Commission for Energy Regulation

An Coimisiún um Rialáil Fuinnimh

Determination of Transmission Allowed Revenues for 2003 Use of System Tariffs

CER/02/124

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1 Introduction

1.1 Background

On 28 September 2001 the Commission for Energy Regulation **("the CER")** set out its determination of allowable revenues for the transmission business for 2001-2005. This determination was addressed to

- ESB National Grid in its capacity as effective Transmission System Operator **("the TSO")** in advance of the transfer of the role to EirGrid and

- ESB Networks in its capacity as licensed Transmission System Owner **("the Owner")**.

This determination was based on, among other things, the CER's interpretation of the roles and responsibilities assigned to both parties under SI 445 of 2000.

The CER approved the entire network capital programme submitted by the TSO for the period 2001-05 as well as an enhanced maintenance programme. The CER reprofiled the projected incidence of capital expenditure over the 2001-05 period from that submitted by the TSO to what it considered a more realistic profile. In view of the major ramping up of capital expenditure entailed by the approved programme as well as the continuing uncertainties over precise demarcation of roles between the TSO and the Owner which were to be resolved by the Infrastructure Agreement, the CER stated that it would annually review and, if necessary, adjust the allowable transmission revenues in the light of, among other things, achieved capital expenditure. The CER chose a one-year price control for the TSO for 2002 for both operating and capital expenditure in view of the start up nature of the new TSO's business and uncertainties regarding its operational relationship with the Owner.

The present determination reviews operational and capital expenditure in 2001 and likely outturn for 2002 as well as projected expenditure in 2003. The focus in particular is on projected operational expenditure by the TSO in 2003 and the resulting output in terms of service levels. The physical outputs associated with the 2001 capital programme are described in some detail in **Appendix 1**. The determination makes no substantive change to the approved capital programme for the remainder of the period 2001 to 2005.

The CER's Direction on the Infrastructure Agreement of November 2001 is currently the subject of High Court proceedings. For the purpose of the present determination, and purely as a necessary working assumption, it has been assumed that the Direction in its existing form comes into effect on 1 January 2003.

The determination takes account of detailed separate submissions which the CER has received from the TSO and the Owner and follow up consultations with both parties.

1.2 One Year Price Control for the TSO

The CER has previously stated that it is in favour of multi-annual reviews of revenue consistent with efficient regulation and giving incentives to the regulated entity to take initiatives which improve efficiency. Such a control is in place for the Owner for the 5 years to 2005, with the sole adjustments to revenue based on volumetric adjustments for maintenance work carried out at the request of the TSO and other recognised pass-through costs. Given the uncertainties which still surround the TSO business and that many cost items are still largely outside its direct control (e.g. ancillary services, constraints costs), the CER has decided to retain a further one-year review period for the TSO's operational and capital expenditure.

2 Transmission Revenue - 2001 Outturn

2.1 TSO Revenue

The following tables describe the allowed expenditure and the actual expenditure incurred by ESB National Grid in the performance of its role as TSO for the year 2001.

Table 1 TSO operating costs (€m in 2001 prices)

	Allowed	**Outturn**
Constraints	11.95	9.0
Ancillary Services	27.30	24.9
Settlement (less depreciation)	3.16	3.6
Regulatory levy	0.52	1.2
External Costs	**42.93**	**38.7**
Network Repairs and Maintenance	5.00	3.2
Non Capitalised Planning and Construction	4.50	2.4
Corporate Overheads	0.67	5.0
Regulation and Pricing	1.11	1.8
System Control (including Power System Computing)	14.52	8.4
Insurance	0.40	-
Customer Records and Billing	0.40	-
Less Depreciation	-3.38	-
Internal Costs	**23.22**	**20.8**

Table 2 Depreciation, Return on TSO Asset Base and Working Capital

	Allowed	**Out-turn**
Depreciation (including SSA)	3.61	3.20
Return on Assets	0.57	0.50
Finance of Working Capital	0.56	0.56
Total	**4.74**	**4.26**

Table 3 TSO Revenue

	Allowed(€m)	**Outturn(€m)**
Total TSO Revenues	**70.89**	**63.76**
Less Other Revenue		**2.6**
Total TSO Revenues to be collected through TUoS	**70.89**	**61.16**

Table 4 TSO Capital Expenditure

	Allowed	Out-turn
Control Centre Replacement	1.00	0.60
IT	3.00	2.76[1]
SSA – Modifications to TESS	1.10	0.72
Premises	2.86	0.10
Total Capital Expenditure	**7.96**	**4.18**

2.1.1 Reasons for difference between Allowed and Outturn Expenditure

The 2001 determination was made on an assumption of EirGrid functioning as a separate independent TSO. This has not transpired to date. The basis of costs for 2001 was therefore different from that assumed at the time of the 2001 determination. A corollary of this, of course, was that the TSO had to bear an allocation of ESB corporate overheads, which had not been anticipated for 2001. ESB National Grid advises that a net saving of €3.2M was realised due to set up costs for EirGrid not being incurred. Another element in the savings is external costs being lower than predicted. There were also savings on capital items, including premises refurbishment, and expenditure on information technology and the National Control Centre replacement project.

The CER will adjust the allowed TSO revenue for 2001 to the outturn amounts.

2.2 The Owner's Revenue

The following table gives the allowed revenue for the Owner for 2001.

Table 5: The Owner's Revenue for 2001 (€m in 2001 prices)

	Allowed
Operating Costs	21.07[2]
Depreciation*	29.33
Operating Profit*	30.46
Total Allowed Revenue	**80.87**

*Note Depreciation and Operating profit are based on the amounts allowed in the 2001 determination

2.2.1 Maintenance Outturn

In its 2001 determination the CER assumed a level of repairs and maintenance for 2001 of 50 man-years of work. The CER and ESB Networks have agreed that it has completed 41.03 man-years of work and the CER has adjusted the allowed revenue accordingly under the formula drawn up in 2001.

[1] This figures includes some expenditure in 2002 and 2003

[2] This figure has been adjusted to reflected the volume of maintenance completed by ESB Networks

2.2.2 The Owner's pass through costs

The outturn expenditure for local authority rates on the transmission system is €5.8m in 2001 which compares with €5.83m allowed in the 2001 determination.

