine the appropriate regulated revenue to apply to the business' forthcoming price control period. During this period, a number of interactions were had with the DSO, including a number of site visits to key installations;
- The final data set and the revenue projections arising from the analysis of the data were provided to the DSO for technical review for accuracy before publication of a consultation paper on 26th July 2005;

- The Commission received submissions on the consultation paper[2]. The review of these submissions, together with a further examination of other issues, resulted in a revision to the revenue proposals contained in the consultation paper.

4.4 FORM OF THE ANALYSIS

Assessing data for a business as complex and diverse as the DSO is complicated. Consequently, no single type of analysis can be applied to the data. Reflecting this, the Commission and its consultants applied the following combination of bottom-up and top-down approaches in assessing the information provided by the DSO:

- **Bottom-up analysis**. This focused on assessing individual elements of the forecast, including:
  - Assessment of the DSO's capex programme, comprising analysis of unit costs, sample investments (through a series of site visits) and review of the methodology used for determining network investment (both replacement and load-related). A key factor considered in this work was the relative merits of age versus condition driven asset replacement. A detailed review of the business cases for major investments therefore formed part of this work;
  - Detailed review of maintenance programmes to determine its appropriateness and cost efficiency; and
  - Establishing the interaction between new network and non-network capex (including asset replacement) and future opex through maintenance savings.
- **Top-down analysis.** This area of work was based on benchmark data and encompassed:
  - Comparison of the DSO's historic costs with those of comparable businesses at a general and activity based level;
  - Comparison of the DSO's technical performance relative to those of peer organisations, including customer minutes lost, number of interruptions and call centre performance;
  - Econometric analysis of cost drivers to determine the combination most appropriate for the DSO;
  - Identifying controllable and non-controllable opex categories and establishing the degree of consistency in approach between the DSO and appropriate comparators; and
  - Benchmarking corporate centre costs against peer organisations.
- **Financial analysis**. The focus of this element of the work has been to:
  - Review the accounting policies and treatments conducted by the DSO;
  - Evaluate the depreciation policy for each main class of asset from an accounting perspective;
  - Consider the appropriate policy for indexing asset values;

[2] See CER paper 05/137 issued 9 Sept 2005

– Review the principles for determining and allocating corporate centre costs to the DSO and for the transfer of costs between businesses; and
– Analyse the drivers of the business's financial health so that these may be reflected in the allowed revenue for 2006 to 2010.

The detailed methodologies followed and data used for each part of this analysis are described in subsequent sections.

4.5 BENCHMARKING THE DSO'S OPEX AND CAPEX

The DSO's 2003 and 2004 opex and capex were benchmarked using PA Consulting's USA benchmarking survey that is based upon expenditure submitted from over 40 US companies.

The benchmarking used a relative comparison based upon a scale factor, which combines the three key distribution characteristics (number of customers, throughput and line length). This approach was used in the distribution price control for 2001 to 2005[3] and by Ofgem in their last Price Review (2000/01 to 2004/05).

Other points to note:

- US companies were used for the benchmarking as this region provided the greatest number of companies with similar characteristics to the DSO's network;
- All of the financial information is in 2003 euros; and
- 2003 benchmarking data was used, as the 2004 USA benchmarking data had not been finalised at the time the review was undertaken.

The measures that were benchmarked are:

- Opex - Comparable opex (non-controllable costs such as depreciation and network rates were removed from all of the opex figures. For the DSO, line diversions and dismantling opex were removed as these are classified as capex in the USA);
- Capex – Network Capex (excluding non network capex for the DSO);
- Capex – Load related capex; and
- Capex – Non load related capex (for the DSO, includes line diversions and dismantling opex).

See Appendix B for more information on PA Consulting's benchmarking program and a worked example of how the scale factors are calculated.

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[3] Specifically the document titled ' Distribution Price review Proposals – 30th July 2001 Page 92

What is included and excluded in each of the benchmarked measures is outlined in Appendix C.

4.6 THE COMBINATION OF EXPERTISE USED

Reflecting the range of analysis required, the Commission has deployed a diverse set of skills to conduct this work, comprising economic, accounting and engineering experts. Individuals have been sourced both within the Commission and from its consultants (PA Consulting Group, Power Planning Associates and Deloitte Consulting). Combined, the team has extensive experience of regulatory reviews in a variety of industries and countries.

5. THE REGULATORY ASSET BASE

This section sets out:

- How the RAB has been determined for the DSO; and
- What rate of return should be applied to the DSO RAB.

5.1 DETERMINATION OF THE REGULATORY ASSET BASE

The majority of the DSO's allowed revenues relate to the depreciation of network assets and a return on the capital employed in the network. In deciding the DSO's allowed revenues during the price control, a number of interrelated issues are considered when determining the Regulatory Asset Base (RAB). In this section, the Commission sets out its view on the treatment given to the following issues:

- The composition of the RAB;
- The valuation of the RAB upon which return on capital employed and depreciation is based;
- The lives of the individual assets included within the RAB;
- The depreciation method applied to the RAB;
- Implications of replaced assets;
- Calculation of additions to the distribution RAB;
- Clawback of depreciation and return on capex approved but not spent in 2001-2005; and
- The appropriate value of the DSO RAB.

5.1.1 Composition of the RAB

The RAB is essentially a valuation of the assets used by the DSO to meet its regulatory obligations to operate Ireland's distribution system. It comprises a range of assets, specifically:

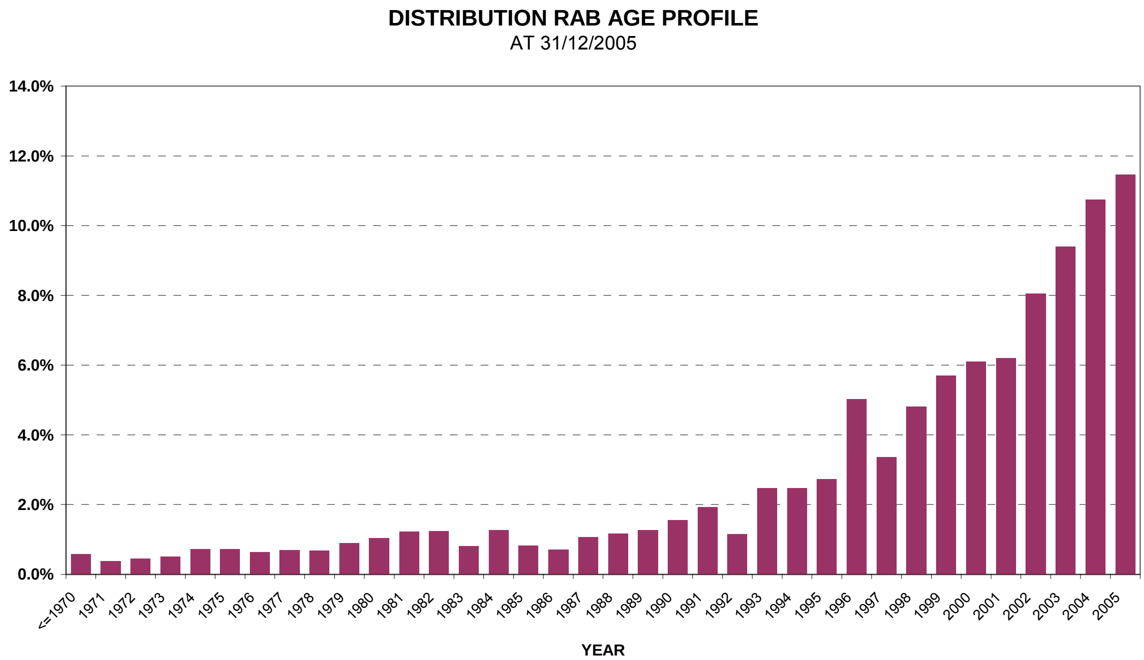
- Network assets, i.e. the wires and switchgear required for the operation of the system;
- System operation and related IT equipment;
- Tools, vehicles, furniture and fittings;
- Telecoms and other IT equipment;
- Premises involved in the delivery of its services; and
- IT related to the Market Opening Implementation Programme.

The networks component is by far the largest constituent of the RAB, accounting for over 90% of its value. Table 5.1 below shows the composition of the networks assets comprising the DSO RAB in 2004.

Table 5.1: Composition of the DSO Network Component of the RAB

Asset Type	% of RAB
Overhead lines (Low Voltage)	8%
Overhead lines (Medium Voltage)	19%
Overhead lines (High Voltage)	3%
Underground cables	27%
Switchgear	10%
Transformers	9%
Substation civil works and ancillaries	13%
Meters and connections	11%

As can be seen from the table, overhead and underground wires comprise around two thirds of the networks asset base. These – and indeed many other components of the asset base – have a widely varied age profile. This age profile is shown in summary in Figure 5.1 below and in more detail in Table 5.2.



	up to 1950	1950 1959	1960 1969	1970 1979	1980 1989	1990 1999	2000-2004	Total
Overhead lines - circuit (kms)	2000	330	450	350	600	600	150	4480
LV lines (excluding services)								
single phase	2,045	16,136	5,443	5,139	5,623	7,727	4,411	46,523
three phase	1,340	221	302	235	402	402	101	3,002
three phase urban	660	109	149	116	198	198	50	1,478
10kV lines								
single phase	2,007	8,495	5,572	3,739	3,236	5,974	13,118	42,141
three phase	901	3,813	2,501	1,678	1,452	2,681	5,888	18,914
20kV lines								
single phase	556	2,356	1,545	1,037	897	1,657	3,638	11,685
three phase	255	1,080	709	476	412	760	1,668	5,360
38kV lines								
20MVA - Single circuit	1,970	610	1,070	890	240	150	150	5,080
40MVA - Single circuit	-	-	100	40	40	40	-	220
110kV lines								
single circuit		18.2	2.1	31.2	27.5	15.0	127.5	221.5
double circuit			25.3	17.9		7.5		50.7
Total: -	9,733	32,839	17,417	13,397	12,527	19,611	29,151	134,675
Underground cables - circuit (kms)								
LV cables -	800	1,200	1,200	1,500	1,700	2,100	1,700	10,200
10kV cables	200	650	650	700	850	1,050	1,600	5,700
20kV cables	-	-	-	-	-	50	330	380
38kV cables	58	40	38	48	21	125	125	455
110kV cables	-	-	35	20	15	3	36	109
Total: -	1,058	1,890	1,923	2,268	2,586	3,328	3,791	16,844
Submarine cables - circuit (kms)								
LV cables -						1	10	11
10kV cables					2			2
20kV cables						65	5	70
38kV cables								-
110kV cables								-
Total: -	-	-	-	-	2	66	15	82
Switchgear (units)								
LV network								
LV panel	7	93	401	2,299	2,143	4,568	4,944	14,455
LV Minipillar	-	-	1,000	16,000	28,000	35,000	28,000	108,000
LV Link (sectionaliser) Minipillar	-	-	-	500	2,500	4,000	2,500	9,500
HV network								
MV Pole Mounted LBFM switch (manual)	-					477	953	1,430
MV Pole Mounted remotely controlable LBFM switch						8	200	208
MV Pole Mounted Recloser						123	229	352
MV RMU	20	77	591	2,196	2,498	5,185	6,183	16,750
MV Open Terminal Bay	104	326	494	338	366	684	306	2,618
MV Metal-clad Panel	-	-	165	145	118	444	268	1,140
EHV network								
38kV Open Terminal Bay	124	396	503	386	188	257	258	2,112
38kV GIS Metalclad Panel				-	15	25	34	74
38kV Air Break Switch	66	40	53	53	19	19	15	265
110kV Open Terminal Bay	-	-	10	18	7	24	9	68
110kV GIS Metalclad Panel		-	12	5	16	2	39	74
Total: -	321	932	3,229	21,940	35,870	50,816	43,938	157,046
Transformers (per unit) - incl. tap changers & reactors								
HV network								
MV/LV 1-phase PMT	724	10,862	7,241	9,414	7,965	38,219	107,279	181,704
MV/LV 3-phase PMT	65	979	652	848	718	3,289	9,085	15,636
MV Voltage Regulator				-	290	169	241	700
Interface Transformers						204	86	290
MV/LV Indoor 3-phase GMT	5	152	281	693	872	1,975	1,733	5,711
EHV network								
38kV Voltage Regulator	1	2	5	8	9	9	5	39
38/MV - 5MVA	9	23	117	127	78	182	50	586
38/MV - 10MVA	8	18	24	25	32	74	45	226
110/38 - 31.5MVA		7	10	10	12	28	9	76
110/38 - 63MVA			12	8	9	20	7	56
110/MV - 20MVA		1	1	3	1	20	13	39
Substation Civil Works and ancillaries								
MV Indoor Substation - Civils, Earths & Ancillaries	17	37	330	726	584	2,075	1,942	5,711
38/MV Indoor Station - Civils, Earths & Ancillaries	16	44	55	60	40	80	8	303
38/MV Outdoor Station - Civils, Earths & Ancillaries	46	38	29	10	10	11	8	152
110/38kV Station - Civils, Earths & Ancillaries	11	7	17	13	19	12	7	86
110/MV Station - Civils, Earths & Ancillaries				4	1	8	6	19
MV/LV Unit Substation complete incls earths & ancillaries			50	1,130	1,116	2,353	3,642	8,291
Total: -	902	12,170	8,824	13,079	11,756	48,728	124,166	219,625
Meters and Connections								
LV single phase customer connection	500,000	200,000	150,000	150,000	214,000	419,000	330,844	1,963,844
LV multi phase customer connection	40	94	3,096	11,595	24,699	41,747	40,156	121,427
HV multi phase customer connection		29	17	33	367	314	296	1,056
Meters								
LV single phase credit simple		300	31,365	258,659	539,375	542,122	365,284	1,737,106
LV single phase credit multi-rate, timer		30	3,102	25,582	53,345	53,617	36,127	171,802
LV three phase credit simple		15	2,277	8,436	18,399	31,238	29,977	90,342
LV three phase credit multi-rate, timer		4	569	2,109	4,600	7,809	7,494	22,585
LV three phase PPM multifunction CT		-	-	-	-	2,527	9,884	12,411
MV three phase PPM multifunction CT		-	-	-	-	300	760	1,060

Table 5.2: DSO Asset Age Profile

The table and figure above shows how the asset base has evolved and includes the effects of capex, depreciation and asset retirement. Section 7 sets out in detail the content of the DSO's historic capex. However, as is clear from table 5.2, a very significant portion of the asset base is very old. The Network Renewal Programme (see Section 7) addresses how the DSO has responded to the need to refurbish its network.

The age profile of the assets comprising the DSO's RAB means that its valuation is highly complex due to their different vintages and quality. In the following sections, the issues associated with that valuation are set out, together with the Commission's decision on the value for the RAB over the period 2006 to 2010.

5.1.2 Valuation of the Regulatory Asset Base

The approach to revaluing the RAB is a crucial decision within the price control process. The RAB plays a key role in establishing the value of the distribution business and hence its ability to cover capital expenditure and provide an adequate return on capital employed. Specifically, the RAB should be such that it is capable of providing sufficient revenue when applying the cost of capital to it, to ensure that the business is able to fund the new investment required in the network.

The core issue in this context is whether the RAB should reflect the value of the assets now (replacement value) or when they were built (acquisition cost).

Using some form of replacement value has a very strong economic foundation. A precise valuation results in tariffs that provide an accurate price signal of the cost of using the distribution network. Therefore, if tariffs were based on asset values that were too small, the value of the network would be understated with a dilution of the impact of any locational signals. Further, it would also encourage inefficient investment decisions and increase the risk that investments made now would be stranded in the future. Thus, taking a replacement cost approach is more likely to result in the correct level of network investment.

It should be noted that this is true irrespective of the ownership of the assets (i.e. whether this resides with the state or private companies).

A number of approaches can be taken to valuing the asset base, including those based on:

- Acquisition cost; assets are valued at their original cost of construction / acquisition. The value of assets are not indexed for inflation nor is their value linked to the cost of replacement

- Replacement cost; assets are valued at what it would cost to replace existing assets. There are two approaches to replacement cost: indexing the acquisition cost of the assets; and revaluing the asset based using a modern equivalent asset (MEA) approach.

- Replacement cost less stranded assets, as above but excluding those assets that are not utilised in the current system. Effectively, this would be the cost of building a replacement system.

- Deprival value, in which the assets would be valued at the lower of their replacement cost or economic value (in the event that they could not be replaced).

The advantages and disadvantages of each approach are outlined in the following table:

Approach	Advantages	Disadvantages
Acquisition Cost	• Simplest approach to valuing the RAB requiring no adjustment to RAB other than for new capex and depreciation	• Does not reflect economic value of assets and therefore likely to reduce incentive to invest • May not provide sufficient cashflow to fund network investment
Replacement Cost	• Consistent with 2001 – 2005 revenue control valuation method. • **MEA approach:** – Ensures the RAB is directly linked to the costs of constructing a new distribution system – Provides better indication of change in market values • **Indexed acquisition cost**: – Simpler to apply than MEA, as it does not require in-depth examination of asset base	• **MEA approach:** – Complex operationally as, in principle, all assets comprising RAB must be reviewed and valued – Assessment of network used for valuation is controversial - specifically whether this should be the existing or a "optimal" network – Risks deterring new investment if some existing assets are stranded when the RAB is revalued • **Indexed acquisition cost** – Simple indexation means that some assets may be overvalued and some undervalued relative to their true market value – The previous point may be worsened by asset retirements/disposals – Does not take into account technological improvements that increase capital efficiency
Replacement Cost less Stranded Assets	• As above, • Any assets that are considered stranded – that is where there is an unambiguous case that they are not required – should, in principle, be removed from the RAB as they do not form part of the operational base of networks.	• Identifying stranded assets is somewhat judgmental, particularly for the distribution system. CER would need to demonstrate that a specific asset should not have been built based on reasonable assumptions • Excluding stranded assets from the RAB may deter investment - i.e. ESB may not invest in some cases if there is a risk that the asset may become stranded, e.g. through expected load not appearing
Deprival Value	• Provides most accurate economic valuation of the network	• Highly complex to apply as requires detailed modeling of system to determine asset values

Based on the above, the Commission has decided that the assets within the DSO's RAB will continue to be valued at Replacement Cost (using indexed acquisition cost).

5.1.3 Asset Lives Applied to the RAB

To date, ESB has applied a variety of different asset lives to its assets. These are summarized in the table below:

Asset	Asset Life
Network Assets	40
Premises	50
Office Equipment, Fixtures and Fittings	10
Telecomms Assets	10
Vehicles	7
Tools	5
IT	5
Other	8

During the previous revenue control period a uniform network asset life of 40 years was applied by the Commission.

Internationally in recent years there has been a general trend towards extending the lifetimes of electricity distribution assets. This is based on the experience of efficient network operators, who have found that equipment that has properly specified, installed and maintained will last longer than had previously been assumed.

Performance of older assets is generally adequate, not least due to the modest pace of technological advance in electricity distribution, and the risks of purely age-related failure are considered to be low. In addition, condition monitoring has replaced age-based techniques in determining effective asset lifetimes.

A specific example of these trends has been seen in the UK among Distribution Network Operators. The following tables show average lifetimes and the standard deviation for a selection of UK electricity assets.

From these data[4] it can be clearly seen that the present treatment of ESB's RAB assets (depreciating the network plant types over 40 years) should be modified.

Table 6.1: UK Network Asset Lives

UK POWER INDUSTRY AVERAGE WEIGHTED ASSET LIVES		
PLANT TYPE	MEAN LIFE (years)	STANDARD DEVIATION (years)
Overhead lines		
LV Overhead lines	52	11
MV lines	43	11
HV lines	46	9
EHV lines	67	11

[4] Industry weighted average replacement profiles are from "OFGEM EDF (LPN) DPCR4 - FBPQ Analysis and Capex Projections" by PBPower December 2004

Underground cables		
LV cables	92	12
MV cables	94	14
HV cables	71	10
Submarine cables		
MV cables	50	5
HV cables	50	6
Switchgear		
LV network	73	12
HV network	47	8
EHV network	52	9
Transformers		
All network	56	11

A consequence of the average asset lifetimes assumed by a utility is that assets older than this age may be considered to be unreliable, dangerous and urgently in need of replacement.

ESB has stated that the criteria for asset replacement are based on asset condition rather than age; however the figure of 40 years is generally mentioned by ESB staff when explaining the need for an asset's replacement. Asset condition with the distribution network generally appears good, and in line with the expected condition of well-maintained assets according to their age and environment. Site visits conducted by the Commission and its engineering advisers during the course the review provided considerable evidence of this.

The use of average lifetimes more in line with current international practice would reduce the amount of annual depreciation, and realign ESB's perception of asset age with current expectations.

Having considered the above research the Commission has decided that network assets contained in the RAB should be depreciated over an average lifetime of 45 years.

5.1.4 Depreciation method

Depreciation of the Distribution RAB reflects the cost of using the RAB assets during the period. In accordance with 'FRS 15 Tangible Fixed Assets' the depreciation method should reflect as fairly as possible the pattern in which an asset's economic benefits are consumed. During the previous price control depreciation was calculated on a straight line basis to write off the depreciable amount of the assets over their expected useful life. CER believes that this method remains a reasonable representation of depreciation for network assets.

As outlined in Section 5.1.3, during the previous revenue control period an asset life of 40 years was applied to network assets; the Commission has deciced that the useful economic life of network RAB assets should be revised to 45 years. Changes in an asset's life should be implemented in accordance with paragraph 93 of 'FRS 15 Tangible Fixed Assets' i.e. the carrying amount (Net Book Value) of an asset at the time of the change should be depreciated over the revised remaining useful economic life of that asset.

The Commission has decided that the straight-line depreciation method will continue to be used. FRS15 will be used to revalue the RAB from 2001.

5.1.5 Replaced Assets

A significant amount of expenditure has taken place in the last decade on replacing assets in ESB's networks. This may have lead to a possible situation where an asset and its subsequent replacement have both been included in the RAB at the same time i.e. the asset has been replaced before its value in the RAB has been fully depreciated. The Commission believes that assets included within the RAB that have been replaced should be removed from the RAB at the time of their replacement.

The Commission's review included consideration of stranded assets within the regulated asset base. This covered:

- Consumer connection assets where the consumer has moved or otherwise ceased consumption
- Substations or feeders built to serve projected loads that did not materialise.
- Excess transformer capacity across the network.

The number of assets that fall into one of the above categories and their contributions to the RAB value is very small in ESB's case.

5.1.6 Calculation of Additions to the Distribution RAB

The regulatory treatment of additions to the distribution asset base, and in particular the capitalisation policy employed, is an important issue in a revenue control. This can be sometimes different from the policy used by the regulated company, as has been the case with ESB over the past 5 years.

A. INTEREST DURING CONSTRUCTION (IDC)

In DPR1 assets were added to the RAB as costs were incurred, not on the date of commissioning. For this reason the Commission did not allow IDC to be added to the RAB as the DSO received a return on the assets from the middle of the year in which the costs were incurred. Depreciation is to be provided as expenditure on assets is incurred in accordance with the cash flow approach to calculating allowable revenues. This implies that expenditure on assets still under construction during the year will be included in the calculation of that year's annual depreciation charge.

The Commission has decided not to change this policy for the period 2001-2005.

B. CAPITAL CONTRIBUTIONS AND GRANTS

During 2001 to 2005 capital contributions and grants were also subtracted from capital expenditure in the relevant year.

The Commission has decided to treat contributions and grants in a similar manner in DPR2.

C. CAPITAL EXPENDITURE 2001 – 2005

The Commission forecasts gross allowed additional capex to the RAB being €153.4m. This amount represents variances between forecast and actual results (e.g. more customers being connected to the network than required, more replacement costs due to greater than expected asset deterioration etc). Where justifiable these variances have been accepted by the Commission and entered into the RAB. Section 7.3 assesses the variances incurred by the DSO during 2001 to 2005 for their inclusion in the 2006 RAB. The DSO has requested a capex variance of €250.2m to be entered into the RAB. The Commission has disallowed €82m of this. After capital contributions, there is a net addition of €63m.

5.1.7 Clawback of depreciation and return on capex approved but not spent in 2001-2005

The DSO revenue allowance for 2001-2005 included depreciation and return on all allowed capex for this period. Following a further review of the proposed additions to and subtractions from the RAB due to actual capex incurred by the DSO over this period, the Commission has decided to disallow revenues earned on allowed capex that was not actually incurred. This has resulted in a claw back of €39m on allowed revenues, equivalent to the revenues earned on €100.3m of capex not incurred. This capex under spend affected a number of areas, including network expenditure, asset replacement, meter costs and non-network capex.

5.1.8 Value of the DSO RAB

Summarising the forgoing sections, the Commission has decided to take the following approach in determining the DSO RAB:

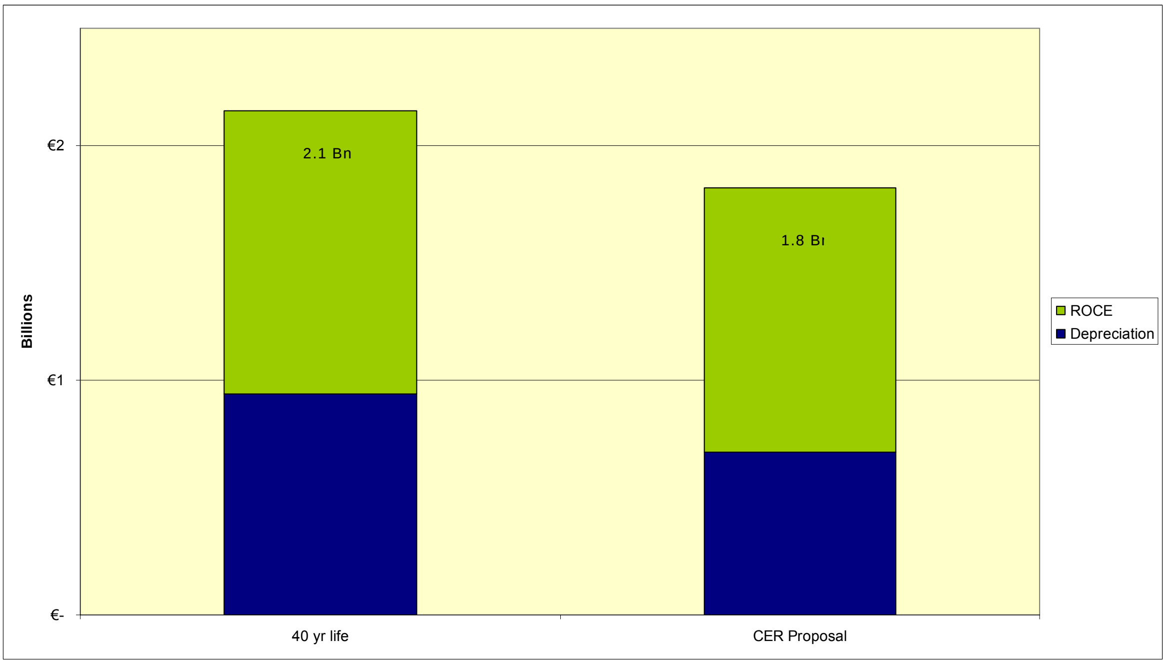
- Continue to value the RAB based on Replacement Cost
- Apply a 45 year life to network assets, increasing from the 40 year assumption currently used.

Figure 5.2 outlines the impact of the above on the amount[5] of network depreciation and return on capital employed for the period 2006-2010:

- The first column shows these amounts in accordance with the 2001-2005 RAB assumptions
- The second column shows the Commission's approach of changing the network asset life to 45 years and applying FRS15 from 2001.

[5] This is an approximation of the impact, as a number of variables are involved in the calculation of these amounts.

Figure 5.2: DSO Depreciation and ROCE



Based on this approach, table 5.4 below shows the opening value of the RAB (i.e. that applying from 2006) and its evolution through to 2010. The RAB has been developed based on the following assumptions:

- The opening RAB is based on the closing RAB from the current price control period;
- An asset life of 45 years is assumed;
- Year on year changes take into account new capex, depreciation and assets that have become fully written off during the preceding year;
- Only allowed capex has been used to update the RAB. Overspend has not been included; and
- FRS15 applies to the RAB from 2001 onward.

		2006	2007	2008	2009	2010
Opening Net Book Value	[€m]	3,369.5	3,662.5	3,889.9	4,106.3	4,288.9
WIP	[€m]					
2001-2005 Allowed Variations	[€m]	59.1				
Fixed Asset Additions	**[€m]**	**509.2**	**493.8**	**466.6**	**438.8**	**384.5**
Capex 2006-2010	[€m]	503.7	491.2	463.5	437.4	382.4
IDC	[€m]	-10.8	-10.5	-10.2	-10.2	-9.5
Capitalized Dismantling Costs	[€m]	16.3	13.1	13.3	11.6	11.5
Fixed Asset Disposals	**[€m]**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Fixed Asset Depreciations	**[€m]**	**-146.3**	**-154.2**	**-162.3**	**-170.9**	**-178.7**
Assets Capitalized before 2006	[€m]	-138.0	-129.4	-122.4	-117.3	-112.9
Capex 2006-2010	[€m]	-8.1	-24.3	-39.1	-52.5	-64.4
Capitalized Dismantling	[€m]	-0.2	-0.5	-0.8	-1.1	-1.3
2006-2010 Capital Contributions & Grants Received	**[€m]**	**-88.7**	**-133.6**	**-111.9**	**-111.8**	**-65.9**
Amortisation of Capital Contributions & Grants	**[€m]**	**18.8**	**21.3**	**24.0**	**26.5**	**28.5**
Before 2006	[€m]	17.8	17.8	17.8	17.8	17.8
2006-2010	[€m]	1.0	3.5	6.2	8.7	10.6
Closing Net Book Value (2004 money)	[€m]	3,662.5	3,889.9	4,106.3	4,288.9	4,457.2

Table 5.4: Path of the DSO's RAB

5.2 COST OF CAPITAL

ESB Distribution's cost of capital is a critical element of the price control, as it determines the allowed return on its asset base.

Despite the ESB's status as a "Semi-State" company, it competes for capital on national and international markets as does any other business. Its cost of capital is therefore related to the riskiness of its return is relative to businesses with other similar assets, which does not depend on the ownership structure of the company. Therefore, for a company such as ESB, which does not have traded equity, the cost of capital must be determined by assessing the returns to assets that have comparable risk because it competes with such businesses for scarce capital.

Thus ESB Distribution's asset intensive nature, setting the cost of capital at the correct level is important to ensure that:

- The return is consistent with what one would expect in similar entities.
- The correct incentives are given to the business for future investment
- The approach reflects current best practice from both regulatory and analytical perspectives

In the following subsections, we set out:

- The general approach that the Commission has followed, that is the application of the Weighted Average Cost of Capital (WACC) and Capital Asset Pricing Model (CAPM)
- How the cost of equity has been determined
- The approach taken to setting the cost of debt
- The level of gearing assumed for the business

- The Commission's decision on the Cost of Capital to apply to ESB's Distribution Business during 2006 to 2010.

Based on the extensive analysis described in this section, the Commission has set ESB Distribution's Weighted Average Cost of Capital at 5.63% for the period 2006 to 2010.

5.2.1 General approach

Determining the cost of capital to apply to regulated businesses is a very common but nonetheless controversial task. All regulators undertake it and a number of approaches have been taken internationally.

The Commission's approach to this work is to draw on the vast body of thinking already undertaken – both within Ireland and elsewhere – and apply this in a practical way to ESB's Distribution business. Moreover, the Commission has adopted a common approach to all of ESB's regulated businesses to ensure that no distortions are created between them.

At a theoretical level, there is considerable academic controversy surrounding the most appropriate approach to setting the cost of capital. Consistent with many other regulators in similar environments, the Commission has decided to adopt the weighted average cost of capital methodology, or WACC. In applying this methodology, however, a number of theoretical and practical issues arise. These are discussed in the following sub-sections. The Commission notes, however, the importance of adopting a consistent approach to all elements of the calculation.

In the following sections, the approach taken by the Commission and the values taken for each component of the calculation is set out. A range is given for each of the elements, together with a point value. The cost of capital is then calculated based on the high and low values for each component and an overall value determined.

5.2.2 WACC

The general principle applied in calculating the allowed cost of capital is that it should give investors the same return as that earned in other activities of similar risk. The cost of capital is generally defined as the weighted average of the cost of equity and cost of debt, with weights equal to the share of these sources of capital in the business's total assets. Thus, if a real pre-tax cost of capital were used, the WACC formula would be as follows:

$$WACC = wd \cdot Rd + we \cdot Re$$

wd: gearing or leverage.

we: equity share

Re: real after-tax cost of equity

Rd: real cost of debt

In the Commission's view, the WACC is the most appropriate model to use, given that it is the approach adopted most commonly and encompasses both equity and debt elements.

5.2.3 Cost of equity

In common with regulators in comparable environments to Ireland, the Commission has decided to use the Capital Asset Pricing Model (CAPM) to determine ESB's cost of equity. The Commission has considered a range of different options for calculating the cost of equity, such as the Multifactor model and the Dividend Growth Model or Dividend Discount Model approaches. However, consistent with the approaches taken by regulators internationally, it is the Commission's view that other methodologies have their own specific advantages and disadvantages and none provides a compelling case for its use in place of CAPM.

The CAPM states that the cost of equity should give shareholders a risk premium above the risk-free return according to a business's systematic risk, which depends upon whether the return to that business is more or less risky than the market return[6]. This is measured by the beta coefficient, which does not measure specific risk (assumed to be eliminated by portfolio diversification). The Commission notes that CAPM is a forward-looking model that is it intended to model future rather than historic returns.

The model specification of the CAPM for the cost of equity (Re) is as follows:

*Re = Risk-free rate + beta * equity risk premium*

Consequently, three elements of the cost of equity must be determined, namely: the risk free rate, the equity risk premium and the "beta"[7]. The Commission's approach to each is set out in turn below. The market return is then considered finally as a check for the consistency of the calculation of the equity return.

A. RISK FREE RATE

The risk free rate is defined as that applying to assets that have certain returns. Four key issues must be addressed in setting the risk free rate:

- First, whether to use current interest rates or averages calculated over longer historical periods.
- Second, the maturity of the risk free assets considered - specifically whether to use short or long-run bonds
- Third, whether the risk free rate should be based on nominal or index-linked bonds
- Fourth, the nationality of the bonds to be used.

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[6] As noted above, this approach is used because the return to ESB's assets (and hence its cost of capital) is independent of its ownership structure. CAPM uses share price data as the basis to determine cost of capital.

[7] The equity beta is an increasing function of leverage or financial risk faced by the company.

First, in recent years, measures of the risk free return have been falling significantly. Consequently, taking a long averaging period to determine the risk free rate means that, all other things being equal, a higher risk free rate will be determined than one focusing on more recent data only. The Commission's view is that this would not reflect the ESB's cost of borrowing in the future. Additionally, given that the CAPM is a forward looking model, using past values as its basis can be argued to be distortionary.

Figure 5.3 shows the path of real forward yields for UK Government Bonds since 1985 and shows the very marked decline experienced during this period.

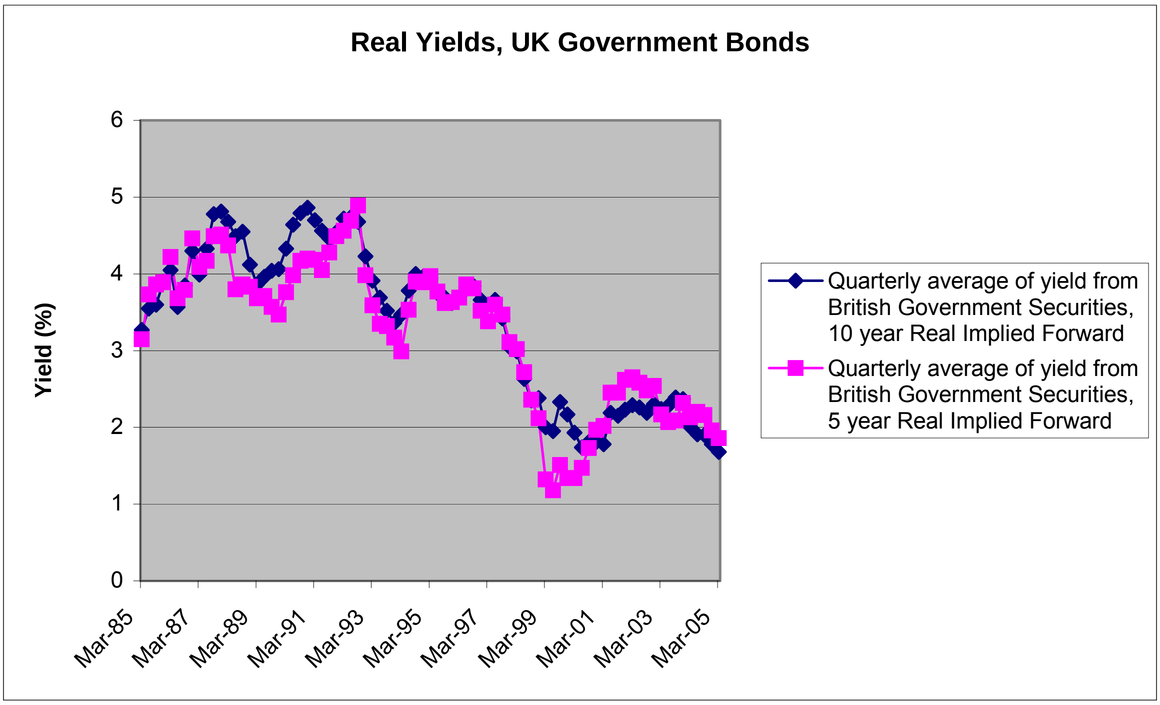


Figure 5.3: Real Yields

The Commission's view is that the risk free rate should reflect the actual cost of borrowing faced by the business. Current rates taken over a range of maturities provide the best estimate of this. This approach is fully consistent with that adopted by Ofgem, OFWAT and the CAA in the UK, together with other international regulators. It reflects the expectation that the current low level of yields will continue.

Therefore, the Commission has used a combination of current spot and forward rates as the basis for the calculation of the risk free rate.

Second, the maturity of the risk free assets must be determined. The Commission believes that a range of maturities up to 10-years is appropriate and fully consistent with international precedent. Additionally, some weight will be given to shorter terms, to match the ESB's expected debt portfolio[8].

Third, it must be decided whether real or nominal denominated bonds should be used. Use of nominal bonds entails calculation of both expected inflation for the duration of the debt (usually determined by evaluating a "consensus" forecast of inflation across the Eurozone or central bank forecasts) and an inflation risk premium. The inflation risk premium is defined as the difference between the yield on indexed linked bonds and equivalent nominal bonds, less expected inflation.

The Commission's preference is to use index-linked bonds as the basis for the risk free rate, however it recognises the concern that the market for such securities may not be sufficiently liquid for an efficient price to emerge. Consequently, a combination of index linked and nominal bonds (adjusted for expected inflation and the IRP) will form the basis of the calculation.

Fourth, identifying which government securities should be used is thus key to the calculation of the risk-free return. Turning to the appropriate nationality of the risk free bond, a liquid market is, of course, a core requirement. The Commission notes that:

- Within the Eurozone, the only substantively traded government index-linked bonds exist in France. Outside the Eurozone, UK index-linked securities provide a highly liquid market. However, their use is not favoured by the Commission because of the need to project movements in the Euro Sterling exchange rate and to calculate and exchange rate risk premium
- For nominal bonds, the Commission favours use of Irish and German government debt, as has been used in previous price controls

Returns on French Government index-linked bonds are shown in the table below, together with nominal returns on Irish and German bonds of comparable duration. The table also shows the implied Inflation Risk Premium (IRP) arising from the comparison of the nominal and index-linked bonds.

