CER Transmission and Distribution Price Review

REVIEW OF DISTRIBUTION OPERATING COSTS 2006 TO 2015

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Document history and status

Revision	Date issued	Reviewed by	Approved by	Date approved	Revision type
V1.0	14 May 2010	G Flynn	DI Bailey	14 May 2010	For issue to DSO

Distribution of copies

Revision	Copy no	Quantity	Issued to
V1.0	1	1	CER for retention and to forward to DSO

File name:	DSO Opex
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Project manager:	David Bailey
Name of organisation:	CER
Name of project:	CER Transmission and Distribution Price Review
Name of document:	Review of Distribution Operating Costs 2006 to 2015
Project number:	VP00673

1. Executive Summary

All prices in this report are expressed as real prices at 2009 price levels, unless otherwise stated.

Conclusions and recommendations are included in the report in bold type and are summarised in Section 6.

A detailed summary of allowed and outturn costs for PR2 and the DSO's forecast and our recommendations for allowed costs for PR3 is included as Appendix C.

This report provides an analysis of the DSO's operating costs incurred in period 2006 to 2010 (PR2) and reviews the DSO's forecast of operating costs for the period 2011 to 2015 (PR3). The report makes recommendations for costs to be allowed by CER in PR3 and the outputs and incentives for network performance and customer service.

1.1. DSO Operating Costs 2006 to 2010

Table A gives a summary of the DSO's operating costs over the period 2006 to 2010, comparing outturn costs with CER's allowed costs. The analysis excludes depreciation and exceptional costs and shows commercial costs separately, since these are not included in DUoS but paid for separately customers and other parties.

Table A CER Allowed Operating Costs against DSO Operating Costs 2006 to 2010

CER Determination	2006 €m	2007 €m	2008 €m	2009 €m	2010 €m	Total €m
Allowed Cash opex (2004 Prices)	264	254	248	244	240	1251
Allowed Cash opex (2009 Prices)	293	286	275	262	252	1368
Total net Adjustments (2009 Prices)	-3	-1	-5	-8	-2	-18
CER Adjusted Allowed Opex	290	285	270	254	250	1350
CER Allowed Opex less Commercial Costs	270	267	252	237	233	1259
DSO Net Opex less Commercial Costs	259	265	250	246	252	1272
Overspend vs Allowed Opex	-11	-1	-3	9	18	12

The DSO's PR2 operating costs of €1272m are €12m[1] higher than the allowed costs of €1260m, excluding commercial costs and exceptional costs, indicating that the DSO has met the targets set by CER. It is important to note that the DUoS tariffs over the period are based only on the allowed expenditures.

[1] In 2006 the CER decided (CER/06/207) to allow the ESB to recover, over five years, a portion of its pension deficit. This has not been taken into account in this report which considers normal operating costs. Pension deficit is still under separate consideration. The impact of this adjustment would result in an under spend.

The DSO met all of the incentivised performance targets for network performance and customer service set out in Sections 4.1.2 and 4.2.1, including a reduction in average minutes lost per customer of 43 % and in customer interruptions of 34%. The DSO has also exceeded the overall customer satisfaction target (ESATRAT) of 85% (actual performance of 90% in 2009).

The DSO implemented a number of efficiency and service initiatives listed in Appendix A to meet the challenge of cost pressures encountered, which are summarised in Appendix B

Three major IT systems have been implemented for asset and work management and mobile data, and the DSO has gained PAS 55 accreditation for asset management.

ESB Networks has also funded from its own funds severance costs of €135m which have contributed to net staff reductions of 287 from 3758 to 3471 across ESB Networks as a whole.

Table B Analysis of PR2 Operating Costs 2006 to 2010

Summary of DSO Operating Costs 2006 to 2010 (€m 2009 Prices)

DSO PR2 Operating Costs (€m 2009 Prices)	CER PR2 Allowed	DSO PR2 Projected Outturn	Var PR2 Outturn Vs CER Allowed
Diversions (Capex in PR3)	111.8	114.6	2.7
Operations and Maintenance	474.9	514.3	39.4
Asset Management	58.2	59.6	1.4
Metering	102.6	100.1	-2.5
Customer Service	110.4	98.3	-12.1
Provision of Data	82.8	74.9	-8.0
Other	144.5	135.9	-8.6
Controllable Costs	**1085.4**	**1097.6**	**12.3**
Non Controllable Costs	**174.1**	**174.1**	**0.0**
Operating Costs Excl Commercial	**1259.5**	**1271.7**	**12.3**
Commercial (Excluded Costs)	**95.6**	**168.3**	**72.7**
Operating Costs Incl Commercial & Diversions	**1355.1**	**1440.0**	**85.0**

Operations and Maintenance (Allowed €474.9m Outturn €514.3m)

Operations and Maintenance Costs of €514.3m were €39.4m higher than allowed costs of €474.9m, an overspend of 8.2%. Planned Maintenance costs were overspent by €16m and Fault Maintenance costs were overspent by €29m, whereas System Control was under spent by €5.4m.

The under spend on System Control costs of €5.4m is mainly due to reorganisation and centralisation of MV network control from 34 Areas to two control centres at Cork and Dublin. The development of the Control Centre IT systems (OMS), and SCADA for the remote control of the network, has also reduced costs.

Planned maintenance costs of €228.5m are €16.1m higher than the allowed costs of €212.3m. There was an overspend of €37.7m on overhead line maintenance and an under spend of €21.4m on maintenance of substations and cables.

Benchmarking indicates that tree cutting costs are lower per km than in Great Britain, (see Section 5.2.2.1) and we consider that the expenditure on tree cutting, although overspent by around €30m, has been efficiently incurred.

It is recommended that the under spend of €18m and the non completion of the HV substation maintenance programme is taken into account in the review of planned maintenance costs for PR3. The PR3 forecast includes provision for reducing backlog and customers should not be expected to pay for planned maintenance twice.

Fault maintenance costs of €197.6m were €28.6m higher than the CER allowed costs of €169m. The overspend arose partly because fault numbers did not reduce as much as was anticipated, due to a delay in the low voltage network refurbishment programme. There were 400 more MV faults on the uprated 20 kV network than anticipated.

The DSO received incentive payments of €55m for improvements in system performance and some of the overspend may be attributed to changes in working practice to meet performance targets. Consideration has been given to deducting part of the overspend from allowed revenue. However, the DSO has met overall performance targets. The price control is an overall settlement and it is not appropriate to deduct revenue for this individual line item. However, the DSO will forfeit any overspend if its operating costs are greater than allowed costs at the end of 2010.