2.2.3 2001 Capex

In 2001 the TSO and the Owner had 116 transmission infrastructure projects underway and completed 62 of those projects by the end of year. The total gross capital expenditure during the year was €89.8m which equates to a net capital expenditure figure of €73.9m, after account is taken of customer and other capital contributions. In the 2001 determination the CER forecast a gross capital expenditure of €93m and a net capital expenditure of €65m. The main reason for the decline in capital contributions was fewer Distribution system exits due in part to a lower than anticipated take up of web-farm connections in the Dublin region. The CER has adjusted the Owner's revenue to reflect the increased net capital expenditure in 2001.

A summary of the physical progress on the transmission system capital programme made in 2001 is attached in **Appendix I**.

2.2.4 Work in Progress

During the course of this revenue review ESB Networks drew the CER's attention to a discrepancy in the calculation of the opening value of the transmission system asset base. At the time of the 2001-05 revenue determination in 2001 the CER had determined that the amounts expended on capitalised assets should be added to the regulatory asset base in the year in which the cost is incurred. However, ESB's accounting policy is to add the assets to their asset base upon commissioning. There were a number of "live" projects at 31st December 2000 and in accordance with ESB's accounting policy these assets were not added to the asset base at that time. The asset base used by the CER in the 2001 determination was ESB's asset base of 2000. Therefore there were a number of projects which were not added to the asset base. ESB Networks has informed the CER that the expenditure related to the work in progress is €47.26m (in 2002 prices). The CER has sought and received detailed information on the projects involved. The CER is satisfied that the expenditure has been efficiently incurred and should be added to the Owner's asset base for the purpose of calculating allowed depreciation and rate of return provisions. The CER will therefore adjust the allowed revenues of the Owner accordingly.

2.3 Allowed Revenue adjusted for 2001 outturn

Table 6 details the allowed Transmission Revenue, TUoS collected and resulting adjustment to the 2003 TUoS revenue.

Table 6 TUoS under recovery for 2001

	(€m)
TSO Approved Outturn Revenue	61.16
Owner Allowed Revenue	80.87
Total Revenue Due	**142.03**
Total TUoS collected in 2001	**139.50**
Under recovery	2.53
Under recovery plus interest*	**2.82**

*Interest rate 2001 5.7%, 2002 5.6%

3 2002 Revenue Forecast

In the 2001 determination, the CER allowed a revenue for the transmission business of €186m in 2002. The TSO has submitted a refined forecast for costs and expenditure for the transmission business in this year. The main area where there is a significant difference between the 2001 estimates and revised 2002 forecasts is external costs, namely ancillary services and constraints.

Table 7 Revised forecasts for 2002 (all figures in €m)

	Previously assumed	Revised forecast
Ancillary Services	32.4	35.0
Constraints	17.9	30.0

The TSO has also noted that the constraint costs could be exceptionally volatile and unpredictable in the second and third quarters of 2002, as they are highly dependent on the specific sequence of events during that period. As such, the forecast of constraint costs of necessity carries a higher degree of unpredictability.

On this basis, the CER believes that it is better not to expose the TUoS customer to volatility in the 2003 TUoS tariff by making a provision to take account of the forecast increase in constraint costs at this time. Accordingly, the CER will continue with the previous estimate of external costs. In the event that the cost of constraints or ancillary services turns out to be higher than that allowed and the TSO can show that the increased expenditure has been reasonably incurred it will continue to be treated as a pass through cost.

4 2003 Revenue Requested

4.1 Revenue requested by TSO

The following table is a summary of the TSO's s revenue submission for 2003.

Table 8 TSO's requested revenue for 2003 by function

	€M (2002 prices[3])
Constraints	20.1
Ancillary Services	36.7
Regulatory levy	1.4
TSO External Costs	**58.2**
Network Repairs and Maintenance	7.0
Non Capitalised Planning and Construction	3.7
System Control (including Power System Computing)	14.3
Regulation and Pricing (including Customer Records and Billing)	3.3
Settlement System Administrator	6.8
Corporate Overheads	6.1
Capacity Margin Administration	0.8
Non Network Depreciation	5.0
TSO Internal Costs	**47.0**
TSO Working Capital	0.7
TSO Return on Assets	1.1
Total	**1.8**
Total TSO Revenue	**107.0**

An alternative way of looking at the breakdown of the "Internal Costs" in Table 8 above is by way of *category* of expenditure. This is detailed in the Table 9 below, again drawing on the TSO's own submitted data.

[3] For the revenue submission the CER requested ESBNG to assume a 3.5% inflation rate for 2002.

Table 9 TSO's requested revenue for 2003 by category

	€M (2002 prices)
Constraints	20.10
Ancillary Services	36.70
Regulatory levy	1.40
Total External Costs	**58.20**
Payroll (Operational)	16.75
Professional Fees	6.00
BSBU Costs	2.10
Maintenance Professional Fees	5.85
Telecoms	4.10
IT Operating Costs	1.80
Insurance	1.00
Business Overheads	2.20
Non Network Depreciation (incl SSA)	7.20
Total Internal Costs	**47.00**
TSO Working Capital	0.7
TSO Return on Assets	1.1
Total	**1.8**
Total TSO Revenue	**107.0**

The TSO also submitted its proposed capital expenditure programme for 2003.

Table 10 TSO Capital Expenditure Proposals

	€m (2002 prices)
Control Centre Replacement	6.00
Settlement System Modifications	4.00
IT	3.95
Premises/Fixture Fittings	1.00
Total TSO Capex	**14.95**

4.2 Revenue for the Owner

The CER has not requested the Owner to make a revenue submission for 2003 as the Owner's revenue is subject to a five-year price control which is set out in the 2001 determination. The amounts shown for depreciation and operating profit are based on the profile of capital expenditure assumed in the CER's 2001 determination. The actual 2001 capital expenditure is now known and the CER will adjust the allowed revenue in 2003 to reflect this increased expenditure and the increase due to the "work in progress" adjustment to the asset base (see 2.2.4 above).