Table 5.4: Risk free returns

Maturity		5			10		5	10
	spot	3yr	5yr	spot	3yr	5yr	Averages	
Nominal								
Nominal return Irish (1)	2.71	3.34	3.71	3.22	3.74	3.96	3.25	3.64
Nominal return German (2)	2.57	3.49	3.86	3.16	3.82	4.1	3.31	3.69
Average	2.64	3.415	3.785	3.19	3.78	4.03	3.28	3.67
Expected inflation		1.6	1.6		1.6	1.6	1.60	1.60
Inflation Risk Premium	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Real Risk Free Rate	2.41	1.585	1.955	2.96	1.95	2.2	1.98	2.37
Real								
Index-Linked Rate French (3)	2.57	3.03	3.05	3.32	3.09	2.94	2.88	3.12
Average	2.49	2.31	2.50	3.14	2.52	2.57	2.43	2.74
Combined Average							**2.13**	**2.49**

Taking account of the various possible approaches, the Commission takes the view that a combination of index-lined and nominal government bonds should be

[8] This assumption is also used to determine the debt premium, described below.

used. This reflects concerns about the current extent of liquidity for index-linked bonds in the Eurozone.

Table 5.4 shows a range for the average risk free return from 2.13% to 2.49%. This compares with a current real yield on UK Government securities of 2%. The Commission notes that many commentators view this rate as likely to increase in the future.

Reflecting this, the Commission has set the risk free return at 2.38%.

While this approach represents a departure from that used in previous price control reviews, the Commission believes that this:

- Takes into account recent developments in bond markets and the availability of data
- Provides a more accurate starting point for the ESB's borrowing costs going forward
- Is consistent with the approach now being taken by regulators internationally.
- Reflects the concern that the historically low rates currently observed may rise in the future.
- Represents the most appropriate basis for the calculation of the risk free rate in Ireland.

B. EQUITY RISK PREMIUM

The Equity Risk Premium (ERP) is defined as the difference between the market return and the risk-free rate – that is the additional return that investors require for holding a risky asset (a security that performs in line with the market as a whole). Two specific areas of controversy surround the determination of the ERP, which are whether to use:

- Geometric (GA) or arithmetic averages (AA)
- Historic averages or forward-looking values.

With regard to the choice between GA and AA, there is certain agreement amongst financial analysts that the GA is the best indicator of the actual past returns and tends to produce a lower value if returns are volatile, while the AA approach is the best predictor of future expected returns, although questions have been raised about the stability of the AA approach[9]. Moreover, in the presence of volatility, considerable differences can emerge between AA and GA approaches (Wright, Mason and Miles report differences of up to 2% between the two approaches).

The issue of whether to use either an historic average or a forward-looking value is more controversial. It is often argued that the historic average ERP will tend toward its long term level (termed "mean reversion") in the long-run, and the

[9] For example, see "A Study into Certain Aspects of the Cost of Capital for Regulated Utilities in the UK" by Wright, Mason and Miles.

arithmetic average is the thus best estimator of expected future returns. Conversely, it can also be argued that historic returns do not explain future returns, hence surveys amongst practitioners should be given some weight in final determinations, although this inevitably raises issues on the objectivity of those surveys.

In the light of these issues, most regulators appear to have used the AA to project forward from historic returns.

Turning to values, historical estimates of the ERP show a wide range, depending on the specific approaches adopted. Dimson, Marsh and Staunton carried out a comprehensive review of ERP globally and their results are presented in the table below.

Table 5.5: International Estimates of the Equity Risk Premium relative to Bills

	Geometric Mean	**Arithmetic Mean**	**Standard Deviation**
Australia	6.2	7.8	18.9
Belgium	2.4	4.2	20.1
Canada	4.1	5.6	18.0
Denmark	1.8	3.0	16.0
France	3.7	5.8	21.9
Germany	5.2	8.3	27.5
Ireland	3.5	5.1	18.4
Italy	4.2	7.7	29.9
Japan	5.6	9.7	33.1
Netherlands	3.7	5.8	21.7
Norway	1.8	4.2	23.9
South Africa	5.1	6.8	19.2
Spain	2.2	4.1	20.3
Sweden	5.0	7.3	22.4
Switzerland	1.6	3.1	17.4
UK	4.0	5.2	16.9
USA	4.6	6.6	20.2
World	4.0	5.1	15.1

Source: Dimson, Marsh and Staunton (2005), 'Global Investment Returns Yearbook 2005', ABN Amro/LondonBusiness School, February.

Forward-looking estimates are shown in the table below for a sample of studies.

Table 5.6: Forward-Looking ERP

Study	**Range**
Welch (2001)	3 – 3.5% (1 year), 5 – 5.5% (10 year), survey
Fama & French (2002)	2.55 (DGM) to 4.32% (Growth Rate based analysis)

Dimson, Marsh & Staunton (2002)	3% (GA) and 5% (AA). 3.9% (global estimate), with 2% variance
Arnott and Bernstein (2002)	2.4%
Ibbotson and Chen (2002)	3.97% (GA) and 5.9% (AA)
Arnott & Ryan (2001)	0 or slightly negative
Graham & Harvey (2001)	3.9% to 4.7% (from survey of CEOs)

The Commission notes that these studies are highly heterogeneous, covering different samples and approaches. However, the Commission believes that forward-looking values should be taken into account in determining the ERP. It also notes that these values are often smaller than suggested by the historic numbers above.

Regulators have not adopted a uniform approach, reflecting the complexity of this area. Moreover, they tend to determine a range rather than a point value. The table below shows recent regulatory determinations from the UK and elsewhere.

Table 5.7: Regulatory determinations of the ERP

Price Control	ERP
Ofreg review of NIE (2002)	3.5%
CAA Airports (2002)	4%
Ofgem DNOs (2004)	2.5% to 4.5%
Ofwat WASCs (2004)	3.5% to 5%
Dte, Netherlands, Distribution (2002)	4% to 7%
CER BGÉ Transmission and Distribution (2003)	5%
IPART, New South Wales, Distribution (2004)	5% to 6%

The Commission's view is that it because of the theoretical and practical uncertainties surrounding the ERP is not appropriate to focus on a single method to determine its value. Table 6.7 below summarises the evidence reviewed by the Commission and sets out its view on the appropriate range for the ERP.

Table 5.8: Equity Risk Premium

ERP Methodology	Min (%)	Max (%)
Regulatory precedent	2.5	6.0
Historical Analysis	4.7	6.1
Forward-looking Analysis	3.0	5.0
Maximum range	2.5	6.0
Commission's value	**5.25%**	

The Commission believes that the appropriate value for the ERP is 5.25%, recognising that this is slightly higher than the average across the range to take into account the historically low values of the ERP observed currently.

C. EQUITY BETA

The core issue in determining Beta – which reflects how risky a company is relative to the market as a whole – in ESB's case is that it is not publicly listed. This is not a unique situation and established approaches exist for determining the value of Beta through use of comparators.

However, in order to calculate the beta for different companies, it is necessary to distinguish between asset and equity betas. This adjustment is required because the beta values are obtained from companies other than ESB, which will have different gearing levels. The higher the gearing, the higher the equity beta because shareholders will demand higher returns to compensate them for a greater financial risk. The adjustment is intended to reflect the underlying operational risks the company faces, before financing is taken into account. Hence the adjustment allows the direct comparison of businesses with different gearing[10].

The usual formula for un-gearing and gearing betas is as follows:

$$\text{Asset Beta} = \text{Equity Beta} / [1 + (\text{Debt}/\text{Equity})]$$

Variants of this model are also used, however the Commission has based its calculation on this approach.

In addition, one could argue that the asset beta be further subdivided between assets related to regulated and unregulated activities. Given the very small proportion of non-regulated activity undertaken by the DSO, the Commission does not believe that this separation is appropriate.

Many practical issues arise in determining the beta. These include the following:

- The degree of operational leverage in the company (i.e. the proportion of its costs that are fixed) and how its revenues move with economic cycles. Selecting the appropriate comparators corrects for these factors.

[10] The specific issue of gearing is discussed in section 5.2.5.

- The frequency of the data used. Typically, monthly data are used in the UK based on the LBS Risk Measurement Service analysis, which comprises a rolling average of 50 months' data for all listed companies. However, weekly or daily data can be used. In general terms, the accuracy of the estimates tends to improve with higher frequency data. The added value of using daily data depends on how quickly the companies respond to market information and vice-versa. If this slow – as is likely to be the case for regulated businesses with largely pre-determined revenues – then daily data may not be appropriate. Indeed, it is also likely that daily data may be serially correlated, potentially distorting estimates of beta. Consequently, the case for using daily or weekly data is less compelling. Therefore, the Commission's view is that monthly data are appropriate to calculate the beta.

- Whether "raw" or "adjusted" values are used. Raw betas are those calculated directly from the regression of company returns against market returns. However, raw betas are often adjusted to reflect an assumed trend of betas towards 1, or to the sector average, in the long-run (a Bayesian adjustment is made to the beta estimate, based on the assumption that, all other things being equal, the beta is assumed to be unity). It is noted that LBS monthly beta estimates use a Bayesian correction.

- Whether it is necessary to adjust betas to reflect differences between regulatory regimes. For example, one could argue that there is a need to adjust the beta of a price-cap regulated company to make it equivalent to a beta of a cost-of-service-regulated company, to take account of the different risks to which they are exposed. The Commission's view is that there is no need for such an adjustment given the sample of comparators used and the way in which they are regulated.

- Whether it is appropriate to take regulatory risk into account in setting the beta. The Commission's view is that unless regulatory interventions cannot be diversified by the firm and also have *systematic* effects (that is they change the relationship between the company's return and the market return by impacting on the business's profits in response to economic shocks, for example) then regulatory risk should not be taken into account in determining Beta. Given that the price control is set for five years and that the Commission intends to take a consistent approach in each review, the Commission believes that this effect can be ignored in determining Beta.

- The period over which Beta is estimated also has a substantial impact on the outcome. Generally, a three to five year estimate should be considered the minimum acceptable period, with a longer period often used as the basis for calculations. The LBS data uses a period of 50 months, which the Commission believes forms a reasonable basis for the calculation.

Although the points above are important, the choice of comparator tends to be the dominant factor in determining the value of Beta. The table below summarises recent betas determined for a range of European utilities.

	Equity Beta	Market Cap (€m)	Total Debt (€m)	Gearing	Asset Beta
National Grid Transco	0.61	23,951.36	19,607.04	0.82	0.42
United Utilities	0.55	7,543.66	6,615.16	0.88	0.32
Viridian	0.47	1,437.65	660.82	0.46	0.21
Scottish Power	0.67	11,883.75	7,506.26	0.63	0.51
Scottish and Southern Energy	0.53	12,162.05	2,839.23	0.23	0.29
RWE	0.73	38,385.58	40,526.84	1.06	0.6
EON	0.65	69,141.04	30,452.48	0.44	0.47
Endessa	0.79	27,531.36	25,985.84	0.94	0.69
Severn Trent	0.42	5,016.81	4,239.31	0.85	0.13
ENEL	0.72	65,574.40	36,470.16	0.56	0.58
Average	**0.61**	**26262.77**	**17490.31**	**0.69**	**0.42**

Table 5.9: Beta estimates for range of European utilities

Based on monthly beta data, a sample of European utilities broadly comparable to the ESB Distribution suggests an equity Beta in the range of 0.4 to 0.8 (based on monthly data), with a mean of 0.6. Evidence from US transmission and distribution companies indicates comparable values. Vertically integrated US companies (which are often subject rate of return regulation and also include potentially more risky activities), suggest a higher Beta value of between 0.3 and 1.2, with a mean of 0.5.

Turning to asset Betas, the effect of removing gearing from the comparison reduces the Betas to the range 0.2 to 0.7. Assuming gearing of 50%, and a tax wedge of 12.5% for ESB, this implies an equivalent average equity Beta of between 0.3 to 0.6[11].

The Commission notes that, in general, Betas for utilities have declined in recent years and that regulators have tended to take this into account in determining the values of Beta – that is to assume that betas will be higher in the longer term. Indeed, regulators have adopted a wide range of approaches to setting Beta for network businesses, which has resulted in a broad band of estimates. For example, Ofgem in its review of DNO charging in 2004 estimated a Beta in the range 0.6 to 1.0, while Ofreg in its review of NIE in 2002 estimated an equity Beta of between 0.7 and 1.0. An average of 19 recent UK and international determinations of equity Beta indicates an average value of 0.9 and range of 0.6 to 1.45. The Commission notes that Equity Betas determined by Regulators in the last three years have been within a narrower range of 0.6 to 1, with an average of 0.89, reflecting movements in the market over this period.

Table 5.10 summarises the evidence described above.

Table 5.10: Estimates of Beta

Beta Estimator	**Low**	**High**
Comparator analysis (1)		
• Equity (Actual Gearing)	0.3	0.9

[11] Note that value is based on actual gearing and hence differs from the table above.

• Asset	0.2	0.4
• Equity (60% Gearing)	0.3	0.6
Regulatory Precedent		
• Since 1999	0.6	1.45
• Since 2002	0.6	1.0

(Based on Monthly LBS data)

The Commission's view is that the Beta for ESB Distribution should be set towards the top of the range of these estimates – that is at 0.80 - since:

- Given the nature of its regulation and scope of its activities, ESB Distribution's returns are likely to be lower risk relative to a market portfolio.
- Some recent regulatory determinations in the UK and elsewhere have tended to understate the degree to which values of Beta are declining, that is they have incorporated the assumption that Beta values are anomalously low for network industries
- The previous point should be balanced against the fact that the ESB must compete with similar network businesses for capital on international markets.

This value includes a modest uplift above the result implied by calculation of the Equity Beta from comparator data, reflecting the potential current undervaluation of beta.

D. OVERALL EQUITY COST OF CAPITAL

The Commission's view of the value for ESB Distribution's cost of equity is therefore 6.58%, based on the range of estimates shown in the table below.

Cost of Equity	Low %	High %	Commission's View
Real risk free rate	2.13	2.50	**2.38**
ERP	3.75	6.00	**5.25**
Asset Beta	0.20	0.40	**0.40**
Equity Beta	0.60	1.00	**0.80**
Cost of Equity	4.38	8.50	**6.58**

Table 5.11: ESB Distribution Cost of Capital

In order to confirm the reasonableness of the cost of equity calculation, the Commission has considered the overall return to equity as distinct from the division into the risk free and risk related elements. International evidence presented by Wright, Mason and Miles (A Study into Certain Aspects of the Cost of Capital for Regulated Utilities in the UK), suggests a geometric average of around 5.5% and arithmetic average of 6.5 to 7.5%. Dimson, Marsh and Staunton estimate this value to lie between 6% and 7%. Therefore, the Commission believes that the value it has taken is consistent with these market data.

5.2.4 Cost of debt

Two elements are required to determine the ESB Distribution's cost of debt: the risk free return, described above; and the Debt Premium, reflecting the company's debt rating. The former takes the same value as for the risk free component of the equity return, as described above.

International evidence suggests several approaches can be taken to calculating the debt premium. These include actual or benchmark costs, embedded costs or forward looking values. In general terms, the most reliable approach is to consider the cost of debt of comparator companies and that associated with the ESB's credit rating. A relevant point in this context is that the ESB borrows at a corporate level, rather than for its Distribution business alone. Consequently, the use of credit ratings could be considered more appropriate than the use of network business comparators.

A second key issue is the maturity of the debt to be considered. The Commission takes the view that this should be consistent with the terms on which the risk free rate is determined; that is, based on a 10 year horizon.

Evidence from benchmark data suggests that for companies with a comparable debt rating to ESB (i.e. BBB or A), the average debt premium across a range of maturities (up to 10 years) is between 1% and 1.6% above the risk free rate. The following table summarises these data.

Table 5.12: Debt premia, 5-10 year maturity

	BBB	A
May 2002 – March 2005	1.92	1.09
Jan 2003 – March 2005	1.65	0.98
Jan 2005 – March 2005	1.33	0.84
Average	1.63	0.97

Recent regulatory determinations on the debt premium are shown in the table below:

Table 5.13: Recent regulatory determinations of the Debt Premium

Determination	Debt Premium (%)
Ofgem, Transco (2001)	A rating, range of 1.5 to 1.9
Ofreg, NIE (2002)	BBB rating, range of 1.4 to 1.8

CAA, Airports (2002)	0.5 to 0.9
Competition Commission, Airports (2002)	0.9 to 1.2
Ofgem, DNOs (2004)	1 to 1.8 (using historical averages)
Ofwat, WASCs (2004)	0.8 to 1.4
CER, BGÉ Transmission and Distribution, 2003	1.4 (based on A- rating)
IPART, New South Wales Distribution	0.9 to 1.1

Overall, Table 5.13 suggests a wide range for the debt premium of 0.5% to 1.8%.

Reflecting the above, the Commission's view is that the Debt premium should be set based on the average of A and BBB rated companies over a 5 to 10 year horizon.

Based on the above analysis, the Commission believes this value should be set at 1.35%, that is towards the top end of the range of 1.0% to 1.5%. This is consistent with recent regulatory determinations in the UK and elsewhere.

5.2.5 Gearing

Another issue in the calculation of a WACC concerns the assumptions made about leverage or capital structure, in particular whether to use either actual or efficient/benchmark values. For regulated businesses, gearing is typically defined as the ratio of net debt to the regulatory asset base.

The key issue to consider is whether the actual or benchmark level of gearing should be used. Generally, regulators have tended to use a target or benchmarking approach. In setting the benchmark gearing, the primary concern is to ensure that gearing does not result in an implied credit rating that would be inconsistent with a reasonable commercial level. Typically, this has resulted in an assumed level of gearing of between 50% and 60%.

The Commission believes that an assumed gearing of 50% is consistent with the approach taken by regulators internationally and reflects the debt grading of companies comparable with ESB.

5.2.6 Taxation

The analysis up to this point has been based on a pre-tax WACC. The WACC must also be expressed on a post-tax basis as this will ultimately determine the revenue accruing to the business.

The Commission sees no compelling reason to change its previous approach on this issue. A pre-tax WACC is defined, based on an assumed effective tax rate of 12.5%, implying a tax wedge of 1.143.

5.2.7 Commission Decision on the Cost of Capital

The table below summarises the Commission's view on the appropriate WACC for the Distribution business.

Table 5.14: Summary of WACC Value

Component	Low %	High %	Commission's View
Cost of Debt			
Risk free rate	2.13	2.49	2.38
Debt premium	1.00	1.50	1.35
Cost of Debt (pre-tax)	3.13	3.99	3.73
Cost of Equity			
Real risk free rate	2.13	2.50	2.38
ERP	3.75	6.00	5.25
Asset Beta	0.20	0.40	0.40
Equity Beta	0.60	1.00	0.80
Cost of Equity	4.38	8.50	6.58
WACC			
Effective tax rate	0.13	0.13	0.13
Gearing	0.60	0.50	0.50
Pre-tax WACC	3.26	6.85	5.63
Post-tax WACC	2.85	6.00	4.92

Given the range of pre-tax WACC of 3.26% to 6.85%, the Commission has decided that the cost of capital to apply to the Distribution business will be 5.63%.

5.3 CONCLUSION

The Commission's decision on the RAB are summarised as follows: (1) continue the existing replacement cost methodology to RAB valuation, (2) extend the asset life applied to the RAB to 45 years; (3) depreciate the RAB in accordance with FRS15; (4) the cost of capital applied to the RAB is 5.63%.

As a result of these proposals the Commission values the Opening Distribution RAB for 2006 at €3369.5m, compared with the DSO's proposed 2006 RAB of €3,709m.

6. SYSTEM PERFORMANCE

This section assesses the DSO's network performance in terms of:

- Customer interruptions – The key international measures – System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI) and Customer Average Interruption Frequency Index (CAIDI)) and Customer minutes lost
- Distribution losses
- Performance against the Customer Charter

The DSO's network performance was analysed according to:

- An assessment of historical performance
- Determination of the system performance

6.1 UNIVERSALLY USED MEASURES OF SYSTEM PERFORMANCE

The three international measures of system performance (SAIFI, SAIDI and CAIDI) are explained below[12].

6.1.1 System Average Interruption Frequency Index - SAIFI

SAIFI is the average number of interruptions per customer during the year and is designed to give information about the average frequency of sustained interruptions (those lasting more than five minutes) per customer in a predefined area.

It is calculated by dividing the total annual number of customer interruptions by the total number of customers served during the year.

$$SAIFI = \frac{\sum N_i}{N_T} \qquad (1)$$

where,

N_i is the number of customers interrupted in fault i

N_T is the total number of customers served

6.1.2 System Average Interruption Duration Index (SAIDI)

SAIDI is the average duration of interruptions for customers who experience an interruption during the year. It is determined by dividing the sum of all durations

[12] Source: ESB

of service interruptions to customers by the total number of customers. This index is commonly referred to as Customer Minutes of Interruption or Customer Hours and is designed to give information about the average time during which customers' supply is interrupted.

It is calculated as:

$$SAIDI = \frac{\sum r_i N_i}{N_T}$$

where,

r_i is the duration of fault I

6.1.3 Customer Average Interruption Duration Index (CAIDI)

CAIDI represents the average time required to restore service to the average customer per sustained interruption.

$$CAIDI = \frac{\sum r_i N_i}{\sum N_i} = \frac{SAIDI}{SAIFI}$$

6.2 ASSESSMENT OF HISTORICAL SYSTEM PERFORMANCE

6.2.1 Customer interruptions

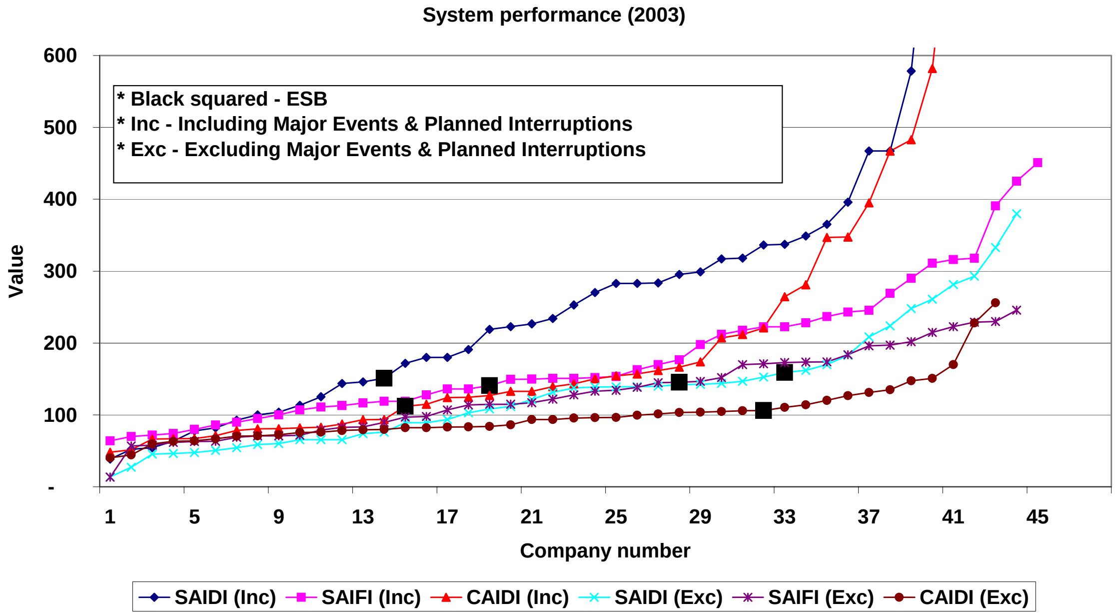
Using these measures, Ireland's network performance was benchmarked against over 40 US companies (figure 7.1 below). The results show that Ireland's network performance is acceptable:

- DSO's SAIDI, SAIFI and CAIDI (all including storms) are better than the benchmark average
- DSO's SAIDI and CAIDI (excluding storms) are 20% and 10% above average[13], but are only 43% of the benchmarked maximum values.
- DSO's SAIFI (excluding storms) is 13% above average[14], but only 60% of the benchmarked maximum value

[13] SAIDI – 162 compared to an average of 134, CAIDI – 110 compared to an average of 101

[14] SAIFI - 1.5 compared to an average of 1.3

Figure 6.1 Network performance benchmarking



Ireland' customer minutes lost (figure 7.2) has improved 26% (96 minutes) since 2001 which reflects the significant investment that has been made to the network during that period.

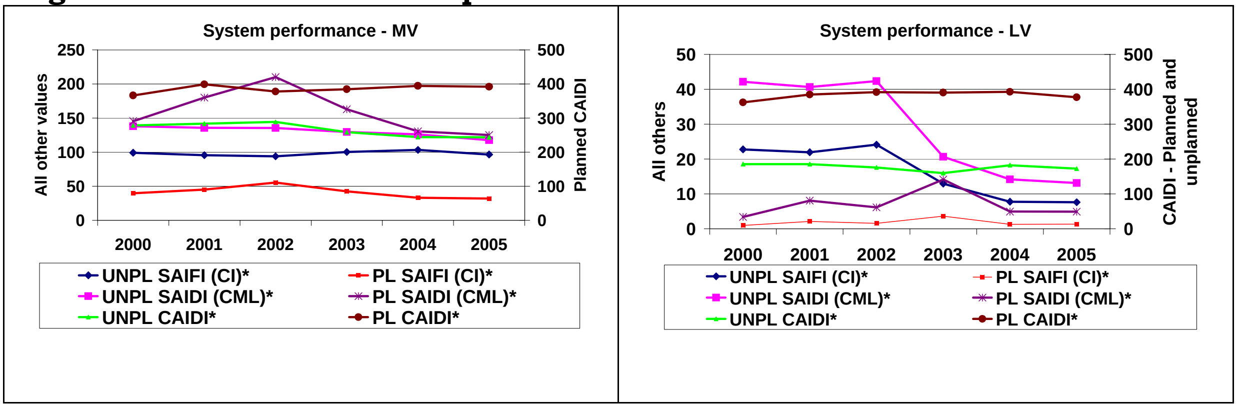
Figure 6.2 Network customer minutes lost

	2001	**2002**	**2003**	**2004**	**2005**
Customer minutes lost (minutes)	371	399	339	289	275

The improvements are also reflected in the system performance figures, especially for MV and LV. These are presented in figure 7.3 below. This shows that:

- All measures have shown improvement. Planned CAIDI has remained stable over time
- The LV network has shown the greater improvement
- The MV network has seen improvement over the past 5 years, especially in the planned storm adjusted SAIDI.

Figure 6.3 Ireland's network performance over time



Legend: UNPL – Unplanned; PL – Planned; * - Storm adjusted

A. CONCLUSION

The DSO's network is performing at an acceptable level when related to other networks and the network's performance has remained stable or downward trending during the last review period.

6.2.2 Distribution losses

ESB Network' transmission and distribution system losses can be seen in relation to energy sales at each voltage level in Figure 6.4. Over the period shown between 1979 and 2003, losses have reduced from around 12% of sales to the current level of around 8%.

Internationally, it is felt that 7.5% to 8.5% is an "optimal" range of losses; however such a statement must be tempered by the acknowledgement that every system has a unique mix of geographic, economic, historic and technical factors that influence the optimum level.

T&D losses as a percentage of energy sent out for the recent period 1997-2003 (Figure 6.5) shows the variability inherent in loss estimation caused by meter reading cycles, absence of bulk metering and general uncertainty.

Overall system losses can be determined as the difference between the net energy generated (sent out) and the total GWh billed in any year. This deficit between net generation and consumption comprises total network and commercial losses.

The total energy inputs in any year are known with reasonably good accuracy. The total generation and net output figures for major generating stations are measured with high accuracy meters, typically 0.2% accuracy, and on a consistent basis. The difference between station generation and net output or "Sent Out" energy corresponds to station use, such as for pumps and other auxiliaries. This internal station use is also known with good accuracy. The station meters can be read on a consistent end of year basis to provide accurate annual generation figures for large generation stations. Recent years however, have seen a significant increase in small scale distributed generation which adds to the complexity of calculating the total generation accurately.

On the other side of the equation are the outputs. This data is much more problematic. In this case there are a very large number of small domestic customers. Metering accuracy for such domestic customers is 2%. It is believed that the average metering error for this class of customers as a whole is close to zero. But it is difficult to verify or be completely confident that this is the case. Any aggregate metering error can change somewhat due to progressive aging of the meter population or changes in the meter renewal programme. Such changes should not have an appreciable impact overall, but even minor aggregate changes will be included in the losses figure.

A more significant issue is that the meters, particularly for domestic customers, cannot be read on a consistent end of year basis. In practice the meters are read at a uniform rate phased, over one month for the larger customers and over two months for the smaller customers, which means that consumption data for the larger customers is on average two weeks in arrears and for the smaller customers one month in arrears. The consumption data overall is therefore about three weeks in arrears in relation to the corresponding generation data. This means that a certain amount of the load growth is lost.

If the meter reading cycles and practice are entirely consistent from one year to the next it is possible to get consistent annual consumption data. However, the situation is complicated by end of year effects. If the beginning and end of year fall on weekends then the meter reading may be reduced somewhat in relation to other years. Also any change in meter reading or data processing practice can impact on the total annual consumption in a year.

The overall result is that it is extremely difficult in practice to get entirely consistent consumption data from one year to the next. There will tend to be a certain amount of random variation arising from changes in practice, year end effects and estimating error. This manifests directly in the total losses figure. Great care can be taken to minimise it, but it is impractical to eliminate it altogether. Fortunately however it tends to be compensating from year to year.

The final challenge in the current Irish context is to divide the network losses into transmission and distribution values. This tends to be done by a calculation of annual losses on the transmission system using the state estimation function of system control, the remainder being distribution losses. In recent years metering with data storage and communications has been installed at the points where the DSO takes energy from the transmission network. This should allow a useful cross-check of the transmission and distribution split.

Figure 6.4 Sales by voltage

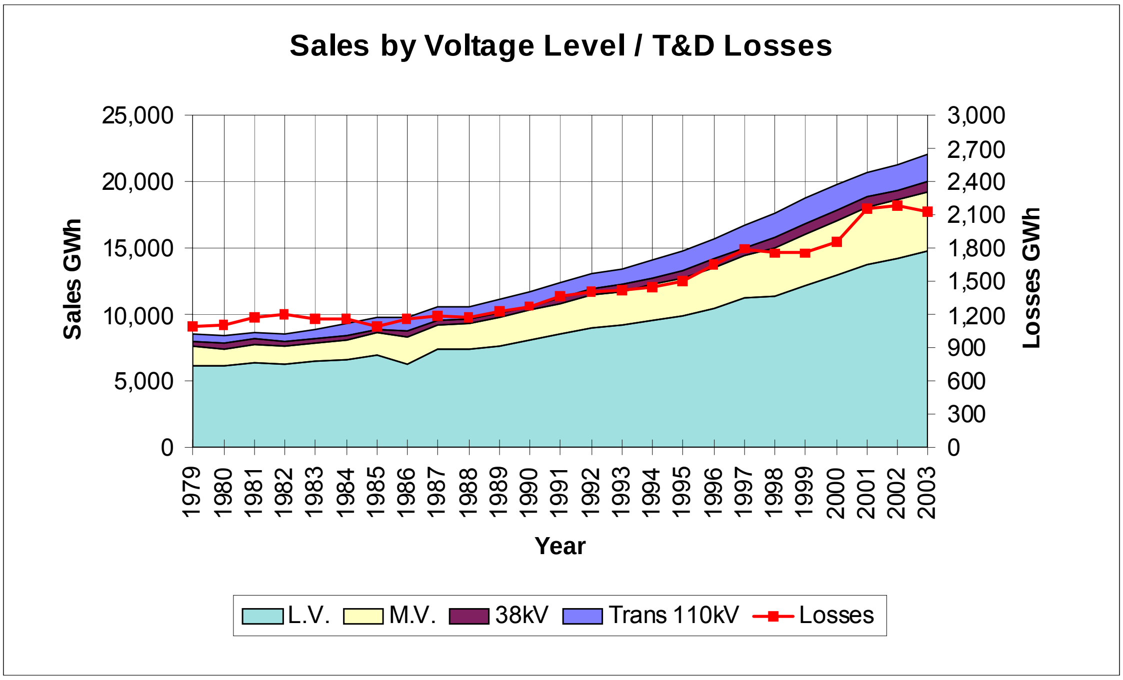
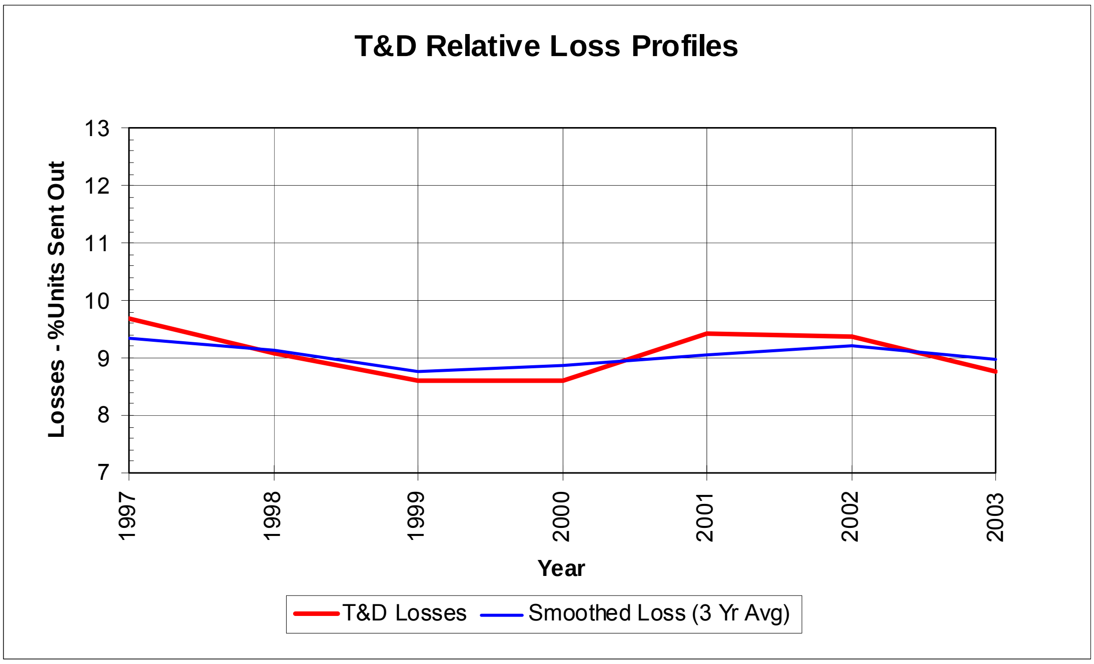


Figure 6.5 T&D losses as a percentage of energy sent out

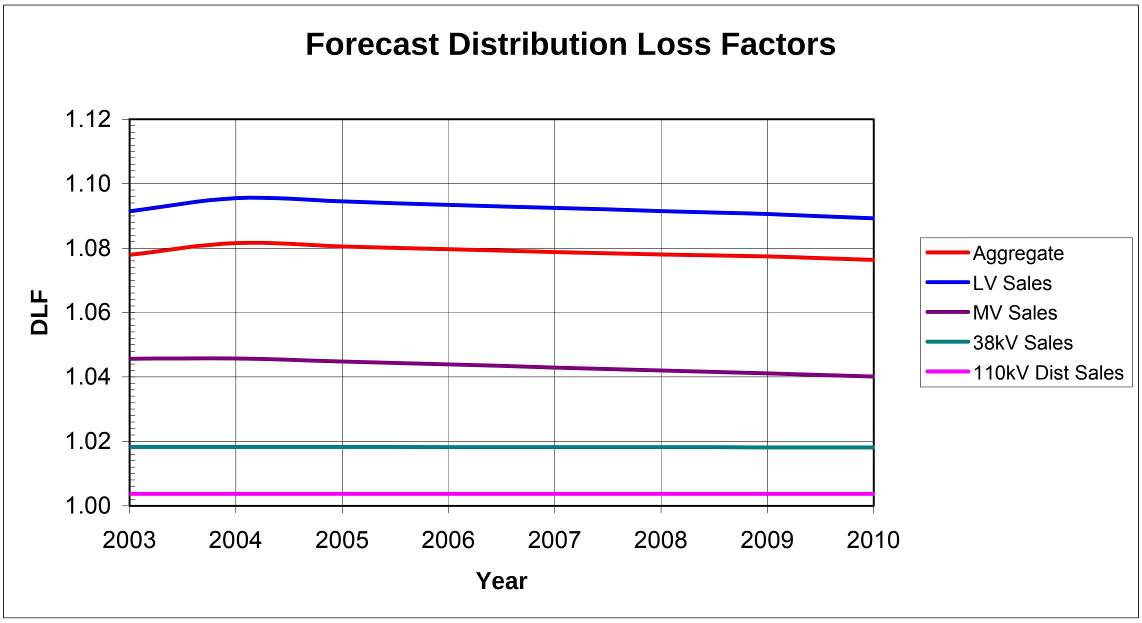


ESB Networks proposes a loss target defined by the average Distribution Loss Factors (DLFs). The Commission considers this to be a reasonable suggestion, particularly as the DLFs are published each year for the coming year. However, as ESB Networks is responsible for their calculation the Commission believes that a better incentive target would be a percentage of energy sent out which would initially be calculated as indicated by ESB in their document "Distribution System Losses" of 25 March 2005 but in the future could be a more direct measurement from the bulk supply metering being installed. ESB's forecast of DLFs is shown in Figure 6.6.

The present estimated calculation of DSO losses as a proportion of energy sent out is 8%. The Commission believes that a reduction to 7.5% during the period 2006-10 should be achievable, even with the cuts in reinforcement and rehabilitation Capex proposed. If the results of the new bulk supply metering show the actual DSO losses to be different, clearly there may need to be an adjustment to the loss targets.

Figure 6.6 DSO Forecast Distribution Loss Factors

Year	2003	2004	2005	2006	2007	2008	2009	2010
Aggregate	1.078	1.082	1.081	1.080	1.079	1.078	1.077	1.076
110kV Dist Sales	1.004	1.004	1.004	1.004	1.004	1.004	1.004	1.004
38kV Sales	1.018	1.018	1.018	1.018	1.018	1.018	1.018	1.018
MV Sales	1.046	1.046	1.045	1.044	1.043	1.042	1.041	1.040
LV Sales	1.091	1.096	1.095	1.093	1.092	1.092	1.091	1.089



By way of comparison, figures 6.7 and 6.8 show the position of UK DNOs with regard to distribution losses and that of international utilities respectively. The latter table should be used with caution as definitions of overall losses may vary between countries and the boundaries between transmission and distribution may also differ. Furthermore, it should be noted that in some countries, losses may be below their optimum level for various reasons.