Asset Management (Allowed €58.2m Outturn €59.6m)

Asset Management costs are those costs associated with policy development and head office engineering activities. They include wayleaves and forestry payments to landowners which have increased from €3m per year in 2006 to a €4.9m in 2009.

Metering (Allowed €102.6m Outturn €100.1m)

Metering costs of €100m are under spent by €2.5m. However, meter reading costs have increased from €10.5m per year to a forecast €13.6m in 2010. It has proved expensive to meet the meter reading performance targets, in particular the requirement for 97 per cent of accounts with four scheduled visits per year. (Performance has improved from 84% in 2005 to 92% in 2009).

Customer Service (Allowed €110.4m Outturn €98.3m)

Customer service expenditure of €98.3m is under spent by €12.1m (14%) compared with the CER allowance of €110.4m, mainly due to an under spend on Area Operations of €16m due to rationalisation. The introduction of hand-held units and mobile data messaging has improved efficiency of customer driven work. Outage planning and live line work and system automation has improved productivity and reduced the need for switching.

Call Centre costs have increased from €6.1m per year to €7.9m per year during PR2 but are under spent overall in PR2 by €1.4m. It was found that the initial staffing levels gave unacceptable customer service, which has now improved following a customer service improvement programme.

Provision of Information (Allowed €82.8m Outturn €72.9m)

Market System costs are associated with the operation and development of a customer information system for operating the electricity market and data exchange with Suppliers. Activity has been monitored by CER throughout PR2 and allowed costs have been reduced by CER during PR2 from €112m to €71m to take account of activity levels.

Other Costs (Allowed €144.5m Outturn €135.9m)

Corporate charges are €13m lower than those allowed by CER mainly due to the transfer of training and legal service costs from the Corporate Centre to the DSO and these are now absorbed under other headings.

Non Controllable Costs €174.1m

Non Controllable Costs include Network Rates and CER Levy. These costs are treated as pass through costs and allowed costs are adjusted to outturn.

1.2. Assumptions for Operating Costs 2011 to 2015

The objective of the DSO submission is to maintain the average unit price (AUP) of DUoS taking into account the €31m additional operating expenditure on sustainability and research and development. The new activities also include additional capital expenditure items, including €500m for smart meters, €187m for electric vehicles charging points and €102m for office moves. DSO has therefore been under some pressure to contain its forecast to provide headroom for this additional capex and opex.

We agree with the DSO’s assumptions of a 1.35% per annum growth in connections during PR3. The DSO’s assumption of an increase in units of 2.85% is considered to be high in view of the economic circumstances. However, operating costs and capital expenditure are more related to peak demand than unit growth and we agree with the DSO that there is likely to be no increase in peak demand throughout PR3.

The DSO has assumed a productivity increase of 1% per annum over PR3. The ESRI Medium Term Review 2008[2] forecasts the average productivity of the Irish economy to be 2.5% per annum over the period 2011 to 2015. The DSO’s activities are highly mechanised and are supported by a significant level of IT investment. There has also been significant reorganisation and staff reduction in PR2 and potential for more in PR3. Much of these developments have occurred in the latter part of PR2 and the full effect is not reflected in costs. We would therefore expect the DSO to achieve at least 2.5% productivity improvement over PR3**.**

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[2] Economic and Social Research Institute Medium Term Review 2008 – May 2008

The DSO's assumption that internal labour costs will be maintained at CPI is considered to be too conservative in the present economic climate and when compared with pay reductions elsewhere in the Irish economy. Our recommendations are based on a reduction in DSO and ESB Group payroll costs of 5% in 2011, which is approximately a 2.5% reduction in controllable costs in 2011.

In making recommendations for allowed costs we have taken excess margin and payroll costs into account when assessing costs which have a component of those costs from other parts of ESB Group.

Our recommendations indicate ongoing reduction in operating costs of 1.5% – 2.5% per annum over PR3 from a derived base Po costs in 2011s. Taking into account that some costs are not controllable the overall reduction in costs from base level is around 2% per annum. This includes an allowance for growth in drivers such as customers, where appropriate.

Our recommendation for allowed costs is an overall settlement tied to meeting statutory obligations and the delivery of outputs under incentives considered in Section 4. It is not dependent on individual line items and the recommendation is based on what is considered to be efficient overall.

The results of our benchmarking of the DSO against GB DNOs indicate that the DSO has an efficiency gap of between 7.5% and 16% on operating costs plus non network capex. There is no doubt that the DSO appears to be closing the efficiency gap with the GB DNOs and has implemented a number of measures adopted by the GB DNOs in the last 15 years. However, there is insufficient evidence to conclude that the DSO is at the efficiency frontier and much evidence to indicate that significant further efficiency improvements are available.

It is evident that benchmarking becomes more difficult as the DSO approaches GB efficiency levels. Whereas it was easy to identify a large efficiency gap in PR1 and PR2 by benchmarking, this is now more difficult as the gap narrows.

1.3. Operating Costs 2011 to 2015

The recommendations for allowed operating costs are based on the assumptions in section 1.2. The particular features of each cost heading have been reviewed including the base level of costs appropriate in 2011, growth factors and potential efficiencies available. Efficiency factors have not been applied for example to non controllable pass through cost.

The proposals for PR3 operating costs are grouped and summarised below year by year and in comparison with historic costs and DSO PR3 forecast.

Table C provides a summary of DSOs forecast of PR3 operating costs and our recommendation for allowed operating costs for PR3.

It is proposed to capitalise diversions costs in PR3 and the footnote to the table shows the reduction in operating costs in DUoS for the DSO forecast and our proposed allowed costs.

The DSO's forecast of operating expenditure in the PR3 period (2010 to 2015) is €1233.3m, which is €76.2m greater than the equivalent PR2 outturn of €1157.3m. This comparison excludes commercial costs and the cost of diversions, which it is proposed will be capitalised in PR3.

The additional costs of €76m include €31m for research and development and sustainability costs associated with future networks that will support wind generation and electric vehicles, using smart metering.

Our recommendation is for allowed PR3 operating costs of €1086.9m, which is €146.3m lower than the DSO's PR3 forecast and €70.2m less than the equivalent PR2 outturn.