5 CER's Assessment and Determination

5.1 Revenue requested by TSO

5.1.1 Internal Operational Costs

Payroll

The CER has engaged in detailed consultations with the TSO on the appropriate level of operational costs which it is reasonable to expect the TUoS customer to fund in return for a modern efficient TSO service. Such a service is vital to developing Ireland's electricity sector and realising the benefits of market liberalisation. Establishing the appropriate or "normative" level of TSO operational expenditure is a difficult exercise for a number of reasons. For a start the TSO function, at least in its contemporary form, is a relatively new distinct business in Ireland. This new business is also coinciding with a period of significant growth in demand for conventional system services, in demands for new services as well as a major ramping up of the transmission investment programme. Benchmarking by reference to TSOs in other jurisdictions can be a useful analytical tool but has to be treated carefully, as the CER has acknowledged in the past. Another important consideration here is to avoid a situation where the regulator seeks to "micromanage" the TSO by being over prescriptive in matters such as approving staff numbers for particular lines of business, or requiring prior regulatory sanction of detailed expenditure lines etc.

One aspect of the TSO's submission which was of particular concern to the CER was the continuing very sizeable increase in staff numbers and, even more so, payroll expenditure in recent years. This is illustrated in Table 11 below:

Table 11 Historic & Forecast Staff and Payroll – ESB National Grid Submission 2002

	1998	1999	2000	2001	June 2002	2002	2003
No. of Staff	83	90	100	149	c.170	187	204
Total Payroll (€m)	4.9	6.0	7.2	10.3		14.9	18.2

Undoubtedly the TSO has had to meet the growing demands in recent years. These include additional demands for conventional TSO services (e.g. increased customer connections) as well as providing new services arising directly from the market liberalisation process (e.g. operation of a trading and settlement system, production of Generation Adequacy and Forecast Statements, All Island Market studies) and other associated developments as well as the establishment of a separate institutional TSO.

The CER is prepared to approve a large amount of the increased resources advocated by the TSO in its submission. However, the sheer scale of the increase, particularly in the light of the scale of increases already experienced in recent years, would warrant a convincing case that the TUoS customer would see tangible benefits in terms of improved service levels and productivity gains before it could be approved.

We return to this issue further below after dealing with another directly relevant category of TSO operational expenditure: professional fees.

Professional Fees

ESB National Grid has submitted costs of €6.0m professional fees which will be incurred by the TSO in 2003.

These include, inter alia,

- Independent advice on the set up of EirGrid
- Accounting audit for EirGrid
- Independent legal advice
- Recruitment consultants
- Consultancy for system planning and system operation
- Development of ancillary services
- Market audit, insurance and modification of the trading system

The inclusion of professional fees for the setup of EirGrid is consistent with CER's request that the submission is based on the assumption that EirGrid will be performing the TSO function in 2003.

Based on the above the CER allows this provision of €6m for professional fees in 2003. Within this amount, €2.4m relates to professional services which should have a direct bearing on achieving the "Customer/Stakeholder Objectives" described below and in Appendix 2. This €2.4m is referred to as "relevant professional fees" further below.

Services Delivery to TSO Customers.

The TSO submitted a document entitled **"TSO Customer/Stakeholder Objectives"** in support of its operational expenditure submission for 2003. This document sets out some 40 specific customer objectives to be achieved within the next two years. It has been the subject of discussion and some, though not many, amendments by the CER. The amended version is attached in **Appendix 2**.

The CER welcomes this document. It has the potential to be a very important commitment to facilitating market liberalisation and securing an efficient electricity network service. Assuming it is delivered upon, this document should justify the very significant increase in the TSO's operating resources in recent years and the further increase in resources now being requested for 2003.

The key issue is timely delivery. Some of the declared objectives do not lend themselves readily to measurement. Many do, however. Deadlines for some specific objectives are also essential and feasible, even allowing for the various contingencies that can arise. Where specific deadlines are realistic and warranted these have been set out in Appendix 2.

The CER has decided to approve baseline combined expenditure of €19.4m on payroll (excluding capitalised staff) and "relevant professional fees" with a further provision of €2.3m to be paid to the TSO in 2003 contingent on delivery of the Customer Objectives described in **Appendix 2**. The CER also reserves the right to claw back €2.2m in the event that these Objectives are not delivered in full. Under this decision a performance audit will be carried at the end of 2003 and, to the extent that objectives are not due or cannot be expected to be fully realised until 2004, at the end of 2004. The CER reserves the right to adjust the TSO's allowed revenue by up to €4.5m under this combined incentive (€2.3m) and clawback (€2.2m) regime by reference to the performance of the TSO in delivering these Customer Objectives. For this evaluation purpose the focus in particular will be on those 17 individual Objectives identified as "Deliverables" in **Appendix 2**. These particular Objectives have been singled out on the basis that they are more easily measured than the remaining Objectives. This is not to suggest that the remaining Objectives are less important or should suffer because of the financial incentives on the TSO to ensure the "Deliverables" are met. The CER acknowledges that it will have to act reasonably, fairly and proportionately in conducting this evaluation exercise. It will have to take account, for example, of any overriding unanticipated circumstances that may intervene or matters which are clearly outside the control of the TSO.

This condition relates to both the substance and the timing of delivery of the list of objectives. It is also without prejudice to ongoing improvements in productivity levels which the CER would expect to arise in the TSO, as in any business, in future years to the benefit of customers. Lastly, it should not be taken as CER agreement that the TSO should necessarily rely largely or exclusively on full time in-house staff resources for meeting all existing or new service requirements.

5.1.2 Business Overheads

The TSO estimates that business overheads will cost €2.2m. Included in this figure is training, telephone charges, stationery, travel expenses etc. The CER has examined this estimate by reference to available guidelines and indicators for such costs and has concluded that a more reasonable provision would be €1.8m.

5.1.3 Information Technology Capex

In its 2000 revenue submission ESB National Grid forecast €45.33m for capital expenditure on IT systems up to 2005 excluding the settlement system for market operation. Not all of this spend was supported or scoped out with detailed accompanying papers. It was also subject to uncertainty surrounding the formation of the independent TSO business and its precise roles. The CER therefore cut back the level of allowed expenditure to €30.56M over the 5 years and re-profiled the incidence of expenditure setting back by 0.5 years expenditure on all projects excluding the settlement system. The CER indicated that it was not opposed in principle to the TSO expending monies on IT projects but that this IT spend ought to be able to deliver operational savings in addition to replacing obsolescent systems and accommodating new roles for the TSO.