Figure 6.7 Development of losses in UK networks

Distribution Network	1990/91 (%)	1995/96 (%)	2000/01 (%)
Eastern	7.0	6.9	7.1
East Midlands	6.6	6.1	6.0
London	7.8	6.7	7.3
Manweb	9.8	8.8	9.1
Midlands	6.2	5.5	5.4
Northern	7.5	6.8	6.6
Norweb	7.1	4.8	6.2
Seeboard	7.9	7.1	7.6
Southern	7.1	7.2	7.2
South Wales	8.9	6.7	7.2
South Western	8.6	7.2	7.9
Yorkshire	6.3	6.5	6.6
ScottishPower	8.5	6.7	7.2
Hydro Electric	9.3	8.9	9.1
Average	**7.6**	**6.7**	**7.0**

Figure 6.8 – Transmission and Distribution losses in selected countries

	1980	1990	1999	2000
Country	**(%)**	**(%)**	**(%)**	**(%)**
Finland	6.2	4.8	3.6	3.7
Netherlands	4.7	4.2	4.2	4.2
Belgium	6.5	6.0	5.5	4.8
Germany	5.3	5.2	5.0	5.1
Italy	10.4	7.5	7.1	7.0
Denmark	9.3	8.8	5.9	7.1
United States	10.5	10.5	7.1	7.1
Switzerland	9.1	7.0	7.5	7.4
France	6.9	9.0	8.0	7.8
Austria	7.9	6.9	7.9	7.8
Sweden	9.8	7.6	8.4	9.1
Australia	11.6	8.4	9.2	9.1
United Kingdom	9.2	8.9	9.2	9.4
Portugal	13.3	9.8	10.0	9.4
Norway	9.5	7.1	8.2	9.8
Ireland	12.8	10.9	9.6	9.9
Canada	10.6	8.2	9.2	9.9
Spain	11.1	11.1	11.2	10.6
New Zealand	14.4	13.3	13.1	11.5
Average	**9.5**	**9.1**	**7.5**	**7.5**
European Union	**7.9**	**7.3**	**7.3**	**7.3**

A. CONCLUSION

The Commission believes that a reduction in Distribution Losses to 7.5% during the period 2006-10 is achievable, even with the reductions in reinforcement and rehabilitation Capex from the DSO's proposals. This corresponds closely with the DSO proposal for cutting the aggregate DLF from 1.080 to 1.076 over the period.

The Commission will also investigate whether time of day losses can be incorporated in the overall distribution loss targets. An analysis of the data from the recently installed bulk supply metering will be an important factor in this decision.

6.2.3 Performance against the Customer Charter

The DSO's performance against the Customer Charter shows that the majority of performance levels were not met (figure 6.9). For the period 2006-2010, performance against the Customer Charter will be incorporated into the incentive mechanism. To this end, the DSO will restructure the current customer charter processes which will provide for improved management and audit of defaults when they occur.

Figure 6.9 DSO's performance against customer charter

Measure	DSO's performance	Notes
G1 - Payment made to customers without power for 24hrs after fault notification.	Almost 100%	48 responses outside charter timescale but only 18 payments made.
G2 - 100% with 2 days notice unless agreed otherwise.	2004 - 99.6%; 2003 - 99.6%	6,855 responses outside charter timescale but only 5,379 payments made.
G3 - 100% calls returned within 3hrs if calls were received between 8.30am and 11.00pm.	2004 - 89% ; 2003 - 91%	902 responses outside charter timescales, but only 31 compensation payments made.
G4 - 100% within 3 working days for domestic and 5 working days for business customers.	2004 - 88%; 2003 - 89%	• Domestic/commercial breakdown not available • 556 responses outside charter timescales, but only 17 compensation payments made
G5 - 100% within 7 working days for domestic and 10 working days for business customers.	2004 - 94%; 2003 - 88%	• Domestic/commercial breakdown not available • 2,104 responses outside charter timescales, but only 470 compensation payments made.

Measure	DSO's performance	Notes
G6 - 100% new connections completion within 2 weeks of receiving ETCI Completion Certificate.	2004 - 76%; 2003 – 78%	• The success rate is understated as the system does not take account of situations where housing schemes are initially connected in name of developer which almost inevitably leads to the generation of a default. DSO unable to quantify the impact of this in reducing the figure of 21,897 below. • 21,897 responses outside charter timescales, and 1,767 compensation payments made.
G7 – The voltage Complaint Investigation Guarantee - 100% contact within 10 days for initial investigation, a further 10 days for the investigation results.	2004 - 87%; 2003 - 84%	662 responses outside charter timescales, but only 84 compensation payments made
G8 - 100% resolution of voltage quality problems within 12 weeks.	2004 - 21%; 2003 – 50%	• These figures give an overly negative impression as system does not take account of situations where there is significant network reinforcement required (this situation is excluded from Charter) or where NRP work is imminent - number of payments reflects truer picture • 917 responses outside charter timescales, but only 124 compensation payments made
G9 – The appointment guarantee - 100% of original appointments stuck to.	2004 - 93%; 2003 - 91%	989 responses outside charter timescales, but only 44 compensation payments made
G10 – The refund guarantee – 100% of the refund made within 5 working days of agreeing the amount to be paid	2004 – Average time to resolve – 7 days	1 payment required
G11 – ELCOM Settlement guarantee – 100% of financial settlement arrangements met within 10 working	2004 – Average time to resolve – 7 days	No payments required

Measure	DSO's performance	Notes
days of agreeing the amount to be repaid		
G12 – The payment guarantee - target 100% checks sent within 10 days.	2004 - 73%; 2003 – 69%	• These figures give an overly negative impression as in some situations the system generates NG12 defaults before the original default is visible (NG6 in particular) • 2,156 responses outside charter timescales, 300 compensation payments made

In some cases there may be valid reasons for the differences between the number of responses generated and payments made. Examples of such cases are situations where ESB fail to gain access or the site not ready site for connection e.g. ducts not completed etc. The new processes that will be introduced will ensure that all defaults are validated and a payment made when required. In addition, the DSO will provide a copy of the customer charter when notifying customers of works being carried out in the customer's area, as well as with other correspondence where appropriate.

A. CONCLUSION

The DSO performed poorly against the Customer Charter requirements. The Commission recognises that this was due, in part, to extraordinary levels of new connections to the system which were prioritised. Nevertheless the DSO's performance against the charter is being added to the incentive component of the price control formula for the next price review.

The introduction of the new charter management and audit process will ensure that all customers will receive payments where these are due.

6.3 DETERMINATION OF THE SYSTEM PERFORMANCE

6.3.1 Customer interruptions

Figures 6.10 and 6.11 below show DSO's historic and forecast network performance. As can be seen, the DSO is forecasting continual improvement in all measures, especially in customer minutes lost which is forecast to decease by 27% (74 minutes) by 2010.

Whilst the significant historical investment in the MV network has improved system performance, the Commission was expecting to see system performance improve even further that the DSO has forecast, due to the MV network being a key contributor to customer minutes lost.

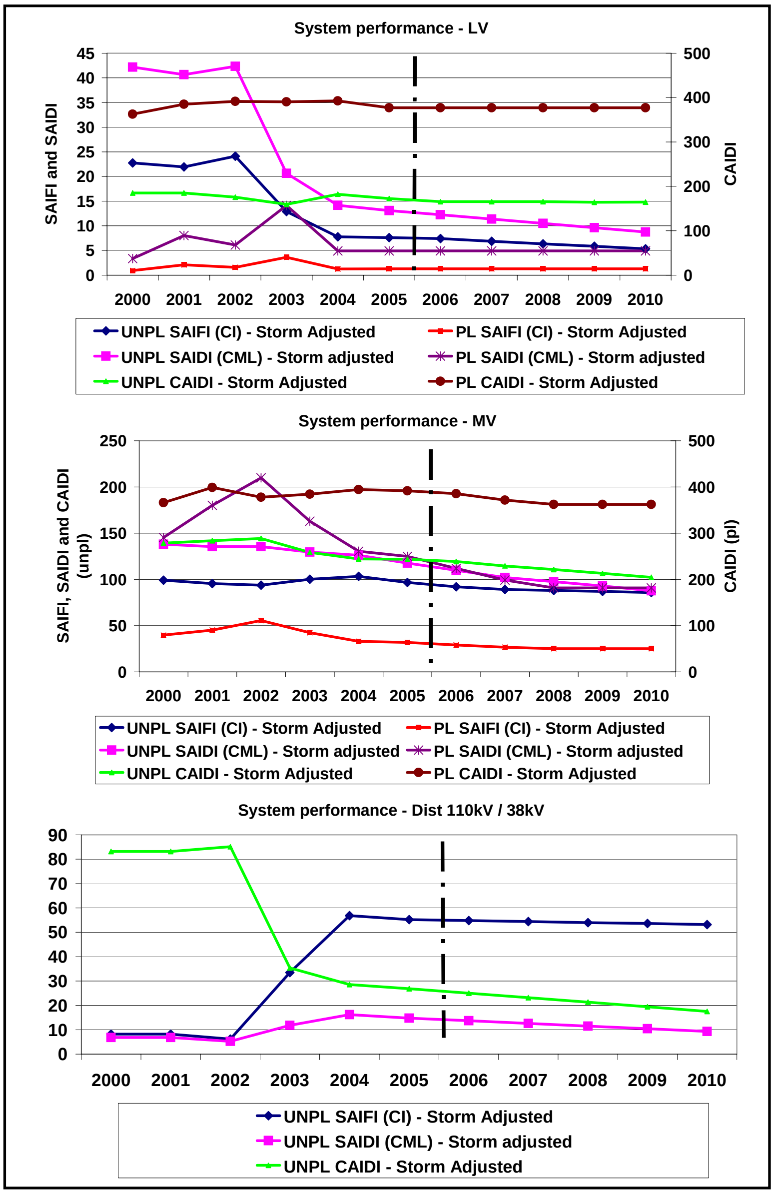


Figure 6.10 Network performance (ESB submitted 2001 – 2010)

Figure 6.11 Network customer minutes lost (ESB submitted 2001 – 2010)

Year	Customer minutes lost (minutes)	Year	Customer minutes lost (minutes)
2001	371	2006	252
2002	399	2007	229
2003	339	2008	214
2004	289	2009	208
2005	275	2010	201

A. DSO'S CUSTOMER MINUTES AND CUSTOMER INTERRUPTION TARGETS VS UK TARGETS

UK DNO's customer minutes lost and customer interruption targets are presented in figure 6.12 and 6.13 below. They show that the DSO's targets remain above these levels, but this is justified by

- Ireland's network performance being acceptable when benchmarked against US companies.
- Ireland's targeted performance levels improving at a greater rate than the UK targets, which should see the gap decrease over the next review period.
- According to the DSO, achieving the DSO's targets would put ESB fault performance on a par with 2004 GB equivalent performance when the benchmark factors are taken into consideration.

Figure 6.12 UK network companies CML targets

Profile of targets for the number of customer minutes lost per customer (CML)

DNO		05/06	06/07	07/08	08/09	09/10
CN	Midlands	101.2	97.7	94.2	90.8	87.3
CN	E Midlands	85.6	81.4	77.2	73.0	68.8
United	Utilities	58.8	56.7	54.6	52.5	50.4
CE	NEDL	70.6	69.0	67.4	65.9	64.3
CE	YEDL	67.4	65.6	63.8	61.9	60.1
WPD	South West	62.1	62.1	62.1	62.1	62.1
WPD	South Wales	71.7	71.7	71.7	71.7	71.7
EDF	LPN	39.5	39.3	39.2	39.1	38.9
EDF	SPN	81.1	76.7	72.4	68.1	63.8
EDF	EPN	77.0	75.2	73.3	71.4	69.6
SP	Distribution	64.7	61.1	57.4	53.8	50.1
SP	Manweb	50.8	48.3	45.8	43.4	40.9
SSE	Hydro	96.7	95.8	95.0	94.1	93.2
SSE	Southern	81.6	79.9	78.3	76.7	75.1
	Average	**72.2**	**70.0**	**67.8**	**65.6**	**63.4**

Figure 6.13 UK network companies customer interruption targets

Profile of targets for the number of customers interrupted per 100 customers(CI)

DNO		05/06	06/07	07/08	08/09	09/10
CN	Midlands	109.1	107.5	106.0	104.4	102.9
CN	E Midlands	80.6	80.0	79.4	78.8	78.2
United	Utilities	56.5	56.5	56.4	56.4	56.4
CE	NEDL	74.7	74.6	74.6	74.5	74.5
CE	YEDL	67.8	67.5	67.2	67.0	66.7
WPD	South West	84.7	84.7	84.7	84.7	84.7
WPD	South Wales	99.0	97.7	96.4	95.1	93.7
EDF	LPN	35.1	35.1	35.1	35.1	35.1
EDF	SPN	89.9	87.9	86.0	84.0	82.1
EDF	EPN	92.9	91.2	89.5	87.8	86.1
SP	Distribution	60.0	60.0	59.9	59.8	59.8
SP	Manweb	45.1	45.1	45.1	45.1	45.1
SSE	Hydro	96.6	96.3	96.0	95.7	95.3
SSE	Southern	90.2	89.3	88.3	87.4	86.5
	Average	**77.2**	**76.5**	**75.8**	**75.0**	**74.3**

B. CONCLUSION

In relation to system performance, the Commission believes that the targets are achievable with the reduced capex spend.

Regarding customer interuptions, the Commission believes that DSO's customer interuption forecasts are achievable; these forecasts have been adopted as target values in the related incentive mechanism in the revenue formula for 2006-2010.

7. CAPITAL EXPENDITURE (CAPEX)

This section examines the DSO's historical and forward looking capital expenditure to determine whether the expenditure is prudent and offers value for money to customers.

The section is set out as follows:

- Objectives for the capex review – how the historic and forecast capex was assessed;
- Historical capex review – a review of the major improvements that were made to the network during the last review;
- Allowances for variations in 2001 to 2005 capex - what the DSO has proposed is included in the 2006 RAB and what the Commission has decided to include;
- Benchmarking DSO's capex – results of benchmarking the DSO's capex against over 40 US comparable distribution companies;
- Determination of the capex allowance – provides the supporting evidence and justification for the Commission's proposed capex; and
- A summary of the capex allowance - comparing the DSO's proposed capex allowance against the approved capex allowance.

7.1 OBJECTIVES FOR THE CAPEX REVIEW

There are a number of objectives to be met when reviewing the DSO's capex, including ensuring that:

- The previous capex has been spent as approved (with the expected benefits to customers);
- Future capex is necessary and justifiable; and
- Network non load related capex is not spent on the "renewal" of the network, an objective that is neither affordable nor economically justified, but rather to ensure the basic adequacy of the network with regard to safety and continuity and wherever possible to enhance voltage levels and reduce losses according to planning standards.

In order to meet these objectives, the following activities were performed:

- Comparing actual against the Commission's approved capex, identifying any under/over expenditure that had occurred;
- Understanding the actual and forecast benefits to the system, and the customer, of the capex incurred;
- Analysis of the DSO's policies and processes that underpin the capex programme;
- Understanding how the allowed capex is linked to the forecast benefits;
- Understanding how the forecast capex was determined; and

- Consideration of numerous items such as maintaining safety standards, improving security of supply and reducing losses.

7.2 HISTORICAL CAPEX REVIEW

The DSO spent €2,661m during the last review period (see figure 7.1 below).

Figure 7.1 – The DSO's capex spend 2001 - 2005

Capex component	2004 Euro ('m)	%
New business	847	32%
Reinforcements	611	23%
Network Non-Load related	1011	38%
Non-Network	192	7%
Total capex	**2,661**	

Significant progress has been made during the period and the Commission recognises the efforts of the DSO in this regard. Before turning to the specific capex components some general comment should be made on the extensive use by the DSO of contractors for a large element of the renewal program carried out in DPR1. The Commission accepts that the Contractor Model introduced by the DSO effectively brings competition to a range of Network activities, as well as allowing the benchmarking of internal costs. This brings a higher degree of assurance on the efficiency of expenditure on defined elements of work than might otherwise be the case and will be kept under review. It also gives added resource flexibility which will be important for future price reviews where significant reductions in capital expenditure may be possible. The DSO also strictly monitors work carried out by contractors to ensure safety standards are adhered to.

It is expected that the contractor model will continue to be used for this review period. The Commission recognises that the customer's best interests are best served by a combination of regulation and the introduction of competition.

The Commission notes that the scope for direct competition in this area is currently limited to a small category of contestable activities. It is recognised that in other countries the impact of direct competition through contestability has been considerable – particularly in the provision of new connections. This issue may need to be considered further in the future.

Below is an overview of the capex components and the major achievements during the last review period.

7.2.1 New business (€847m)

New business consists of the following categories.

- Domestic connections for housing schemes – domestic customers moving into a housing scheme where builders have already completed the necessary ducting, wiring and payments needed for the original connection;

- Domestic connections for non housing schemes - domestic customers requiring a connection to the distribution network for a single house (urban or rural);

- Industrial and Commercial connections – businesses that require to be connected to the distribution network;

- Meters – the cost of the meters used for new connections; and

- Generation connections – connecting new generators to the network.

The key achievements during the last review include:

- Over 371,000 new customer connections will have been made to the Distribution system with an unprecedented 90,600 connections in 2004;

- The units distributed over the Distribution system will have grown by 16% to 21,819 GWh reflecting the continuing strong growth of the Irish economy and the demand for electricity.

7.2.2 Reinforcements (€611m)

Reinforcement is the enhancement of the network to deliver electricity to new customers while avoiding overloading of plant under normal and reasonable contingency operating configurations. It consists of enhancements to the 110kV, 38kV, medium voltage (10/20kV) and low voltage networks.

During the last review period, over half of the reinforcement capex was spent on the 110kV network, 23% on the 38 kV network and 23% on the medium and low voltage networks.

The key achievements during the last review include:

- The capacity margin on the 38kV network is forecast to increase from 8% to 28%; and

- The capacity margin on the 110kV network is forecast to increase from 15% to 40%.

7.2.3 Network Non-load related (€1,011m)

This contains all of the projects that enhance the network but are unrelated to load growth and includes refurbishing substations, transformers and switchgear, the MV and LV renewals programme, the under grounding of cables and pillars and energy management.

The majority of the non-load related capex was spent on the MV (initially LV/MV) renewals programme, which included renewal of approximately half of the networks in the five year period 2001 to 2005. Given increasing concerns relating to the condition of the MV system, in 2002 a proposal was made to CER to prioritise and fast track full completion of the MV renewal by 2005, with the commencement of the LV programme to follow in 2006. In March 2003, CER approved this acceleration of the MV network renewal programme (NRP) on the basis that it had the biggest benefits in terms of reducing public safety risk, improving network resilience to storms and improving continuity of supply for customers.

However, due to cost escalation and the discovery of assets in worse condition than expected, among other factors, the NRP overspent but did not finish the intended scope. Some 16% of the MV network remains to be renewed. The DSO intends to complete this in 2006 and commence the rural LV programme in 2007. An urban LV renewal project is proposed to start in 2006.

The key achievements during the last review include:

- Approximately 40 new HV Distribution Substations will have been added to the network;
- 54,700 km of MV Network will have been refurbished, which together with the 12,300 km refurbished pre-2000, will mean that 84% of the MV Network will have been refurbished;
- The total number of MV faults decreased by 31% between 2000 and 2004;
- 450km of Siemens copper 38kV line will have been replaced;
- 23 Siemens stations will be substantially replaced or retired; and
- Approximately 100 Circuit breakers deemed obsolete in 110kV and 38kV stations will have been replaced.

7.2.4 Non-Network (€192m)

Non-network capex is expenditure that is not directly related to ensuring that the electricity requirement of customers is met. Non-network capex includes the following areas:

- IT systems and infrastructure;
- IT software;
- Telecommunications;
- Vehicles and accommodation; and
- Preparation for Market Opening.

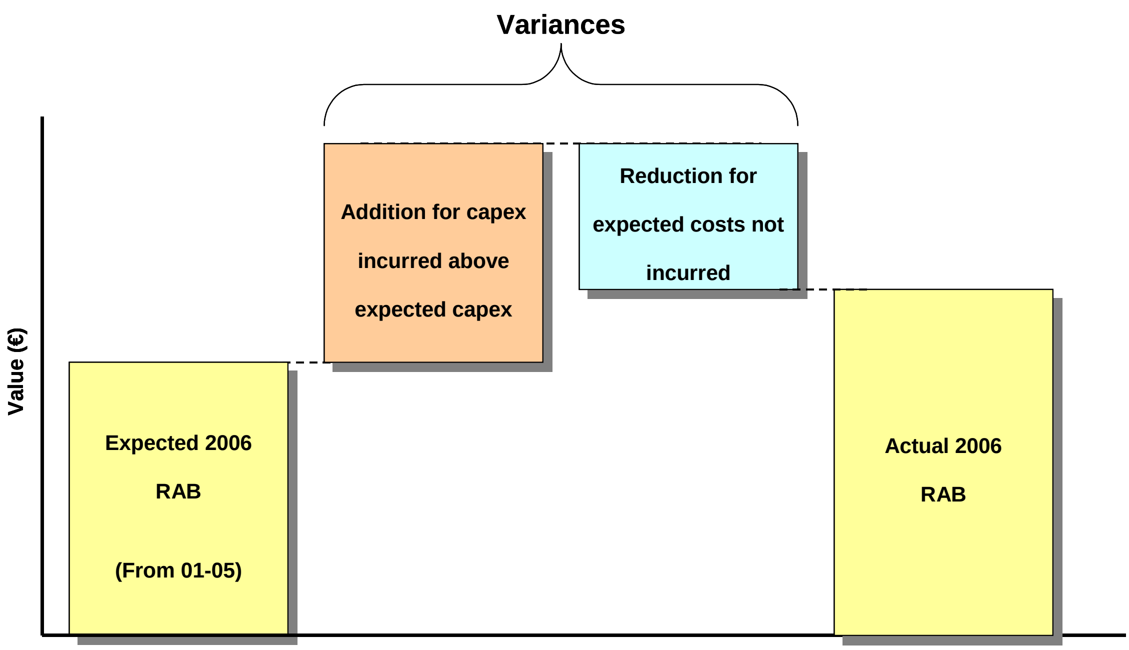
It was recognised at the beginning of the decade that the DSO lacked the support of modern IT business systems and in May 2000 a 'Transform' Programme was approved with a budget of €37m to procure an Integrated Work and Asset Management system to replace the obsolete system implemented in the 1980s. There was some pre-contract expenditure on initiation of the 'Transform' programme. However, to meet the needs of the Market Opening Implementation Programme (MOIP) IS resources were diverted from other developments leading to the postponement of the project.

The major investment in the last year has been for the Market Opening Implementation Programme (MOIP) with a planned expenditure for 2005 of €73m. This includes the provision of SAP-ISU configured to meet market processes and enabling sophisticated communication between suppliers, the MRSO and Networks.

7.3 ALLOWANCES FOR VARIATIONS IN 2001 TO 2005 CAPEX

The DSO's starting RAB for 2006 is based upon the 2001 opening RAB plus all additional allowed Capex over the period 2001-2005. However, the DSO overspent on a number of Capex areas over the period. In addition, further capex due to higher than expected customer connection levels was also incurred. The Commission has therefore considered these overspends, and where expenditure above the allowed levels was justified, this capex has been added to the RAB. However, over the period 2001-2005, the DSO was given additional revenue per connected customer above forecast levels (through the revenue formula); the allowance per customer was based upon the rate of return and depreciation of the capex incurred by the DSO in connecting the customer. This has also been taken into account in the Commission's calculations. Changes are made to the expected RAB based upon: (1) additional capex that has been incurred beyond what was forecast, and (2) anticipated capex that was not incurred. This is illustrated in Figure 7.2 below. The Commission has also disallowed revenues earned by the DSO on approved capex that was not incurred.

Figure 7.2 – Understanding the inclusion of capex variances into the 2006 RAB



This section assesses the variances incurred by the DSO during 2001 to 2005 for their inclusion in the 2006 RAB. The DSO's requested capex variances: (before customer contributions) and the Commission's acceptance / rejection of these are summarised in figure 7.3 below.

Figure 7.3 – Breakdown of the variances included in the 2006 RAB

	€ (m, 2004)		The Commission's acceptance into the 2006 RAB
	DSO proposed	**CER allowed**	
New business			
Higher number of domestic and commercial customers	**71.6**	**71.6**	Accepted
Higher costs for domestic customer connections	**89.1**	**41.9**	Reduced
Higher costs for commercial customer connections	**71.3**	**71.3**	Accepted
Lower overall meter costs	**-19.8**	**-19.8**	Accepted
VSS adjustment:	**-10.0**	**-10.0**	Accepted
Generation connection costs	**19.0**	**12.0**	Reduced
Reinforcements			
Reduction on overall reinforcement capex	**3.4**	**3.4**	Accepted
Network Non load related			
Asset Replacement	**-16.0**	**-16.0**	Accepted
MV Network Renewal (01-05)	**76.9**	**50.0**	Reduced
Other Networks expenditure including quality of supply	**-30.6**	**-30.6**	Accepted
Non network			
Reduction on overall non network capex	**-4.6**	**-6.55**	Reduced
Total	**250.2**	**147.3**	

Additional Customer Contributions			
New Connections	**-71.7**	**-71.7**	
Generation connections	**-12.0**	**-12.0**	
Reinforcement	**-17.3**	**-17.3**	
Asset Replacement	**-3.6**	**-3.6**	
Total	**-104.6**	**-104.6**	

These are explained below.

7.3.1 New Business

A. HIGHER NUMBER OF DOMESTIC AND COMMERCIAL CUSTOMERS

This variance is the result of the number of new connections being larger than expected. The value is based upon the increase in new connections and the Commission approved cost per new customer.

The DSO has requested €71.6m to be added to the RAB, which has been accepted by the Commission. However through the 2001 – 2005 Price Control formulae the DSO was allowed additional revenues of €6.1m for these additional connections. This €6.1m has been subtracted from the 2006 allowed revenue, since revenue will now be earned on the capex allowance of €71.6m over the full lifetime of these assets.

The Commission has allowed the additional €71.6m into the 2006 RAB.

B. HIGHER COSTS FOR DOMESTIC CUSTOMERS

The DSO has requested that €89.1m be added to the 2006 RAB to cover connection costs above the allowed level. In response to this, the Commission has revised it's allowed connection costs for each year over 2001-2005 as follows:

- G1 Domestic scheme housing – An increase of €115 per connection[15] to the allowed cost, which corresponds to 56% of the requested additional capex for G1 connections. This is based upon the 2001 actual cost, which is viewed as representing an efficient economic cost and maintainable throughout the review period.

- G2 Domestic non-scheme housing - An increase of €156 per connection[16] to the allowed cost, which corresponds to 37% of the requested additional capex

[15] 2004 value

[16] 2004 value

for G2 connections. This is based upon the 2004 actual cost, which is viewed as representing an efficient economic cost and maintainable throughout the review period (the 2004 actual connection cost is 12% less than the 2001 cost, during which time the number of new connections had increased by 30%).

Applying the Commission revised allowed connection costs over the period 2001-2005 results in an allowed additional capex of €41.9m.

The Commission has allowed the additional capex of €41.9m into the 2006 RAB.

C. HIGHER COSTS FOR COMMERCIAL CUSTOMERS

There is significant variability in the types and cost of commercial connections that depend on the capacity of the connection, the voltage level and whether the connection is to be metered (e.g. a bus shelter connection costs are significantly less than costs for a large business with a 38kV connection).

Because of the large variability in costs, it is difficult to accurately forecast the number and types of each connection and thus adjustments to the RAB are expected for commercial connections.

The Commission has allowed this additional capex of €71.3m into the 2006 RAB.

D. LOWER OVERALL METER COSTS

The Commission has reduced the 2006 RAB by €19.8m.

E. VOLUNTARY SEVERANCE SCHEME (VSS) ADJUSTMENT:

In the last price review the DSO provided CER with details of its plans for reducing staff numbers under a Voluntary Severance Scheme (VSS). The CER decided that no allowance should be made in respect of VSS payments as the scheme was deemed to be self financing. Payroll expense falls within Opex and Capex. The DSO has proposed to reduce the Payroll element of New Business Capex by €10m which represents the VSS element disallowed in accordance with the Commission's determination of 2001 (CER01/128).

The Commission has reduced the 2006 RAB by €10m.

GENERATION CONNECTION COSTS

In the last price review the Commission allowed Capex of €12m on generator connections; this was to be fully offset by customer contributions, as generators pay 100% of their connection costs. Total Capex for the period was €32m, which was offset by €25m in contributions. The Commission is not allowing the remaining €7m to be added to the RAB. As the DSO over this period issued quotes for each connection job, full costs should have been recovered from the generators; any quoting errors or cost over runs should not therefore result in higher charges for the general DUoS customer. With the introduction of the standard pricing regime, individual quotes will no longer be prepared, so any deviations between actual costs and contributions will be added to the RAB[17].

7.3.2 Reinforcements (€3.4m)

Total DSO expenditure in this area was €3.4m greater than the allowed capex over 2001-2005. The Commission is satisfied that the overspend of €3.4m was efficiently incurred.

The Commission has allowed the additional capex of €3.4m into the 2006 RAB.

7.3.3 Network Non load related

A. ASSET REPLACEMENT (- €16M)

The under expenditure on asset replacement was largely as a result of the re-prioritisation of elements of the asset replacement programme to maximise the overall benefits from Networks capital expenditure in the period 2001 to 2005. Most of the under expenditure on asset replacement was due to the meter and time switch replacement programmes being curtailed because of the level of new connections, the focus on the profile metering programme and re-calibration of pre-payment meters for Euro conversion and tariff changes.

The Commission has reduced the 2006 RAB by €16m.

[17] see CER decision paper CER/05/090

B. MV NETWORK RENEWAL - 01 TO 05 (€-50M)

The DSO's variance is €76.9m is detailed in figure 7.4 below.

Figure 7.4 – Breakdown of the MV Network Renewal 01-05 variance requested to be included in the 2006 RAB

Component	**€ (2004 m)**	**The Commission's acceptance into the 206 RAB**
Allowance for higher unit cost approved by the Commission	41.5	Accepted
Completion of in-progress LV renewal for which there were contractual commitments	3.1	Accepted
Refurbishment to an increased standard of 20kV (rather than the previous 10kV standard)	5.4	Accepted
Resource mix – increased use of contractors	13.8	Rejected
Higher overhead costs	13.1	Rejected
Total	**75.9**	**Reduced to €50m**

The Commission has disallowed the resource mix variance, as the higher cost has already been included in the 'Allowance for higher unit cost approved by the Commission'. The DSO was expected to manage its resource mix so that they remained below the allowed level.

The Commission has disallowed the higher overhead cost variance as the DSO was expected to manage its overheads so that they remained below the allowed level.

The Commission has allowed the additional capex of €50m into the 2006 RAB.

C. *OTHER NETWORKS EXPENDITURE INCLUDING QUALITY OF SUPPLY (- €30.6M)*

The reduction was due to reduced workload as a result of the reprioritisation of projects due to the number of new connections and the accelerated renewal program.

The Commission has reduced the 2006 RAB by €30.6m.

7.3.4 Non network

The breakdown of non network spend is as follows:

Figure 7.5

	€ (2004, m)		The Commission's acceptance into the 2006 RAB
	ESB	**CER**	
Telecommunications	**-3.1**	**-3.1**	Accepted
IT Systems	**5.0**	**3.45**	Reduced
Transport	**-5.5**	**-5.5**	Accepted
Tools	**-11.7**	**-11.7**	Accepted
Premises	**10.3**	**10.3**	Accepted
Furniture/equipment	**0.4**	**0.0**	Rejected
Total	**-4.6**	**-6.55**	

The Commission is allowing €3.45m of the overspend for IT systems. This relates to an overspend included in the analysis of the Market Opening Implementation Project (MOIP), which has been allowed following a review of this expenditure.

The Commission has decided to allow the over expenditure for the 'Premises' component, since this expenditure was incurred as part of an effort to centralise certain functions in order to drive efficiencies. This expenditure has enabled savings to be made on expenditure on other items such as transport and tools.

The Commission is not allowing the overspend on furniture as this cost should have been controlled by the DSO.

The Commission is proposing to reduce the 2006 RAB by €6.55.

7.3.5 Additional Customer Contributions

The Commission approved addition to the RAB will be offset by additional customer contributions, above forecast levels, received by the DSO over the period 2001-2005. These are outlined below:

A. HIGHER NUMBER OF DOMESTIC AND COMMERCIAL CUSTOMERS

Additional customer contributions over the period 2001-2005, which were above forecast levels, will reduce the overall allowed additional capex being added to the RAB.

This results in the 2006 RAB being reduced by €71.7m for additional customer contributions.

B. GENERATION CONNECTIONS

Additional customer contributions over the period 2001-2005, which were above forecast levels, will reduce the overall allowed additional capex being added to the RAB.

This results in the 2006 RAB not being changed for generation connections, as the CER approved overspend of €12.0m is fully offset by the €12.0m from additional customer contributions.

C. REINFORCEMENT

Additional customer contributions over the period 2001-2005 were €17.3m above forecast levels. As stated above, total DSO expenditure in this area was €3.4m greater than the allowed capex over 2001-2005. The expenditure has been added to the RAB. The additional customer contributions of €17.3m will however be removed from the RAB.

This results in the 2006 RAB being reduced by €17.3m due to customer contributions for reinforcement.

D. ASSET REPLACEMENT

Additional customer contributions over the period 2001-2005 were €3.6m above forecast levels.

This results in the 2006 RAB being decreased by €3.6m.

7.3.6 Conclusion

The Commission has allowed additional capex of €168.05m into the 2006 RAB (before customer contributions). This represents a 33% reduction on the DSO proposed increase of €250.2m.

After additional customer contributions have been taken into account, the 2006 RAB increased is €63.45m (€168.05m – €104.6m).

7.4 BENCHMARKING THE DSO'S CAPEX

In section 6, the DSO's network performance (SAIDI / CAIDI / SAIFI) was benchmarked against the system performance of over 40 US companies. The results showed that the DSO's network has performed at an acceptable level when related to these companies.

This section uses the same US companies to assess the DSO's capital expenditure. The following capex measures were benchmarked:

- Domestic connections
- Industrial and Commercial connections
- Generation connections

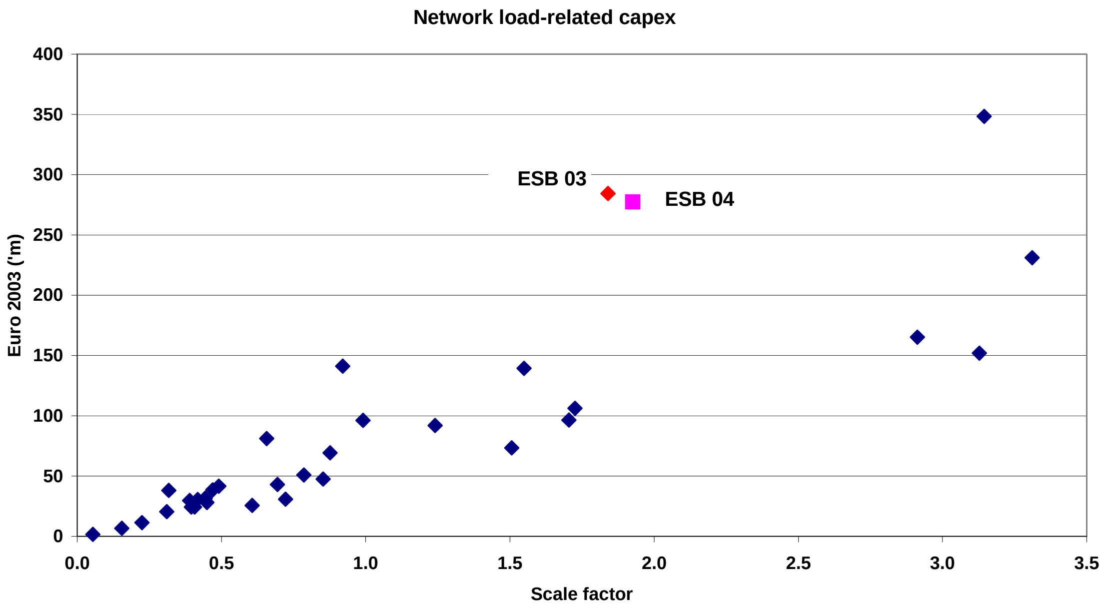
- Meters
- Reinforcement

Regarding the benchmarking of the DSO's load related capex:

- This high level measure was used to ensure that variations between the DSO's and the US companies load-related capex due to different capex classifications was minimised.
- No direct relationship has been made as the Commission recognises that load-related capex is influenced by factors that are outside the DSO's control.

The results are shown in figure 7.6 below and indicate that the DSO's load-related capex is higher than the majority of the companies benchmarked reflecting the high level of investment required to meet load growth.

Figure 7.6 – Benchmarking data – 2003 and 2004 Network load related capex



7.5 DETERMINATION OF THE CAPEX ALLOWANCE

The DSO proposed and Commission final allowed capex is summarised in figure 7.7 below:

Figure 7.7 – The DSO proposed and Commission allowed 2006 – 2010 capex

	€ (2004, m)			
Capex component	**DSO**	**CER**	**Reduction**	
New business	908	854	54	6%
Reinforcements	618	530	88	14%
Network non-load related	981	755	226	23%
Non-Network	154	139	15	10%
Total capex	**2,661**	**2,278**	**383**	**14.4%**

This section provides an overview of DSO's capex submission and reviews each capex component to explain the reasoning behind the Commission approved capex.

7.5.1 New business capex

Based upon an analysis of DSO's new business capex, the Commission's allowed new business capex (all in 2004 Euro 'm) is outlined in figure 7.8 below:

Figure 7.8 – Summary of the allowed new business capex

	€ (2004, m)			
	DSO	**CER**	**Difference**	
Domestic Connections	456	430	26	-6%
Commercial Connections	244	230	14	-6%
New meters	38	23	15	-40%
Generation connections	170	170	0	0%
Total new business capex	**908**	**854**	**64**	**-7%**
Customer contributions (domestic, commercial)	-603	-342	-261	+43%
Customer contributions (generation)	-170	-170		
Total new business capex (net of customer contributions)	**135**	**342**	**-207**	**+53%**

These conclusions are explained below.

A. DOMESTIC AND COMMERCIAL CONNECTIONS)

Domestic and commercial connections consists of the following:

- G1 Domestic scheme housing
- G2 Domestic non-scheme housing
- G3 - Industrial and Commercial

The following observations are made for DSO's proposed new business capex for domestic and commercial customers:

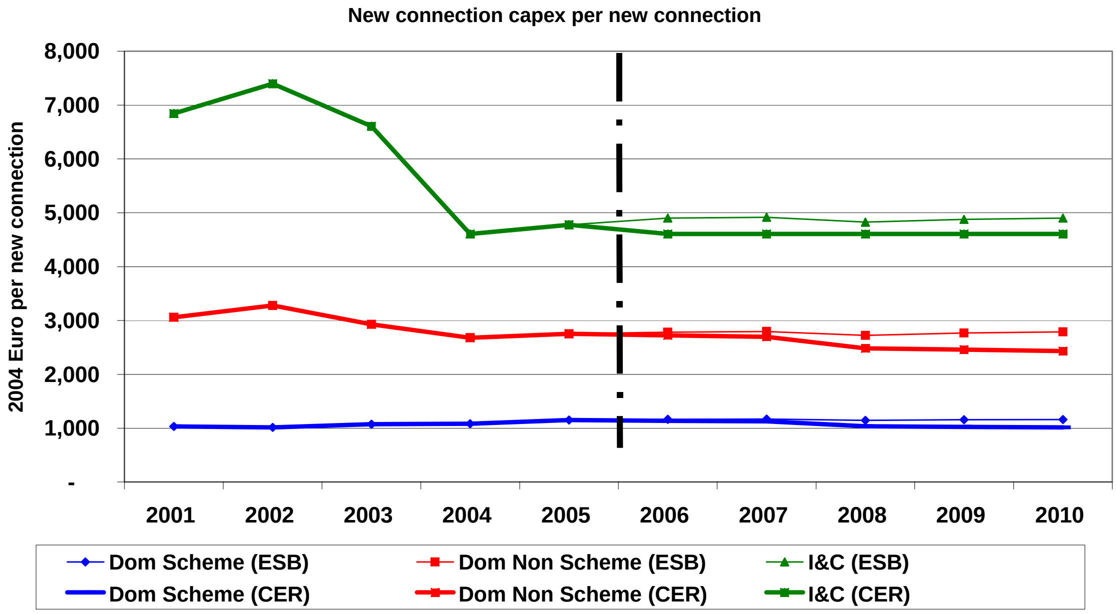
- Benchmarking has shown that DSO's load related capex (which includes new connections) is above average.