Table C Summary of Proposed and Recommended Operating Costs 2011 to 2015

	2009 Actual	2011	2012	2013	2014	2015	DSO PR3 Forecast	PR2 Outturn	Variance PR3-PR2	Variance %
		DSO Forecast								
Operations and Maintenance	103.6	102.7	101.6	101.3	100.8	101.5	507.8	514.3	-6.5	-1.3%
Asset Management	12.6	13.7	13.2	13.0	13.0	12.9	65.8	59.6	6.2	10.4%
Metering	21.3	24.8	24.7	24.8	24.9	24.9	124.1	100.1	24.0	24.0%
Customer Services	18.1	18.6	18.5	18.4	18.3	18.3	92.2	98.3	-6.1	-6.2%
Provision of Data	13.8	17.4	17.7	17.5	17.4	17.3	87.1	74.9	12.3	16.4%
Corporate Costs	13.9	14.9	14.8	14.8	14.7	14.7	73.8	72.9	1.0	1.4%
Other	11.4	12.4	12.4	12.3	12.3	12.2	61.7	55.1	6.5	11.9%
Sustainability	2.3	6.1	6.1	6.2	6.2	6.2	30.8	7.9	22.8	288.3%
Non Controllable Costs	34.5	37.3	37.3	37.3	37.3	40.8	190.0	174.1	15.9	9.1%
Operating Costs	**231.4**	**248.0**	**246.3**	**245.5**	**244.8**	**248.7**	**1233.3**	**1157.1**	**76.2**	**6.6%**
	2009 Actual	**2011**	**2012**	**2013**	**2014**	**2015**	**PR3 Recommended**	**DSO PR3 Forecast**	**Variance Recommend vs DSO Forecast**	**Variance %**
		Recommended								
Operations and Maintenance	103.6	93.1	91.1	89.1	87.1	85.2	445.6	507.8	-62.2	-12.2%
Asset Management	12.6	12.4	12.2	12.0	11.8	11.7	60.2	65.8	-5.6	-8.6%
Metering	21.3	20.8	20.5	20.1	19.8	19.4	100.5	124.1	-23.6	-19.0%
Customer Services	18.1	17.3	16.9	16.4	16.0	15.6	82.3	92.2	-9.9	-10.7%
Provision of Data	13.8	14.8	14.6	14.4	14.2	14.0	71.9	87.1	-15.2	-17.5%
Corporate Costs	13.9	13.5	13.2	12.9	12.5	12.2	64.3	73.8	-9.5	-12.9%
Other	11.4	11.0	10.9	10.8	10.7	10.5	53.9	61.7	-7.7	-12.5%
Sustainability	2.3	3.6	3.6	3.6	3.6	3.6	18.2	30.8	-12.6	-40.8%
Non Controllable Costs	34.5	37.3	37.3	37.3	37.3	40.8	190.0	190.0	0.0	0.0%
Operating Costs	**231.4**	**223.9**	**220.2**	**216.6**	**213.1**	**213.2**	**1086.9**	**1233.3**	**-146.3**	**-11.9%**

A summary of our recommendations of allowed costs for individual line items is given below:

Capital Driven Opex

From PR3 onwards CER proposes to treat diversions of cables and overhead lines associated with new connections as capital expenditure. Diversions costs are therefore considered under capex.

Operations and Maintenance (PR2 €514.3m DSO €507.8m Recommended €445.6m)

System Control (PR2 €88.2m DSO €75.9m Recommended €70.1m)

System Control Costs have been falling during PR2 due to application of technology and centralisation and this is forecast to continue in PR3.

Planned Maintenance (PR2 €228.5 DSO €247.2m Recommended €198.0m)

110kV and 38 kV (HV) Substation Maintenance PR2 €37.4m DSO €59.6m Recommended €35.1m

The main increase in expenditure in the DSO forecast relates to 110 kV and 38 kV substation maintenance, which are forecast to increase by €22m compared with PR2.

The DSO has under spent HV substation maintenance costs by €18m in PR2 and the forecasts for PR3 make provision for removing the backlog. This element of cost is removed from allowed costs as the DSO has already been paid for this work. Other savings are also available from the review of maintenance practices, payroll and other efficiency savings.

110kV and 38 kV (HV) Cables Maintenance PR2 €2.56m DSO €9.46m Recommended €4.6m

Similarly there is a backlog in 38 kV and 110 kV cable maintenance and these costs have been allowed on the basis of 2010 forecast costs which are considered to reflect normal levels of required maintenance.

MV Substation and Minipillar Maintenance PR2 €40.12m DSO €40.46m Recommended €34.1m

The DSO has spent significantly on replacement of oil switchgear and on minipillar refurbishment and it is to be expected that these costs will fall 5% per year over PR3.

Tree Cutting All Voltages (PR2 €85.5m DSO €92.1m Recommended €84.7m)

We have accepted that the MV tree cutting programme should be organised on a three year cycle. However, we consider that efficiencies will be available in actively managing the programme to reflect need and risk. There will be some inevitable slippage in the programme due to site conditions and outage requirements. We have therefore applied 5% abatement. In addition we would expect a reasonable efficiency factor as the programme advances and less work is required on the next cut.

Overhead Line Hazard Maintenance (PR2 €62.7m DSO €45.5m Recommended €39.6m)

Overhead line hazard maintenance is reducing due to the MV network renewal programme completed in PR1 and PR2 and the LV network renewal programme which is to be completed over PR2 and PR3. DSO has changed its approach to overhead lines which effectively capitalises much of the work required. We therefore accept the reductions proposed by DSO and have added an efficiency factor.

Fault Maintenance (PR2 €197.6m DSO €184.7m Recommended €177.5m)

During PR2 fault costs rose significantly with an overspend of €29m, which has not wholly been accounted for, but which may be partly due to additional costs of achieving system performance and incentive payments. It is recommended that the additional annual costs incurred in PR2 and reflected in PR3 forecasts are accepted in part as a price worth paying for improvements in system performance.

Proposals have been made for further incentivised improvements in quality of supply 22% for CML and 11% for CIs - see section 4.1.4

There is an expected reduction in faults and fault costs during PR3.

Asset Management (PR2 €59.6m DSO €65.8m Recommended €60.2m)

Asset Management costs have risen during PR2 due to increases in forestry and wayleave payments to landowners for rights to place equipment on land and for forestry sterilisation costs. Other costs are expected to reduce in line with efficiency assumptions.