Energy Management Systems (EMS)

The following more up to date position regarding the Energy Management Systems (EMS) has emerged from recent discussions between the CER and ESB National Grid:

- A contract has been placed for the EMS which consists of a new National Control Centre, Emergency Control Centre and Dispatch Simulator.
- The EMS project also includes the replacement of approximately 30 Remote Terminal Units (RTUs) and an upgrade to telecoms.
- The entire project, including internal costs and overheads, is budgeted to cost less than 12 months ago, although it will still be a major investment.
- The CER allowed for expenditure of €1M in 2001 of which €0.6m has been expended.

The CER will be following up with the TSO in the near future some particular concerns it has with aspects of the EMS project.

Other I.T. Systems

ESB National Grid is proposing to expend a total of €27.4m on other IT systems by 2005 including €2m for Internet Development and €3.1m to develop a TUoS and Ancillary Services billing system. Also included is €6.7m for “Other systems” and €15.6m for “Enterprise Applications. It is fair to say that most of this expenditure, or €17.45m, is profiled to take place in the years 2004 and 2005 and is outside the direct scope of this determination. Over the period 2001 to 2003 ESB National Grid are forecasting expenditure of €9.95m as compared to a CER budgeted amount of €9.8m in 2002 prices.

ESB National Grid outlined to the CER the following projects:

- an electronic dispatch and logging system,
- a company web portal, data transfer mechanisms,
- a company intranet,
- the capacity margin settlement system,
- the ancillary services settlement system,
- a replacement market operations system,
- a document management system and
- a new HR and payroll system.

The CER has no disagreement in principle with the implementation of these systems. Indeed some, such as Ancillary Services billing, capacity margin settlement and TUoS billing are needed urgently. The CER has concerns, however, that the costs put forward, despite being trimmed as compared to those submitted last year, are too high and are unlikely to deliver either net enhanced benefits or an overall reduction in costs to the consumer. The CER considers that a number of these projects can be delivered by off the shelf products in a more cost effective manner.

The CER has therefore decided:

- that a budget of €0.4m be allowed for Internet Development consistent with the allowable spend for 2001 to 2003 given last year, which gives a budget of €0.14m for 2003
- that €2.03m be allowed by the CER for the implementation of the necessary billing systems for 2001 and 2002.. These monies are to cover an Ancillary Services and TUoS billing system and are allowed

conditional on the implementation of such a system and the entering into a regulatory approved ancillary services agreement as anticipated in **Appendix 2**. The CER does not see that there should be additional monies for any such billing systems in the period to 2005.

- In addition the CER will allow €0.2m associated with the costs of setting up a separate TSO business in 2003 for, inter alia, HR, payroll and document management. This is in addition to the €0.91m allowed for other systems in 2001 and 2002 which included other systems associated with the setting up of the TSO business.
- The CER believes it is not prudent to allow any additional monies for Enterprise Applications projects for 2003 as €4.09m has already been allowed in 2001 and 2002 and ESB National Grid has not outlined to the CER the benefits they are likely to deliver. In the absence of any such analysis the CER naturally assumes that the financing of these projects will be possible out of operational cost savings as would be prudent utility practice should ESB National Grid wish to proceed.

The combined effect of the above is a reduction from the €9.8m allowed by the CER previously for the period 2001 to 2003 to €7.6m going forward. Where the CER can receive ex ante actual outlines justifying the expenditure and its benefits the CER is willing to consider a relaxation of this cap

5.1.4 Corporate Overheads /Repairs and Maintenance

ESB National Grid has highlighted to the CER increases in specific costs of €5.56m all of which come under the auspices of corporate overheads. The CER would like to address these points. More specifically ESB National Grid stated that

- Maintenance costs have risen by €2.6m over that allowed in 2001 principally due to increases in professional fees associated with the maintenance,
- Telecoms charges from ESB Telecoms have risen by €2.0m and
- Business Services costs have risen by €0.48m.
- An increase in insurance costs of €0.48m

ESB National Grid has put it to the CER that it is unable to control some of these costs as it is bound to a single supplier, namely ESB. The CER would not accept that the TSO, and ultimately the TUoS customer, should have no alternative but to accept revised cost demands from ESB in its capacity as a monopoly provider. The following is the CER's assessment of allowable expenditure:

- Maintenance professional fees: The CER has not received justification for an increase in these fees. ESBNG is currently carrying out further investigation on some aspects of these costs which have still to be resolved and will report on this examination in a few weeks time. In the meanwhile, the CER does not see a case for allowing these increased fees, although it will keep the matter under review.

- Telecoms charges: ESB National Grid has stated that there are three main reasons for price increases, namely, reallocation of costs (€0.8m), increase in rates charged by ESB Telecoms (€0.3m) and increased/enhanced services provided (€0.9m). As part of the 2001 review the CER accepted ESB's allocation rules for telecoms costs and will not revisit this now. The CER believes rate increases should be adequately covered by the inflation adjustment. As for the increase in costs due to increased and enhanced services the CER allows this increase.

- Business Services costs: The CER allows an increase in line with the increased number of staff now predicted by ESB National Grid over the number indicated in the 2001 review.

- Insurance: The CER accepts that since the regulatory submission in 2000 the insurance market has hardened and allows this as an external cost to the TSO business going forward.

5.1.5 Settlement System

Previously, the CER described the Settlement System Administration function as an external cost to ESB National Grid. The CER believes that ESB National Grid now has sufficient experience in this area to exercise at least a measure of control of costs arising and thus includes these costs as internal operating costs going forward. For the capital expenditure associated with the settlement function the CER will continue with the current practice.

ESB National Grid has included in its submission a provision of €4m for capital expenditure on the trading system. This includes a provision of €1.5m for modifications to the existing trading system and a provision of €2.5m for participating in the review of the trading model. The CER believes that there is a high level of uncertainty in this area and thus the CER allows a provision of €2.5m in total for capital expenditure in 2003.

5.1.6 Working Capital and Return on Assets

As part of its overall assessment of the appropriate level of transmission revenues for 2001/2002 the CER assessed the appropriate return for the TSO business on its regulatory asset base composed of non-network assets comprising mainly IT equipment and also for an appropriate level of operating capital to ensure liquidity in meeting its financial obligations. The CER deemed that 20% of the external costs faced by EirGrid ought to provide a sufficient level of working capital for the business and that this, in addition to the RAB ought to be remunerated at 6.5% in real terms consistent with the level of remuneration for the ESB Networks businesses. The TSO business with its short lived investments, captive customer base and revenues guaranteed under the regulatory framework assuming they had been reasonably and justifiably incurred, would in the longer term represent no higher and quite possibly a lower risk than ESB Networks businesses.