- For domestic non-scheme housing connections, there is a historical downward trend over 2001-2005 on a per new connection basis yet the DSO is forecasting an upward trend for 2006-10.
- The DSO is forecasting a continual upward trend for domestic scheme housing connections.

The Commission believes that the new connection capex on a 'per new connection' basis should improve over time. Thus the Commission has based its allowed new business capex on the following (these are also illustrated in figure 7.9 below):

- Domestic scheme housing and domestic non-scheme housing – The 2006 cost per new customer being the 2005 value with a 1% general productivity improvement. Future costs incorporate the following savings
- 1% per year from 2007-2010 due to general productivity improvement
    - 7% on the labour element of the costs from 2008 due to efficiency improvements resulting from the Mobile Workforce Management
- G3 - Industrial and Commercial – The Commission accepts that it is difficult to forecast industrial and commercial connection costs due to the variability of connection types (and associated costs). The Commission therefore is setting the initial allowed capex at the 2004 level and will allow changes on a case-by-case basis.

Figure 7.9 – New connection capex per new customer 2001 – 2010 ESB submitted and CER approved



The result of using the Commission's new connection capex per new connection is a reduced capex of €660m, which is a 6% reduction on the DSO's proposed capex.

Customer Contributions

Capex on new business is entered into the RAB, less customer contributions. Connection charges are designed to recover a % of connection and metering costs from the customer. The 2001 determination[18] stated that the DSO was to increase the rate of customer contributions to new connection costs (through connection charges) from 41% to 50% over the period 2001-2010, with the rate for 2006 to be at 46%.

The Commission has decided that a contribution rate of 50% be achieved in 2006, remaining at this level for the entire period 2006-2010.

The level of connection charges published by the DSO will be consistent with the allowed revenues and unit prices as set out above. The DSO will need to demonstrate this consistency to the Commission for approval of those charges.

[18] Determination of Distribution Allowed Revenues CER 01/128

B. NEW METERS

The Commission has benchmarked the DSO's meter costs against costs in the UK[19]. The results are presented in figure 7.10 below.

Figure 7.10 – Comparison of meter costs

Meters	**ESB (2004)**	**UK (2004)**	**% Reduction[20]**
LV single phase credit simple	€111	€43	62%
LV single phase credit multi-rate, timer	€185	€71	62%
LV three phase credit simple	€174	€85	51%
LV three phase credit multi-rate, timer	€264	€114	57%
LV three phase PPM multifunction CT	€1,283	€170	87%

As can be seen the DSO's meter costs are significantly above the UK costs with no reasonable explanation for the variance. The electromechanical meters currently used by the DSO have a lifetime of about 30 years, compared to 10 years for UK meters (although it should be noted than the expected lifetimes for electronic meters are increasing). While this reduces the cost difference on a per annum basis, recent changes in metering technology would indicate that it is not prudent to buy into electromechanical meter technology for the next thirty years. In coming years there may be a need for more advanced metering than offered by electromechanical meters.

The DSO is to undertake a comprehensive review of metering policy in 2006, and will make proposals around future metering policy to the Commission based on this review. While the Commission has reduced the allowed new meter costs to align the DSO's meter costs with costs from the UK, the reduction in 2006 has been lessened in order for the review to be carried out. However the total reduction has not been changed. The reductions from the DSO proposals are as follows:

- 2006 and 2007 – 20% and 30% respectively
- 2008 to 2010 – 50%

[19] Ofgem DCPR4

[20] % reduction in ESB's costs required to match the UK costs

The introduction of a new prepayment system is scheduled to take place during this price review. To this end, a pilot project is to commence at the end of 2005. The costs associated with this pilot project and the wider rollout of prepayment meters will be subject to a separate review. Any allowances for prepayment meters will take account of metering capex already allowed.

This results in an allowed new meters capex of €23m, which is a 40% reduction on the DSO's proposed capex. Costs associated with the introduction of prepayment meters will be subject to a separate decision.

C. GENERATION CONNECTIONS

Connection charges for generators connecting to the distribution system are designed to recover 100% of the connection costs, meaning that no additions should be made to the RAB due to capex spent on generator connections (as they are fully paid for by the customer). A system of standard pricing for renewable generators was introduced in 2005[21]. Under this system, if over a period of time these charges over or under recover compared to the actual connection costs, the difference will be added to or subtracted from the RAB, provided the costs are efficiently incurred.

D. CONCLUSION

The Commission has allowed a new business capex of €844m (2004), which represents a 7% reduction on the DSO's capex.

7.5.2 Reinforcement capex

The allowed reinforcement capex allowance is presented in figure 7.11 below:

Figure 7.11 –2006 – 2010 reinforcement capex

	€ (2004, m)			
	ESB	**CER**	**Reduction**	
Reinforcements	618	530	88	14%

The 14% reduction is a result of the economic and technical analysis of the DSO's reinforcement capex.

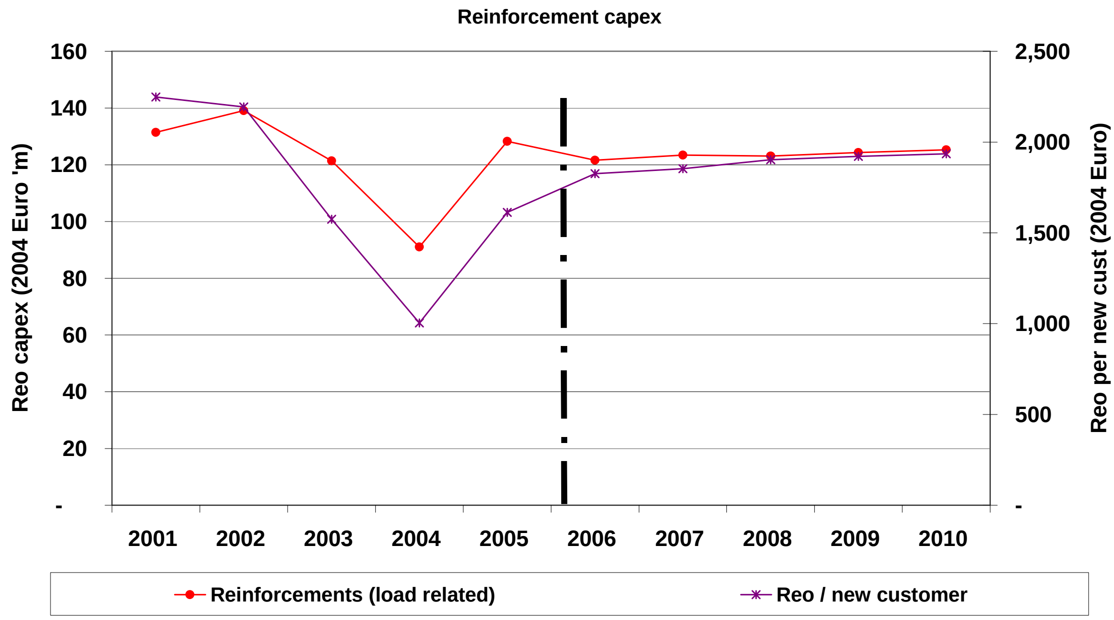
A. ECONOMIC ANALYSIS

The following observations are made for DSO's proposed reinforcement capex:

- Benchmarking has shown that DSO's load related capex (which includes reinforcement) is significantly above industry norms
- The DSO is forecasting an upward trend both in overall reinforcement capex and in reinforcement capex per new customer (Figure 7.12 below)

[21] See CER decision paper on "Standard Pricing for Renewable Generators" CER 05/090

Figure 7.12 – Reinforcement capex 2001 – 2010 submitted by the DSO



B. TECHNICAL ANALYSIS

The technical analysis involved the review of the Dublin City Plan (DCP) 2004-2013 and the Country Network Investment Plan 2004-2010 (CNIP). See Appendix F for further details.

The conclusions from the technical analysis are as follows:

- The UK and Irish planning standards appear similar in scope, and the CER disagrees with the DSO's perception that they are working to a lower standard. The DSO contends that transformer loading standards are however tighter in Ireland, but when the specification of the transformers is consistent with the loading standard, similar levels of economy are achieved. The application of the DSO standards should consequently be more flexible and economic.

- The justification for the projects was examined and several were found to be able to be deferred (the need for the project is real but the justification relates to exaggerated contingencies, thus the project could be deferred by 2 to 3 years without affecting quality and continuity of supply) or cancelled (the justification is invalid or has been overtaken by events and the project is no longer needed).

- A review of the plans for 110kV/MV substations indicated total costs in the range of €3M to €10M, all for a design with two 20MVA transformers. While variability of costs between sites is to be expected, there is concern that the more expensive stations could be made less costly through prudent design.

- The expenditure of large sums to deal with low probability events will tend not to be economically optimal and that the consideration of such High Impact Low Probability issues should be in the context of general disaster planning coupled with modest capital costs to provide the necessary system flexibility.

- DSO overheads are understood to be less than 10% of prime cost.

C. CONCLUSION

The Commission believes that the DSO can reduce their reinforcement capex by 14% to a Commission approved level of €530m:

- 9% - Prudent and economically appropriate application of the planning standards – deferring projects with marginal customer benefits and cancelling unnecessary projects.

- 5% - Cost savings brought about by in-house efficiencies and tight procurement of contracting services.

Also, additional expenditure not directly caused by greater than expected load growth and any capex not prudent and economically justified will not be allowed to enter the RAB.

7.5.3 Network non-load related capex

The allowed network non-load related capex is presented in figure 7.13 below:

Figure 7.13 –2006 – 2010 network non-load related capex

	2004 Euro ('m)			
	ESB	**CER**	**Reduction**	
Renew Prog - Rural LV Network	275	199	76	29%
Response capex	169	125	44	26%
Renew Prog – HV Substation	79	79	0	0%
Renew Prog – MV Overhead Lines	181	111	70	39%

	2004 Euro ('m)			
	ESB	CER	Reduction	
Renew Prog - 110 & 38kV Cables	45	45	0	0%
Renew Prog - Urban LV Renewal	83	58	25	30%
Renew Prog – MV Substations	37	37	0	0%
Renew Prog - 110kV & 38kV Lines	33	33	0	0%
Renew Prog – LV cables and associated items	20	20	0	0%
Renew Prog - Meters and Time-switches	25	15	10	40%
Continuity Improvement	17	17	0	0%
Renew Prog - Cutouts	9	9	0	0%
Trial	5	5	0	0%
Renew Prog – MV Cables	2	2	0	0%
Total non load related capex	**981**	**755**	**226**	**23%**

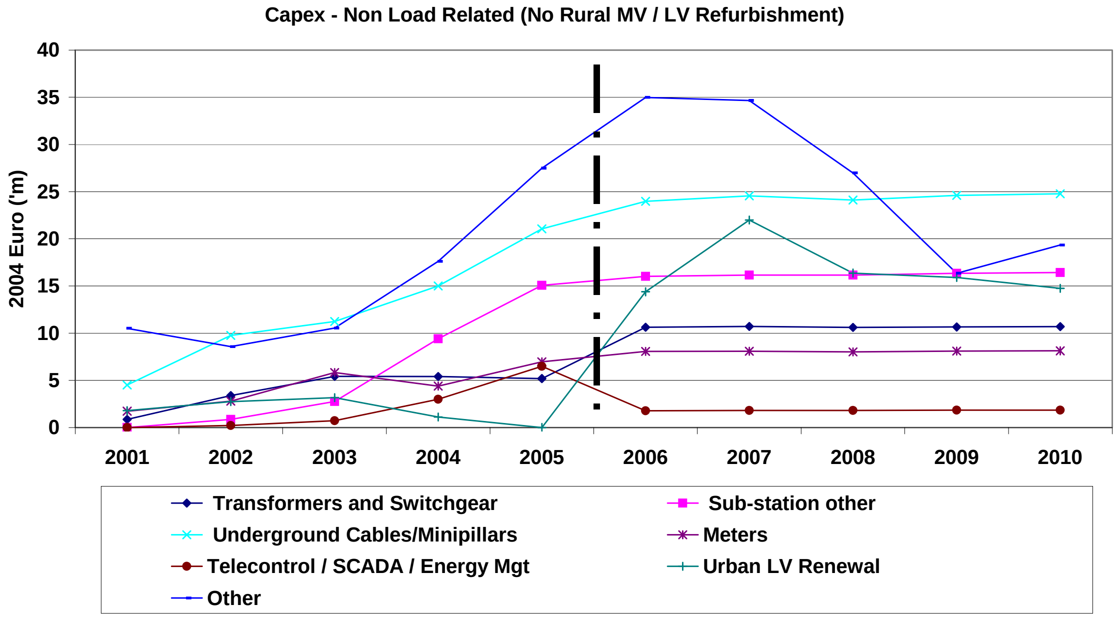
The reductions are the result of the economic and technical analysis of the DSO's network non-load related capex outlined below.

A. ECONOMIC ANALYSIS

The following observations are made for DSO's proposed non load capex:

- The significant investment in the MV network has seen improvement in network performance, yet the DSO target MV performance figures appear conservative.
- It is questionable as to whether all of the proposed significant investment in the LV network is required, as it is not forecast to significantly improve network performance.
- The majority of DSO's non network capex categories (excluding the renewals program) show significant historical increases which the DSO are expected to be maintained at these high levels in the future (see figure 7.14 below).

Figure 7.14 – non load related capex (excluding the renewal program) 2001 – 2010 submitted by the DSO



B. TECHNICAL ANALYSIS

The Commission considered the breakdown of non-load related Capex provided by the DSO, along with the report and presentation entitled Distribution Network Maintenance & Renewal Programme 2006-2010[22], which provides a detailed and comprehensive description of the refurbishment and remedial works planned by ESB[23]. The distribution site visits also gave the technical study team the opportunity to see first hand the results of NRP1 and the rationale for NRP2. These have formed the basis of the key categories outlined below.

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[22] Distribution Network Maintenance & Renewal Programme 2006-2010, submitted to CER 7 April 2005 as part of the DPR2 process.

i. Renewal programme - LV Rural (DSO €275M, the Commission €199M)

The DSO has estimated that at the end of 2004 there were some 181,700 LV groups[24] supplying rural customers. In the first phase of the NRP programme (1996 – 2002) approximately 16% of the groups were renewed, of the remaining little or no maintenance work has been undertaken for at least a decade. It is recognised that the remainder of the groups are generally in a fair to poor condition, the main issues being pole rot, conductor corrosion, earth wire corrosion and reduced ground clearance.

Whilst a number of groups may have been upgraded as additional customers are added to the network there remains a significant number of groups where consumer demand has grown and networks do not meet current criteria in terms of voltage and fault level, the DSO proposes to replace any 3 or 5 kVA transformers and build new MV extensions to split LV groups where there are high usage customers at distances over 250m from existing transformers.

A report produced by EA Technology on behalf of the DSO[25] looked at maintenance condition assessment procedures and includes a view of various asset conditions. However, it does not base its comments on first hand inspection, but infers its condition profile from "non-specific, general knowledge and experience" and does not therefore provide justification for the condition-based replacement of rural LV overhead lines.

The DSO proposal is to renew 42% of the groups over the 5-year period 2006-2011. This is an ambitious plan expected to cost some €275M. This equates to 71,400 groups over 5 years or 300 groups/week.

The Commission allows €199M of capital expenditure but expects the DSO to use its best endeavours to limit unnecessary replacement and focus expenditure directly on assets requiring immediate attention and thereby cover the maximum possible proportion of the LV rural asset base. Electrical improvements as originally proposed by the DSO should be able to be funded through the savings made.

The Commission intends to review carefully the execution of this programme and only allow the expenditure efficiently incurred to enter the RAB.

ii. Response capex (DSO €169M, the Commission €125M)

Response CAPEX is capital expenditure initiated by events or external parties. This classification of CAPEX covers:

- Resolution of Voltage complaints (€63M)
- Undergrounding of overhead lines to facilitate development (€37M for MV, €8M for HV and €7M for LV)

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[24] An LV Group is the low voltage network emanating from a distribution transformer that supplies from 1 to 10 domestic consumers.

[25] EA Technology Report: "ESB Distribution Network Asset Condition" No. 5750, July 2004

- Replacement of plant damaged by faults (€16M)
- Metering – Replacement of meters and timeswitches (€16M)
- Other response capex including that required due to vandalism, corrosion, cable fault remedial work and installing ducts during general road works for future cable installation (€22M)

The resolution of voltage complaints is key to improving the LV network in a targeted manner as the consumers are effectively identifying the problem areas for the DSO. Wherever possible, customers whose increased consumption has caused the problem should be charged a customer contribution (DSO is already changing the content of its standard agreement so as to define normal and high consumption to this end).

Undergrounding of lines tends to be expensive, but allows access for development, enhances visual amenity, improves continuity and reduces maintenance costs. The DSO will recover a portion of these costs from customers and local authorities who gain from this work. Past cooperation between ESB and councils has been excellent in this regard and should be encouraged in the future.

The metering capex needs to be reduced in the light of the high relative costs of meters indicated by DSO. The rest of the response capex is allowed as proposed by the DSO, provided the expenditure is efficiently and prudently undertaken.

The Commission recognises that this area of expenditure can be difficult to forecast and has revised its earlier view on an appropriate expenditure; allowed response capex for 2006-2010 is set at €125m. The Commission accepts the principle that response capex efficiently incurred net of charges levied ultimately should be recovered by the DSO. Any over or under forecasting of this area of expenditure will be adjusted at the beginning of the next price control period.

iii. Renewal programme – HV Substations (DSO €79M, the Commission €79M)

Of the original 63 Siemens 38kV Substations, 29 have been retired from service in the first price control period. The aim is to have all of the remaining stations retired or replaced by the end of 2010. Seven of the remaining stations are included in this plan. The others are included the Network Reinforcement plan.

There are a substantial number of old circuit breakers and protection relays, which are not as reliable as new equipment. At the 110kV and 38kV levels protection does not operate as it should for approximately 15% of faults and this generally means that more customers are interrupted than should be. There are also some shortcomings in the functionality of protection. The plan includes the upgrading of 50% of the old electromechanical relays and replacing outdoor circuit breakers more than 40 years old and 50% of indoor circuit breakers more than 50 years old.

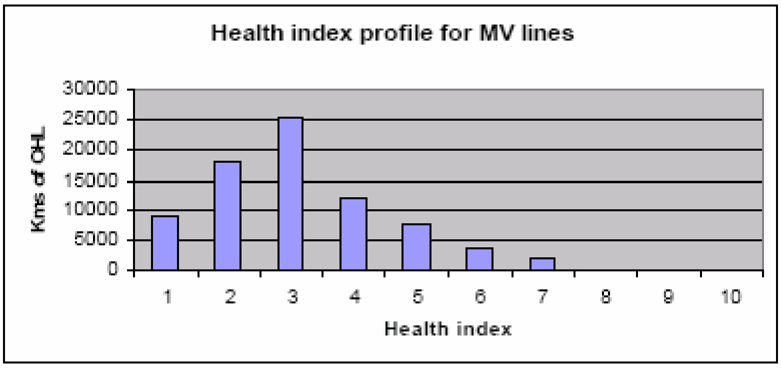
The majority of substations have chain-link fences. As development takes place in the environs of substation there is a need to upgrade to palisade fencing. There is also a need to implement oil containment measures to eliminate the risk of a major oil leak contaminating ground water.

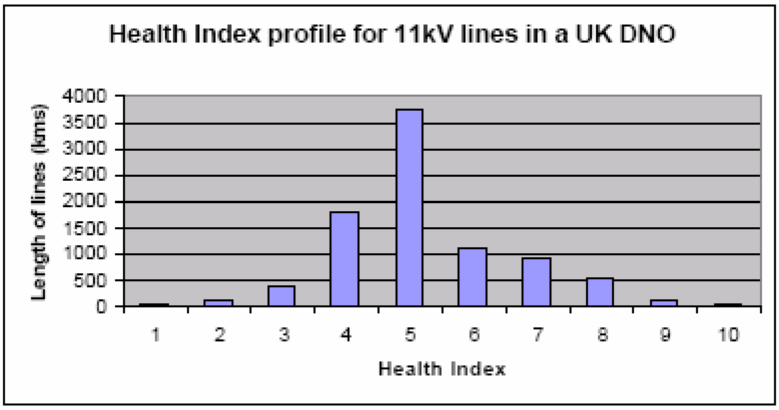
The Commission, subject to efficient implementation, has allowed this capex.

iv. Renewal programme – MV Overhead lines (DSO €181M, the Commission €111M)

The DSO is planning to complete the major refurbishment and upgrading programme on MV overhead networks by end of 2006. It will be ten years since the programme commenced and the refurbishment standards applicable to the lines done early in the programme are not as rigorous as the current ones. The continuity performance of some lines refurbished early on in the programme is not as good as those done more recently. It is planned to upgrade 50% of those lines to the same refurbishment standard as the later lines.

The EA Technology Report on ESB Network Condition does not recommend significant additional refurbishment to this asset class and states that the ESB asset condition spread is considerably better than in a typical UK DNO. The following graphs[26] show the EA "Health Index Profile" for ESB and a typical UK DNO. EA state that assets with an index greater than 6 "indicate assets in increasing (sic) poor condition with a sharply rising probability of failure". This would apply to 3% of the DSO's lines, but to over 20% of a normal asset base. This reflects the significant capex invested in ESB Networks' system.





The two elements the DSO proposes here are the completion of the MV Overhead Renewal Programme (€130M) and the upgrading of pre-2003 20kV lines to the

[26] The DSO graph shows the state of the MV network after completion of the full investment programme proposed by DSO.

current NRP standard (€46M). This is after nearly €1bn has been spent on NRP1, mainly on MV overhead line renewal.

The completion of NRP1 (MV Overhead Renewal) should be reduced to €111M as the remaining lengths can be addressed on a hazard or as-necessary basis. This reduction is on the basis that the DSO can make at least some savings through focussing on tight condition-based asset renewal. The need for re-renewing the 20kV lines renewed before 2003 shows shortcomings in DSO investment decisions and is disallowed.

The Commission believes that this programme is not justified in its entirety and has allowed a capex of €111m.

v. *Renewal programme* – 110kV & 38kV Cables *(DSO €45M, the Commission €45M)*

The DSO has identified substantial need for the replacement of a selection of high voltage cables and this is considered reasonable for environmental, safety and security reasons.

The Commission has approved this capex, subject to efficient implementation and prudent management of capacities.

vi. *Renewal programme* – Urban LV Renewal *(DSO €83M, the Commission €58M)*

The LV urban overhead network is roughly one-tenth the size of the rural network. However, about 50% of the network predates the rural network. According to the DSO, the condition of this old network is very poor with approximately 40% of the poles needing to be replaced due to rot. The cost of pole replacement is much greater than for rural networks because of the greater ground excavation and reinstatement costs, traffic management etc. Also the work at pole-top involves more conductors.

The EA Report concludes (on the basis of information from the DSO) that the urban LV overhead network is in poor condition. Site visits undertaken by CER Consultants confirmed some problem areas in Dublin, Limerick and Waterford, but many of these were being tackled on a hazard basis under general repairs and the overall asset condition was not felt to constitute a crisis.

The proposed refurbishment of 40,000 spans of LV overhead lines is not entirely justified and only 70% of the €83.4M submission is being allowed.

The Commission recommends that the overhead lines to be renewed should be carefully selected on a hazard and condition basis to ensure that the majority of the expected benefit of the complete programme is realised within the reduced budget.

vii. *Renewal programme* – MV Substations *(DSO €37M, the Commission €37M)*

MV substations are often operated by technicians located on-site. It is vital that they are in good working order. It is planned to replace remaining outdoor oil filled switches as these will represent too great a safety risk. The DSO has developed new maintenance condition assessment procedures with the help of consultants EA Technology. Any decision to overhaul the large population of cast resin switchgear will be based on these new condition assessment techniques. Much of this switchgear is in outdoor metal-enclosed package substations. In the damp and dusty environment it is subject to tracking and eventual breakdown often causing an explosion and fire. The new procedures will identify the units affected and the requirement for overhaul.

The Commission has approved this capex, provided it is efficiently undertaken, based on genuine safety concerns supported by condition monitoring.

viii. *Renewal programme – 110kV & 38kV Overhead Lines (DSO €33M, the Commission €33M)*

Many of the original 1930s Siemens-type lines are in poor condition. A programme is underway to rebuild 450km of line by the end of 2005 and it is proposed to rebuild a further 500km in the 2006-2010 period, which represents approximately 25% of the population. Inspection and remedial work will be carried out on a much of the remaining lines. This work should be allowed for safety and continuity reasons.

The Commission has approved this capex.

ix. *Renewal programme – LV cables and associated items (DSO €20M, the Commission €20M)*

There is a particular very old (pre-ESB) underground cable system in Dublin, which is very fault-prone. It represents roughly 1% of the network. It is planned to start a programme of replacement and complete 25% within the period 2006-2010. There have been incidents where children have received shocks by inserting objects into old or damaged minipillars. A policy of inspection of minipillars has been initiated and it is planned to continue this into the 2006 - 2010 period. There will be a requirement to replace a small proportion of minipillars arising from these inspections.

The Commission has approved this capex.

x. *Renewal programme – Meters and Time-switches (DSO €25M, the Commission €15M)*

Cost savings should be achievable in procurement of meters and the used of combined electronic meters with integrated timers for dual tariff use. See section 8.5.2B for further information.

The Commission has approved a capex of €15m.

xi. *Continuity Improvement (DSO €17M, the Commission €17M)*

The DSO is proposing a number of initiatives to improve continuity:

- For HV Stations/Lines, the DSO plan to replace a type of 20kV recloser (€2M);
- For MV overhead lines they propose to install remotely controllable reclosers and triple pole switches, a plan that they had for 2001-05 but failed to

implement due to NRP1 (€10.5M), install lightning arresters on 20kV Lines (€2M) and retrofit overhead line fault indicators (€1M);

- In MV Substations they intend to install Fault Passage Indicators in Urban MV/LV Subs (€0.5M) and additional 10kV fuses (€1M)

The Commission, subject to efficient implementation, has allowed this capex.

xii. Renewal programme – Cutouts (DSO €9M, the Commission €9M)

The large majority of the cut-outs[27] in customers' premises are fit for purpose. However, a survey of cut-outs in pre 1976 domestic premises indicates there are issues such as signs of overheating, inadequate sizing which would warrant replacement of about 15%.

The Commission, subject to efficient implementation, has allowed this capex.

xiii. Renewal programme – trial (DSO €5M, the Commission €5M)

The DSO uses a technique called Fault Phase Earthing (FPE) on their rural 10kV system in order to improve continuity. They are proposing to undertake a trial of FPE on their 20kV network. This is considered to be reasonable due to the potential continuity improvement that might be achievable with a modest capital expenditure.

The Commission, subject to efficient implementation, has allowed this capex.

xiv. *Renewal programme – MV Cables (DSO €2M, the Commission €2M)*

The plan includes the replacement of very old 5 kV rated cable circuits in Dublin. These cables have been in service since before the formation of ESB with a total length of 17km

The Commission has approved this capex.

Dismantling (DSO €105m, CER €65.7m)

Dismantling represents the costs of all dismantling associated with 110kV, 38kV and MV/LV reinforcement, and non-load related capital programmes. The driver for this is the level of capital expenditure and the estimated cost of dismantling is calculated as 10% of the work-years required for reinforcement and non-load related expenditure. This is more normally defined as a component of the capital cost of refurbishment or other projects. ESB has historically determined this component by applying a percentage figure to the relevant capital expenditure forecast.

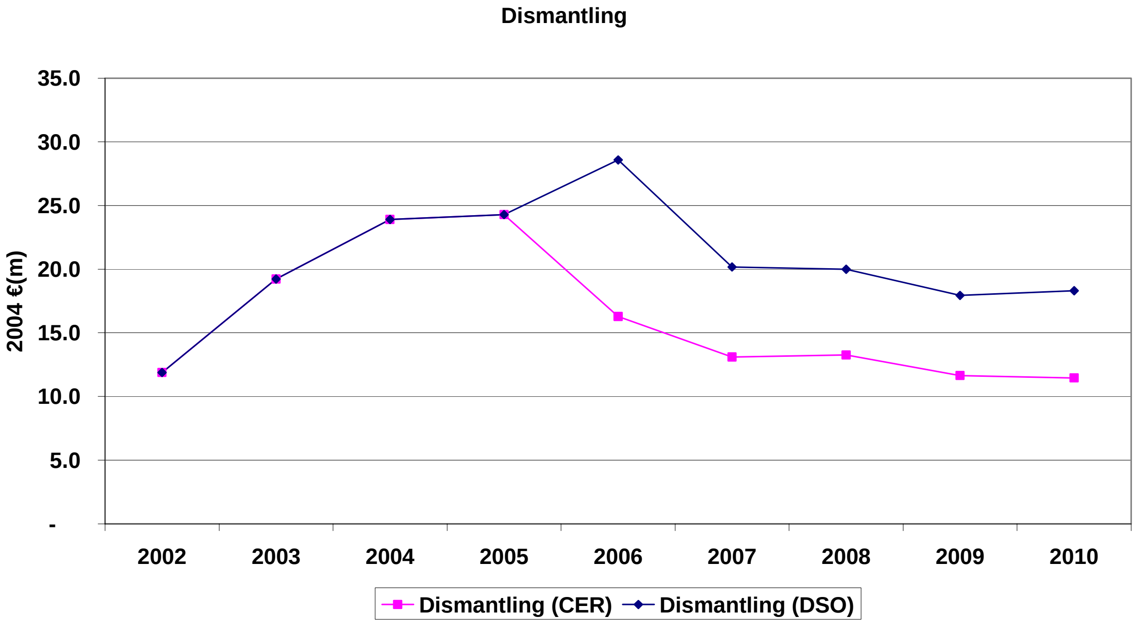
[27] Simple protective devices on the incoming supply to each domestic connection

To date dismantling has been defined as a non-controllable costs, with the estimated cost of dismantling being calculated as 10% of the work-years required for reinforcement and non-load related expenditure. This cost has historically been determined by applying a percentage figure to the relevant capital expenditure forecast The Commission however believes these costs are at least partially controllable and therefore should be classified as such for the period 2006 to 2010.

In addition, as allowed operating expenditure, this is immediately paid by customers and not spread over a long period, as is Capex. The Commission believes that dismantling costs should be treated as Capex and not Opex, since dismantling costs are associated with capital expenditure programmes. The allowance methodology (a % of reinforcement and non-load related expenditure) will be continued. While the Commission has decided to treat dismantling costs as Capex, DSO's submission included this item under Opex, as has been the practice to date.

During the first control period, allowed opex on dismantling was set at 5.3% of reinforcement and non-load related expenditure. The DSO's actual opex expenditure over this period varied from 4.6% to 6.2% (with an average of 5.5%). The DSO's proposals for the period 2006-2010 imply a higher rate of expenditure on dismantling, varying from 6.3% to 7%. The Commission does not believe the increased expenditure on dismantling, as a percentage of reinforcement and non-load related expenditure, is justified. The DSO has demonstrated that these costs can be kept at levels below 5%.

The Commission expects the DSO to at least match the levels achieved during the first control period, and therefore has allowed capex on dismantling at 5.3% of allowed reinforcement and non-load related expenditure in 2006, reducing annually to a level of 4.9% in 2010. The allowed capex is based on the Commission's allowed reinforcement and non-load related capital expenditure.



C. CONCLUSION

The Commission believes that the initial network renewal programme (NRP1) has been successful in renewing the MV network, which should result in better security of supply, lower losses and reduced maintenance and repair costs. There is still substantial work to be completed and the bulk of the DSO's costs for this programme have been allowed, most notably with the exception of the re-renewal of the 20kV lines renewed before 2003.

While it is normal for a distribution network operator to prefer a new network to an old one, the reality of networks worldwide is that of an asset age profile determined by the historic patterns of growth and development.

The majority of the elements of the plan are allowed, but with general efficiency and contracting savings (in addition to cuts in the HV line and meter refurbishment as discussed above). However, the three largest components of the proposed programme (NRP2) are believed by the Commission not to be fully justified in their scale and scope and should therefore be reduced.

7.5.4 Non network capex

The allowed non-network capex is presented in table 7.15 below:

Figure 7.15 –2006 – 2010 non-network capex

	€ (2004, m)			
	DSO	CER	Reduction	
Total Accommodation vehicles	88	79	10	10%
Dist Asset Management	29	26	3	10%
Total Control/Operations (EMS)	13	12	1	10%
Total IT Infrastructure	0	0	0	0%
Total Enterprise Applications	12	11	1	10%
Total Telecoms	12	10	1	10%
Total non network capex	**155**	**139**	**17**	**10%**

A. REVIEW OF SUBMITTED NON NETWORK CAPEX

DSO's historical and proposed non-network capex is presented in figure 7.16 below:

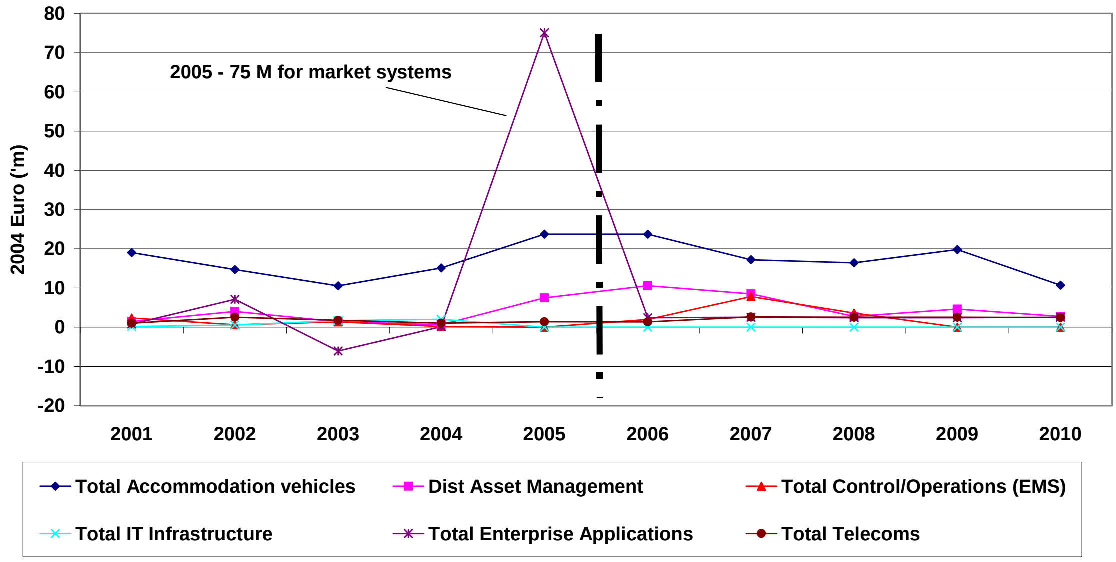


Figure 7.16 – non network capex 2001 – 2010 submitted by the DSO

A further breakdown of the main items of the above figure is presented in Appendix D.

From initial discussions it appears that very few staff resources are available to progress the planned programme of work. It is expected that resources will become available once the market-opening project is completed but this may be delayed by the need to provide ongoing support for the new IT systems. Detailed project plans have not been established and cost estimates are based only on information provided by potential suppliers at technology briefings. There are no user requirements defined or details of the required internal IT and business user staff resources required to progress these major work programmes. There is also the need, as yet undefined, to provide ongoing support to the new systems.

Analysis related to specific areas of non-network capex is provided below.

i. Accommodation/vehicles

The expenditure on vehicles of €48.2m during the five years is €6.3m higher than that in the previous 5 years and produces no identifiable benefit. Accordingly it the plan figures have been reduced pro-rata by €6.3 to equate to the previous 5 years expenditure. Given the claims that the new Mobile Workforce Management application will reduce overheads in transport and travel time this should be factored into the transport provision with a 15% reduction through 2008-2010 giving an additional reduction of €3.66m and an overall total through the period of €10.06m.

ii. Distribution asset system (support and planning)

The proposed spend in this category includes the implementation of the Asset Register and Maintenance Management system at €7.6m and the Mobile Workforce Management system at €8.9m. Cost estimates for these systems are provided at a summary level without any detailed breakdown. Similarly, the reasons for expected cost profiles are not documented. It is important that the DSO aims for functionalities that are fit-for-purpose rather than state-of-the-art. The DSO is to provide the Commission with information regarding the specification of the asset register system as this project is initiated. Without suitable cost breakdown and supporting reasons, these estimates seem too high.

Taking into account the risk relating to resourcing, it is assumed that the work for Distribution Asset Management will slip one year with the expenditure proposed for 2006 of €10.6m split between 2006 and 2007 in proportion €3.6 and €7.0m and that for other years slipping by a year.

iii. Distribution control/operations (EMS)

The only item in this area relates to the replacement of the SCADA/EMS software at a total cost of €13.4m. As indicated previously, cost estimates for these systems are provided at a summary level without any detailed breakdown. The reasons for expected cost profiles are also not documented. Although these are specialised operational systems, these estimates seem too high without suitable cost breakdown and supporting reasons

iv. Corporate IT infrastructure

The submission does not show any intended spend during the review period.

v. Enterprise applications

The expenditure under Enterprise Applications is principally for the upgrade and replacement of PC hardware, peripherals and software packages. Upgrade and replacement policies and cycles are in line with industry practice and the costs are spread evenly across the five years for costing purposes. Based on this level of expenditure a more aggressive policy in procurement exploiting public sector discounts should realise savings of the order of 10%.

vi. Telecoms

€1m has been set aside for miscellaneous projects. While this provision is largely based on experience, every attempt should be made to identify projects and the number of unforeseen capital projects should be kept to a minimum. The provision should in turn be reduced.

B. CONCLUSION

The Commission believes that there is a serious risk that works will progress more slowly than planned and the expenditure will not be realised. Accordingly it is envisaged that the first year will be principally taken up in initiating the projects, including developing user requirement definitions, establishing plans and identifying staff resources from the business and

internal IS to effect the work. In subsequent years it should be possible to progress the work through suppliers and the use of contract staff.

The Commission has approved a reduced non-network capex of €139m.