Metering (PR2 100.1m DSO €124.1m Recommended €100.5)

Metering Reading (PR2 €58.6m DSO €71.9m Recommended €60.7m)

DSO seeks an increase in meter reading costs associated with meeting performance targets for making 4 actual visits to each premise in each year, 97% target (92% at December 2009). Should DSO have difficulty meeting targets then it would be appropriate to revisit the targets in particular areas with CER and Suppliers and agree targets that are appropriate for credit control and to maintain complaints at optimum level.

There are no specialist skills peculiar to the electricity industry in these activities and it should be possible to exert downward pressure on these costs during PR3 meaning the increase is not justified.

Customer Service (PR2 €98.3m DSO €92.2m Recommended €82.3m)

Call Centre (PR2 €36.3m DSO €35.0m Recommended €32.8m)

At the PR2 review in 2005 CER had considerable concerns over customer service performance levels and increased allowed costs and targets and incentives were introduced to stimulate an improvement, which has been achieved. From 2011 to 2015 competitiveness is an important national issue and DSO proposes to focus on consistently delivering cost-effective levels of service and this is reflected to some extent in the forecast.

The incentive regime will also need to change to reflect the changed circumstances. Having reached target levels the DSO needs to be incentivised to maintain that position. We recommend that the incentive scheme is adapted to incentivise DSO to maintain ESATRAT performance at the present target levels of 85% as indicated in Section 4.2.2.

Area Operations (PR2 €52.8m DSO €52.9m Recommended €45.4m)

The DSO has included an increase in operating costs for Area Operations but in our view the savings arising in PR2 are likely to continue, as the IT systems are fully exploited and the mobile data system is extended to cover more types of work. There is also the potential for further rationalising of the Area structure by centralising certain activities and reducing the number of depots.

Customer Relations (PR2€9.2m € DSO €4.3m Recommended €4.0m)

We have accepted the reduction in customer relations costs proposed by DSO and applied an efficiency factor over PR3.

Provision of Information (PR2 €74.9m DSO €87.1m Recommended €71.9m)

DSO has explained that Market Systems Costs are expected to rise due to the need for more responsive IT systems and the need to handle the volume of market switching which has risen from 54,479 in 2008 to 456,570 in 2009. There is also a volume driver on the amount of data being stored.

DUOS (PR2 €4.0m DSO €3.8m Recommended €3.3m)

DUOS billing is maintained 2009 levels with assumed efficiencies

MRSO (PR2 €6.2 DSO €10.1m Recommended €9.4m)

The DSO has included additional costs in the area of MRSO due to the level of churn and modifications associated with Free Electricity Allowances and global aggregation which require additional staff

Market Systems (PR2 €64.7m DSO €73.3m Recommended €59.1m)

It is recognised that this activity is not wholly under the control of DSO, but it is part of DSO's responsibilities to deliver efficient market systems. These costs have therefore been subject to the same level of efficiency savings and the 2011 costs have been fixed at the 2009 level. It is recognised that any new activities required by the market may lead to request for adjustments, higher or lower, as has been the case in the past.

Corporate Costs (PR2 €72.9m DSO €73.8m Recommended €64.3m)

Corporate costs reduced during PR2 from €15.2m in 2006 to €14.7m in 2010. However it is considered that these costs should have reduced by more than this due to transfer of legal services and training centres to the DSO. No explanation has been provided for the forecast increase in corporate costs or any challenge mounted by DSO.

Other Controllable Costs (PR2 €55.1m DSO €61.7m Recommended €53.9m)

Other controllable costs consist of safety, environmental, and central services costs such as pension administration and revenue collection. Some increase has been allowed for environmental costs and other costs have been subject to efficiency savings.

Sustainability and Research and Development PR2 €7.9m DSO €30.8m Recommended €18.2m

This additional expenditure is linked to the government environmental targets including wind generation and electric vehicles and the DSO proposals for capital expenditure of €187m on electric vehicle charging points. This programme and its governance and funding should be overseen by Government, with participation by CER, ESB, ESB Networks, EirGrid and other stakeholders including generators and electric vehicle and EV charging point interests.

The sustainability expenditure makes provision for €14.2m of identified expenditure of which €8.2m involves subsidy for microgeneration, ie €6m of R & D projects, and a further unspecified €17m of R & D projects.

R & D can produce success and failure and we have reservations that participation in collaborative research of this type will identify the viability of this project or provide solutions and we recommend sustainability and research and development expenditure of €18.2m.

We recommend that tariff support for microgeneration should be provided outside of DUoS, possibly using a PSO mechanism.

Non Controllable Costs PR2 €174.1m DSO €190.0m Recommended €190.0m

Non- Controllable costs are normally allowed as pass through, subject to them being efficiently incurred, and historically have consisted of rates and CER levy.

Opex Allowed Costs

The impact of operational costs (excluding depreciation) on the unit cost of electricity per customer in the table below:

Table D Trends in Unit Costs

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Customers (m) (Actual / DSO Forecast	2.070	2.151	2.204	2.234	2.259	2.287	2.317	2.348	2.381	2.416
GWh DSO Forecast	22903	23457	24043	23084	22902	23269	24014	24758	25526	26317
DSO Operating Costs €m	259.4	265.3	249.5	245.6	251.9	248.0	246.3	245.5	244.8	248.7
Actual / Allowed Operating Costs €m	259.4	265.3	249.5	245.6	251.9	223.9	220.2	216.6	213.1	213.2
Cost per customer (DSO Forecast)	125.3	123.3	113.2	110.0	111.5	108.4	106.3	104.5	102.8	102.9
Cost per customer (Allowed)	125.3	123.3	113.2	110.0	111.5	97.9	95.0	92.2	89.5	88.2
DSO Cost per kWh (cents)	1.13	1.13	1.04	1.06	1.10	1.07	1.03	0.99	0.96	0.95
Actual / Allowed Cost per kWh (cents)	1.13	1.13	1.04	1.06	1.10	0.96	0.92	0.87	0.83	0.81

Table D shows trends in unit costs over PR2 and PR3.

The DSO forecasts of costs and units distributed would give rise to a reduction in unit costs per kWh of 13.4% 2010 to 2015. The reduction in cost per kWh based on recommended costs and the DSO forecast of units is 25.8% from 2010 to 2015.

1.4. DSO Performance Targets and Incentives

We have examined the DSO’s benchmarking of quality of supply performance against GB DNOs and have concluded that it is not intended to be an exhaustive model but it is illustrative of the sensitivity of system performance to network topography, customer dispersion, fault rates and the level of system automation.

The rate of improvement of DSO network performance demonstrates the effectiveness of incentives but also indicates that there is some way to go for DSO to achieve optimum network performance.