In conducting the review of revenues for 2003 the CER asked the TSO to outline its case for a rate of return consistent with the risks that it faced. The CER stated that it considered that the return of 6.5% would continue to be appropriate for 2002 while the TSO remains a ring fenced division of ESB. The CER also recognised that in the absence of certainty in the precise roles and responsibilities of EirGrid that there are inherent difficulties in finding publicly quoted companies in the same business and facing the same risks.

The TSO responded by engaging a financial consultant to set out the appropriate parameters for the Weighted Average Cost of Capital (WACC) for 2003 and beyond. ESBNG's financial consultant determined a real pre-tax rate of 8.2% to be appropriate and differed from the CER's assessment for the network asset companies conducted in 2001 primarily in the assessment of the equity beta and the addition of a small company premium. In arriving at its determination, ESBNG's financial consultant highlighted "the unique operating characteristics of the company" and subsequently developed its argument by comparison with consultancy companies, asset management companies contract operators and others (including the London Stock exchange.

As previously stated the CER recognises the difficulties in such a comparison but believes that the companies chosen by ESBNG's financial consultant conduct a very different business and face substantially greater risks than the TSO. The TSO's business has a guaranteed customer base, most likely indefinitely but certainly for the lifetime of such assets as they are investing in to conduct their business. It also has guaranteed revenue recovery through the stringent security provisions in the TUoS Agreement and the backing of the regulatory regime to guarantee revenue for the business where it can be demonstrated to the regulator that such expenditure has been reasonably and justifiably incurred. Finally, but perhaps most important of all, the TSO is protected by a statutory monopoly position and is likely to remain so for the foreseeable future.

The CER therefore does not accept that a company whose investments are primarily short term IT investment with a guaranteed customer base faces any greater risks than the network asset owner business and indeed a priori expectation is that the cost of capital should be lower. The CER has therefore decided to cap the level of return at 6.5%. When the Infrastructure Agreement and Transfer Agreement between Eirgrid and ESB come into effect and the current uncertainties regarding the precise functions and scope of the TSO business are resolved it will, of course, be open to Eirgrid itself – as opposed to ESB National Grid - to make a case that its allowed rate of return should be reconsidered. If so, the CER will reconsider the matter.

5.1.7 Ancillary Services

Ancillary Services costs include the provision of Operating Reserve, Reactive Power, System Support and Black Start facilities. The CER recognises that with a near monopoly provider of generation facilities in Ireland that these costs are not fully within the control of the TSO at this juncture. The CER would like to see ancillary services markets move to a more competitive situation in the next few years and welcomes the TSO's proposal to competitively tender for a new black start facility. The current forecast for ancillary services costs for 2003 is as below:

Table 12 Ancillary Services Expenditure

Ancillary Services	€m (2002 prices)
Currently forecast	36.7

The CER allowed ancillary services costs as a pass through cost in 2001 and 2002. The CER will continue to allow ancillary services as a pass through cost in 2003. Thus, the CER allows this revenue for 2003.

5.1.8 Constraints

The current forecast for constraint costs for 2003 is as below:

Table 13 Constraints Expenditure (€m)

Constraints	€m (2002 prices)
Currently forecast	20.10

The CER acknowledges that forecasting constraint costs is a complex task. The CER allowed constraints as a pass through cost in 2001 and 2002. The CER will continue to allow constraints as a pass through in 2003. Thus, the CER allows this revenue for 2003.

5.1.9 Other Revenue

ESB National Grid carries out a number of services for which it charges a fee and collects other revenue which is netted off the allowed transmission revenue. These services include system studies, capacity margin administration and revenue from the interconnector auctions. The CER assumes ESB National Grid will collect €1.7m of revenue in this manner in 2003.

5.2 Owner Revenue

The Owner revenue has been set for the five-year review period and therefore the adjustments to the 2003 revenue are due to the inclusion of the CER levy and the adjustment due to the increased capital expenditure in 2001.

5.3 2003 Network Capital Expenditure

In the 2001 determination the CER approved the network capital expenditure proposals of ESB National Grid for 2001 to 2005. The CER re-profiled the expenditure to what it considered a more realistic profile. It also undertook to review the allowed revenue based on actual achieved capital expenditure as assessed through the annual revision of EirGrid's Development Plan.

ESB National Grid has submitted a revised forecast of capital expenditure for 2003 which is not significantly different from that forecast in the determination. The CER does not see that there is a strong case for adjusting the earlier (reprofiled) forecast of 2003 network capital expenditure of €130m in 2000 prices (gross).

While the CER has approved the capital expenditure set out above for 2003 the CER is making its approval conditional on certain arrangement regarding the Owner's input to capital expenditure forecasts. The forecast capital expenditure figures which underlie the 2001-05 Revenue Determination of September 2001 were produced by the TSO. Going forward from 2002, ESB Networks, acting in its capacity as Transmission

System Owner, will have full and open access to the plans and pricing methodologies, including any scheme drawings, and detailed design for the largest projects on the system (those costing more than €2m) if and to the extent that it is not currently in possession of the necessary information. ESB National Grid is required to have provided the necessary information to ESB Networks no later than 13th September 2002. This will allow ESB Networks to be in a position to satisfy itself of the reasonableness of the cost of delivery put forward by ESB National Grid and following such an inspection, and no later than 1st December 2002, ESB Networks shall notify the CER where it believes that the level of costs provided for may be insufficient and shall be held accountable subsequently for any cost variances. This arrangement is designed to recognize that the future revenue stream of the prospective Owner (i.e. ESB Networks) will be determined in large part on regulated returns on an approved costed capital programme and the Owner, therefore, has a legitimate interest in the costing of this programme. The CER will incorporate any amendments into the 2004 transmission tariffs.

5.4 Additional use of Transmission System – Telecoms

The CER is aware that ESB is making further use of the transmission system, in particular the use of the system by ESB's telecommunication businesses. While the CER welcomes this development it proposes to assess the appropriate payment for the use of the network in this way so as to incentivise ESB to make optimal use of the network to the benefit of the TUoS customer. The CER will address this specific issue over the coming year in time for any retrospective adjustment at the next review if this is warranted.