7.6 CAPEX ALLOWANCE

The DSO proposed and Commission allowed capex is summarised in figure 7.17 below:

Figure 7.17 – 2006 – 2010 allowed capex

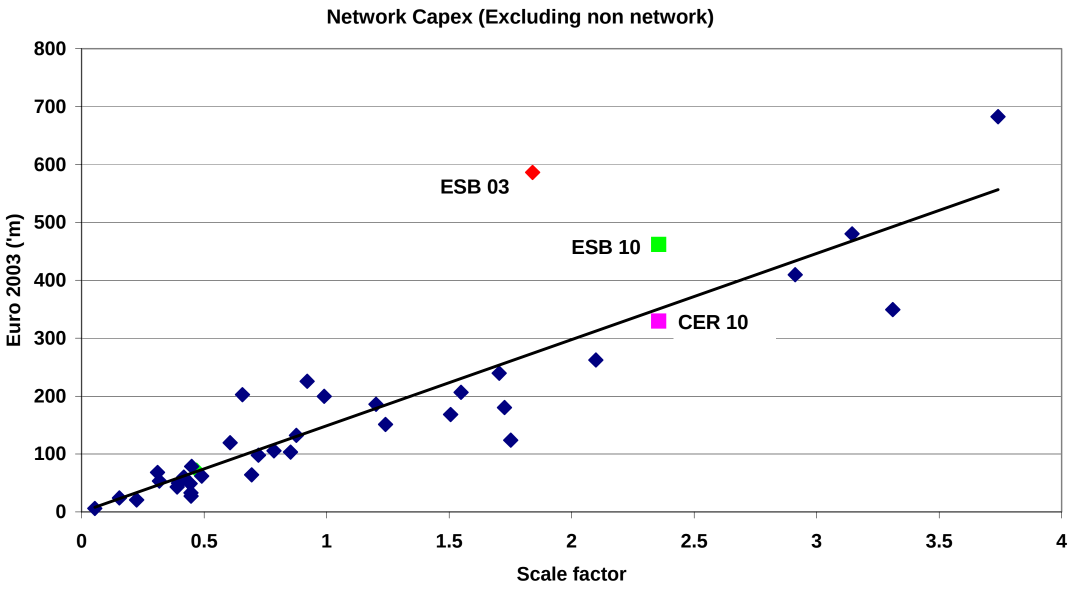
	€ (2004, m)			
Capex component	**DSO**	**CER**	**Reduction**	
New business	908	854	54	6%
Reinforcements	618	530	88	14%
Network non-load related	981	755	226	23%
Non-Network	154	139	15	10%
Total capex	**2,661**	**2,278**	**383**	**14.4%**

The Commission will assume a monitoring role in the rollout of the capex programme. While the Commission currently reviews capital projects in detail at the end of the five-year review period, an active and ongoing reporting process will be put in place over the coming months.

To understand the impact on the DSO's, the DSO's and Commission's 2010 forecasts were converted to 2003 prices and benchmarked (using the information from the earlier benchmarking section).

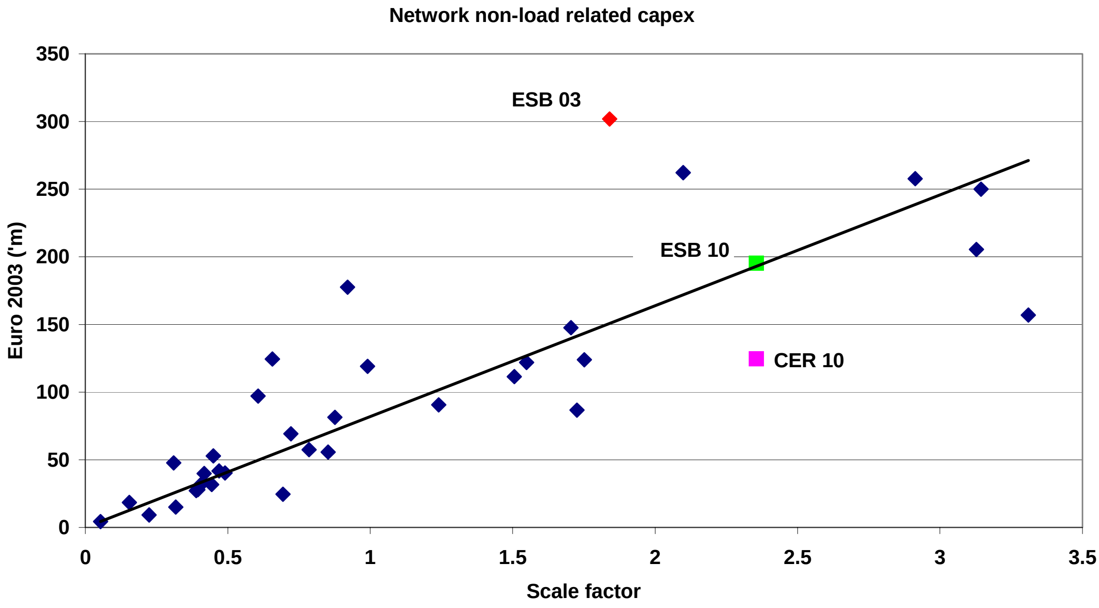
The network capex results (presented in figure 7.18 below) shows that the Commission allowed capex is aligned with average industry expectations.

Figure 7.18 – Network capex - 2010 forecast capex against benchmarks



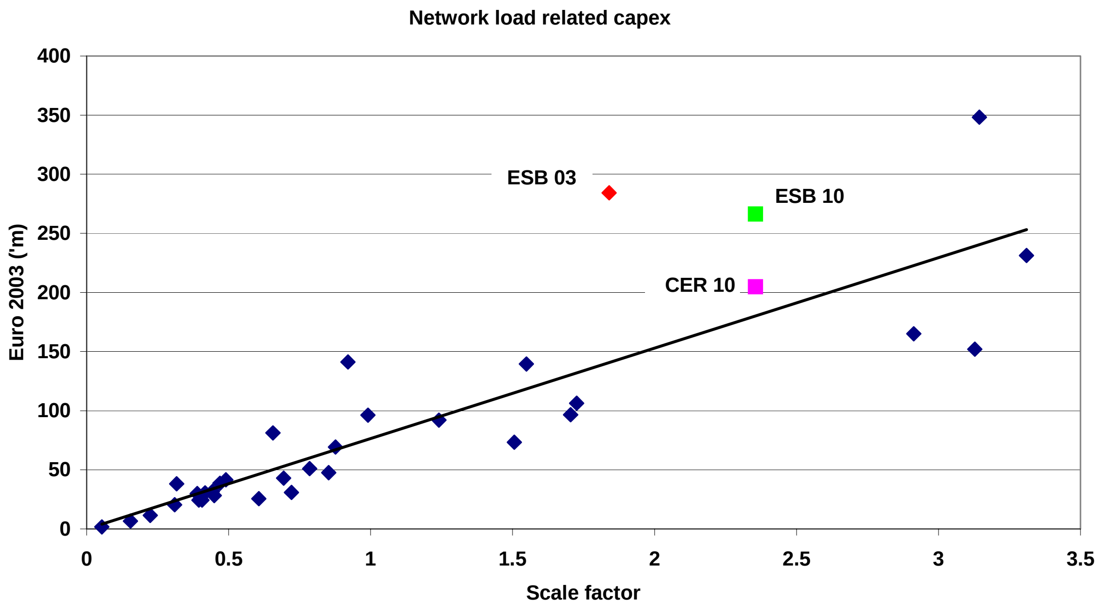
Benchmarking network non-load related capex (figure 7.19 below) also shows that with the Commission allowed capex, network non-load related capex is below average industry expectations.

Figure 7.19 – Network non-load related capex - 2010 forecast capex against benchmarks



Benchmarking network load related capex (figure 7.20 below) shows that with the Commission approved capex, network load related capex is approaching average industry expectations.

Figure 7.20 – Network load related capex - 2010 forecast capex against benchmarks



8. OPERATIONAL EXPENDITURE (OPEX)

This section looks at the DSO's historical and forward looking operational expenditure to determine whether the DSO's proposed expenditure is prudent and offers value for money to customers. This section is set out as follows:

- Objectives for the review of Opex
- Review of 2001-2005 Opex
- Benchmarking ESB's Opex
- Assessment of Forward looking Opex 2006-2010

8.1 OBJECTIVES FOR THE REVIEW OF OPEX

The objective in setting an allowed opex is to ensure that efficiency improvements continue to be made, to the benefit of customers. This should result in setting the DSO challenging but realistic and achievable targets and incentives, all the while moving closer to international best practice. Before proposing an appropriate level of opex, the review of both historic and forward looking opex needs to assess a number of issues:

- Historic trends in opex
- Comparison of actual opex against allowed opex
- Benchmark DSO opex against international comparators
- Evaluate future required opex
- Impact of capex programme on opex requirements

Approach to the review of Opex

The setting of allowed opex for the five-year control period involves a number of steps. An analysis first was undertaken to evaluate the DSO's performance over the previous revenue period. Were the expected efficiencies in opex achieved? More importantly, were there any efficiency improvements in the controllable opex? This analysis also sought to identify where any over/under spend had occurred. In addition, accounting or financial issues were identified, with a view to avoiding any difficulties that these issues might present at the next revenue review. The DSO's opex of 2003 was also benchmarked against comparable companies.

The historical opex analysis and trends, together with the benchmarking analysis, were used as background to the assessment of the forward-looking opex. As part of the evaluation of future efficiency levels, the opex costs were also analysed on a controllable and non-controllable cost basis. The potential impact of the capital expenditure programme was also taken into account in the evaluation of the required future opex. These inputs, along with a bottom-up review of the forecast opex submitted by the DSO, guided the Commission's decision for the allowed level of opex for this control period.

The approach taken ensures that the allowed operating expenditures meet the objective of ensuring that efficiency improvements continue to be made, to the benefit of customers.

8.2 HISTORICAL OPEX REVIEW

The CER decision paper of September 2001, "Determination of Distribution Allowed Revenues"[28], set out the DSO's allowed operating expenditure for each year over the period 2001-2005. Certain items of this expenditure were to be adjusted year on year, depending on outturn, where these operating cost items were deemed to be non-controllable by the DSO or dependent on the capital investment program. Examples of such items include dismantling costs, non-repayable line diversions and rates. The calculation of the revenues in each year over the period included upward adjustments for some of these items, as the required capital investment was above forecast levels.

Over the revenue control period, the DSO, with the Commission's approval, has initiated a number of further projects whose costs were not included in the 2001 determination. The operating expenditure related to these projects has been recovered through additions included in the annual allowed revenue calculations. Examples of such adjustments[29] are operating costs associated with the Load Profile Project, the Bulk Supply Metering Project, the Market Opening Project, the Business Separation Project and the Accelerated Network Investment programme.

The following table summarizes actual operating expenditures made by the DSO against the Commission approved operating expenditures[30], taking account of all adjustments that were allowed in the annual revenue calculations over the control period.

Table 8.1: CER Allowed Opex vs Actual DSO Opex, 2001-2005

	2001	2002	2003	2004	2005
CER determination 2001:	€ m	€ m	€ m	€ m	€ m
Allowed cash opex (real 2000)	193.0	181.2	178.7	182.6	187.5
Allowed cash opex (€ 2004)	224.0	210.3	207.4	211.9	217.7
Total Adjustments (€ 2004)	2.0	11.9	18.2	16.3	41.7
Total CER allowed (€ 2004)	**226.0**	**222.2**	**225.5**	**228.3**	**259.4**
ESB Networks net cash opex (€ 2004)	**243.1**	**231.1**	**238.4**	**243.4**	**260.5**
Overspend vs allowed opex (€ 2004)	**17.1**	**8.9**	**12.9**	**15.1**	**1.2**

[28] CER 01/128

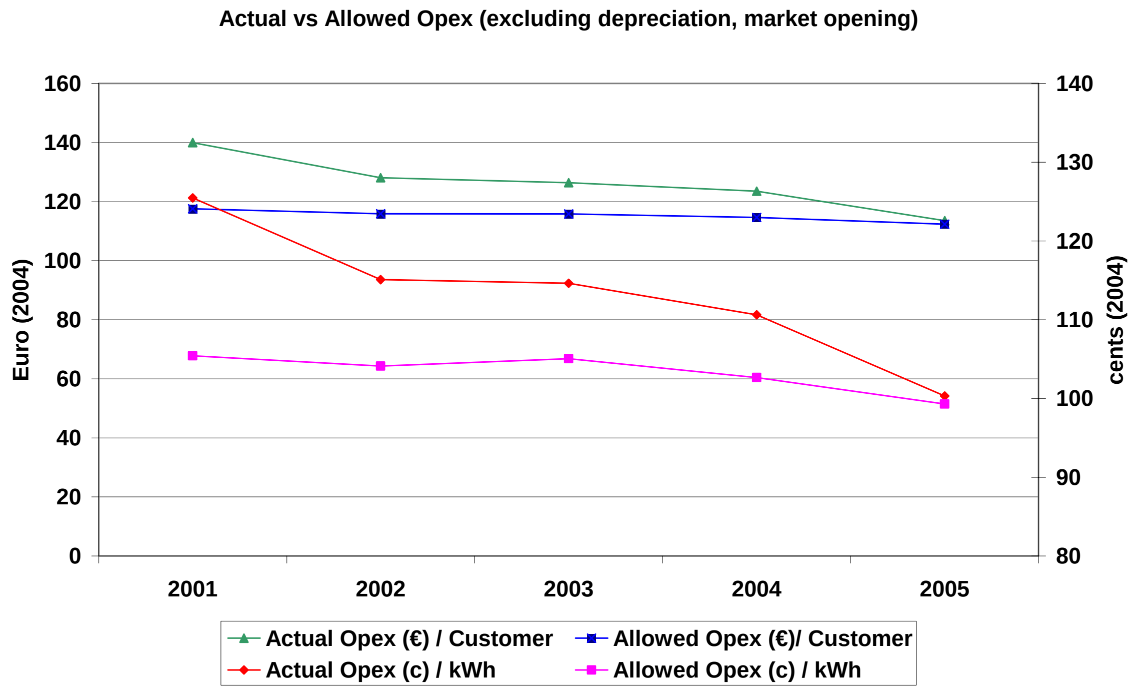
[29] Each year the Commission approves an allowed revenue for the DSO. Published papers from the Commission include details on allowed costs for extra expenditure approved after 2001 (these are not however split into the capex and opex constituents). For example, see CER 04/294.

[30] The allowed operating expenditure is outlined on page 8 of "Determination of Distribution Allowed Revenues", CER 01/128. Note that the values are in £, 2000 prices.

The main areas of cash expenditure in 2004 included Network Operations and Maintenance (€92.3m), Capital Driven Opex (€51m), Provision of Information (€23.7) and Metering (€20.7m)

While it can be seen that the DSO exceeded their allowed expenditure, which included efficiency targets, by 2005 the gap had been reduced compared to earlier years. It is also important to note that the DUoS tariffs over the period were based only on the allowed expenditures.

The following graph shows DSO's total opex in terms of opex per customer served and opex per kWh distributed, and allowed opex per customer. The figures exclude network depreciation and market opening opex.



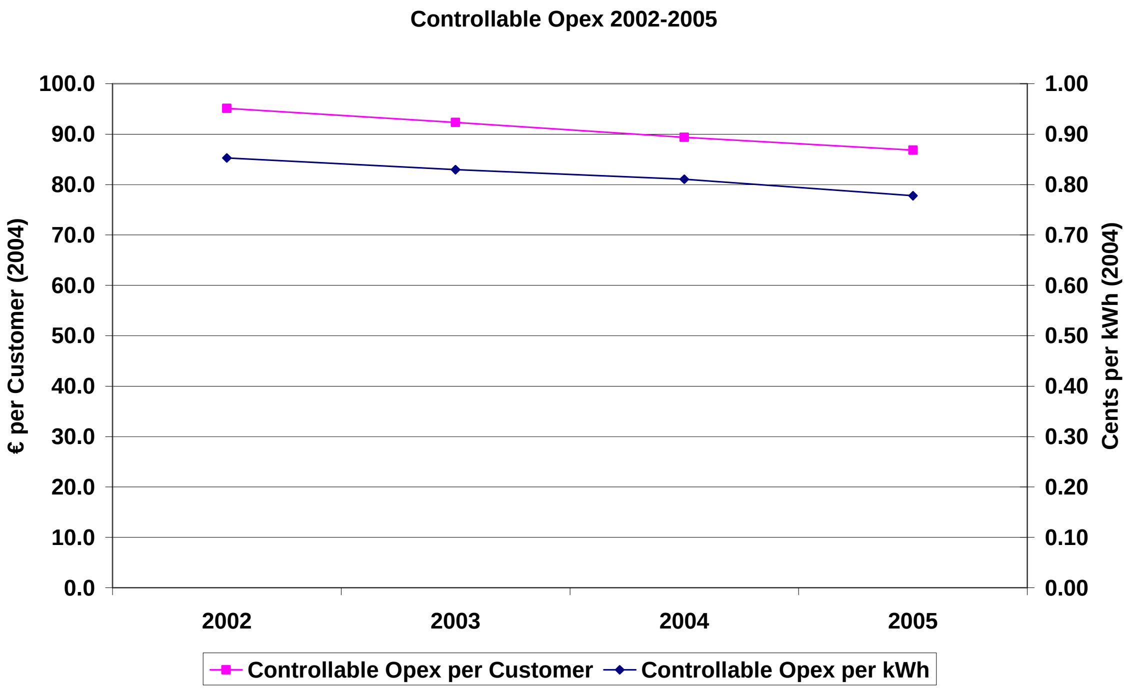
This shows that while overall opex remained above levels allowed in the 2001 determination, it did reduce over the period 2001-2005, both on a per customer and a per unit basis.

8.2.1 ASSESSMENT OF CONTROLLABLE OPEX 2001-2005

Controllable opex are operational costs over which DSO has control; network maintenance would be a good example of such a cost. Other costs are deemed to be non-controllable, such as network depreciation.

Table 8.1 above showed that the DSO operational expenditures exceeded the allowed opex over the period 2001-2005. While it is not possible to compare individual expenditure items against the headings of allowed expenditure items as described in the CER decision paper of 2001[31], it has been possible to evaluate the trend in controllable opex - the DSO has reduced controllable opex per customer by 8.7% and controllable opex per unit distributed by 8.8% in real terms over the period 2002-2005.

The following graph shows this trend in DSO's controllable opex[32].



As can be seen from the graph above controllable opex is decreasing on an annual basis. A significant factor in this trend however is the fact that there has been a large increase in customer numbers and unit throughput over the period. The spreading of fixed costs against these increases automatically results in reductions on a per customer and per unit basis.

In terms of reducing opex levels, the objectives of the previous review have been partially met. To ascertain whether the reductions achieved in opex bring the DSO in line with international comparators, it is necessary to benchmark their opex.

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[31] This was due to changes made to the activity headings under which opex expenditures are recorded in the DSO's systems.

[32] Controllable Opex for the period 2002-2005 is defined, for the purposes of these graphs, as total opex less opex on capital driven opex, market opening, commercial opex, rates, network depreciation, insurance, pension and further opex classified as other (these headings are described in further detail below as part of the forward looking opex assessment)

8.3 BENCHMARKING THE DSO'S OPEX

A. COMMISSION'S BENCHMARKING

In addition to the benchmarking of the DSO's capex and system performance, the following opex measure was benchmarked:

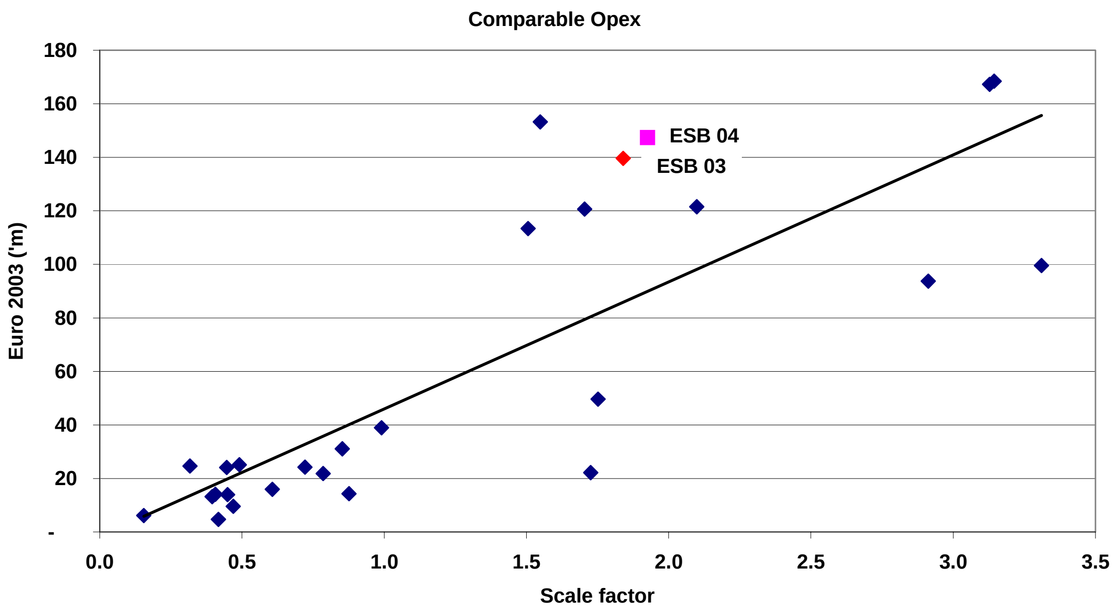
- Comparable opex (non-controllable costs such as depreciation and network rates were removed from all of the opex figures. For the DSO, line diversions and dismantling opex were removed as these are classified as capex in the USA)

As noted above, high level opex measures were used to ensure that comparisons were conducted on a 'like for like' basis, with the likelihood of variations between the DSO's and the US companies opex due to different classifications being minimised.

See Appendix B for more information on benchmarking and a worked example of how the scale factor was calculated.

The results are presented below and show that the DSO's comparable opex is high relative to the other companies benchmarked and is €53m higher than the average expected expenditure for the DSO's scale factor

Benchmarking data – 2003 and 2004 Comparable opex



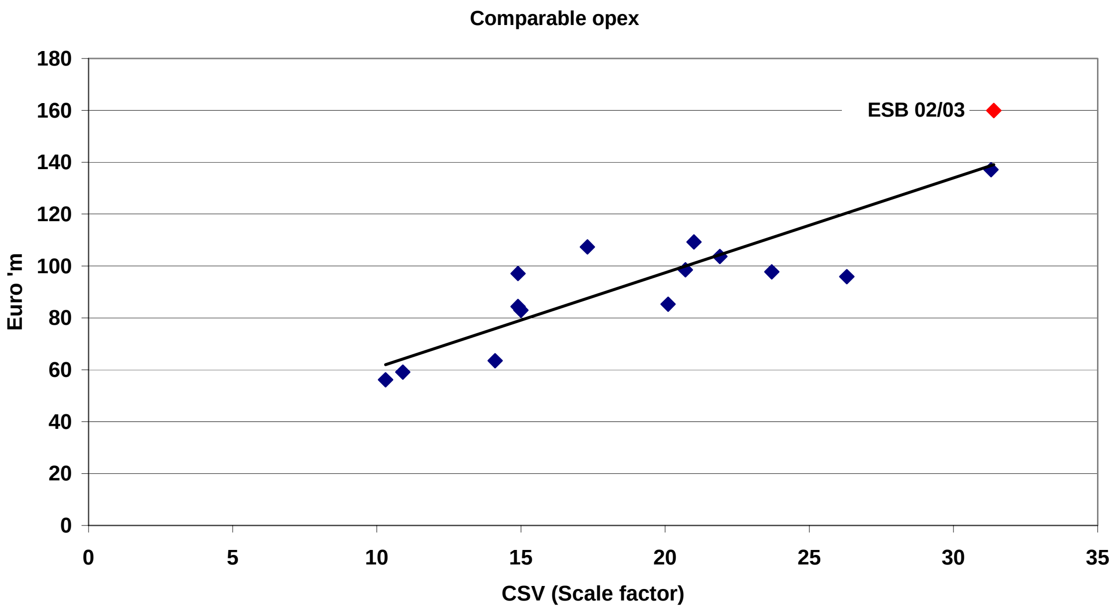
B. BENCHMARKING USING OFGEM'S APPROACH

For the next UK price control review (DPCR4), the UK regulator (the Office of Gas and Electricity Markets (Ofgem)) considered that the scale of operations was the main cost driver for DNO costs, and hence that any cost efficiency assessment should be based on measures of scale.

According to the regulator, the main measures of scale for the UK distribution companies were network length, customer numbers and units of electricity distributed. Ofgem used these to construct a scale factor (called a Composite Scale Variable – CSV[33]), which comparable opex (using Ofgem's definition) was benchmarked against.

The DSO modelled their opex using Ofgem's approach, which produced the results below:

Benchmarking data – 2002 / 2003 Comparable opex (Ofgem)



Points to note regarding the DSO's and Ofgem's analysis:

- A comparison was also made using purchase power parity, which produced similar results
- Ofgem notes that results are sensitive to the weights used
- DSO's own benchmarking showed inefficiency in the range 3% to 11%.

8.3.2 Conclusion

Benchmarking the DSO's comparable opex shows that their expenditure is high.

While the Commission accepts that there is no optimal way to compare opex across different networks, the above results, using two different approaches and different companies, show that the DSO's comparable opex is higher than average.

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[33] The CSV is a simple weighting process of the individual variables CSV = length$^{\alpha}$× customers$^{\beta}$ × units$^{\gamma}$, where $\alpha+\beta+\gamma=1$. In DPCR4, Ofgem used weights of $\alpha=0.5$ and $\beta=\gamma=0.25$.

8.4 DETERMINATION OF THE OPEX ALLOWANCE

The previous section analysed the DSO's opex for 2003 and 2004, showing that their expenditure is high relative to comparable companies. In reviewing the DSO's proposed 2006-2010 opex submission, the Commission noted that the proposals would not result in any significant reduction in opex levels by 2010. A significant factor in the slow rate of efficiency gains was due to pay increases, although offset to some degree by a reduction in overall staff numbers.

Nevertheless, the payroll increases incorporated in the DSO's submission outstripped the assumed productivity gains; in effect, under these proposals, overall efficiency would decrease. The Commission believes that any payroll increase, in order to be justified, should be more than offset by increased productivity, in which case it will be self-financing. From a position of opex being higher than comparable companies, payroll increases greater than productivity increases are not tenable.

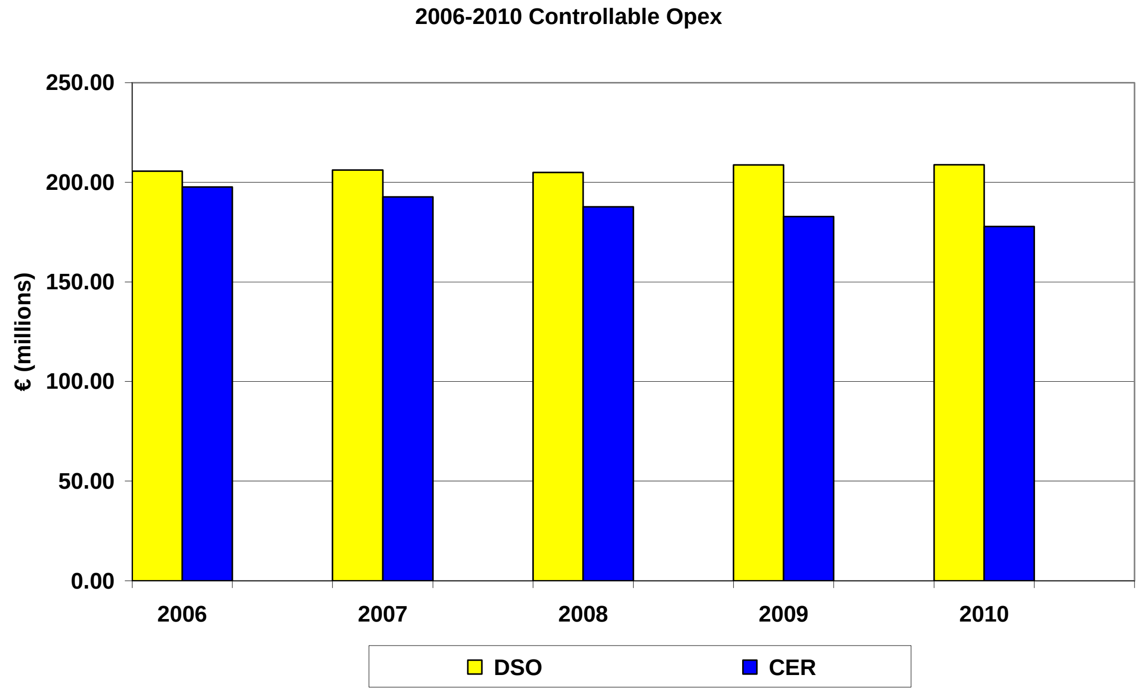
It is the view of the Commission that the DSO's opex levels in 2010 should be in line with efficient comparable companies and to this end has made reductions on most areas of the DSO's opex.

The DSO's opex proposals and the final allowed opex for the period 2006-2010 fall under the following headings:

Opex Areas	DSO	CER	Reduction €	%
Capital Driven Opex	**107.8**	**95.1**	13	12%
Network Operations & Maintenance	**480**	**427.2**	53	11%
Asset Management	**57**	**52.3**	4	8%
Metering	**99**	**90.9**	8	8%
Customer Service	**102**	**98.1**	4	4%
Provision of information	**129**	**111.4**	17	13%
Commercial	**86**	**81.2**	5	6%
Corporate	**77**	**76.6**	0	0%
Other (Non-Controllable):				
Network Depreciation	**955**	**653.1**	302	32%
Rates, Insurance and Pension	**179**	**179.3**	0	0%
Other (Controllable)	**42**	**38.9**	3	7%
Total	***2312***	***1904***	***408***	***17.7%***
Non-Controllable Opex	**1278**	**964**	**314**	**24.6%**
Controllable Opex	**1034**	**940**	**94**	**9.1%**

The following table shows the trend path of the allowed opex, compared to the DSO's proposals, for controllable opex. By 2010, the Commission's allowed controllable allowed opex will be significantly lower than DSO's proposed position, with a gradual cost reduction path followed to arrive at this point.[34]

[34] Figures represent total opex less opex on market opening, call centres, rates, network depreciation, insurance and pension. Opex on line diversions is included, but dismantling is excluded, as this will be defined as Capex.



The DSO's proposals are assessed under each of the activity headings below, together with the Commission's allowed expenditure for each area. The figures cited are all in 2004 € values. Within each of the headings, the opex is divided between controllable and non-controllable costs.

The final section summarizes the opex proposals put forward by DSO together with the Commission's decision on allowed expenditure. This also summarizes the total opex in terms of controllable and non-controllable costs, showing the trends in these costs over the period 2002-2010. A breakdown of the annual amounts for each activity is also included at the end of this section.

A. CAPITAL DRIVEN OPEX (Controllable. DSO €108m, CER €95m)

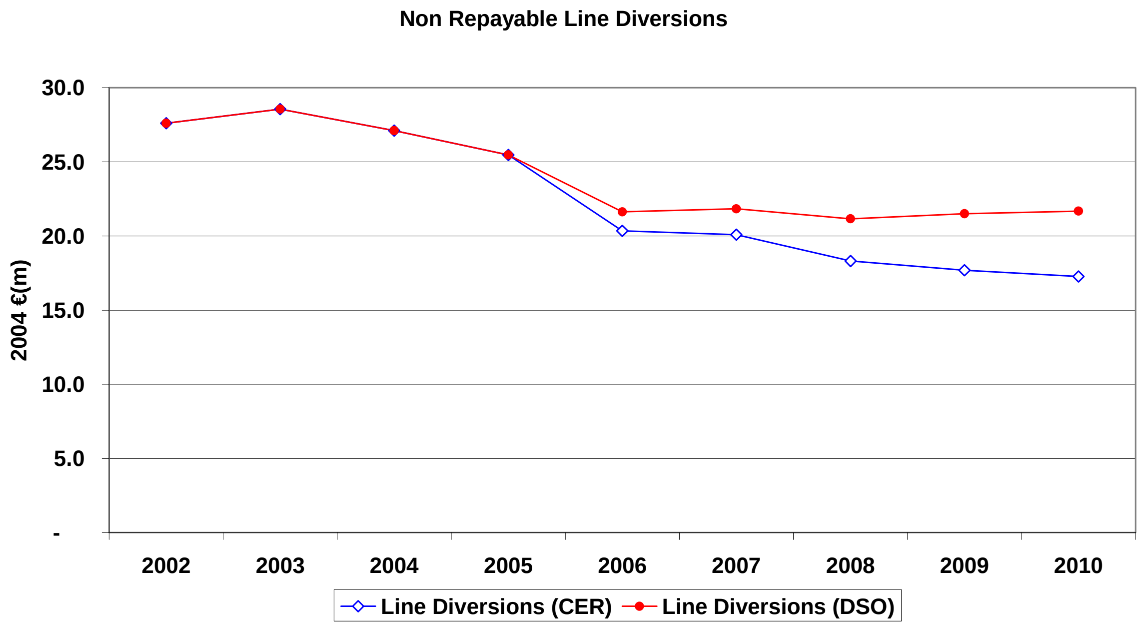
To date, capital driven opex has consisted of line diversions and dismantling. In section 7, the Commission decided that future dismantling costs be treated as Capex and not Opex, since dismantling costs are associated with capital expenditure programmes.

Non-Repayable Line Diversions (DSO €108m, CER €95m)

Non-repayable line diversions consist of the relocation of LV and MV overhead lines, free of charge, as required to allow development to take place; this is included in operating costs. While line diversions are driven by developments outside of the DSO's control, the levels of costs incurred are nevertheless partially controllable.

During the first control period, allowed opex on line diversions was set as 17% of new business capital expenditure. Over this period DSO reduced expenditure on line diversions from a high of 18% down to 14.8% in 2004. For the period 2006-2010 the DSO's proposals imply a gradual increase in expenditure on line diversions, as a percentage of new business capital expenditure, rising from 14.4% (2006) to 14.8% (2010). The total proposed expenditure is €108m. Since these costs are controllable to a certain degree, the Commission therefore has made continued reductions in expenditure in this area.

The Commission has allowed opex on line diversions as 13.9% of new business capital expenditure over the period 2006-2010. The allowed opex in 2006 will be at 14.2%, falling to 13.4% by 2010. The allowed opex is based on the allowed new business capital expenditure for the period.



Summary

While expenditure in this area is driven by capital expenditure, the Commission is of the view that expenditure on line diversions is controllable to a certain degree. Dismantling costs, which were previously treated as opex, will now be treated as Capex.

Overall, the Commission has made a reduction of 12.7% on DSO's proposals for capital driven expenditure over the period 2006-2010. Part of this reduction is due to the reduction in the capex programme as proposed by the DSO, which drives expenditure on these items.

Opex Area		Totals for 2006-2010, € (2004, m)			
		DSO Proposed	CER Proposed	Reduction €	%
Capital Driven Opex CDO - Non Repayable Line Diversions	(Controllable)	**107.8**	**95.1**	**12.7**	11.8%

B. NETWORK OPERATIONS & MAINTENANCE (CONTROLLABLE DSO €480m, CER €427m)

Network operations and maintenance consists of **system control, planned maintenance** and **fault maintenance**. The DSO's submission proposes a steady increase in total expenditure for these items.

System Control (DSO €94m, CER €84m)

The increase in system control costs in 2005 and 2006 are, according to the DSO, explained by the roll out of the OMS system, as well as two additional Control room operators and increased switching costs in Network Services. DSO propose that the costs are then maintained at 2006 levels for the remainder of the period. As such, the DSO does not propose any reductions in costs in this area over the period 2006-2010, with total expenditure of €94m.

The Commission understands there will be some additional resource requirement to support the implementation of the new SCADA system with populating the data base and testing as well as for the OMS implementation. This justifies additional resource provision through 2006 and 2007 during project implementation. Beyond that the improved functionality and flexibility of the modern SCADA should enable efficiencies in organisation of the operations function. Further benefits are also claimed for the project in enabling centralisation of network management from Areas and the provision of a more user friendly interface. This should lead to reductions in the provisions through to the end of the decade. The new platform and operating system will be fully supportable and no additional maintenance costs are expected. The centralisation of network management from Areas should also produce significant savings.

Given the improvements in the proposed facility development the Commission believes that greater efficiencies should be achieved in this area, leading to overall reductions in expenditure in this area.

The Commission has allowed expenditure of €84m over 2006-2010.

Planned Maintenance (DSO €216m, CER €191m)

Planned maintenance costs are proposed to increase by almost 10% over the period 2006-2010. DSO has stated that this trend is explained by a combination of station maintenance, increased timber cutting costs and hazard maintenance. However, the MV substation maintenance programme is expected to fall after 2006, and hazard costs are also expected to fall over 2006-2010.

The maintenance program if made up of a number of elements:

110kV and 38kV Overhead Lines (DSO €13.7m, CER €12.0m)

The 110kV & 38kV Overhead Lines will be the subject of an annual helicopter patrol to spot hazards which will then be cleared straight away (€6.9M) and a timber patrol and cut on a three year cycle (€6.8M). The timber cutting unit costs are estimated by DSO to increase, through a three-year cutting cycle and increases in contractor costs. However, the DSO has stated that a four-year timber cutting cycle is optimum for MV lines. The Commission recognises that contractor costs will tend to rise through improved safety rules, however by cost control and optimum execution, cost savings should be possible.

The Commission has allowed €12m on this maintenance programme.

110kV and 38kV Cables (DSO €4.4m, CER €3.9m)

Capital expenditure in this area will make redundant, replace or otherwise improve most of these cables. The Commission is therefore of the view that expenditure for the remaining cables may be overstated and that reduced expenditure in this area is achievable.

The Commission has allowed €3.9m on this maintenance programme.

110kV and 38kV Substations (DSO €57.4m, CER €49.9m)

In 110kV & 38kV Substations some €57M of expenditure is proposed by the DSO. Of this, fabric maintenance accounts for €15M. The Commission is of the view that this expenditure is not fully warranted and can be reduced to €11.1m. Inspection and testing accounts for €19M and maintenance for €23M and given their safety impact, the Commission approves this work. However, through improving working efficiency and cost controls, this programme should be achieved at €38.8m.

The Commission has allowed €11.1m on fabric maintenance and €38.8m on inspection, testing and maintenance.

MV Overhead Lines (DSO €61.1m, CER €53.7m)

For MV Overhead Lines, DSO propose hazard patrols on a three year cycle for rural lines and annually for urban lines; expenditure is due to resulting hazards being cleared immediately (€15.7M) and a timber patrol and cut on a four year cycle (€45.4M). The Commission expects the DSO to be able to achieve some efficiencies in this area, thereby reducing expenditure in this area.

The Commission has allowed €53.7m on this maintenance programme

MV Substations (DSO €30.3m, CER €26.6m)

For MV Substations, the DSO propose (under capex) the replacement of all cast resin Ring Main Units (RMUs) in kiosks, Metropolitan Vickers unit substations and all oil-filled outdoor RMUs, associated transformers and LV boxes. This has been allowed under this review and will substantially reduce the maintenance load. Under Opex, ESB propose hazard patrols and remedial action (€20M) and detailed switchgear inspections and subsequent overhaul (€10M). DSO have stated that they are moving from cyclical maintenance to a condition-based regime. In the light of this it is expected that further savings could be made in this category.

The Commission has allowed €26.6m on this maintenance programme

LV Urban Overhead Lines (DSO €15.6m, CER €14.4m),

LV Rural (DSO €20.8m, CER €19.3m)

The Commission recognises that contractor costs will tend to rise through improved safety rules, however by cost control and optimum execution, cost savings should be possible. Through these cost controls and optimum execution, reduced costs should be achieved.

The Commission has allowed a total of €33.8m on this maintenance programme

LV Cables and Associated Pillars and Link Boxes (DSO €12.7m, CER €11.1m)

Inspection and repair of LV Pillars and Link boxes amounts to €13M in the DSO plan. In the Capex plan, the replacement of old cast iron underground link boxes, Cast iron Section Pillars and Urban Mini-pillars is proposed and has been allowed. The Commission believes that due to this Capex programme, the required opex for this maintenance programme should be less than that proposed by the DSO.

The Commission has allowed €11.1m on this maintenance programme

Commission allowance for Total Planned Maintenance Opex

The Commission has allowed total expenditure on planned maintenance of €191.0m over 2006-2010. The overall reduction in forecast planned maintenance is less than 12% and should be achievable without adversely affecting safety or reliability.