The DSO has based the forecast on the 2010 forecast, which is based on a trend that excludes the 2009 figures that the DSO considers to be abnormally low due to a benign spring. Basing the target on a simple regression including 2009 gives a starting point for 2010 of 101 CIs and 64 CMLs. These are not considered to be credible starting points and it is proposed to adopt the average of 2008 and 2009 as the starting point for CIs (119 compared with the DSOs figure of 122) and for CMLs (87 compared with 88).

The DSO has established models for deriving targets for unplanned outages and has forecast further improvements in CIs of 10% and CMLs of 20% during PR3. We have examined the models and have modified the target to 11% for CIs and 22% for CMLs. These targets are considered to be stretching and yet provide sufficient opportunity for the DSO to achieve incentive payments, which we recommend continue at the existing levels. We also agree that the targets should be based on interruptions of three minutes or more, which is a technical change from the one-minute threshold adopted up to 2010.

The DSO has proposed that targets for planned interruptions are set annually based on the workload in any one year, which will avoid windfall gains from uncompleted work programmes. We agree with this approach and have examined the models which appear to have a sound theoretical basis and include a proportion of live work. However performance should be monitored and the incentive rate adjusted if the gains appear to be out of line with customer benefits.

The DSO has proposed a fund of €10m per year for worst served customers and we recommend that this approach is explored further and that thresholds are set to fairly identify beneficiaries. The scale of the fund should be set at £10m for the whole of PR3, with particular targets in mind, based on network performance data.

We recommend that the incentive scheme be modified to incentivise the DSO to maintain existing target levels of performance as proposed by the DSO throughout PR3 and that the DSO will be rewarded for over and under achievement of the ESATRAT target of 85% under the existing incentive arrangement. CER should consider the benefit of applying a dead band apply between 82.5% and 87.5% to further incentivise maintaining existing levels of performance, which was 90% in 2009.

The measurement of customer satisfaction using the RED C survey has been successful in improving overall customer satisfaction levels. It is recommended that a new inventive be adopted based on the Red C performance to ensure that customer satisfaction levels are maintained.

1.5. Benchmarking

This section summarises benchmarking studies we have undertaken for CER, which are set out in a report in Appendix D. ESB Networks DSO costs and TAO 110 kV costs have been benchmarked against GB DNO costs, excluding Scottish DNOs, which are not responsible for 132 kV assets.

We have also carried out bottom up benchmarking of tree cutting costs and fault costs on a per km basis and explain some of the apparent differences in performance.

Our findings are as follows:

Benchmarking of ESB Networks DSO and 110 kV TAO opex and non network capex indicates that the DSO costs are 7.5% above the Upper Quartile of the GB DNO costs and 16 % above the efficiency frontier. This is consistent with our recommendations for allowed costs which give a reduction of 11% in controllable opex from €232m in 2009 to €207m in 2015.

A model of fault costs based on our standard unit costs and the fault data for GB DNOs and the DSO, indicates that DNO costs of faults per km are inherently 1.5 times that of the DSO. This is because the DNOs have a higher proportion of underground cable, and hence cable faults, which are more expensive to repair. The model corresponds with actual outturn cost data. Whilst this indicates that the DSO is as efficient as the average DNO in respect of fault costs, the DNOs carry a cost penalty in the top down benchmarking.

Tree cutting costs have been benchmarked and the DSO's costs of €107 per km are lower than the DNO costs of €251 per km. This may be partly due the relative tree cover and the temporary increase in tree cutting in GB due to new safety regulations.

We compared IT and Telecoms costs and System Control support costs and found them to be relatively high. This corresponds with the findings of one of the DSO's benchmarking studies, which indicates that some technical costs such as fault and maintenance (cost per km) are considered to be best in class or low, whereas support costs leave room for improvement. The study indicates that ESBN may have some unfavourable characteristics. Our view is that the DSO network is atypical and has characteristics which mean that costs per km may be inherently lower than companies with a more typical mix of overhead line and underground cable.

1.6. Losses

The DSO proposes to convert 15,000 km of 10 kV network to 20 kV operation during PR3, mainly due to reinforcement drivers. The saving in losses will amount to 20-25MW at the times of system peak, which will offset the expenditure over a 25 year period.

The DSO's approach to measuring the outcome of investments to reduce system losses using a network model and averaging results over a three-year period is a reasonable basis for estimating system losses. However our experience is that any theoretical model of network losses is likely to have significant inaccuracies due to the assumptions made and simplifications inherent in such models and may not be suitable for calculating incentives. Any gains or losses from the method proposed by the DSO are likely to be of a windfall nature and not due to additional initiatives taken by the DSO. It is noted that the DSO has not proposed any initiatives to reduce losses beyond the investments in the capital programme. Such initiatives generally lead to only small reductions in losses that are not measureable against background errors.

It is recommended that CER should proceed with modelling system losses as proposed by the DSO but incentives should not be paid until the model has been shown to be accurate and that any reductions in losses beyond that built into the capital programme can be identified as being as a direct result of actions by the DSO.

1.7. Generation Connection Incentive

The DSO has proposed incentives for connecting generators to the network based on achievements in relation to each of three milestones - planning stage, detailed design stage and construction stage. The DSO proposes adjustments to target dates due to matters considered to be outside the DSO's control. We recommend an incentive linked to MW of connected generation based on overall target dates based on the project timescales agreed with CER. This approach avoids sub optimisation over the various stages and encourages catch up where there is slippage in any one stage.

2. Introduction and Assumptions

2.1. Introduction

Conclusions and recommendations are included in the report in bold type and are summarised in Section 6.

This report reviews the Distribution System Operator (DSO) efficiency and operating costs, excluding network depreciation, over the PR2 period (2006 to 2010) and PR3 period (2011 to 2015). The review considers the costs, systems processes, and initiatives of the DSO over PR2 and identifies key issues to be considered in PR3. The report then reviews the DSOs proposals for expenditure in PR3 and makes recommendations on the level of expenditure, outputs and incentives to be allowed by CER.

2.2. Objectives

The objective of the review is to assess the DSO's performance in achieving the outputs required by CER during PR2within the CER allowed costs. The review identifies any changes in circumstances put forward by the DSO and CER to explain any variances in outputs and costs and makes recommendations for adjustments to allowed costs. A further objective is to appraise the DSO forecast of operating costs and non network capital expenditure for PR3. The report makes recommendations on changes to the programme of work and expenditure to be allowed by CER together with the level of outputs for quality of supply, customer service and incentives required to achieve these outputs.