5.5 2003 Transmission Revenue

Based on the above assessment the CER determines the allowed revenue for the transmission business to be €220m (2003 prices) for 2003. A summary of costs is shown in the table below.

Table 14 2003 Transmission Business Revenue – by category

	€M (2002 prices[4])	€M (2003 prices[5])
Constraints	20.1	21.04
Ancillary Services	36.7	38.42
Regulatory levy	0.7	0.73
Insurance	1	1.05
TSO External Costs	**58.5**	**61.25**
Internal Operation Costs[6]	19.45	20.36
Service Provision	2.25	2.36
BSBU Costs	1.88	1.97
Maintenance Professional Fees (incl ESBI fees)	3.68	3.85
Telecoms	3.10	3.25
IT Operating Costs	1.80	1.88
Business Overheads	1.80	1.88
Non Network Depreciation	5.49	5.75
Internal Costs	**39.45**	**41.31**
TSO Working Capital	0.76	0.80
TSO Return on Assets	1.09	1.14
Total	**1.85**	**1.94**
Less Other Revenue	**1.7**	**1.78**
Total TSO Revenue	**98.1**	**102.71**
Owner Operating Costs	24.29	25.43
CER levy	0.7	0.72
Owner Depreciation	37.82	39.60
Owner Operating Profit	39.15	41.17
Total Owner Revenue	**101.96**	**106.92**
Payback for 2000 under-recovery	7.21	7.55
Payback for 2001 under-recovery	2.53	2.82
Total	**10.28**	**10.37**
Total TUoS Revenue	**210.34**	**220.00**

[4] 2002 prices based on an assumption of inflation of 3.5% in 2002
[5] 2003 prices based on an assumption of inflation of 4.7% in 2002 and 3.5% in 2003. This assumption for 2002 is more realistic than the 3.5% assumption which the CER gave to ESBNG in January at the outset of the 2003 tariff review
[6] This figure includes payroll costs and professional fees, see section 5.1.1

Appendix 1 – 2001 Capital Programme - Physical Outputs

The Capex programme for 2001, as originally agreed, showed 114 projects which were scheduled to be active in 2001; of these 80 were due for completion in 2001 with the remainder continuing over a number of years.

Of the 80 projects originally due for completion in 2001 fourteen were dropped for a variety of reasons. The reasons include: refusal of planning permission; IPPs not proceeding; changes in scope and design (giving rise to rescheduling for delivery in 2002); need for Distribution stations deferred (due to downturn in high tech sector); the agreement of the PACT deal; outages not being available (on certain heavily loaded lines).

Two projects were added and four project completions were postponed due to inability to provide system outages in the winter.

The following is a summary of the most recent transmission capital work programme. The changes to this programme compared to the original programme are shown below.

No. of Live Projects on 2001 Programme	No. of Projects originally for completion in 2001	No. of Projects Completed in 2001
116	80	62

At year-end a total of 62 projects were declared complete. This achievement resulted from an increase in the resources committed to the transmission network by ESB Networks and ESB National Grid.

During 2001 contractors were deployed on a greater number of transmission construction projects and the intention is to continue to increase the level of contractor deployment to achieve even more challenging targets for 2002.

The goals achieved during 2001 include the following: -

- Installation of 16km of 220kV Cable (2 Projects)
- Construction of 33kM of 110kV lines (4 Projects)
- Installation of two new 220kV Substations.
- Construction of two new 110kV Substations providing 91.5MVA of additional transformer capacity.
- Upgrading of the interconnectors with Northern Irish Electricity including the doubling of transformer capacity at Louth, by installing a 600MVA transformer, and the installation of a new 110kV Substation at Coraclassey.
- Provision of additional transformer capacity and capacitor installations in existing transmission substations
    - 220KV Transformers: - 625MVA
    - 110kV Transformers: - 63MVA
    - Capacitors: - 60MVAR
- Uprating/Refurbishment of 490kM of 110kV lines involving 18 circuits.

Appendix 2 – TSO Customer/Stakeholder Objectives

Introduction

This document outlines ESBNG's Customer[7]/Stakeholder Objectives in support of the TSO Revenue submission staffing requirements. In total 40 specific objectives are outlined.

It is important to note that the TSO plays a central role in the industry and has a major impact on the costs seen by the industry as a whole. These costs may be:

(a) **TSO Managed Costs:** costs more directly under the control of the TSO (e.g. ancillary services, constraints, network development), or

(b) **TSO Influenced Industry Costs:** costs arising to participants as a result of the policies or performance of the TSO, including for example connection and access arrangements, provision of information, timely and efficient handling of queries, connection requests, policy modifications required due to changed circumstances, maintaining best practice in relation to network and system operation technology, etc.

It is much more appropriate that the performance of the TSO be assessed against the quality of the service it delivers under the above headings, rather than by comparatively small variations in its own internal business costs. Undue restrictions on the TSO's available resources has a massively more profound effect on the costs seen by and imposed on the overall industry.

ESBNG accepts that if the resources that it identifies as required are provided to it, then it should expect to be judged on delivery of a quality and efficient service. We would only add a caveat as to the mobilisation time necessary to get to proper service levels, arising from time required for recruitment, training, backlog and procedure design/redesign. For these reasons, while a steady improvement will be recognisable once approvals are in place, it will take a period of one to two years to realise all of the 40 objectives. Having said that, most of the improvements will be in place well in advance of that and some will come into immediate effect. Specific deadlines are indicated for some of the objectives below.

[7] Customers being generators, transmission connected demand and suppliers

1. TSO Implementation & Licence Obligations

In establishing the TSO function the 1999 Electricity Act sets forth a number of obligations previously not performed by the TSO in Ireland. A number of other necessary elements, while not specific licence obligations are essential "must-haves" for a TSO business.

1.1 Provision of Connection Offers in a consistent and timely manner.

The current level of connection applications, pre-feasibility studies, and re-quotations following acceptance of an offer, must be dealt with to facilitate new market entrants and to continue to facilitate connections for the DSO. Generation customers have raised this as an issue requiring resolution.

1.2 Review and re-design the generator connection process.

A redesigned process is expected to reduce administration & analysis costs and streamline/shorten the time to connect new parties to the system.

Deliverable 1 :

Reduce the Generation Connection Offer Process from the existing 90 business days to 70 business days, to be applied to applications received on or after 1st December 2002

Deliverable 2

Comprehensively review the Generator Connection process and propose a revised process to CER by 31st January 2003.