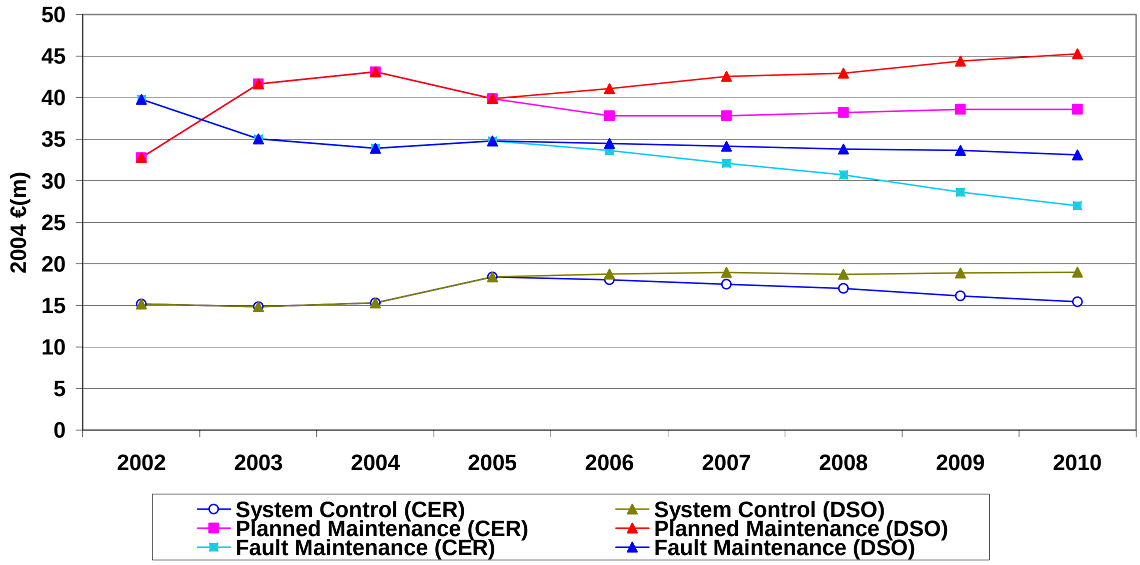
Fault Maintenance (DSO €169m, CER €152m)

The DSO projects fault maintenance expenditures to drop by between 0.5% - 1.6% annually. This is due to an anticipated 2% reduction in fault volumes over this period. The DSO proposes that only in 2010 will fault maintenance expenditure be less than 2004 levels. With the investment in the MV renewal program and the refurbishment of part of the LV network, the Commission is of the view that the reductions of required expenditure on fault maintenance should be far more pronounced[35]. As a result, annual reductions should be achieved in this area, both through lower volume of fault maintenance requirements and efficiency gains.

The Commission has projected annual reductions in fault maintenance opex from 2005 levels, with total allowed opex being set at €152m.

[35] Refer to Capital expenditure chapter7 for details on system investment.

Network Operations and Maintenance



Summary

Overall, the Commission has made a reduction of 10.9% on DSO's proposals.

Opex Area		Totals for 2006-2010, € (2004, m)			
		DSO Proposed	**CER Proposed**	**Reduction €**	**%**
Network Operations & Maintenance					
NOM - System control	(Controllable)	94.3	84.2	10.1	11%
NOM - Planned maintenance	(Controllable)	216.2	191.0	25.2	12%
NOM - Fault maintenance	(Controllable)	169.1	152.0	17.2	10%
Total		**479.7**	**427.2**	**52.5**	**10.9%**

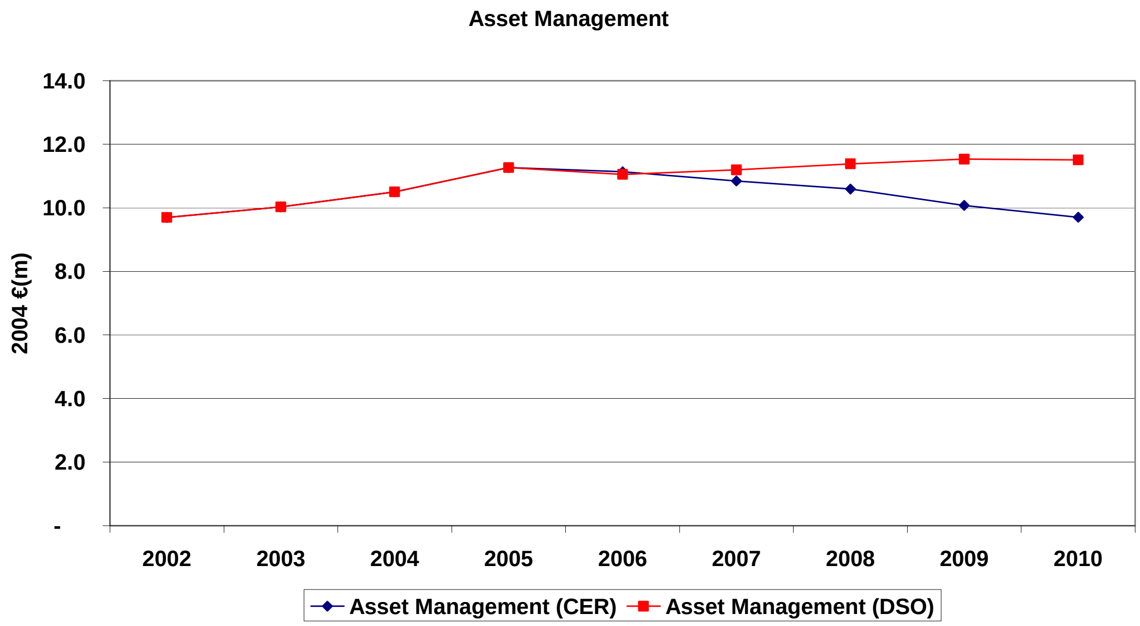
C. ASSET MANAGEMENT (CONTROLLABLE. DSO €57M, CER €52M)

Asset management consists of mast interference and forestry compensation costs, the regulation and public safety policy functions within Networks and the asset managers supporting Networks Distribution standards, policy and work programmes.

DSO have stated that the staffing levels in these areas are projected to remain constant over the period.

Asset management expenditure increased steadily over the period 2002-2005; the DSO's proposals include further increases, although at a reduced rate. The DSO state that this is due to pay inflation; payroll made up 36% of expenditure in this area in 2004. Under these proposals, by 2010 opex in this area would be 14.3% above 2003 levels. The Commission is of the view that the payroll increases should be self-financing, as working efficiencies offset such increases – payroll increases therefore do not justify increases in this area. The DSO should be seeking efficiencies in this area to reverse the trend of increasing costs, and return to previous lower expenditure levels.

The Commission has allowed decreasing expenditure in this area from 2005 levels.



Summary

Overall, the Commission has made a reduction of 7.6% on DSO's proposals.

Opex Area		Totals for 2006-2010, € (2004, m)			
		DSO Proposed	CER Proposed	Reduction €	%
Asset Management	(Controllable)	**56.7**	**52.3**	**4.3**	7.6%

D. METERING (CONTROLLABLE. DSO €99M, CER €91M)

Operational costs on metering cover **meter reading, QH data processing** (for Quarter Hour meters), **data aggregation** and **customer meter operation** costs. Overall, the DSO proposal shows an increase in total opex in this area.

Meter Reading (DSO €52m, CER €48m)

The rise in metering reading costs is, according to the DSO, due to the growth in the number of meters to be read, as well as a move to employing larger meter reading companies. These are anticipated to provide a greater level of service. However the Commission notes that the level of service projected, in terms of the percentage of meters read, show no improvements on current service levels. Currently, the Service Level Agreement[36] target of 80% successful reading of meters is being met – the DSO submission assumes a continuation of this level of

[36] ESB Networks Service Level Agreement, SLA 14: "80%, or greater, of actual readings for scheduled meter reading visits. This will include customer readings received during the meter reading time period." The SLA was approved by the Commission in November 2004 - see CER/04/345 and CER/04/344.

service. In addition, while in absolute terms the metering reading costs will increase with greater numbers, the cost per meter visit is also projected to increase up to 2008, before falling again. The proposed cost per visit in 2010 will however still be 11% above 2002 levels.

The Commission has decided that the cost per visit should be decreasing from 2005 levels, and is of the view that the reductions in costs at the end of the control period should be achieved sooner.

In addition, the Commission has decided that the DSO will continue to read customer meters four times per annum. The proposal to move to six meter reads would have resulted in an increased cost of almost €4m per annum. The longer term costs of meter reading, beyond 2010, were also taken into consideration. The Commission believes that the issues arising from estimated meter reads, both from suppliers and end-user customers can be addressed through other means more cost effectively. Many of these issues are not necessarily related to the frequency of meter reading. However, the Commission will conduct a review of these issues in 2006.

The Commission has decided that the DSO will continue to carry out four meter reads per annum,.

In addition the Commission also has reviewed the service levels assumed in the DSO's proposals. The Commission notes that all new houses have outdoor meters; with the unprecedented numbers of new connections over the last five years and the levels of new connections forecast over next five years, the proportion of meters with access difficulties is reducing significantly. This should result in a natural increase in service levels (in terms of actual meter reads per scheduled visit) without any consequent incremental cost per meter visit – this should in fact help reduce costs. The Commission has decided to adjust upwards the target levels for meter reading outlined in SLA 14, with a target of 84% of reads per visit by 2010; the profile of this target will be an increase of 1% per annum, with a 2006 target rate of 80%. This should be achievable through improvements in reading practices and customer awareness programs. These targets may be reviewed by the Commission, and incentives/penalties put in place if this is deemed appropriate. This is consistent with the Commission's decision on Service Level Agreements (CER 04/345).

QH Data (DSO €8.7m, CER €7.8m)

The DSO proposals for QH data opex also show increased expenditure, due to increased staff numbers to handle the increase in customers in this area. However over the period 2006-2010 there is no decrease in the cost per customer. The Commission is of the view that efficient work practices should result in decreases on a cost per customer basis.

The Commission has allowed opex of €7.8, consistent with annual reductions in the cost per customer over the period 2006-2010.

Data Aggregation (DSO €24.4m, CER €22.3m)

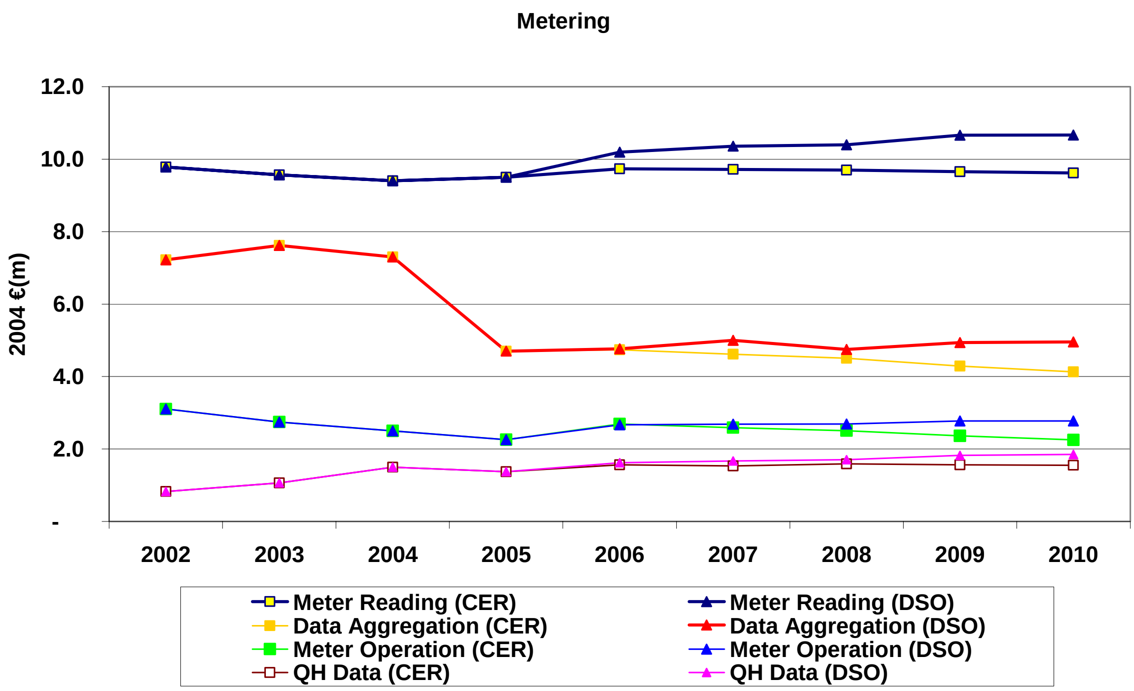
The DSO proposals on data aggregation show a steady level of costs over the period to 2010. These costs are however greater than costs in 2005. The Commission believes that increased efficiencies are achievable and should result in expenditure reductions.

The Commission has allowed opex of €22.3m, consistent with cost decreases on an annual basis over the period 2006-2010.

Customer Meter Operation (DSO €13.6m, CER €12.4m)

Similarly, the DSO proposals for customer meter operation are relatively static from 2006, after an increase from 2005 levels due to a greater number of sites. This followed two years of significant reduction in expenditure in this area.

The Commission has allowed opex of €12.4m, consistent with decreasing expenditure continues over this period.



Summary

Overall, the Commission has made a reduction of 8.1% on DSO's proposals.

Opex Area		Totals for 2006-2010, € (2004, m)			
		DSO Proposed	CER Proposed	Reduction €	Reduction %
Metering					
M - Meter reading	(Controllable)	52.3	48.4	3.9	7%
M - QH Data	(Controllable)	8.7	7.8	0.9	10%
M - Data Aggregation	(Controllable)	24.4	22.3	2.1	9%
M - Customer meter operation	(Controllable)	13.6	12.4	1.2	9%
Total		**98.9**	**90.9**	**8.0**	**8.1%**

E. CUSTOMER SERVICE (Controllable. DSO €102m, CER €98m)

Customer service covers expenditures on **call centres, area operations** and **customer relations**.

Call centres (Non-controllable, DSO €27m, CER €30.8m)

The DSO call centre costs come from the National Customer Contact Centre (NCCC), through a Service Level Agreement (SLA) between the NCCC and the DSO. The Commission has reviewed the pass through to DSO of these costs[37]. and benchmarked the NCCC to international performance levels.

The DSO's proposals were based upon anticipated charges from the NCCC.

The Commission has allowed opex of €30.8m for call centres

Area operations (DSO €69m, CER €61m)

Area operations covers a range of activities including responding to customer generated operational calls, network operations work including safety investigations, distribution station visits and operational switching of distribution networks.

The DSO state that the changes in expenditure in this area is due to inflation; removing inflation however the DSO proposals still show gradual increases in overall costs. The DSO has stated that reductions in area activities have been assumed in 2008 in line with additional productivity associated with the implementation of the Mobile Workforce Management System. The proposed opex does not however show reductions after 2008. Over the period 2002-2005 costs in this area have been decreasing. The Commission believes that costs should continue to decrease as the system condition improves, due to previous and forecast investment and the work programme set out for this control period, as well as through increased efficiencies in working practices.

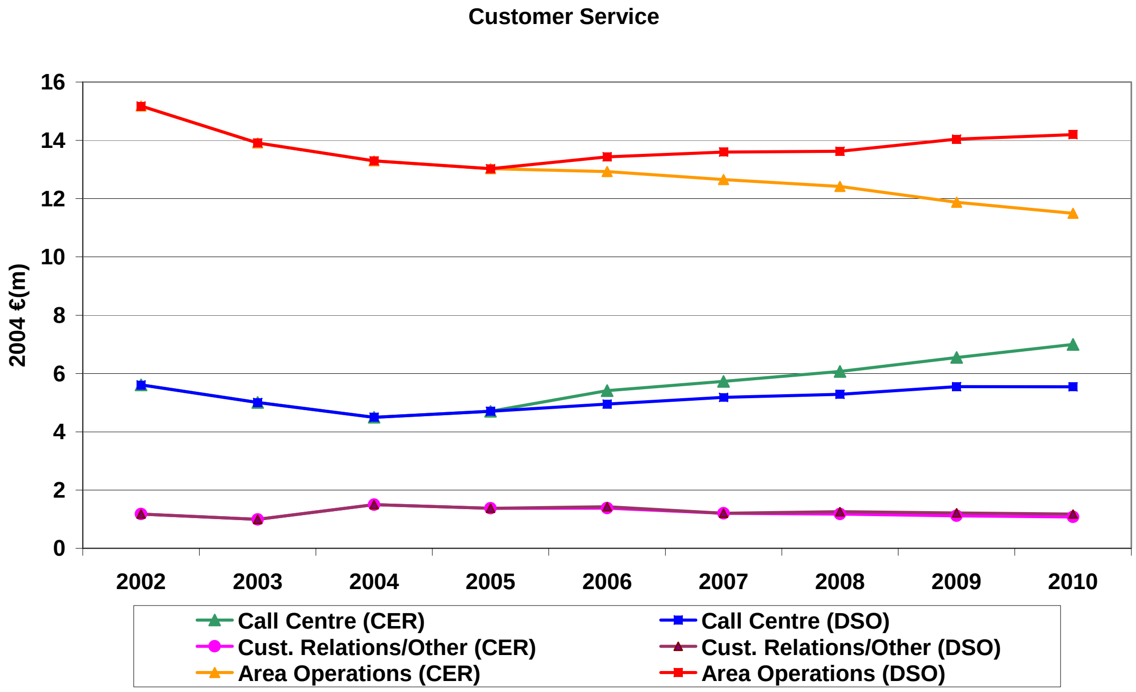
The Commission has allowed opex of €61m, consistent with decreasing costs over the period 2006-2010 from 2005 levels.

[37] Section 6.4.3, 2006-2010 ESB Price Control Review - Public Electricity Supply

Customer relations/Other (DSO €6.3m, CER €6.0m)

For customer relations and "other" costs, the DSO proposes opex of €6.3m over 2006-2010.

The Commission has allowed opex of €6m on customer relations.



Summary

Overall, the Commission has made a reduction of 6.8% on DSO's proposals.

Opex Area		Totals for 2006-2010, € (2004, m)			
		DSO Proposed	CER Proposed	Reduction €	Reduction %
Customer Service					
CS - Call centre	(Non-Cont.)	26.5	30.8	-4.2	-16%
CS - Area Operations	(Controllable)	68.9	61.4	7.5	11%
CS - Cust. relations / Other Cust Service	(Controllable)	6.3	6.0	0.3	5%
Total		**101.7**	**98.1**	**3.6**	**3.5%**

F. PROVISION OF INFORMATION (Controllable and Non Controllable. DSO €129m, CER €111.4m)

Provision of information includes **DUoS Billing, MRSO** (Meter Registration System Operator) and **MOIP** (Market Opening Implementation Project) costs.

DUoS Billing (DSO €3.5m, CER €3.2m)

The DSO's proposals follow an increase in 2005 due to ramping up to meet full market opening and the impact of MOIP. Following a bedding-in period, reductions follow in 2007 and beyond. The Commission is of the view that through cost controls reductions in expenditure are achievable in this area

The Commission has allowed expenditure of €3.2m on this item.

MRSO (DSO €7.7m, CER €7.1m)

While acknowledging that the MRSO workload will increase to some degree as the fully open market evolves, the Commission is of the view that the level of expenditure in DSO's proposals is not fully justified. Cost efficiencies need to be made in MRSO opex.

The Commission has made a reduction of the DSO's proposals for MRSO opex, to €7.1m. This allows for increased costs but at a slower rate.

MOIP (Uncontrollable. DSO €117m, CER €101m)

While these costs have been deemed as uncontrollable, the overall level of these costs has been subject to a separate review by the Commission. The allowed costs for the period 2006-2010 are a result of this review, and set an appropriate level of opex to ensure that DSO can provide all the services required due to market opening in an efficient manner. The following is a summary of this review:

Background

In March 2003 the CER approved expenditures for the Market Opening Implementation Programme (MOIP) to support full market opening in February 2005[38].

Following on from the successful implementation of the MOIP, ESB Networks' submission to the Commission on the Distribution Price Review for 2006-10 included ongoing MOIP related operating expenditure to support IT systems required for the newly-opened market.

As part of its review of the DSO's forecast Capex and Opex for 2006-10, CER employed an independent IT consultant to review and make recommendations as to the treatment of these costs.

ESB Networks Proposal

The table below sets out ESB Networks' proposed MOIP operating expenditure out to 2010. (Note: All costs are expressed as nominal amounts €m.)

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[38] See "CER Approval of Expenditures for Market Opening IT Programme – CER/03/175".)

	Market Opening Operating Expenditure €m (2004)					
	2005	**2006**	**2007**	**2008**	**2009**	**2010**
Networks Direct Cost of MOIP Support	1.10	1.10	1.10	1.10	1.20	1.20
IT Charges Relating to MOIP	11.50	9.20	8.60	8.30	8.10	8.00
Sub-Total MOIP Incremental Costs	**12.60**	**10.30**	**9.70**	**9.40**	**9.30**	**9.20**
MOIP Depreciation	14.60	14.20	13.80	13.40	12.90	
Contact Centre Charges/Depreciation	1.40	0.40	0.40	0.30	0.30	0.20
Sub-Total MOIP Depreciation	**16.00**	**14.60**	**14.20**	**13.70**	**13.20**	**0.20**
Industry Co-ordination & Design	3.40	3.00	2.70	2.70	2.70	2.60
Market Readiness Co-ordinator	0.50					
Total MOIP Operating Expenditure	**32.50**	**27.90**	**26.60**	**25.80**	**25.20**	**12.00**

The explanation document also provided information on the proposed resource for the MOIP IT Support as set out below:

	2005	2006	2007	2008	2009	2010
ESB Networks FTE[39]s	7	7	7	7	7	7
ESB ITS FTEs	51	37	30	30	30	30
Total FTEs	**58**	**44**	**37**	**37**	**37**	**37**

A detailed breakdown of the constituent elements of the IT charges relating to MOIP and the MOIP Depreciation was not provided by the DSO. However during a meeting with ESB Networks the following clarifications were made:

[39] Full time equivalent

- The MOIP IT charges included both MOIP IT Support FTE charges and those related to IT Infrastructure.
- The whole of the ESB Networks MOIP capital expenditure of €65.90m had been depreciated over 5 year period in the figures provided. It was accepted that for Price Review purposes this should have been a 7 year period as originally directed by the CER.
- No account had been taken of previous amounts of MOIP approved expenditure that had been capitalised in the Revenue Reviews prior to 2005. Amounts for MDS[40], other market opening IT systems and the MOIP 2002 approved capex have been shown in the Revenue Review formulae from 2001 to 2005. A detailed breakdown of the MDS and MOIP depreciation included in the 2001 to 2005 Revenue Review formulae has been provided but no revised figures for 2005 to 2010 have yet been supplied. An analysis of the Commission's view of revised depreciation has been produced below.
- As part of the CER's consultation on the governance of the retail electricity market the role of Design Administrator was addressed. The final CER decision on this was given in the document "Governance Procedures for the Liberalised Retail Electricity Market – A Response and Decision Paper" (CER/05/081). The role of Design Administrator, which encompasses the Industry Design and Co-ordination roles, will be provided by ESB Networks for a fixed term. The costs for the Design Administration will be separately recorded and in advance of each year a budget set based on the forecast workload for the role. The costs will be recovered by ESB Networks through the Revenue Review pass through costs.
- The amount allowed for the Market Readiness Co-ordinator of €0.50m for 2005 was to cover expenditure on this role beyond the Inter Participant Testing capital work.

CER Response

Detailed below is the Commission's response to the DSO's proposal on MOIP expenditures for 2006-10. These represent a slight change to the figures contained in the consultation paper CER 05/117; this is due to a calculation error contained in the table presented in that paper.

	MOIP Operating Expenditure €m (2004)					
	2005	**2006**	**2007**	**2008**	**2009**	**2010**
Hosting & Data Storage	2.97	2.97	2.97	2.97	2.97	2.97

[40] Metering and Data Services

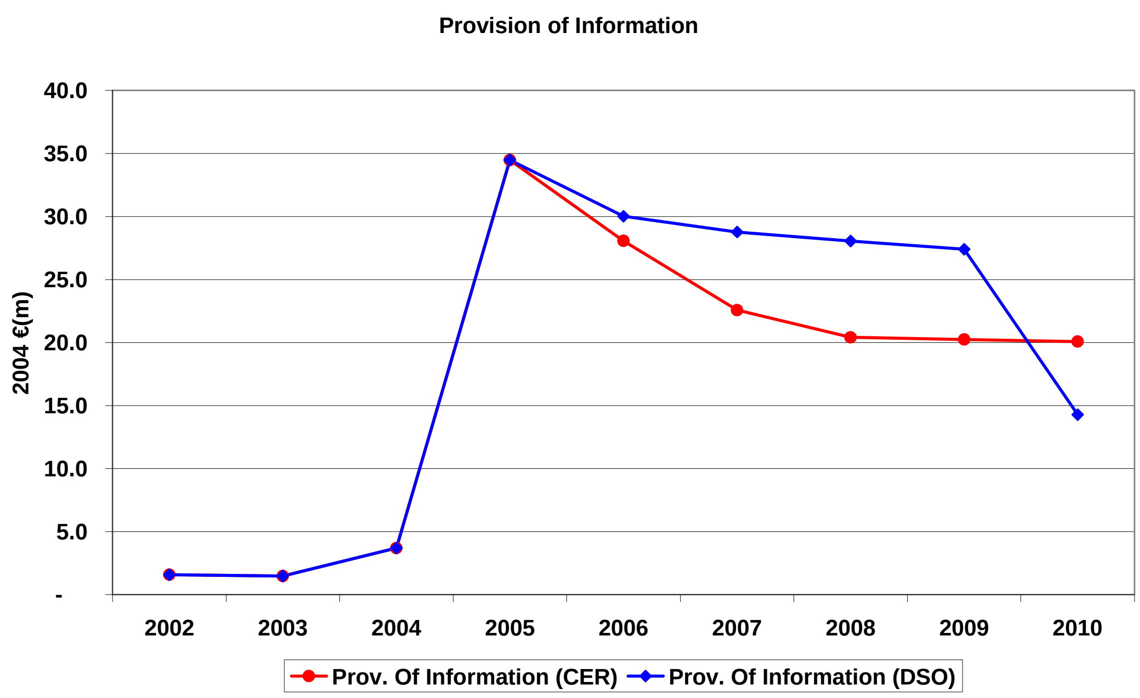
SAP Licenses	1.09	1.09	1.09	1.09	1.09	1.09
Data Centre Infrastructure	0.62	0.62	0.62	0.62	0.62	0.62
Sub-Total IT Infrastructure Operating Costs	**4.68**	**4.68**	**4.68**	**4.68**	**4.68**	**4.68**
Networks Direct Cost of MOIP Support						
ESB ITS MOIP IT Support Charges						
Sub-Total MOIP Support Operating Costs	**10.90**	**7.44**	**6.73**	**6.38**	**6.26**	**6.14**
Less Redundant System Savings	-2.09					
Sub-Total MOIP Incremental Costs	**13.49**	**12.12**	**11.41**	**11.06**	**10.94**	**10.82**
MOIP Original Capex Depreciation	12.05	9.19	7.42	5.65	5.65	5.65
MOIP Knowledge Transfer Depreciation	0.06	0.06	0.06	0.06	0.06	0.06
MOIP Training Backfill Depreciation	0.14	0.14	0.14	0.14	0.14	0.14
MOIP Productivity Backfill	0.15	0.15	0.15	0.15	0.15	0.15
MOIP Additional Capex Depreciation	0.49	0.49	0.49	0.49	0.49	0.49
MOIP Inter Participant Testing Depreciation	0.46	0.46	0.46	0.46	0.46	0.46
Sub-Total MOIP Depreciation	**13.35**	**10.49**	**8.72**	**6.95**	**6.95**	**6.95**
Industry Co-ordination & Design	1.53	3.00				
Market Readiness Co-ordinator	0.92					
Contact Centre Supplier Support	0.45	0.33	0.33	0.33	0.33	0.33
Sub-Total Other Costs	**2.90**	**3.33**	**0.33**	**0.33**	**0.33**	**0.33**
Total MOIP Operating Expenditure	**29.74**	**25.94**	**20.46**	**18.34**	**18.22**	**18.11**

The 2006 – 2010 operating expenditure for ESB Networks MOIP support and IT Infrastructure is acceptable. The depreciation for MOIP must take into account all depreciation related to IT projects which were superseded by MOIP and for which allowance had been made in the MOIP approval. Depreciation for MOIP should be made over an expected useful life of 7 years

The estimated levels of FTEs for MOIP IT Support of 44 in 2006 decreasing in 2007 to 37 are in line with acceptable levels. However, further information on the split of internal to external staff is required and the translation of the FTEs to anticipated costs.

The operating expenditure for the Industry Design and Co-ordination (Design Administration) roles should only be included in the price review for 2005 and 2006. As the budget for the Design Administration role is being approved on an annual basis further operating expenditure for 2007 onwards should be approved each year and included in the Revenue Review at that time.

Provision of Information - Summary

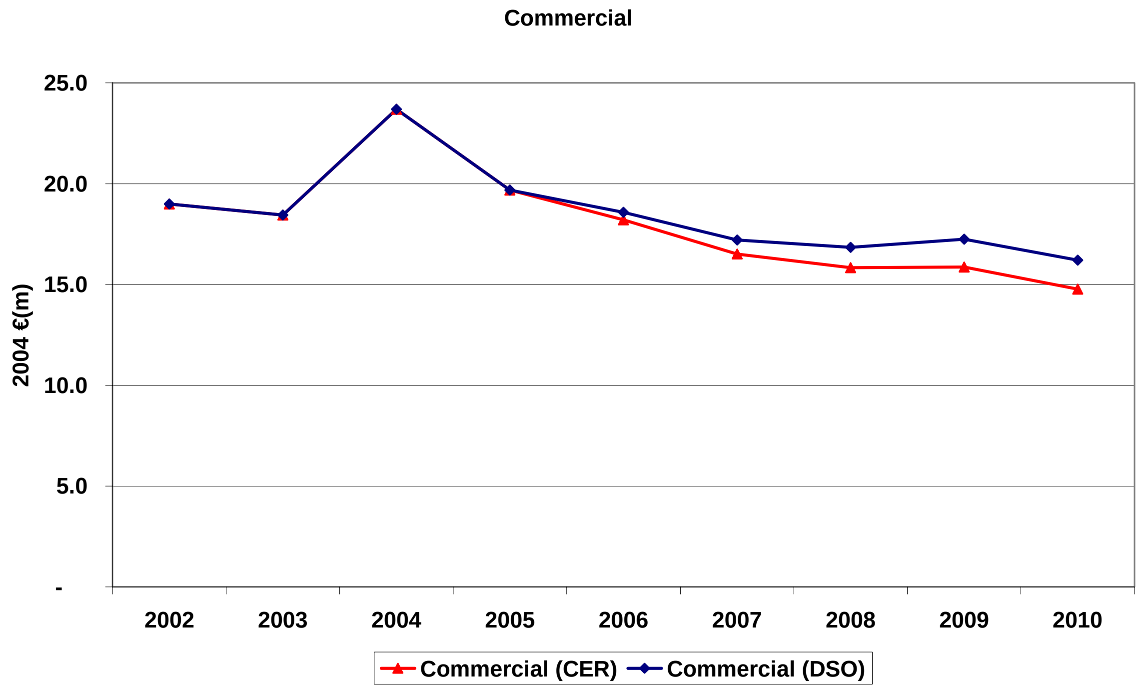


Overall, the Commission has made a reduction of 30.9% on DSO's proposals.

Opex Area		Totals for 2006-2010, € (2004, m)			
		DSO Proposed	CER Proposed	Reduction €	%
Provision of information					
POI - DUoS Billing	(Controllable)	3.5	3.2	0.3	8%
POI - MRSO	(Controllable)	7.7	7.1	0.6	8%
POI - Market Opening	(Non-Cont.)	117.3	101.1	16.3	14%
Total		**128.5**	**111.4**	**17.1**	**13.3%**

G. COMMERCIAL (NON CONTROLLABLE. DSO €86M, CER €81M)

Commercial costs are costs associated with activities which are recovered from third parties including repayable line diversions, third party damage, and energising and de-energising suppliers' customers. The DSO's commercial costs proposals for the period 2006-2010 show a downward trend, following increased expenditure in 2004 and 2005. The Commission is of the view that the unit costs of commercial activities are controllable, and has therefore allowed reduced levels of expenditure. The Commission will review the levels of charges to third parties, and future revenues will be consistent with charges approved following that review. Changes in the charges will result in changes in the allowed expenditure.



Commercial costs are recouped through payments made to the DSO by third parties for the services provided. These costs are subtracted from the Opex total when calculating the required revenue for the DSO; commercial costs therefore do not contribute to DUoS tariffs.

Summary

The Commission has made a reduction of 5.7% of the DSO's proposed Commercial opex. These costs are covered by revenues received for the provision of these services. The levels of these charges will be subject to a separate review, with allowed expenditure/recovery subject to the outcome of that review.

Opex Area		Totals for 2006-2010, € (2004, m)			
		DSO Proposed	CER Proposed	Reduction €	%
Commercial					
C - External repayable / COS adjustments	(Controllable)	49.1	46.4	2.7	
C - Supply repayable	(Controllable)	22.1	20.7	1.3	
C - Other inter ESB	(Controllable)	14.9	14.1	0.8	
Total		**86.1**	**81.2**	**4.9**	**5.7%**

H. CORPORATE (Controllable. DSO €77m, CER €77m)

This expenditure is made up of **company wide costs, corporate affairs** and **corporate charges – general.**

This expenditure is described in detail in the following section.

Corporate centre costs

Within the ESB Group, certain costs are incurred and recorded at the corporate centre. These are referred to as Corporate Overheads, and mainly relate to administration and management costs of the ESB Group.

Typically, the incurrence of corporate overhead costs cannot be attributed to any particular business unit (s) and as such they cannot be allocated based on cost causation principles.

During the previous revenue control review, the cost centres located within Corporate Centre were:-

- Secretarial & Legal
- Directors & Management
- Regulation & Strategy
- Finance
- Corporate Affairs
- Corporate Finance
- Human Resources
- Other Staff Costs
- Health and Safety
- ESI Levy

As part of the 2001 – 2005 revenue control review, the costs within the centres were reviewed and their level was benchmarked with information from Ofgem's 1997 review.

CER approved levels of corporate overheads (excluding Corporate Affairs) for 2001 were then allocated to the different separated businesses[41] within ESB on a variety of basis, including:

- Staff Numbers
- Basket measure, based on a weighting of turnover, profit, staff numbers and assets of the businesses in equal proportions to derive a percentage allocation to each business

For the succeeding years in the price control period, the amount to be allocated to each business was based on the 2001 value indexed at an annual rate of CPI - 2%.

In respect of corporate affairs an amount of €1.47[42] per customer was allowed in the Distribution business only, as a reasonable level of expenditure on customer relations within the business. Health and Safety costs were also allocated 100% to Distribution.

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[41] These allocations also took into account the amounts that be should notionally be allocated to ESB's unregulated activities.

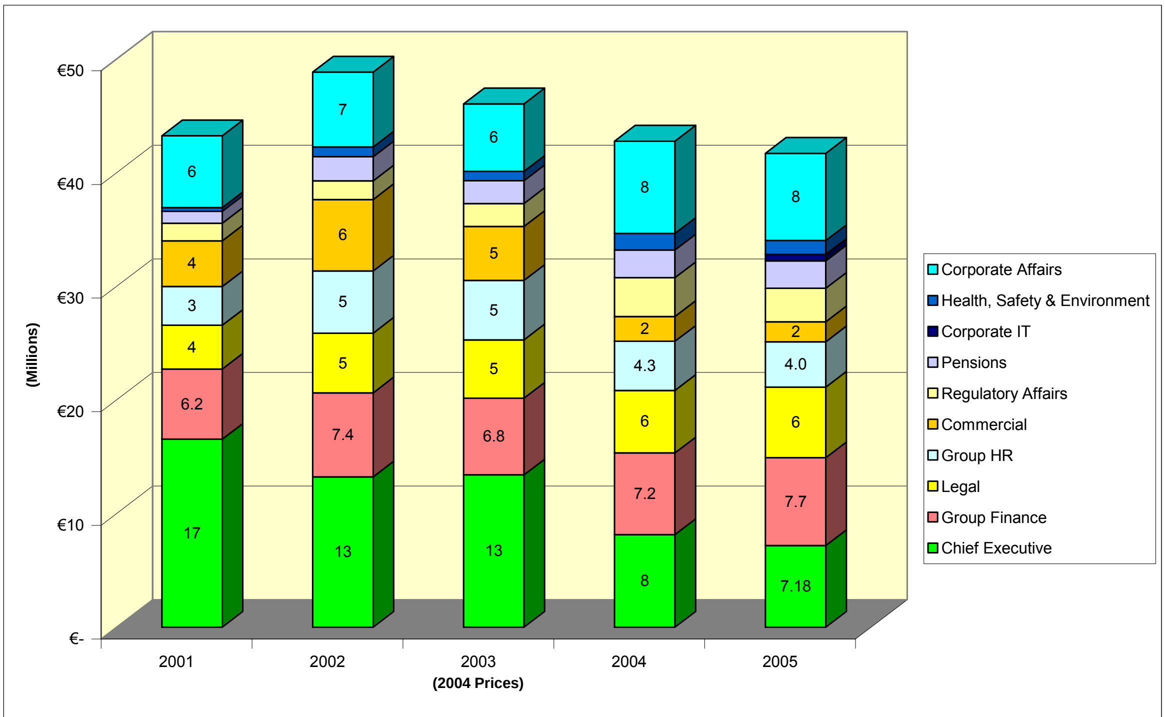
[42] 2004 prices

Subsequent to the review the corporate cost centre changed to the following structure:

- Chief Executive
- Group Finance
- Legal
- Regulatory Affairs
- Health, Safety & Environment
- Insurance[43]
- Corporate Affairs
- Commercial
- Group HR
- Pensions
- Corporate IT

The costs previously recorded in the 'Other Staff Costs' and 'ESI Levy' cost centres are now recorded in the individual ESB businesses.

Between 2001-2005, ESB incurred the following corporate costs.



A comparison of the total corporate costs (excluding Corporate Affairs) incurred by ESB with the amount approved by CER is as follows:

	2001	2002	2003	2004	2005
2004 Prices	**€'mil**	**€'mil**	**€'mil**	**€'mil**	**€'mil**
ESB corporate costs	36.9	42.3	40.1	34.7	34
Corporate Costs allowed within regulated revenue	37.7	37.0	36.2	35.5	34.8
Difference	(0.8)	5.3	3.9	(0.8)	(0.8)

The corporate cost allowance approved by CER included approximately € 10 m in costs that ESB now records in the accounts of the separated businesses (as

[43] Insurance premiums are not included within corporate overhead charges and are dealt with as costs within the businesses. They are not considered further in this section.