The objective in setting allowed operating costs 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
- Evaluation of future required opex
- Impact of capex programme on opex requirements

2.3. Data Sources and Assumptions

All prices in this report are expressed as real prices at 2009 price levels, unless otherwise stated, based on the following inflation factors.

	2006	2007	2008	2009	2010-2015
CPI Inflation factor	4.0%	4.9%	4.1%	-4.6%	0%

CER allowed costs are as set out in the CER PR2 decision paper[3] with annual adjustments made during the price control period by CER, for example due to higher than forecast number of connections and pass through items.

The review has been informed by the DSO's response to the questionnaire on historic and forecast operating costs and associated information papers and network plans, together with further data provided by the DSO at meetings and from supplementary questions raised by CER and consultants. The review takes into account provisional outturn costs and performance for 2009. CER has also provided a significant amount of background information on previous price reviews and updated information during the period 2006 to 2010.

[3] CER Paper 05/138 2006 - 2010 Price Review Decision on Distribution System Operator Revenues September 2005.

3. Review of Operating Costs

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:

- Review of 2006-2010 Opex
- Benchmarking DSO's Opex
- Assessment of the DSO forecasts of Opex 2010-2015

3.1. Overview of Historic Operating Costs 2006 – 2010

The CER PR2 decision paper set out the DSO's allowed operating expenditure for each year over the period 2006-2010. Certain items of this expenditure are classed as pass through costs which are adjusted year on year, for example network rates.

During PR2 the DSO met an unprecedented increase in new connections and provided 200,000 new connections in 2006 and 2007, adding 10.5% to the customer base. Adjustments upwards were made to allowed operating costs for the increase in new connections in 2006 to 2008, but adjustments downwards were required when the number of new connections fell. The DSO provided 325,000 connections in PR2 compared with 327,000 which CER had assumed as the basis for PR2 allowed costs.

Market IT systems expenditure was also adjusted in response to the requirements of users of these systems, such as Suppliers.

The DSO has also signalled the cost of settling a claim successfully pursued in the courts by contract meter readers under employment legislation. SKM understands that the CER is not minded to accept this cost during the current price review process.

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

- **Table 1 -** CER Allowed Opex Vs DSO Actual Opex 2006 – 2010

CER Determination	2006 €m	2007 €m	2008 €m	2009 €m	2010 €m	Total €m
Allowed Cash opex (2004 Prices)	264	254	248	244	240	1251
Allowed Cash opex (2009 Prices)	293	286	275	262	252	1368
Total net Adjustments (2009 Prices)	-3	-1	-5	-8	-2	-18
CER Adjusted Allowed Opex	290	285	270	254	250	1350
CER Allowed Opex less Commercial Costs	270	267	252	237	233	1259
DSO Net Opex less Commercial Costs	259	265	250	246	252	1272
Overspend vs Allowed Opex	-11	-1	-3	9	18	12

Table 1 excludes network depreciation, commercial costs and certain exceptional costs.

Commercial costs of €168m are excluded services not included in DUoS charges but paid for directly and include; customer paid diversions, third party damage and metering work for Suppliers which are regulated separately from DUOS. Commercial costs are €78m higher than forecast mainly due to additional work associated with the high level of economic and connections activity.

Exceptional costs of €502m have been incurred, including:

- Public Service Obligation (PSO) costs of €46m which pass through to customers outside DUOS.
- The DSO has incurred severance costs of €135m, funded by the DSO and not customers, and which have contributed to net staff reductions of 287 from 3758 to 3471 across ESB Networks as a whole. (Distribution and Transmission).
- Pension deficit costs of €201m have been incurred and CER is considering separately whether these costs should be borne by customers through DUoS.
- The DSO has also provided a rebate to customers of €119m for market support to relieve pressure on tariffs in 2008, which will be repaid as part of a project to establish new offices at Carrickmines during PR3.

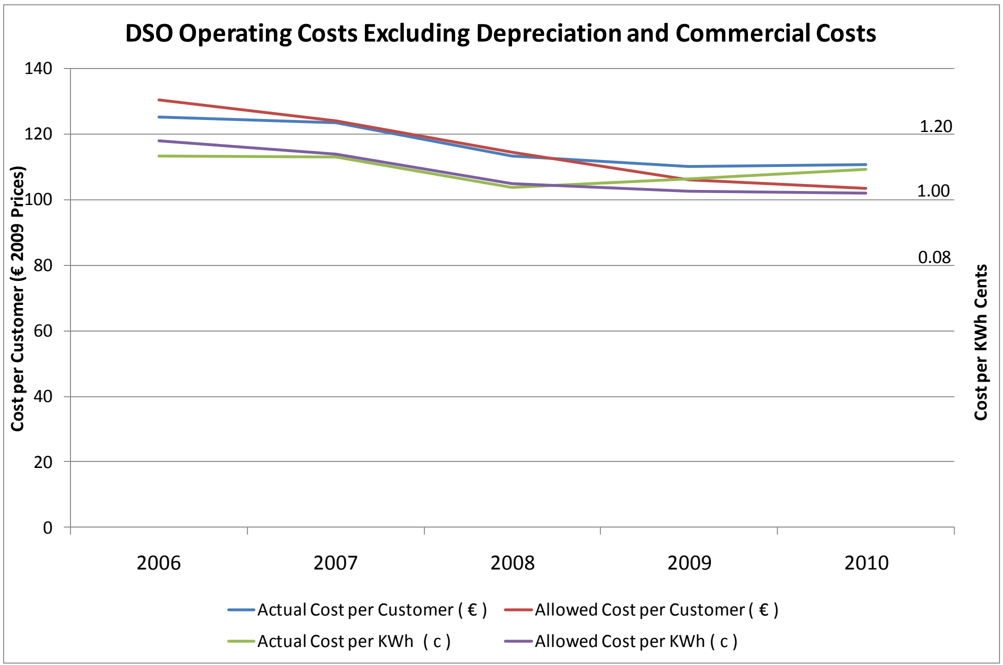
The DSO's PR2 operating costs of €1272m are €12[4]m higher than the allowed costs of €1260, excluding commercial costs and exceptional costs, indicating that the DSO has met the targets set by CER. It is important to note that the DUoS tariffs over the period are based only on the allowed expenditures

[4] In 2006 the CER decided (CER/06/207) to allow the ESB to recover, over five years, a portion of its pension deficit. This has not been taken into account in this report which considers normal operating costs. Pension deficit is still under separate consideration. The impact of this adjustment would result in an under spend.