1.3 Review and re-design the generator connection agreement.

A redesigned agreement is expected to be easier for parties to understand (reducing their overhead costs) and easier for the TSO to administer. The current agreement is a combined agreement which incorporate Connection construction, Use of System and on-going Connection terms and obligations. This, in conjunction with a number of recent changes (e.g. deep to shallow charging, firm/non-firm) have made the agreement unwieldy. Pending changes (e.g. contestability) if accommodated without a redesign will complicate the agreement further.

Deliverable 3 :

Submit to CER for approval, a revised Generator Connection Agreement (or agreements) by 31st May 2003.

1.4 Develop, publish and administer a demand connection process.

This will enable a clear, consistent and transparent process for connecting new demand to the transmission system. Developing and publishing a process will make clear TSO and customer obligations.

Deliverable 4 :

Submit to CER for approval, a Demand Connection Process by 31st January 2003

1.5 Develop and publish a demand connection agreement.

An industry standard transmission demand connection is required to provide clear, consistent and transparent terms for connection for demand customers.

Deliverable 5 :
Submit to CER for approval, a Demand Connection Agreement (or agreements) by 31st May 2003.

1.6 Planning an efficient reliable network in a timely fashion.
Network planning has traditionally been carried out on a four-year cycle. Increasing uncertainty and the greater pace of change in the electricity market requires more frequent and comprehensive updates.

1.7 Publication of section 38 Forecast Statements in timely manner.
The publication of the Forecast Statement and Generation Adequacy Statement each year will provide the market with essential information regarding connection opportunities.

Deliverable 6 :
Submit next completed Generation Adequacy Report to CER by 30th November 2002.

Deliverable 7 :
Submit next completed Forecast Statement to CER by 31st March 2003.

1.8 Development Plan

Deliverable 8 :
Develop proposals in relation to the Development Plan and its consultation process and discuss with CER by 1st December 2002, with a view to ensuring that EirGrid will be in a position to comply with Condition 6 of the TSO licence when this becomes operational.

1.9 Transmission Planning Criteria, Operational Criteria and Security Standards.
The criteria and standards form the basis of network expansion, grid access decisions, and grid operations and so impact directly on tariffs, connection lead times and quality of supply. Under the TSO licence, standards are to be proposed to CER for approval with a review to take place within 12 months.

1.10 Manage the increased complexity, under the restructured industry, in matching demand with supply and ensuring reserve capability including nomination process, ancillary services management and interface with various market participants.
Management of the restructured industry & market requires additional effort to ensure reliability and continuity of supply to customers. Prior to restructuring, as everything was managed centrally, processes were essentially internal "command and control" whereas the new industry structure gives greater freedom to generators to decide running and outages.

1.11 Establish performance monitoring for compliance with Grid Code and Ancillary Service and System Support Service arrangements.
Greater complexity of the new industry structure including Grid Code compliance requirements and commercial arrangements has created

additional requirements for monitoring, analysis and reporting. Monitoring and ensuring the performance of connected parties (generators, transmission connected demand and the DSO) ensures system performance and service to customers is maintained and will not diminish as a result of restructuring. This is more complex to manage in a manner, which closely observes generator's technical and commercial requirements while ensuring system security meeting constraints at the most economic cost.

1.12 Establish/negotiate commercial agreement for the provision of Ancillary Services.

Formalisation of service provision requirements will allow for implementation of performance standard and non-performance remedies to ensure fair value is achieved for payments rendered.

Deliverable 9 :

Complete formalisation of service provision requirements in commercial Ancillary Service Agreements by 1 January 2003.

1.13 Resolve Grid Code implementation derogation backlog.

Implementation of the Grid Code has resulted in a significant volume of derogation requests, which require significant effort to resolve. This includes review of a number of important elements of the code in light of emerging generation technologies, which must be progressed to meet the requirements and aspirations of developers.

Deliverable 10 :

Eliminate 90% of the current backlog of Grid Code derogations by 31st December 2002 (subject to necessary technical information being available).

1.14 Development of a permanent billing system for transmission use of system (TUoS).

A permanent but flexible system is required to ensure TUoS charging will occur reliably into the future and be ready to facilitate tariff design changes as new methods are reviewed and approved.

Deliverable 11 :

Develop, test and implement a new comprehensive TUoS settlement system by 30th June 2003.

1.15 Development of a permanent settlement system for Ancillary Services.

A permanent but flexible system is required to incorporate revenue class metered values and ensure ancillary services settlement will occur reliably into the future and be ready to facilitate payment design changes as new methods are reviewed and implemented.

Deliverable 12 :

Develop, test and implement an Ancillary Services settlement system by 30th September 2003.

1.16 Support for other energy market developments under consideration by CER (e.g. the criteria for market participation,

support for standing bilateral contracts, secondary pricing) may require extra resources depending on outcome.

Given increased market opening and new participants, overheads on report production, checking, reconciliation and query management are all expected to increase, with resources required to keep to the timetable.

2. Service Delivery

Improvements are proposed for the fundamental TSO services, which will increase their value to customers and stakeholders.

2.1 Support for Energy Market trading nomination acceptance on a 7-day basis.

This would allow generators and suppliers to "fine-tune" their day ahead energy nominations over weekends (rather than the current agreed process where energy nominations for a Monday are made on a Friday). Some formal indication of market requirements would be required before implementing this process.

2.2 More dynamic calculation of Interconnector ATC.

Improve interconnector ATC calculations to ensure that, on a given day, as much capacity is available, given system conditions, to parties wishing to import or export.

2.3 Development and maintenance of a tariff forecasting function to provide reliable forecasts of input costs and transmission system usage for development of use of system tariffs.

Improved forecasting of costs (e.g. constraints) and utilisation (e.g. tariff energy & demand variables) will allow for more reliable tariffs, which will be much less in need of adjustments and carry-forward of over or under collection and more reflective of the actual costs to serve customers in that year. This will also facilitate a move toward incentivising the TSO to control costs for which they are accountable and to deliver value to the industry.

2.4 Proactive analysis and management of Ancillary Service, System Support Service and Constraints costs.

Proactive analysis and management will allow more detailed strategies to be developed to manage these costs. It is important to note that the costs seen by the TSO for Ancillary Services and Constraints is in the order of €60m per annum. Proactive and diligent management through procurement arrangements and through daily implementation of management strategies will deliver much greater benefits than the costs of additional personnel and systems required to do so.