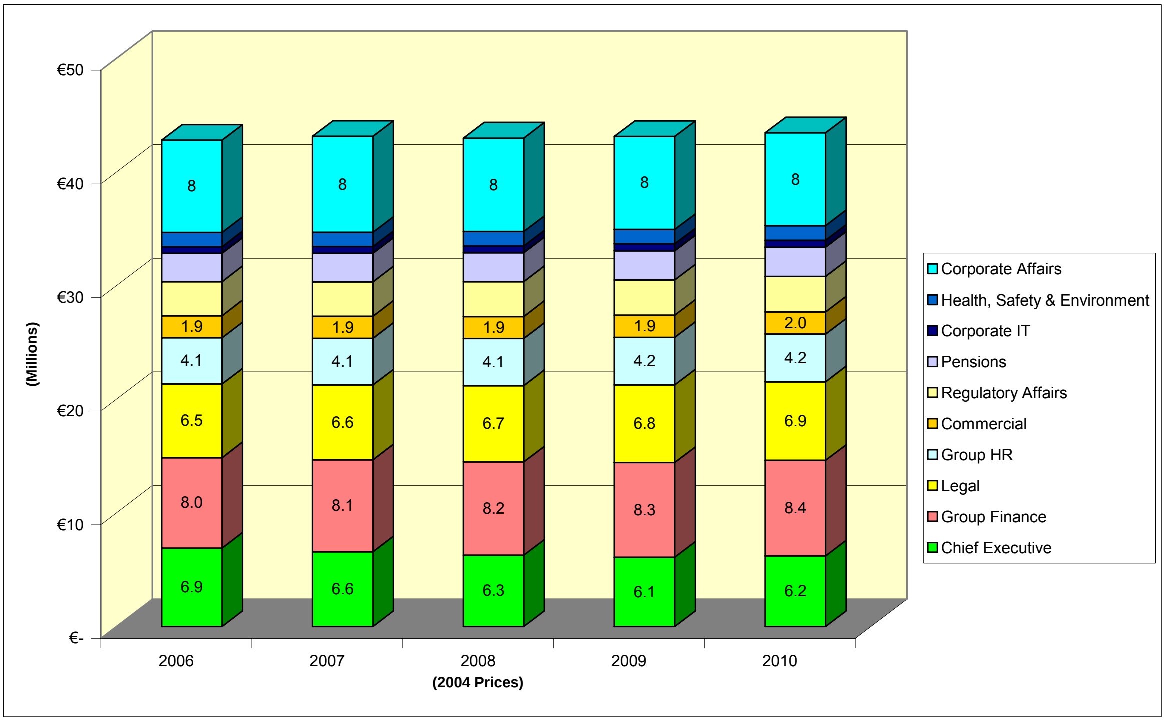
outlined above). ESB did not receive any additional revenue in relation to these costs other than that included in the corporate overhead allowance.

Between 2001 and 2002 there were significant cost increases in a number of the corporate centres due to increased staff costs and professional fees. These were mainly in the following cost centres:

- Pensions (100%)
- Group HR (61%)
- Commercial (56%)
- Legal (36%)
- Group Finance (20%)

By 2004, reductions in the amount of professional fees in the Chief Executive and Commercial cost centres had reduced the overall level of corporate costs.

For the period 2006 – 2010, ESB has forecasted the following levels of corporate costs.



As can be seen from the above chart the main cost headings within corporate overheads in 2006 are:

- Corporate Affairs (19%)
- Group Finance (19%)
- Chief Executive (16%)
- Legal (15%)
- Group HR (10%)

Over the 5 years corporate overheads are forecasted to increase by 1% in total, with a forecasted 10% decrease in Chief Executive costs being compensated for by increases in other centres principally Group Finance and Legal.

The forecasted level of Corporate Overheads (excluding Corporate Affairs) for 2006 is higher than the equivalent 2005 corporate overhead allowance after adjusting for costs that are now recorded in the individual businesses. The majority of this difference arises in the following cost centres:

- Group Finance
- Legal

The operating costs of the international companies used to benchmark the operating costs of each of the separated businesses include all relevant management and administration costs for each business.

Within ESB some of these costs are incurred at a corporate level, whilst others are recorded within the individual business units. The costs incurred at corporate are allocated to each of the business and become part of their operating cost base.

As separation of the regulated businesses within ESB became more developed during the last review period, the various regulated businesses have expanded their own capabilities to operate as individual business units.

Taking account of the above, and in consideration of comments received to the Consultation paper and receipt of further detail from ESB Corporate supporting Group Finance cost requirements, the Commission has decided on the following basis for forecasting 2006 - 2010 Corporate costs.

Cost Centre	2006 – 2010 Cost Forecast
Chief Executive	Based on forecast 2006 costs with the continuation of the annual 2% cost reduction[44] in real terms from the previous review In order to bring the cost base of the regulated businesses in line with international benchmarks.
Insurance	Excluded from Corporate Overheads. These costs are dealt with as a separate cost in each of the separated businesses based on their individual needs.
Corporate Affairs	No allowance is to be given for these except for an amount of €1.50 per customer in the Distribution business for customer relations within the business, as set out in the 2001-2005 review.
Group Finance	Group finance carries out range of activities covering - Group Accounting (consolidated accounts, internal audit, etc.) - Taxation - Treasury

[44] Set in the previous Revenue Control review

	CER has decided that the costs associated with the preparation of consolidated Group accounts and reporting will not be borne by the individual regulated businesses as these costs wouldn't be incurred by the regulated businesses if they operated on a standalone basis. Following review of further detail received from ESB supporting cost requirements, CER has decided to reduce the costs of Group Finance by a 4% (instead of 35%[45] originally stated in the consultation paper) to reflect these disallowed costs from the regulated businesses. CER has based its allowed costs on the amounts forecasted for 2006 with the continuation of the annual cost reduction of 2% from the previous review. This is to bring the cost base of the regulated businesses in line with international benchmarks.
Legal	Excluded from Corporate Overheads. These costs are dealt with as a separate cost in each of the separated businesses based on their individual needs.
Group HR	Based on forecast 2006 costs with the continuation of an annual reduction of 2% in costs to bring the cost base of the regulated businesses in line with international benchmarks.
Commercial	The Commercial cost centre includes the following activities: - Corporate Strategy - Major investment /divestments - Examination of Major Corporate Projects as required - Individual Governance Roles (e.g. Subco directorships, etc.) - Ongoing review of Board papers providing technical and commercial input - Business Separation – Programme Management Based on the above activities CER has decided that it is not appropriate to allocate these costs (apart from Corporate Strategy and Business Separation – Programme Management) to the regulated businesses as they relate to Group activities and not the operations of the regulated businesses. ESB has not provided sufficient information to separately identify these costs. CER has decided to allow only 50% of costs of Commercial sought by ESB to the regulated businesses. CER has based its allowed costs on the forecast 2006 costs with the continuation of the annual cost reduction of 2%. This is to bring the cost base of the regulated

[45] Based on an international FTE activity analysis benchmark

	businesses in line with international benchmarks.
Regulatory Affairs	Based on forecast 2006 costs with an annual reduction of 2% in costs to bring the cost base of the regulated businesses in line with international benchmarks.
Pensions	Based on forecast 2006 costs with an annual reduction of 2% in costs to bring the cost base of the regulated businesses in line with international benchmarks.
Health, Safety & Environment	Based on forecast 2006 costs with the continuation of the annual reduction of 2% in costs to bring the cost base of the regulated businesses in line with international benchmarks.
Corporate IT	This is a new cost centre within Corporate and contains the costs of ESB's Chief Information Officer. The allowed costs are based on forecast 2006 costs with an annual reduction of 2% in costs.

The impact of the above on Corporate Costs is

Cost Centre	2006	2007	2008	2009	2010
	€'mil	**€'mil**	**€'mil**	**€'mil**	**€'mil**
Chief Executive	6.8	6.4	6.2	6.0	6.1
Commercial[46]	1.0	0.9	0.9	0.9	0.9
Regulatory Affairs	2.9	2.9	2.8	2.8	2.7
Corporate IT	0.6	0.6	0.6	0.5	0.5
Group Finance	7.5	7.4	7.2	7.1	6.9
Health, Safety & Environment	1.2	1.2	1.2	1.1	1.1
Group HR	4.0	3.9	3.8	3.8	3.7
Pensions	2.4	2.4	2.3	2.3	2.2
	26.4	25.7	25.0	24.4	24.2

The above corporate overheads shall be allocated using the following basis.

Cost Centre	Allocation Basis
Chief Executive	Basket measure for all business units within ESB Group i.e. including subsidiaries and unregulated businesses
Insurance	Excluded, as dealt with in the cost base of each business
Corporate Affairs	€1.50 per customer in the Distribution business
Group Finance	Tax and Accounting (77%) - Basket to all Business Units within ESB Group Treasury (23%) - Basket to DSO, TAO and PG

[46] The residual 50% of Commercial costs (€ 4.6M) may be recovered from non-regulated ESB businesses.

Commercial	Basket measure for all business units within ESB Group
Group HR	Group staff numbers
Regulatory Affairs	Basket measure for Regulated Businesses
Pensions	Group staff numbers
Health, Safety & Environment	DSO, TAO and PG based on staff numbers.
Corporate IT	Basket measure for all business units within ESB Group

ESB had proposed that modifications be made to the definitions of Turnover and Profit used in the basket measure. These modifications were

- Turnover be defined as 'Turnover less upstream costs'
  ESB has proposed that the allocation to PES be based on its third party turnover only rather than total PES Turnover which includes revenue related to upstream costs.

- Profit be defined as 'Normalised profit'
  Normalised profit would be the profits of the business units excluding the impact of any deferred revenues.

For the purpose of the allocation methodology, the Commission has defined 'Profit' as 'allowable profit' from a regulatory perspective and to define PES's 'Turnover' as 'turnover less upstream costs'.

DSO Corporate Costs 2006-2010

The Commission has calculated that the DSO's share of general corporate costs over the period is €51.4m. This was based on further data provided to the Commission following the publication of the consultation paper.

The Commission has allowed corporate affairs expenditure of €1.50 per customer per annum, and reduced expenditure on company wide costs on an annual basis from 2005 levels.

Opex Area		Totals for 2006-2010, € (2004, m)			
		DSO Proposed	**CER Proposed**	**Reduction €**	**%**
Corporate					
Company wide costs	(Controllable)	9.8	8.9	0.9	9%
Corporate Affairs	(Controllable)	16.5	16.3	0.2	1%
Corporate Charges - General	(Controllable)	50.7	51.4	-0.7	-1%
Total		**77.0**	**76.6**	**0.3**	**0.4%**

I. OTHER (Controllable and Non-Controllable. DSO €1176m, CER €871m)

Other expenditure is made up of **network depreciation, rates, insurance, pension** and further "**other**" costs.

Network depreciation (DSO €955, CER €653m)

Network depreciation is wholly dependent on past capital expenditure and the profile of the RAB. At present, due to the profile of historic investment, there are more assets entering the RAB due to current investment than there are assets leaving the RAB as they become fully depreciated. This means that as a result of the levels of capital expenditure in recent years, together with the capex allowed for the period 2006-2010, network depreciation will continue to increase steadily.

The DSO proposals for network depreciation costs were based on a 40 year asset life. The Commission's allowed opex has been calculated on the basis of a 45 year asset life.

Rates, insurance and pension costs (DSO €179.3m, CER €179.3m)

Expenditure on rates and insurance (€178.1m) will be allowed as a pass through cost provided the DSO incurs these costs in an efficient manner, with the annual revenue setting formula adjusting for any changes from forecast levels. The DSO will need to provide evidence to the Commission that these have been reasonably incurred.

Pension costs have been allocated under corporate centre costs. The expenditure allowed for here refers to additional payments made by the DSO to match employee payments for additional pension service, where certain employees are entitled to make such payments.

The Commission has accepted the DSO forecast costs for rates and insurance; adjustments will be made to annual revenues for any differences from forecasts.

Further Opex Costs (DSO €42m, CER €39m)

A number of further costs fall under the opex heading of "Other". These items include legal costs, ESI levy, Environmental, Revenue, Health and Safety, Networks Publicity and Miscellaneous. These are all partially controllable costs, with the exception of the ESI levy.

The Commission has accepted the DSO's proposals for such items, providing they are reasonably incurred. However, the Commission has not allowed some health and safety costs as they have already been included under corporate costs. The total allowed opex is €38.9m

PSO levy

The Public Service Obligations (PSO)[47] levy is paid by all customers to their suppliers. For accounting purposes this is included as an operational cost of the DSO, as they collect this revenue from suppliers, but is not part of the required revenue since it is offset by PSO income.

Summary

The majority of expenditure under the heading "Other" is uncontrollable; the main driver for this expenditure is network depreciation. Total opex falling under the category "other" is summarized in the table below.

Opex Area		Totals for 2006-2010, € (2004, m)			
		DSO Proposed	**CER Proposed**	**Reduction €**	**%**
Other					
Network Depreciation	(Non-Cont.)	955.0	652.5	302.5	32%
Rates	(Non-Cont.)	158.4	158.4	0.0	
Insurance	(Non-Cont.)	19.7	19.7	0.0	
Pension	(Non-Cont.)	1.2	1.2	0.0	
Subtotal		1134.3	831.8	302.5	
Other					
Legal	(Controllable)	10.9	10.9		
ESI Levy	(Non-Cont.)	7.3	7.3		
Environmental	(Controllable)	2.9	2.9		
Revenue	(Controllable)	5.0	5.0		
Health & Safety	(Controllable)	14.7	11.8		
Networks publicity	(Controllable)	0.3	0.3		
Misc	(Controllable)	0.8	0.8		
Subtotal		41.8	38.9	2.9	6.9%
Total		**1176.1**	**870.7**	**305.4**	**26.0%**

8.4.2 Implications of Capex spend – physical system and business systems.

The focus of the extensive capex during 2001-05 on improving system reliability and reducing maintenance volumes suggest that Opex costs should fall for the DSO assets during the 2006-10 period. In addition, expenditure on new business and IT systems should also lead to reduced opex costs. This has been reflected in the Commission's allowed expenditure for a number of items in the section above.

[47] See Statutory Instrument No. 217 of 2002, Electricity Regulation Act 1999 (Public Service Obligations) Order 2002.

8.5 OPEX ALLOWANCE

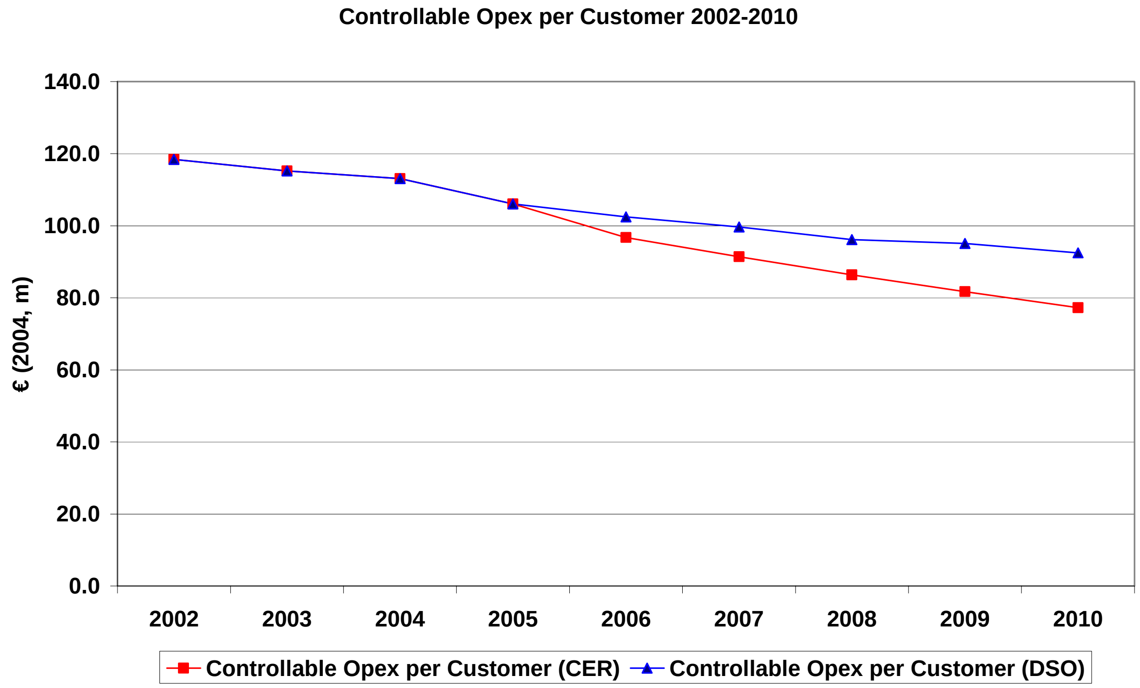
The table below summarises the DSO and Commission's allowed operating expenditure for the period 2006-2010.

Opex Areas	DSO	CER	Reduction €	%
Capital Driven Opex	**107.8**	**95.1**	13	12%
Network Operations & Maintenance	**480**	**427.2**	53	11%
Asset Management	**57**	**52.3**	4	8%
Metering	**99**	**90.9**	8	8%
Customer Service	**102**	**98.1**	4	4%
Provision of information	**129**	**111.4**	17	13%
Commercial	**86**	**81.2**	5	6%
Corporate	**77**	**76.6**	0	0%
Other (Non-Controllable):				
Network Depreciation	**955**	**653.1**	302	32%
Rates, Insurance and Pension	**179**	**179.3**	0	0%
Other (Controllable)	**42**	**38.9**	3	7%
Total	***2312***	***1904***	***408***	***17.7%***
Non-Controllable Opex	**1278**	**964**	**314**	**24.6%**
Controllable Opex	**1034**	**940**	**94**	**9.1%**

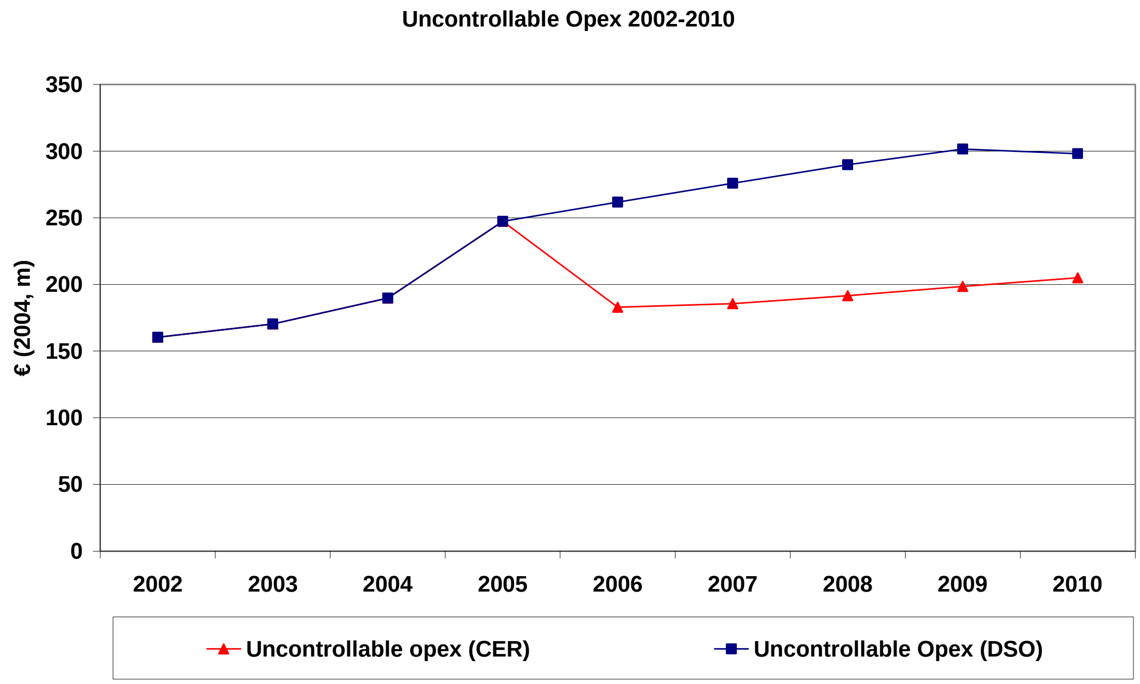
Trends in Controllable and Non-Controllable Opex 2002-2010

From the table above, it can be seen that controllable opex under the Commission's proposals makes up just under 50% of total opex. The graph below shows the trend in controllable costs per customer over the period 2002-2010.[48]

[48] Controllable Opex for the period 2002-2005 was defined above in section 9.2.2 as total opex less opex on capital driven opex, market opening, commercial opex, rates, network depreciation, insurance, pension and elements of further opex classified as other. For the purposes of the graphs below, for the full period 2002-2010 non-repayable line diversions, commercial costs and "other" costs have been included as a controllable cost, while call centre costs have been excluded.



The graph below shows the trends in uncontrollable costs; the step change in 2006 reflects the shift to a depreciation of network assets over a 45 year period, rather than a 40 year period as had been the case from 2002-2005. Uncontrollable costs are made up largely of network depreciation costs.



In summary:

- Controllable opex:

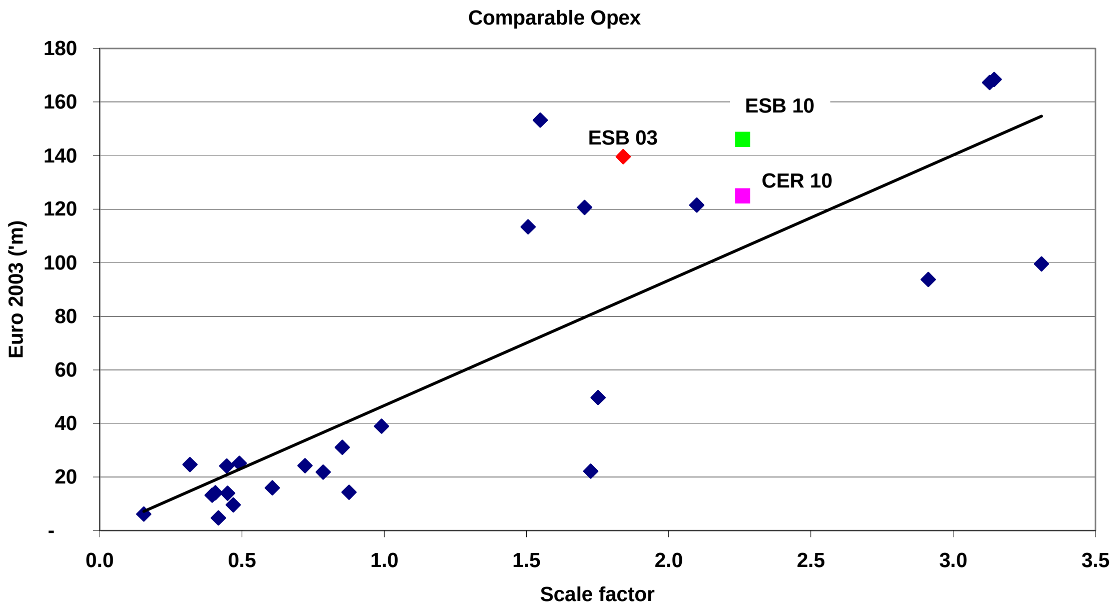
- The DSO propose a small rise in overall controllable opex throughout the 2006 – 2010 review period
- However, this corresponds to a reduction in controllable opex per customer of 11% by 2010 against 2005 levels
- The allowed opex will result in a reduction in controllable opex per customer of 25% by 2010 against 2005 levels
- The Commission has decided that line diversions will be classified as partially controllable opex and that dismantling will be treated as partially controllable capex rather than opex

- Uncontrollable opex has increased consistently from 2002 to 2005 by 58%
- Uncontrollable opex, following the Commission's decision, will make up approximately 50% of overall opex over the period 2006-2010, with 2010 levels 19% below 2005 levels, and 25% above 2002 levels.
- The main driver for this is the change in network depreciation costs – these rose annually in the first control period. The Commission's decision to change the asset lives to 45 years reduces the network depreciation element of opex.

Finally, to understand the impact on the DSO's opex, the DSO's and Commission's 2010 opex forecasts were converted to 2003 prices and benchmarked (using the information from the earlier benchmarking section).

The comparable opex results are presented in the figure below and show that the Commission approved opex is expected to result in the DSO's comparable opex being closer aligned with average industry expectations. It is important to note however that it would be expected that the average industry expectations line would be at a lower level in 2010 than the line shown for 2003.

Comparable opex - 2010 allowed opex and DSO allowed opex against benchmarks



Opex income streams

The allowed opex will be offset by a number of opex income streams. These include income from Commercial Expenditures, a portion of profit from the disposal of assets and other miscellaneous income. These items reduce the allowed revenues by approximately €113m over the period 2006-2010.

Conclusion:

The following table summarizes the allowed opex for each activity for each year over the period 2006-2010.

Opex Area	€ (millions, 2004)					
	2006	2007	2008	2009	2010	Total
Capital Driven Operations						
CDO - Non Repayable Line Diversions	20.4	20.0	18.8	18.1	17.7	95.1
Network Operations and Maintenance						
NOM - System control	18.1	17.5	17.0	16.1	15.4	84.2
NOM - Planned maintenance	37.8	37.8	38.2	38.6	38.6	191.0
NOM - Fault maintenance	33.6	32.1	30.7	28.6	27.0	152.0
Asset Management	11.1	10.8	10.6	10.1	9.7	52.3
Metering						
M - Meter reading	9.7	9.7	9.7	9.7	9.6	48.4
M - QH Data	1.6	1.5	1.6	1.6	1.6	7.8
M - Data Aggregation	4.7	4.6	4.5	4.3	4.1	22.3
M - Customer meter operation	2.7	2.6	2.5	2.4	2.2	12.4
Customer Service						
CS - Call centre	5.4	5.7	6.1	6.6	7.0	30.8
CS - Area Operations	12.9	12.7	12.4	11.9	11.5	61.4
CS - Customer relations / Other Cust Service	1.4	1.2	1.2	1.1	1.1	6.0
Provision of Information						
POI - DUoS Billing	0.8	0.7	0.7	0.5	0.5	3.2
POI - MRSO	1.3	1.4	1.4	1.5	1.5	7.1
POI - Market Opening	25.9	20.5	18.3	18.2	18.1	101.1
Commercial						
C - External repayable / COS adjustments	9.9	9.0	9.5	9.5	8.5	46.4
C - Supply repayable	4.2	4.2	4.1	4.1	4.1	20.7
C - Other inter ESB	4.1	3.4	2.2	2.2	2.2	14.1
Other						
O - Depreciation/Amortisation	117.0	124.1	131.4	137.4	143.3	653.1
O - Network Rates	30.5	31.1	31.7	32.3	32.8	158.4
O - Insurance	4.0	4.0	3.9	3.9	3.9	19.7
O - Pension	0.2	0.2	0.2	0.2	0.2	1.2
O - Other (Corporate, other)	23.3	23.4	23.0	22.9	23.0	115.6
Total	380.7	378.2	379.8	381.8	383.5	1904.1

9. PRICE CONTROL

This section describes:

- The overall form of the price control, specifying the approach taken by the Commission and the incentives that it intends to create
- How base and subsequent year revenues have been determined

9.1 STRUCTURE OF THE PRICE CONTROL

The Commission believes that the price controls for each of the ESB's regulated businesses should be set using a common set of principles. Applying different principles for each business would risk creating an inconsistent set of incentives. However, in developing the detailed proposals for each business, the Commission has taken into account the specific features of each business.

At a general level, the Commission has decided to retain a price control formula of broadly similar form to that currently applied to the DSO. It will contain:

- A rolling retention of benefits achieved through costs lower than target levels. As in the current price control, the DSO will be able to retain these benefits for five years so that it remains neutral as to when in the regulatory cycle those efficiencies are gained. It is up to the DSO to prove the creation of additional benefits and request their inclusion in the rolling retention.
- A factor to account for changes in the number of customers from expected levels
- An incentive linked to the level of distribution losses, allowing the DSO to benefit from reductions in their level
- Uncertain costs, such as those relating to market opening, changes in legislation or other aspects of regulation, will be reviewed on a case by case basis by the Commission
- Pass-through costs should be kept to a minimum. Incentives to minimise pass-through will be applied where practical
- An additional incentive mechanisms to improve quality of service, continuity in supply and call centre performance
- The "K" factor and inter-year adjustments as being broadly the same as in the existing price control

The Commission's position on each of the above is set out below in turn.

9.1.1 CPI-X

The Commission has decided not to continue the application of a strict CPI-X approach. The Commission is setting X at zero, while it has profiled allowed opex to reflect increased efficiencies year on year. This in practice will have the same effect as putting a value on X and profiling the allowed revenues over the control period to drive efficiencies.

9.1.2 Benefit retention

The Commission will continue the use of a five-year rolling retention mechanism since this will deliver the most even distribution of efficiency savings across the duration of the price control.

For opex, the DSO will be permitted to retain the annual savings made for a period of five years, provided such savings have not been made at the expense of performance and quality of service. Therefore, the Commission has included a set of additional incentives to be applied in respect of these elements, which are described below.

In assessing the benefit to be retained on capex, the Commission will pay attention to the cost, volume and quality of the investment made. For example, no benefit will be retained if the DSO were to make savings through reducing the volume of its investment, as this is independent of the benefits defined in its capex plan. The efficiency savings will be reviewed as part of the next price control and as in this review inefficient expenditure will not be allowed into the RAB. Revenue earned on capex not spent will be clawed back, except where the DSO can show that the avoided spend is due to efficiencies on its part.

9.1.3 Cost Drivers

The current Distribution price control formula contains a cost driver based on customer numbers. This is intended to model the impact of changing customer numbers year to year on the DSO's costs so that this can be reflected in its allowed revenue. This factor is used because the impact of customer numbers is deemed to be outside the DSO's control.

The Commission has considered the use of a broader set of cost drivers for the period 2006 to 2010. For example, Ofgem, in its recent Distribution Network Operator review, has adopted a "composite" cost driver, comprising customer numbers, network length and GWh distributed. Such a composite driver has the benefit that it reflects greater diversity in the factors influencing the business's costs.

The Commission modelled the impact of using a composite driver. The work involved taking different combinations of the three components and using different functional forms (principally linear and log based). In each case, the composite variable proved to be less accurate at predicting the DSO's costs than using customer numbers alone. On the assumption that the cost structure of the DSO will not be substantively different in the future, the Commission has decided not to change the current approach - that is to continue the use of customer numbers as the sole cost driver.

9.1.4 Uncertain costs

Uncertain costs are defined as those that could not reasonably be foreseen by the business and comprise elements such as:

- SEM related costs and others related to market opening
- Changes in legislation or regulation that impose a cost on the company, such as environmental restrictions

- Restructuring costs driven by changes in legislation

The Commission has decided that such costs should be dealt with on a case-by-case basis. In each case, the DSO would be expected to ensure that changes in opex or new capex would take place in an efficient manner and this would be reflected in the allowance provided – that is there would not be an automatic pass-through of such costs.

9.1.5 Pass-Through Items

The previous price control contained a provision for the pass-through of certain types of costs, such as business rates, that are deemed to lie outside the business's control. The Commission will continue to use this approach.

However, as with "uncertain costs", the Commission believes that the DSO should provide evidence that it has attempted to minimise such costs through negotiation wherever possible. The DSO, therefore, will be required to provide a detailed justification of this expenditure and to have demonstrated that it has taken reasonable steps to minimise their impact as part of the annual review process.

9.1.6 Additional incentive mechanisms

The DSO's current price formula contains three key incentives:

- The value of "X", to drive overall efficiency gains
- To reduce the level of distribution losses below a target level
- To reduce customer minutes lost below a target level.

For the latter two items, the previous price control contained target levels for each year and a monetary rate to be applied to the differential between actual and target values. This adjustment was made year on year and provided a continuous incentive to improve performance.

The Commission will continue to use this general approach and to broaden the range of factors to be taken into account. Specifically, the Commission has decided that the following will be included:

- Quality of response from the Customer Contact Centre. This incentive will be based on a target response time to customer enquires. The aggregate penalty or benefit in respect of this element will be set at 1.5% of the DSO's allowed revenue
- Supply interruptions. This will be based on a combination of customer minutes lost, as now, together with the number of interruptions that have occurred and will encompass both planned and unplanned outages. Targets will be set for both elements and a penalty or benefit applied. The Commission notes that the target levels will have been set in conjunction with improvements in performance associated with the DSO's capex plans. The total penalty or benefit associated with this component will be set at a maximum of 1.5% of allowed revenue
- Customer Charter. In the event that the DSO fails to make payments due to not meeting customer charter requirements, such shortfall will be recovered

through the price control mechanism. An extra 10% of the outstanding payments will be added to provide an additional incentive for the DSO to ensure it makes all customer charter payments due.

The impact of all incentives will be limited to 4% of the DSO's allowed revenue. The targets and values used to operationalise these incentives are described below. However, for 2006 the limit is set at 2.5% as a transition step to the 4% limit which will apply from 2007 to 2010.

9.1.7 Inter-year Adjustments for over or under recovery

Alternative approaches to the current two-stage "K" factor mechanism have been considered by the Commission (including the use of a single step correction). However, despite its complexity, the Commission has taken the view that there is little justification for changing the current approach.

9.2 DETERMINATION OF BASE YEAR REVENUE AND ITS PROFILING ACROSS THE REGULATORY REVIEW PERIOD

Subsequent sections of this document set out how the various components of the DSO's regulatory revenue have been determined and how expected efficiency improvements have been used to determine the future path of regulatory revenue. In this section, the principles that have been applied to that calculation are set out.

In general terms, the Commission has sought to strike a balance between:

- Allowing the DSO to make the investments required to develop the Irish distribution system
- Ensuring that the DSO provides Irish consumers with value for money
- Incentivising efficiency gains on a continuous basis throughout the price control period

Providing the business with sufficient revenue to operate the system, develop it and provide a reasonable return on its assets. Ensuring that the DSO has sufficient cashflow to finance its operations has been a necessary component in the Commission's thinking.

In this section we present the Commission's allowed regulated revenues and price control for the DSO during the period 2006 to 2010**.**

9.3 KEY PRINCIPLES

Ensuring that the DSO has sufficient revenue throughout the period to maintain effective operations is core to the price control. Specifically, the DSO should be able to finance its planned investment, operating costs, financing costs and taxation liabilities. The Commission has therefore developed a cash-flow model of the DSO designed to ensure the compatibility of the price control with these objectives.

However, as noted in section 10.1 the Commission also has the objective of improving the DSO's efficiency over time so that it more closely matches the performance of its peers. Therefore, the Commission has included a set of incentives linked to key performance indicators within the price control formula to encourage specific desirable behaviours. The penalties associated with these incentives will be capped at a level that does not endanger the DSO's secure continued operation.

9.4 ALLOWED REVENUE

Table 10.1 sets out the allowed revenue calculation and is structured as follows:

- The calculation commences with the opening RAB, as defined in Section 6.
- Allowed Capex is then added and depreciation subtracted from the RAB for each successive year of the price control period
- Allowed operating costs are added, together with any deferred revenue from previous years (i.e. through the operation of the K factor).
- The next stage of the calculation is to determine the NPV of the total cash required by the DSO, using the WACC as the basis for discounting.
- Finally, the NPV of the change in the RAB over the price control period (i.e. the opening value less the discounted value of the closing RAB, with the discount rate set at the cost of capital derived in Section 6) is added to the total cash required to determine the net present value of the cash required by the DSO to finance the increase in the RAB over the regulatory period..

CPI-X, as noted above, has not been used as the basis for the price control. A core issue in setting the trajectory of prices is the relative values of X and the starting price level in 2006. By changing the value of X, the price control formula will profile the distribution of revenues over time, while maintaining the same NPV of revenue for the DSO. However, the Commission has profiled the allowed opex in order that continued efficiencies are made year on year. CPI has been allowed.

In this way, the price control is constructed to ensure that that the DSO has sufficient cash to meet its requirements over the price control period.

Table 10.1 below shows the values calculated by the Commission for each of the above.

Table 10.1: Allowed Revenues

RATE OF RETURN	[%]	5.63%					
Real Values (2004)							
			2006	2007	2008	2009	2010
RAB PROJECTION							
Opening	[€m]		3,369.5	3,662.5	3,889.9	4,106.3	4,288.9
Capex	[€m]		420.4	360.2	354.7	327.0	318.5
Depreciation	[€m]		-127.4	-132.9	-138.3	-144.4	-150.2
Closing	[€m]		3,662.5	3,889.9	4,106.3	4,288.9	4,457.2
			2006	2007	2008	2009	2010
Operating Costs	**[€m]**		**225.8**	**223.7**	**221.6**	**217.2**	**214.8**
Clawbacks / Deferrals	**[€m]**		**-19.7**	-5.3	0.0	0.0	0.0
Capex	**[€m]**		**420.4**	**360.2**	**354.7**	**327.0**	**318.5**
TOTAL ANUAL COSTS	**[€m]**		**626.6**	**578.6**	**576.3**	**544.2**	**533.4**
NPV of TOTAL CASH OUTLAY (@ 01/01/2006)	[€m]	**2,485.8**	604.3	527.5	497.3	444.4	412.3
year	[°/1]		1.0	2.0	3.0	4.0	5.0
Index	[°/1]		1.056	1.116	1.179	1.245	1.315
Opening Assets Value	[€m]	**3,369.5**					
NPV of Closing Assets Value	[€m]	**3,389.4**					
Difference	[€m]	-19.9					
NPV REQUIRED CASH	**[€m]**	**2,465.9**					

Table 10.2 and 10.3 below show the Commission's approved and ESB´s proposed profile for the DSO's allowed revenue for the period 2006 to 2010. Figures are shown in 2004 values.

Table 10.2: ESB's proposed profile for the DSO's allowed revenues

		2006	2007	2008	2009	2010	Total
Operating Costs	[€m]	267.3	277.0	277.8	280.1	275.3	1,377.6
Deferrals / K factor	[€m]	44.0	0.0	0.0	0.0	0.0	44.0
Depreciation	[€m]	184.1	191.5	196.3	200.1	201.9	973.8
Cost of Capital	[€m]	146.8	237.7	302.8	373.1	459.6	1,520.0
Total DUoS Required	**[€m]**	**642.2**	**706.2**	**776.9**	**853.3**	**936.8**	**3,915.4**

Table 10.3: the Commission's profile for the DSO's allowed revenues

		2006	2007	2008	2009	2010	Total
Operating Costs	[€m]	225.8	223.7	221.6	217.2	214.8	1,103.1
Deferrals / K factor	[€m]	-19.7	-5.3	0.0	0.0	0.0	-25.0
Depreciation	[€m]	127.4	132.9	138.3	144.4	150.2	693.2
Cost of Capital	[€m]	201.4	216.2	228.8	240.3	250.3	1,137.0
Total DUoS Required	**[€m]**	**535.0**	**567.4**	**588.7**	**601.8**	**615.4**	**2,908.4**

9.5 PRICE CONTROL FORMULA

The Commission has reviewed the price control formula used currently and has introduced a number of changes to reflect the additional incentives that it wishes to apply to the DSO. The new incentives were described in Section 3.4.

The formula is as follows:

$$R_t = \prod_{2005}^{t}[(1+CPI_j - X)/100]*B_0 + \prod_{2005}^{t}[(1+CPI_j)/100*[INCENT_t + PCust_t*(FCust_t - Cust)_t]$$
$$+\Delta P_t + \Delta U_t + K_{t-1} + K_{t-2}$$

Where:

Rt is the maximum level of revenue allowed in year t and the revenues on which the next year's tariffs are based.

CPI is the annual average percentage change in the Irish (all-items) Harmonised Index of Consumer Prices (HICP) for the 12-month period October to September in the year j. Where j>t, CPI_j is a forecast value. Where j<=t CPI_j is the value for Irish (all items) HICP published by Eurostat in *Eurostatistics for short-term economic analysis.*

X is the efficiency factor, set at 0.

B_0 is the level of allowed revenues in real 2006 prices for the DSO in each year of the price control

PCustt is the revenue earned (or foregone) by the DSO for each additional connection above or below forecasted levels. This value is based on the average allowed revenue per customer as determined as $R_t/Cust_t$ in each year t.