The allowed expenditure included efficiency targets and is indexed to inflation. However, the DSO experienced deflation of -4.6% in 2009, which reduced the indexed revenue. The DSO found it particularly challenging to meet reduced allowed costs when the DSO's input prices were not falling.

The following graph (Figure 1) shows allowed opex and DSO's opex in terms of opex per customer served and opex per kWh distributed, excluding network depreciation, commercial costs and exceptional items.

- **Figure 1 -** Trend in Unit Operating Costs PR2



This shows that while overall operating costs fluctuated around the costs allowed in the 2006 determination, they did reduce over the period 2006-2010, both on a per customer and a per unit basis.

The downward trend indicates a reduction in costs per customer but is not in itself a direct indicator of improving efficiency, as many of the DSO's operating costs are fixed costs and do not vary in proportion to increase in customers or units distributed.

3.2. Assessment of Operating Costs 2006 to 2010

Table 2 presents a summary of the DSO operating costs for 2006 to 2010 set against allowed values. A breakdown of Table 2 is given in the relevant sections of the report and a summary of PR2 and PR3 operating costs showing more detail is provided as Appendix C.

Overall the DSO has contained cost increases within the CER allowed costs and has faced a number of pressures during PR2, including an unprecedented increase in new connections and pressure on input prices caused by overheating of the World economy during 2006 and 2007. A breakdown of Table 2 is given in the relevant sections of the report and a summary of PR2 and PR3 operating costs showing more detail is provided as Appendix C.

- **Table 2 -** Summary of Distribution Operating Costs 2006 to 2010 (€m 2009 Prices)

DSO PR2 Operating Costs (€m 2009 Prices)	CER PR2 Allowed	DSO PR2 Projected Outturn	Var PR2 Outturn Vs CER Allowed
Diversions (Capex in PR3)	111.8	114.6	2.7
Operations and Maintenance	474.9	514.3	39.4
Asset Management	58.2	59.6	1.4
Metering	102.6	100.1	-2.5
Customer Service	110.4	98.3	-12.1
Provision of Data	82.8	74.9	-8.0
Other	144.5	135.9	-8.6
Controllable Costs	**1085.4**	**1097.6**	**12.3**
Non Controllable Costs	**174.1**	**174.1**	**0.0**
Operating Costs Excl Commercial	**1259.5**	**1271.7**	**12.3**
Commercial (Excluded Costs)	**95.6**	**168.3**	**72.7**
Operating Costs Incl Commercial & Diversions	**1355.1**	**1440.0**	**85.0**

The cost pressures encountered by the DSO during PR2 are summarised in Appendix B. We have reviewed the evidence provided on cost increases and have noted a significant increase in material prices during PR2, in particular metal prices and electrical equipment, which have a greater impact on capex than opex.

The DSO implemented a number of efficiency and service initiatives listed in Appendix A.

Three major IT systems have been implemented for asset and work management, and mobile data and the DSO has gained PAS 55 accreditation for asset management.

ESB Networks has undertaken significant re-organisation in PR2 reducing the number of directors from 9 – 7 directors, the number of divisions from 7 – 5 divisions and depot rationalisation from 81 to 60 depots. ESB Networks has also funded from its own funds severance costs of €135m which have contributed to net staff reductions of 287 from 3758 to 3471, across ESB Networks as a whole.

The DSO met all of the incentivised performance targets for network performance and customer service set out in Sections 4.1.2 and 4.2.1, including a reduction in average minutes lost per customer of 43 % and in customer interruptions of 34%. The DSO has also exceeded the overall customer satisfaction target (ESATRAT) of 85% (actual performance of 90% in 2009).

Some notable achievements include:

- Reduction in Average Minutes Lost per customer CMLs (excluding those on the MV network renewal and storms) from 275 in 2005 to 132 in 2008.
- Reduction in customer complaints from 8978 in 2005 to a forecast of around 4000 in 2009.

- Improvement in Mori customer service rating from 68% to 78%.
- Improvement in the Telephone Service Factor (TSF) rating from 63% to 90% (answering telephone calls within 20 seconds).
- Customer Connections Charter payments were down from 7959 in 2006 to 1100 in 2009.

3.2.1. Diversions

Allowed €111.8m Outturn €114.6m

Diversion costs are the costs of overhead line diversion required to facilitate new housing developments, which are not subject to customer contribution. These costs are allowed as a proportion of new connections expenditure. PR2 allowed costs were based on a reduction from 14% of new connections expenditure in 2006, reducing to 13.4% by 2010. Expenditure of €114.6m was €2.7m overspent but close to target costs after adjustment for the higher than forecast level of new connections in 2006 and 2007.

3.2.2. Operations and Maintenance Expenditure

Allowed €474.9m Outturn €514.3m

Operations and maintenance expenditure of €514m is overspent by €39m (8.2%) compared with the CER allowance of €475m, due to higher than forecast planned maintenance costs and fault maintenance costs.

- **Table 3 -** Operations and Maintenance Costs (€m 2009 prices)

	CER PR2 Allowed	DSO PR2 Projected Outturn	Var PR2 Outturn Vs CER Allowed
System Control	93.6	88.2	-5.4
Planned Maintenance	212.3	228.5	16.1
Fault Maintenance	169.0	197.6	28.7
Operations and Maintenance	**474.9**	**514.3**	**39.4**

System Control (Allowed €93.6m Outturn €88.2m)

System Control costs of €88.2m is €5.4m less than CER allowed costs of €93.6m.

The under spend on System Control costs of €5.4m is mainly due to reorganisation of the Areas and centralisation of MV network control from 34 Areas to two control centres at Cork and Dublin. The development of the Control Centre IT systems (OMS), and SCADA for the remote control of the network, has also reduced costs.

Hitherto, the control of the MV network was from each of the 34 areas during the day and the responsibility of Area standby staff out of hours. 24/7 control of the MV network will operate from two centres in future. Two Areas transferred in 2009 and the remaining Areas will transfer in 2010 and 2011.

The Outage Management System (OMS) has been further developed over PR2 and provides an efficient platform for MV network control and fault management. The OMS system operates in conjunction with remote control facilities (SCADA), which, by the end of 2010 will cover the majority of the 10 kV and 38 kV substations and other switching points on network.