2.5 Proactive dynamic event analysis for determining the best mix of Ancillary Service products to meet system response requirements.

Examine pre and post event response of Ancillary service product mix to determine the most cost-effective manner to meet system performance requirements.

2.6 Review and scope development for additional business system requirements (e.g. Capacity margin, PSO levy, forthcoming review of trading arrangements) which may arise).

The TSO is a central administrative function in the industry and may be asked to perform many supplemental administrative functions on behalf of the industry for the ultimate benefit of customers for which resource would not normally be dedicated.

3. Information Provision

Customers' requirements for information provision have grown considerably under the restructured industry, particularly in light of the new forms of customers, generators and suppliers. Interacting with these new customers and demand customers connected to the transmission system represent a new business requirement for the TSO. More generally international experiences suggests that arising from their independence and central responsibilities that the TSO plays a pivotal role providing information to the industry in every restructured jurisdiction.

3.1 Statements of TUoS Charges and Structure of Charges

To be submitted to CER for approval within two weeks of determinations of allowed revenues.

Deliverable 13 :

Submit Statement of Charges to CER for approval, within two weeks of receiving clear information from CER on approved revenue.

3.2 Derive and publish indicative tariffs and loss factors.

This will allow generation (and demand) developers to have better insight into future charges and loss factors, which should, ultimately, increase investor confidence in the market.

3.3 Develop and implement an improved process to co-ordinate outages and advise customers of system works, which may affect their operation (i.e. single ending) in a timely manner.

This process will improve co-ordination with customers and allow customers to manage internal risks better with a higher level of knowledge of system conditions, which may affect their operations. A number of customers have raised this as a problem requiring resolution.

3.4 Develop and implement an improved process for dissemination of power quality and system disturbance information to customers.

This process will provide more timely information to customers on system disturbances and power quality as it affects their operation. A number of customers have raised this as a problem requiring resolution.

3.5 Implement processes whereby customers requests, queries and information requirements are handled in a timely manner through a combination of personal interaction and communication via email and the website in a targeted (by audience) and customer friendly manner.

This will provide a greater degree of accessibility and understanding of the transmission system, processes a customer must undertake to obtain connection to and or use of the system and make it easier for customers to interact and do business with the TSO.

3.6 Provide resource to provide greater facilitation and education to parties in connecting to the system or in applying for use of system.

This will allow customers coming on to the system to quickly develop a fuller understanding of the system and processes and their obligations and responsibilities as a user.

Deliverable 14 :
Provide formal Stakeholder workshops of up to [5 days] total duration per annum on [subjects to be agreed].

3.7 Provide resources to allow greater interaction with customers allowing the TSO to better understand customer needs.
This will allow the TSO to adjust processes and services to better meet customer needs and to assess what new services are needed.

4. Policy Development & Issue Resolution

Initial policy development and implementation issues, international experience and developments, evolution toward a full market opening in 2005 and changing governmental and social policies all contribute to a changing environment for the TSO. This creates an essential requirement for the TSO to undertake constant review and examination of TSO policies and policies affecting the TSO and the TSO's customers and stakeholders.

4.1 Allow the TSO to undertake timely policy reviews to reflect changing industry conditions.
This is required to support the required response to changing circumstances and new policy developments (e.g. contestability) which continuously arise.

4.2 Allow the TSO to better meet CER timetables for submissions, consultation responses and information requests.
This allows more expeditious resolution of issues and should assist promoting best decisions.

4.3 Allow TSO the opportunity for greater consultation and communication with stakeholders including more consultation forums.
This allows for a greater understanding by the TSO of stakeholder issues and allows for more expeditious resolution of those issues.

4.4 Review of Transmission Loss Adjustment Factor (TLAF) Methodology for consistent outcomes through the full range of generator sizes and dispatches.
This may allow for the implementation of a revised methodology, which would allocate losses to generators in a manner more consistent with their loss contribution.

Deliverable 15 :
Review Transmission Loss Adjustment Factor (TLAF) Methodology and report on outcome and proposed future methodology (if different) by 31st May 2003.

4.5 Review charging and loss factor application for volatility and examine methods to manage volatility.
Reduced volatility in charges and loss factors will increase developer confidence in the Irish market and ultimately improve end customer energy prices through reduced developer risk premiums.

4.6 Review elements of the tariff design (e.g. MIC based charging) for desired outcomes and examine other methods.

Determine is tariff design elements are achieving their desired outcome, including design objective, transparency and ease of administration.

4.7 Support the development of EU policy for cross border trading arrangements and review present interconnector trading arrangements for conformance with EU directions and continental Europe integration.

This will allow for more effective electricity trade between Ireland and the rest of Europe allowing for increased supply and generation market access.

5. Facilitating Competition

The TSO, as an independent central industry function, plays an essential role in facilitating competition. As evidenced by developments in England and Wales over the last decade (including the review and subsequent development and implementation of new trading arrangements - NETA), the TSO's role in facilitating competition is without end.

5.1 Support the All-Island market review for overall design workability particularly for indicative implications on generation costs and transmission network developments, and arrangement for ancillary services, system support services and congestion and constraints.

A workable all-island market has the potential to improve trade, reduce transaction costs, improve investor confidence and increase the market participation base.

5.2 Increase the Ancillary Service supplier base.

Improve access to new providers of Ancillary Services and ultimately reduce customer costs through a broader and more competitive supplier base.

Deliverable 16 :

Complete competitive procurement process for a new Black Start source by 30th April 2003.

5.3 Increase the Interruptible Load Service supplier base

Improve access to new providers of Interruptible Load Service and ultimately reduce customer costs through a broader and more competitive supplier base.

Deliverable 17 :

Design, develop and implement a suitable procurement process for the procurement of Interruptible demand by 31st July 2003

5.4 Establish contestability processes for transmission connections.

Subject to CER direction on policy formation and legislative interpretation, processes, agreements and specifications/standards will be required to facilitate contestable connection while ensuring such connections will not jeopardise system integrity (through substandard design or construction), ensure efficient system development and ensure access to the facilities for the TSO to serve other customers. TSO recognises that generators already enjoy the statutory right to construct their own shallow connections, regardless of the current absence of approved or standard arrangements, and this right may only be denied on grounds of system integrity.