FCustt is the Forecast Number of Connections to the system in year t

Custt is the Number of Connections to the system in year t assumed in the determination of B_0.

PL is the amount of revenue per GWh distributed that the Commission will allow ESB to retain (forego) for reducing (increasing) losses compared with allowed losses, in 2006 prices. From the end-user perspective the value of a lost unit is the end-user price he/she faces. This cost, which includes generation, transmission and distribution, is approximately 13 c/kWh (from 2006 supply tariff average unit price). This equates to €130,000/GWh. Consistent with CER's 2001 decision the CER has decided to set PL at a level lower than the end-user tariff as this ensures a balance between giving an appropriate incentive to the DSO and providing a reasonable benefit to the customer. PL is therefore set at €65,000/GWh.

FLt is the revised forecast distribution losses in year t expressed as a percentage of total GWh distributed (this will be converted to absolute terms as the incentive is stated in GWh terms]. This forecast is made before the end of year t-1 when determining the next year's allowed revenue.

Lt is the distribution losses in year t, expressed as a percentage of GWh distributed (this will be converted to absolute terms as the incentive is stated in GWh terms).

INCENTt is the value of incentive penalties in year t in €m in respect of the penalties or payments in respect of the incentives defined in table 10.4. The impact of all incentives will be limited to 4% of the DSO's allowed revenue in each year. (However, for 2006 the limit is set at 2.5% as a transition step to the 4%

limit which will apply from 2007 to 2010.) Each individual incentive term (Customer Minutes Lost, Customer Interruptions, Losses, and Customer satisfaction rating for Call Centre Services) is limited to 1.5% of the DSO's allowed revenue in each year.

The variable is defined as follows:

$$INCENT_t = \min(\sum_i INI_{it} + CHARTER_t, 0.04 * R_t)$$

$$INI_{it} = if(P_{it} * |F_{it} - A_{it}| > 0.015 * R_t, then(if(F_{it} > A_{it}, then 0.015 * R_t, else -.015 * R_t)), else P_{it} * (F_{it} - A_{it}))$$

where: F_i and A_i are as follows:

$\mathbf{F_{it}}$	$\mathbf{A_{it}}$	$\mathbf{P_{it}}$
FCI_t	CI_t	PCI_t
$FCML_t$	CML_t	$PCML_t$
$ESATRAT_t$	$SATRAT_t$	$PSATRAT_t$
$FCust_t$	$Cust_t$	$PCust_t$
FL_t	L_t	PL

and where:

CI_t is the number of customer interruptions per 100 customers in year t and FCI_t the corresponding forecast value

PCI_t is the value applying to deviations from target levels of the number of customer interruptions, in € per unit of CI_t. This will be set in accordance with the values in table 10.4

CML_t is customer minutes lost in year t per customer and $FCML_t$ is the corresponding target value

$PCML_t$ is the value applying to deviations from target levels of customer minutes lost, in € per minute. This will be set in accordance with the values in table 10.4. It is based on estimating the value of a CML using a value of a lost MWh of €7000.

$ESATRAT_t$ is the expected satisfaction rating for Customer Call Centre Services. This will be determined each year based on the PES's performance against defined measurable elements and on customer survey information, gained through surveys conducted by an independent organization approved by the Commission, funded by the ESB under the Commission's direction. The Commission will develop the form of this measure in conjunction with the PES. $ESATRAT_t$ shall be expressed as an index of performance, with a score of 100 representing a perfect rating.

$SATRAT_t$ is the result of the annual performance reporting and satisfaction rating for Customer Call Centre services conducted by an independent organization approved by the Commission, funded by the ESB under the Commission's direction, consistent with the measurable elements and customer survey information contained within $ESATRAT_t$

The detail of the ESATRAT and SATRAT mechanisms is currently being developed by the Commission and the final details will be published before the new tariff year commences.

$PSATRAT_t$ is the payment to be made to or by the DSO defined as a value in € per 1 point deviation (or part thereof) between $SATRAT_t$ and $ESATRAT_t$

$CHARTER_t$ is the value of any unmade payments under the Customer Charter, plus 10%.

PL is the amount of revenue per GWh distributed that the Commission will allow ESB to retain (forego) for reducing (increasing) losses compared with allowed losses, in 2006 prices. From the end-user perspective the value of a lost unit is the end-user price he/she faces. This cost, which includes generation, transmission, and distribution is approximately 13 c/kWh (from 2006 supply tariff average unit price). This equates to €130,000/GWh. Consistent with the Commission's 2001 decision the Commission has decided to set PL at a level lower than the end-user tariff as this ensures a balance between giving an appropriate incentive to the DSO and providing a reasonable benefit to the customer. PL is therefore set at €65,000/GWh.

FLt is the revised forecast distribution losses in year t expressed as a percentage of total GWh distributed (this will be converted to absolute terms as the incentive is stated in GWh terms]. This forecast is made before the end of year t-1 when determining the next year's allowed revenue.

Lt is the distribution losses in year t, expressed as a percentage of GWh distributed (this will be converted to absolute terms as the incentive is stated in GWh terms).

These values shall be set as in Table 10.4 below.

Table 10.4: Components of $INCENT_t$

Variable		2006	2007	2008	2009	2010
FCI_t		200.67	178.27	174.73	172.92	170.66
PCIt		€186,000	€186,000	€186,000	€186,000	€186,000
FCMLt		378.83	230.11	215.09	208.45	201.38
PCMLt		€235,730	€235,730	€235,730	€235,730	€235,730
ESATRATt		To be determined	To be determined	To be determined	To be determined	To be determined
PSATRATt		To be determined	To be determined	To be determined	To be determined	To be determined
PL		€65,000/ GWh	€65,000/ GWh	€65,000/ GWh	€65,000/ GWh	€65,000/ GWh

ΔPt is the change in pass-through costs from those included in Bt, as available when setting tariffs in year t. This includes changes in business rates, MRS costs etc. which the CER has indicated will be allowed on a pass-through basis. These costs will be expressed in Nominal values in year t.

ΔUt is the change in Uncertain Costs allowed by the Commission in year t. This may include costs associated with: market opening; regulatory or legislative changes; or environmental requirements.

Kt-1 is the correction factor, which ensures that prices in year t are adjusted by an amount equal to the difference between what was actually charged in year t-1 and the forecast of what should have been charged, with interest payments added on.

Kt-2 is the correction factor, which ensures that prices in year t are adjusted by an amount equal to the difference between what was actually charged in year t-2 and the forecast of what should have been charged, with interest payments added on.

A. PRICE CONTROL VALUE AND PROFILE

Taking into account the evidence presented by the DSO's distribution business and the Commission's own extensive analysis, the Commission has decided that:

- The price control be set at an allowed revenue of €561m in 2006 (nominal), equating to an average DUoS tariff of 2.47 cents/kWh distributed

- The “X” factor will be set at zero

Based on the approach described above, Figure 10.1 below shows the Commission’s allowed profile for the DSO’s allowed revenue for the period 2006 to 2010. Figure 10.2 shows the price control compared with the DSO’s cash requirement for the duration of the price control. This shows a relatively flat revenue profile over the control period. It should be noted however that forecasted revenues will vary according to the terms of the control formula as described above.

Figure 10.1: Allowed Revenue

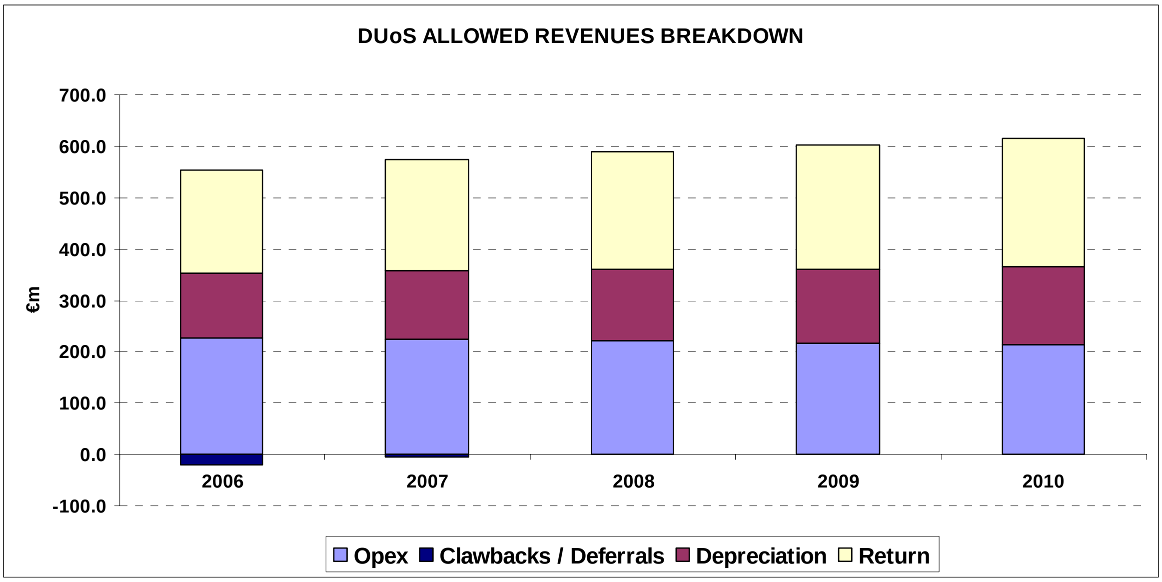


Figure 10.2 below shows the Commission's approved capex and opex, for the period 2006 to 2010, along with the Distribution Use of System Average Tariff (annual and average tariffs). The capex and opex for 2001 to 2005 have been included for reference purposes only.

Figure 10.2 the Commission's allowed capex and opex

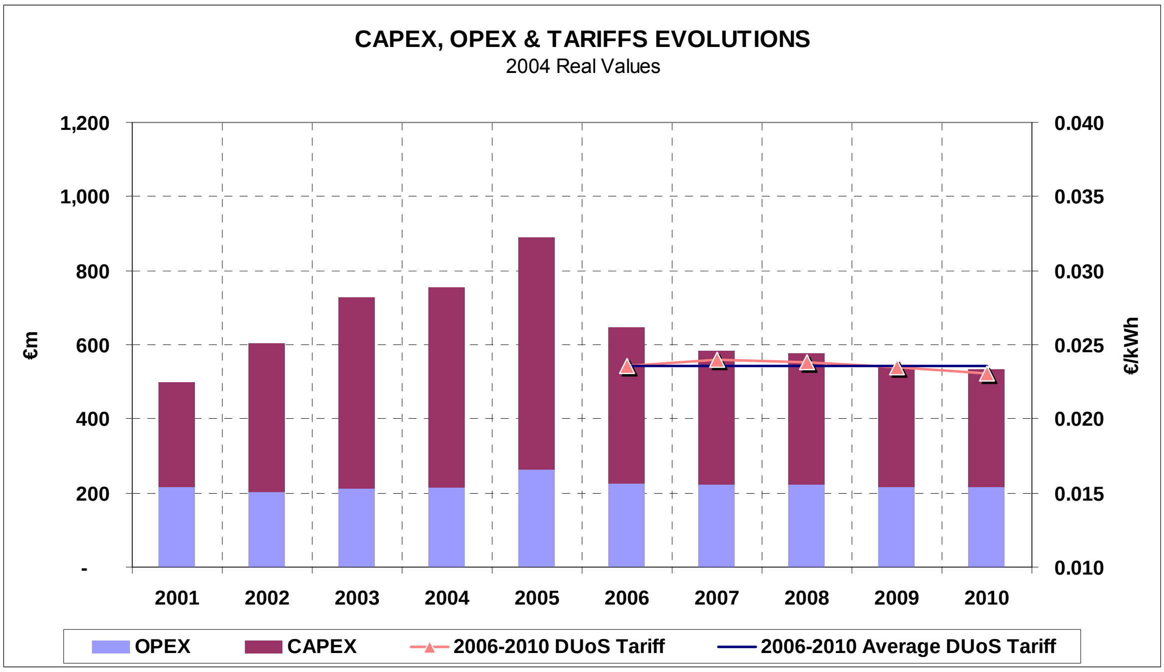
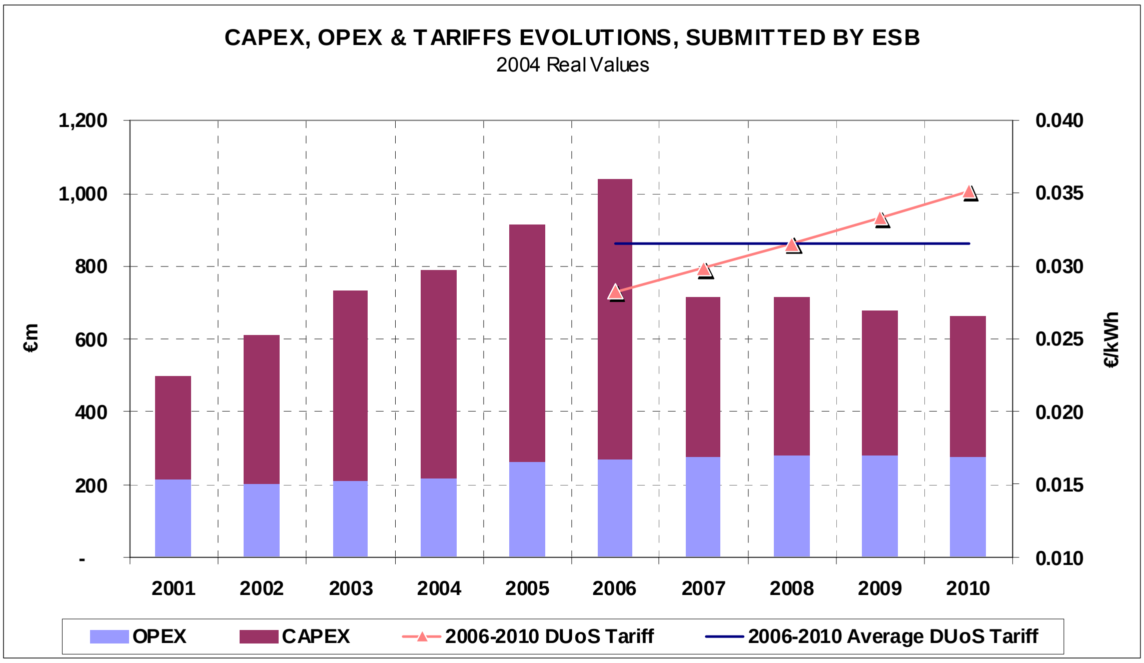


Figure 10.3 shows, for comparison, the DSO's calculation of the DUoS tariff, together with the OPEX and CAPEX it has requested for the next regulatory period.

Figure 10.3: DSO Capex and Opex projections



The Figure shows the substantial difference between the tariffs, resulting from the reduced levels of opex and capex the Commission has allowed the DSO. On average, the difference between the Commission and DSO proposed tariffs is in the region of 0.08c/kWh.

APPENDIX A: UNDERLYING ASSUMPTIONS

The underlying assumptions upon which the DSO 2006 to 2010 price review is based are outlined in table A.1 below.

Table A.1 – Underlying assumptions

	2006	**2007**	**2008**	**2009**	**2010**
Number of customers ('m)	2.01	2.07	2.12	2.17	2.23
Number of regulated units ('000 GWh)	22.73	23.67	24.66	25.64	26.66
Gross potential maximum demand (GW)	4.28	4.49	4.72	4.95	5.20

A.1 GROWTH IN CUSTOMERS AND REGULATED UNITS

CER has accepted the DSO's growth projections based upon

- Forecasts based upon validated historical data
- Growth rates being aligned with average GDP growth expectations
- ESB's demand forecasting process incorporating both a 'bottom up' and a 'top down' approach. The 'top down' approach ensures consistency between ESB's forecasts and the forecasts in the following publications:
    - National Spatial Strategy for Ireland 2002 – 2020
    - Generation Adequacy Report 2005 – 2011

A.2 GROWTH IN POTENTIAL MAXIMUM DEMAND

CER has accepted the DSO's maximum demand projections as it is consistent with:

- The historical trend
- The projections contained in the Generation Adequacy Report 2005 – 2011

Figure A1 shows ESB's distribution forecast, the transmission forecast from the generation adequacy report 2005 – 2011 and an estimate of the distribution maximum demand based upon the transmission forecast. As can be seen, the estimate and ESB's forecast are aligned

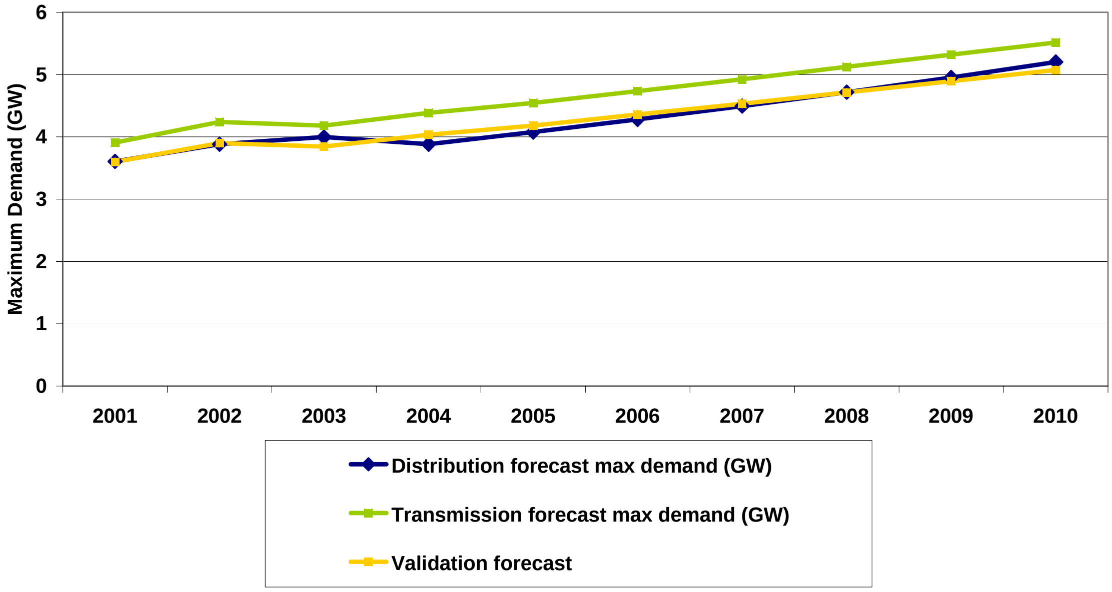


Figure A1 Maximum demand projections

B.1 PA CONSULTING'S BENCHMARKING PROGRAMME

PA performs annual benchmarking studies in the utility industry, in North America and around the world. These studies began in 1989 with the introduction of a transmission & distribution study for electric utilities, and expanded quickly to cover customer services, gas distribution, and later corporate and shared services. The benchmarking studies also include electric system reliability, call centre operations, and metering services for both gas and electric utilities. Figure B1 below summarizes the annual surveys that they run.

Figure B1 – Summary of PA's Annual Benchmarking Studies

Program	Years Performed	Scope of Subjects	Participants
Electric T&D	1989-2005	Cost, service level metrics, best practices, all processes (engineering, construction, operations, maintenance) all areas - transmission, substations, distribution	About 75 utilities annually, 45 North Americans, 30 South Americans, South Africans
Utility Customer Service	1991-2005	Cost, service level metrics, best practices, all customer contact processes - call centres, field service, billing, collections, energy theft	Electric, gas, and water utilities, 45 North Americans, 30 South Americans, 10-15 Europeans, South Africans
Electric Distribution Reliability	1998-2005	Performance measures, reliability improvement approaches	75-85 utilities annually, from North America, South America, and Europe, and occasionally Australians
Gas Distribution	1992-1995, 1999-2001	Cost, service level metrics, best practices for all processes of construction, operations, maintenance, management	30-40 Gas distribution utilities annually, including North and South America, and occasionally Australians
Call Centre Operations	2002	Call centre performance, practices, technology, staffing and outsourcing, and operations management	40 North American Utilities
Electric & Gas Meter Services	2005	Meter asset management, maintenance, supply management	20 North American and European utilities
Corporate & Shared Services	2001-2003, 2005	Cost, Service, Staffing -- for HR, IT, Legal, Accounting, Finance, Safety, Fleet, Supply Mgt., etc.	Electric, gas, and water utilities, North America only until 2005

PA's annual Transmission and Distribution survey covers all aspects of the electric delivery business, including both transmission and distribution. Specific subject areas involved in the study highlight the design, construction, operations, and maintenance of a wires network. Figure B2 below lists the primary subject areas detailed in the annual statistical report.

Figure B2 Subject areas of PA's annual Transmission and Distribution survey

Overall Processes	Distribution Processes	Substation Processes	Transmission Processes
Cost and Statistical Information	Distribution Statistics	Substation Statistics	Transmission Statistics
T&D Statistical Information	Distribution Planning & Design	Substation Planning, Design & Construction	Transmission Planning, Design, & Construction
Focus Area: Customer Count	Distribution Automation	Substation Operations & Maintenance	Transmission Operations & Maintenance
T&D FERC Cost Data	New Distribution Service Connection	Focus Area: Substation Crew Practices	Transmission Contracting
Focus Area: A&G Costs	Distribution Customer Contributions	Substation Work Management Processes	Focus Area: Energy Control Center Operations
T&D Delivery Cost Components	Distribution Field Activity	Substation Contracting	Focus Area: Transmission Hot-Line Maintenance
Translating Budgets to Activities	Distribution PM Programs	Substation Automation	Focus Area: Transmission Vegetation Management
Focus Area: Breakdown by Cost Categories	Distribution Work Management Process	Focus Area: SCADA/Communications	Focus Area: Transmission System Computer Models
Focus Area: T&D Revenue	Distribution Vegetation Management	Focus Area: On-line Monitoring of Substation Components	Focus Area: Transmission Customer CIAC
Electric System Reliability	Focus Areas: Dist. Vegetation Management Practices		
Reliability - End User View	Distribution Contracting		
Distribution Reliability Measurement & Practices	Street Lighting		
Distribution Storm Restoration Practices	Distribution Mobile Computing		
Focus Area: Estimated Restoration Times	Focus Area: Distribution Customer Equipment Trouble Calls		
Distribution Reliability Improvement	Focus Area: Distribution Customer Satisfaction		
Focus Area: Distribution Outage Management Systems	Focus Area: Distribution Wood Pole PM		
Substation Reliability			
Transmission Reliability			
Staffing and Safety			
T&D Safety			
Focus Area: Safety Programs			
T&D Staffing Information			
Focus Area: T&D Overtime			
Focus Area: T&D Work Force Planning			
Focus Area: T&D Training			
Support Processes			
T&D Materials Management			
Focus Area: T&D Support Services			
Focus Area: T&D Meter Shop			
Focus Area: T&D Asset Management			
Focus Area: T&D Project Management			
Focus Area: Contract Management			
Focus Area: IT Change Management Process			
Focus Area: T&D Public Improvement Projects			
Focus Area: Records Management			

B.2 THE SCALING FACTOR

The approach uses a scale factor to reflect cost drivers in the electricity distribution sector as a whole, and is calculated by considering customer numbers, units distributed and circuit length as parameters.

Scale Factor for company i = (1 + 0.25(dUi/Ui + dLi/Li))Ci

- Ci = number of customers;
- dUi/Ui is the proportional deviation in units distributed from the overall average; and
- dLi/Li is the proportional deviation in circuit length from the overall average.

Combining the data in this way allowed an average opex or capex value to be determined for DSO's scale factor. This was done by producing a linear trend line for the benchmarked data (including DSO's values).

It is important to note that the line represents only an average expected value. Best practice for a given scale factor would be below this as only the lowest opex or capex values (not all) would be used for a given scale factor. Thus when comparing DSO's opex or capex values to this line, is comparing the DSO to only the average, not best practice.

As an example, for DSO's scale factor:

- Number of customers = 1,805,000 approx

- Units distributed = 20,080,000 MWh pa approx
- Line Length = 151,822 kms

Thus for the DSO:

- Units distributed / customer = 11.124 approx i.e. (20,080,000/1,805,000)
- Line Length per customer = 0.084 approx i.e. (151,822/1,805,000)

Benchmark averages:

- Units distributed / customer = 30.57
- Line Length per customer = 0.049

Thus for the DSO:

- dUi / Ui = -0.636 i.e. (11.124-30.57)/30.57
- dLi / Ui = 0.714 i.e. (0.084-0.049)/0.049
- Scale factor = 1.84 = [1+0.25(-0.636+0.714)]*[1,805,000/1,000,000]

APPENDIX C: OPEX AND CAPEX MEASURES USED IN BENCHMARKING

This appendix outlines the DSO's and capex and opex categories that are contained within each of the benchmark measures:

- Comparable opex
- Load related capex

C.1 OPEX - COMPARABLE OPEX

DSO's comparable opex is broken down as follows:

Included	Excluded
NOM - System control	CDO - Non Repayable Line Diversions
NOM - Planned maintenance	CDO – Dismantling
NOM - Fault maintenance	M - Meter reading
NOM – Other	M - QH Data
Asset Management	M - Data Aggregation
C - External repayable / COS adjustments	M - Customer meter operation
C - Supply repayable	CS - Call centre
C - Other inter ESB	CS - Area Operations
O – Other	CS - Customer relations / Other Cust Service
	POI - DUoS Billing
	POI - MRSO
	POI - Market Opening
	O - PSO
	O - Network Rates
	O - Depreciation/Amortisation

Legend: CDO – Customer Driven Opex; NOM - Network Operations & Maintenance

M – Metering; CS – Customer Service

POI – Provision of Information; C - Commercial

O - Other

C.2 LOAD-RELATED CAPEX

The load driven capex is broken down as follows:

ESB Included	ESB Excluded
New Business:	Non network capex
(i) Commercial/Industrial Supplies	Non load related expenditure
(ii). New housing Schemes	
(iv) Non-scheme Houses	
(v) Whole Current Metering	
Reinforcements	
Generation Connections	
Removal of under-utilised assets	

APPENDIX D: COMPONENTS OF NON NETWORK CAPEX

The main items included through this period for Asset Management are:

- Asset Register and Maintenance management – at a cost of €7.6m to improve the effectiveness of maintenance planning and condition monitoring.
- Mobile Workforce management –at a cost of €8.9m to improve productivity and reduce waiting and travel time.
- Integrated WAMS – at a cost of €5.3m to improve productivity through the provision of work order generation and resource scheduling.

For Control/Operations the major items are:

- SCADA replacement – at a cost of €6.1m to replace an obsolete and inflexible system that is increasingly expensive to maintain.
- OMS Phase 2 – at a cost of €3.9m to develop the existing system to adopt Corporate IT standards and exploit the reporting capability.
- GIS Update – at a cost of €3.4m to display asset geographic information and enable integration with the Asset Register.

There are two other projects supporting the overall 'transform' programme:

- Data Design & Integrity – at a cost of €5.3m to ensure the integrity of corporate data through the management of its design and capture.
- Programme Delivery and IT infrastructure- at a cost of €2.0m to drive delivery of all projects ensuring that they comply with business and IT requirements.

Non-network IT/Telecom expenditure is defined as the expenditure which is not directly associated with network assets and which is not easily associated with a specific network asset. It includes items such as:

- Transport Fleet and Equipment Management systems
- Distribution control and operation systems including control centre SCADA and EMS
- Desktop PCs and servers for both administrative and operational use
- Software packages or in-house software development of applications
- Project Management, Work Management and Work Scheduling systems
- Private Mobile Radio and Polling Radio not associated with specific network assets.

APPENDIX E: FORMULAE FOR THE RAB'S ANNUAL DEPRECIATION AND CUSTOMER CONTRIBUTIONS CALCULATIONS

E.1 ANNUAL DEPRECIATION

CER has recommended DSO should receive in its regulatory revenues, half year regulatory depreciation of capital spend in the year of addition and half year regulatory return (at allowed WACC) on capital spend in the year of addition. Therefore, depreciation for the 2006-2010 CAPEX Plan has been calculated according to CER´s recommendation, as follows:

$$ADEPRE_i^y = if\left\langle\left(year_i - year_y\right)\geq 0; if\left\{\left(year_i - year_y\right)= 0;0{,}5; if\left[\left(year_i - year_y\right)\geq A_{life};0, if\left(\left(year_i - year_y\right)= A_{life};0.5;1\right)\right]\right\},0\right\rangle * \frac{CAPEX_y}{A_{life}}$$

Where:

$ADEPRE_i^y$ =is the depreciation in year "i" of CAPEX commissioned on year "y"

$CAPEX_y$ = Is the CAPEX invested in year "y"

A_{life} = is the Assets Life for CAPEX invested in year "y"

$Year_y$ = is the year when CAPEX was commissioned.

$Year_i$ = is the actual year

Therefore, the total depreciation in year "i" is the sum of all depreciation for every kind of CAPEX, calculated as mentioned above. The calculation is made in real values.

E.2 CUSTOMER CONTRIBUTIONS:

Following CER´s recommendation, Customer contributions for the 2006-2010 regulatory period have been estimated as a percentage of the allowed New Business CAPEX, as follows:

$$CC_i = \sum_y NBCAPEX_y^i * \%CC_i$$

Where

CC_i = is the Customer Contributions for year "i", in €M

$NBCAPEX^i_y$= are the New Business CAPEX for year "i", in €M

"y"= represents the three kind of New Business CAPEX: New Housing Schemes CAPEX, Non-Scheme Houses and Commercial & Industrial Supplies.

$\%CC_i$ = is the percentage of Customer Contributions for year "i".

As requested by CER, a fixed 50% percentage has been used along the second regulatory period.

Reinforcement Capex as submitted by ESB Networks is derived from the Dublin City Plan (DCP) 2004-2013 and the Country Network Investment Plan 2004-2010 (CNIP).

A critical issue in the determination of reinforcement needs is the nature of the planning standards used and their philosophy of application. ESB often compare their standards to the UK P2/5 security standard[49] and argue that theirs is less secure and therefore cheaper to implement than the UK's. This appears to be based on a misunderstanding of the application of the UK standard, which defines the following classes of supply.

A. Up to 1 MW – no redundancy at all is provided.

B. 1-12 MW – within 3 hours of a fault, most of the load should be met by reconfiguration – again there is no immediate redundancy provided.

C. 12-60 MW - within 15 minutes of a fault, most of the load should be met by reconfiguration; still no redundancy.

D. Over 60MW – less than 60 seconds after a fault, the full demand less 20MW should be met by automatic reconfiguration; limited redundancy but also with a condition to minimise disruption after a second fault.

E. 300-1500 MW – Immediate (under 60 second, so automatic switching is still allowed) restoration; so there is redundancy at this level, along with some double contingency for part of the load.

F. over 1500 MW (equivalent to the average demand for the whole of Ireland) subject to specific transmission standards for England, Wales and Scotland.

Furthermore, the application philosophy of P2/5 is generally that its contravention through load growth or other effects is not considered something to be avoided at all costs, but rather it is the trigger to consider reinforcement options.

The UK and Irish planning standards appear similar in scope, and DSO's perception that they are working to a lower standard does not coincide with the opinion of CER's technical advisers who believe that the DSO is working to a stringent standard.

F.1 THE DUBLIN CITY PLAN

The DCP covers Dublin city and the wider county and is an excellent overview planning document that draws together the candidate projects for meeting demand growth in the Dublin area over a ten year period 2004-13. The clear

[49] Engineering Recommendation P2/5, issued in 1978, is a guide to system planning which took into account the results of extensive reliability studies using fault statistics and risk analysis and the relationship of these to the costs of system reinforcements, including the effects on losses. ER P2/6 (2005) which supersedes P2/5, does not revisit these analyses; it simply replaces the previous Table 2, which related solely to CEGB steam generation, with a new Table 2 that is generation technology independent.

presentation allows the reader to understand many of the complex issues and options in the context of relatively high demand growth and the typical challenges of acquiring sites and permissions within urban and suburban areas. During the course of the present Distribution Price Control, the entire DCP has been reviewed with ESB Networks staff.

The key issue for the purposes of the revenue control is whether the proposed Capex programme represents the least-cost, realistic, optimum development. The fact that the DCP covers 2004-13 means that some projects are already complete, some are in progress and a number are scheduled after 2010. Furthermore, ESB use probability factors to reflect the interaction between projects, the vagaries of the planning environment and uncertainty in load growth as shown in the Table below. This evaluation of DSO's proposals must therefore be performed at a high level.

Table A ESB Capex Probability Classifications

Probability	**Typical Project Characteristics**
High (60 - 80%)	• Project is required to meet DSO planning criteria. • Project Driver is not speculative (based on confirmed system growth or major development) • No alternative investment options are available • Site / Planning Permission well advanced, or no specific problems identified
Medium (40 – 55%)	**As for "High" projects, but one of the following exceptions applies**: • Project Driver is conditional (Customer load or system growth requiring confirmation) • Anticipated difficulty with obtaining site or planning permission • Complex interaction with TSO – likely to delay Connection Agreement
Low (15 – 30%)	**As for "High" projects, but more than one of the following exceptions applies**: • Project Driver is conditional (Customer load or system growth requiring confirmation) • Anticipated difficulty with obtaining site, planning permission or wayleaves • Complex interaction with TSO – likely to delay Connection Agreement • Interaction between DSO projects in a location such that alternative solutions may be possible

	• Impact of deferring project for up to 2 years beyond planned date considered acceptable.

As an example of the overall DCP, an overview of the Dublin South County, one of the five main areas in the report, should give a flavour of the issues and options.

The Dublin South County covers the coastal area from Dun Laoghaire/Dundrum in the north to Greystones/Kilcoole in the south. The area has a distinct 110kV network based on Carrickmines 220/110kV station with 3-110/38kV stations feeding the 38kV network. As with much of the greater Dublin area, the South County has significant ongoing commercial and housing development and exhibits an average load growth over the area in the order of 4.2% per annum. However, this growth tends to be centred on specific areas e.g. Dundrum Town Centre new development and the Central Park Business Park. Overall the 110kV/38kV/MV system is reaching its capacity and therefore its ability to meet new load demands both locally and across the network as a whole.

ESB proposals to overcome future potential problems are to develop the 110kV network and provide 7 new 110kV/MV stations over the period 2006-2010, additional transformer capacity will be required from the 220kV system; there is limited reinforcement at the 38kV/MV level. The principles behind this for a medium to high load density area such as Dublin South County (and the greater Dublin Area) are:

- All load flows through the 110kV system, this network will require reinforcement and security improvements during the period.
- Most load (apart from HV connected customers) flows through the MV network
- Loads on the 38kV system can be reduced or contained; 38kV system losses can be minimised
- Reinforcement of the 110/38kV transformer capacity and 38kV network are minimised; the aim must be to retire 38kV equipment without replacement where sensible.

Each of the 110kV/MV proposals note that “other than requirement to feed new load there is no MV plan”. **Where new MV capacity is being provided and relieving or replacing 38kV/MV capacity there will be a need to restructure the MV network; from the statement made is it assumed that these costs are not included in the project proposal and therefore appear elsewhere.**

One of the new 110kV/MV stations visited was Taney. The Taney substation was planned to supply the massive Dundrum retail development, the new load from which would otherwise have overwhelmed the local distribution network. The plot of land made available to ESB was relatively small and irregular in shape. The resulting substation design was compact, modern and impressive. Compact GIS 110kV switchgear was employed along with an extensive 20kV switchboard for operation at 10kV. The substation is costing in excess of €10M.

A review of the other plans for 110kV/MV substations indicated total costs in the range of €3M to €10M, all for a design with two 20MVA transformers. While variability of costs between sites is to be expected, there is concern that the more expensive stations could be made less costly through prudent design.

Whilst the proposals appear broadly sensible a few concerns do arise

- All the 110kV/MV proposals appear in the Investment Management Process with a high probability; for each project; the question however must be one of deliverability with the level of installations planned.
- Associated MV costs do not appear in the overall CAPEX.
- Although the project probability has been factored into the CAPEX calculation, no sensitivity test seems to have been made against a range of load growth scenarios.

F.2 COUNTRY NETWORK INVESTMENT PLAN

The CNIP does for the whole country excluding Dublin county what the DCP does for Dublin. Again, the report is excellent and consolidates the plans of the different regions. In so doing, the CNIP calibrates those plans, giving higher priority for areas suffering severe load-related constraints.

As for DCP, a review of the CNIP in one area will illustrate the factors to be considered in evaluating the whole in order to determine whether the proposed Capex programme represents the least-cost, realistic, optimum development. The Limerick area was a key part of the site visits and is discussed below.

Limerick and its surroundings is an area of high growth with large industrial and commercial developments to the south and east together with rapid housing development. There is significant investment by major companies such as Dell Computers, to tap into local academic and technical resources, which in turn is attracting other high-tech and component supply businesses. The main supply inputs into the 38kV distribution network are at Limerick 110/38kV Station and Ardnacrusha Hydro Electric Station. This latter was developed in the late 1920s as were the 38kV steel tower lines which radiate from Ardnacrusha. These tower lines use small cross section conductors, are of limited capacity and are in similar condition to other “Siemens” tower lines seen elsewhere in the country. Many of these lines now pass through housing developments or are under threat from housing and infrastructure development.

The existing 38kV system demands at both sites are in excess of the firm transformer capacity (n-1 planning criterion) and the 38kV network interconnecting the two is limited, under threat and not directly uprateable. From the information provided and what has been seen from site visits, the network is in need of both reinforcement and extensive renewal/refurbishing.

ESB proposals are to introduce, where justified, new 110kV/MV stations within the immediate Limerick area and 110kV/38kV stations within the outer areas of the Limerick/Ardnacrusha 38kV network. This proposal reduces the load on both the Limerick and Ardnacrusha 38kV busbars and reduces load on the 38kV network and on local 38/MV transformer stations. The 38kV network between

Ardnacrusha and Limerick is to be restructured to retire selected 38kV circuits and stations and replace/upgrade key 38kV circuits.

The ESB approach is both sensible and appears justifiable in that introducing new infeeds to high load density areas of the main MV distribution from a higher voltage (110kV) achieves a number of objectives within one project. However, the proposals as presented within the Country Network Investment Plan 2004-2010 are a mix of load and non-load related expenditure but are not costed.

A number of individual projects are required by October 2004 and 2005. During the site visits some projects were seen to be in progress. There was no sign of on site progress at two 110kV/MV stations, shown as required by October 2005. One of these two is listed in the Investment Management Process as having a probability of 0.25 whilst the other does not appear. Two issues arise:

- there appears to be some carry over from DPR1 allowed CAPEX;
- the criteria for allocating capex spend between load and non-load categories is not clear.

F.3 ANALYSIS OF DSO MAJOR CAPEX

While the DSO Reinforcement capex plans have not been submitted to CER in detail due to the very large number of projects involved, a list of major capital projects was submitted with their stated probability of completion during 2006-10 and their associated "Prime Cost", that is the estimated cost without overheads stated in 2004 Euro.

This list was then analysed using the CNIP and DCP to study the projects along with notes taken during the site visits, especially where these documents were discussed in detail with their authors. The DSO overheads are understood to be between around 10%. Cost control in projects has been identified as an issue and continued improvement in this area should generate further savings. These have been estimated at 5%. Finally, the justification for the projects was examined to see whether they could be:

- allowed;
- deferred (the need for the project is real but the justification relates to exaggerated contingencies, thus the project could be deferred by 2 to 3 years without affecting quality and continuity of supply); or
- cancelled (the justification is invalid or has been overtaken by events and the project is no longer needed).

The result of this analysis was an overall cost reduction of 14% on the DSO's reinforcement proposals.