Planned Maintenance (Allowed €212.3m Outturn €228.5m)

- **Table 4 -** Planned Maintenance Costs (€m 2009 prices)

Planned Maintenance (€m 2009 Prices)	DSO PR2 Forecast	CER Allowed	DSO PR2 Projected Outturn	Variance Outturn Vs Forecast	Variance Outturn Vs Allowed
110 & 38 kV Lines	**15.2**	**13.3**	**14.8**	**-0.5**	**1.5**
Maintenance			11.2		
Timber Cutting			3.6		
110 & 38 kV Cables	**4.9**	**4.3**	**2.6**	**-2.3**	**-1.7**
110 & 38 kV Substations	**63.8**	**55.5**	**37.5**	**-26.3**	**-18.0**
MV LV Rural Lines	**91.0**	**81.0**	**111.3**	**20.2**	**30.3**
MV LV Rural Timber Cutting			71.0		
MV LV Rural Hazard			40.2		
MV Substations and LV Plant	**47.8**	**41.9**	**40.1**	**-7.7**	**-1.7**
LV Urban Lines	**17.3**	**16.5**	**22.3**	**5.0**	**5.9**
LV Urban Timber Cutting			10.8		
LV Urban Hazard + steel pole			11.5		
Total	**240.1**	**212.3**	**228.5**	**-11.7**	**16.1**

Planned maintenance costs of €228.5m are €16.1m higher than the allowed costs of €212.3m. Table 4 shows that there has been an overspend of €37.7m on overhead line maintenance and an under spend of €21.4m on maintenance of substations and cables.

The overspend is mainly due to higher than forecast tree cutting costs of around €30m. Tree cutting represents around 37% of the planned maintenance costs and is an essential part of the DSO's plans to improve quality of supply and is also important for public safety.

Tree cutting costs are higher than forecast due to health and safety requirements. Tree cutting is carried out by contractors who receive safety training from DSO. We have investigated the method used by DSO to carry out this work and visited sites to understand how contracts are applied in practice. Contractors bid for specific "groups" of work and have an opportunity to put in site specific prices, which is important to obtain best value.

Benchmarking indicates that tree cutting costs are lower per km than in Great Britain, (see Section 5.2.2.1) and we consider that the expenditure on tree cutting, although overspent by around €30m, has been efficiently incurred.

We note that tree cutting costs are forecast to reduce in 2010 and the DSO has signified a reduction in contract prices of 7% for PR3.

The DSO has provided details of the maintenance programme completed from 2007 to 2009 which indicates a backlog of 20% in completed orders. The backlog is around 30% for cable and substation maintenance and between 10% and 20% for overhead line maintenance. The DSO plans to increase MV substation and minipillar maintenance to catch up on this programme in 2010.

The DSO has reviewed substation maintenance policies in line with GB DNO practice, although substation maintenance intervals appear to remain conservative.

It is recommended that the under spend of €18m and the non completion of the HV substation maintenance programme is taken into account in the review of planned maintenance costs for PR3. The PR3 forecast includes provision for reducing backlog and customers should not be expected to pay for planned maintenance twice.

Fault Maintenance (Allowed €169m Outturn €197.6m)

Fault maintenance costs of €197.6m were €28.6m higher than the CER allowed costs of €169m. The overspend arose partly because fault numbers did not reduce as much as was anticipated, due to a delay in the low voltage network refurbishment programme. There were 400 more MV faults on the uprated 20 kV network than anticipated.

The DSO received incentive payments of €55m for improvements in system performance and some of the overspend may be attributed to changes in working practice to meet performance targets. Consideration has been given to deducting part of the overspend from allowed revenue. The DSO has met overall performance targets. The price control is an overall settlement and it is not appropriate to deduct revenue for this individual line item. However, the DSO will forfeit any overspend if its operating costs are greater than allowed costs at the end of 2010.

CER's allowed PR2 costs for fault maintenance were set at 10% lower than the DSO's PR2 forecast in anticipation of reduced fault rates following the network renewal programme. However, overhead lines uprated from 10 KV to 20 kV experienced a (temporary) higher fault rate due to higher electrical stress levels, leading to 400 additional MV faults. This effect will reduce as weaknesses are revealed and rectified. The low voltage overhead line renewal programme was delayed and has not yet produced a significantly lower fault rate.

During PR2 fault costs rose significantly with an overspend of €29m, which has not wholly been accounted for and may be partly due to additional costs of achieving system performance and incentive payments. For example, the DSO uses generators in some cases to minimise outages. The emphasis has changed to restoring supply as quickly as possible, which sometimes requires more staff and increases overall costs of restoration and repair.

It is accepted that savings have been made in closely associated activities of Area Operations and System Control of some €23m and there has been some reallocation of costs between these activities as they have been reorganised

3.2.3. Asset Management

(Allowed €58.2m Outturn €59.6m)

The majority of the asset management costs of €59.6m are associated with development of policy and standards with assistance from specialists from ESBI. DSO achieved PAS 55 accreditation for its Distribution asset management practices in 2009. This followed extensive discussions with the assessors and GB based DNOs. The DSO was particularly credited for its contracting and procurement practices.

The increase in these costs marginally above allowed costs is due to mast interference & forestry payments, which compensate for poles and towers on farmer's land and payments where land cannot be planted with trees due to overhead lines.

3.2.4. Metering and Meter Reading

(Allowed €102.6m Outturn €100.1m)

- **Table 5 -** Metering Costs

Metering (€m 2009 Prices)	CER PR2 Allowed	DSO PR2 Projected Outturn	Var PR2 Outturn Vs CER Allowed
Meter reading	55.0	58.6	3.6
NQH Data	8.7	6.8	-1.9
Customer meter operation	25.0	11.6	-13.4
Data Aggregation	13.9	23.1	9.2
Metering	**102.6**	**100.1**	**-2.5**

Metering costs of €100m are under spent by €2.5m. However, meter reading costs have increased from €10.5m per year to a forecast €13.6m in 2010, since it has proved expensive to meet the meter reading performance targets, in particular the requirement for 97 per cent of accounts with four scheduled visits per year. (Performance has improved from 84% in 2005 to 92% in 2009).

Meter reading is carried out by contract meter readers, to standards set by CER, to meet the credit control needs of Supplier and customers expectations. The existing practices are relatively expensive, being based on six bills and a target of four actual reads per year. This compares with GB where typically bills are quarterly with only one read per year. However, GB Suppliers rely heavily on prepayment meters for unreliable payers and estimated accounts, both of which are unpopular with customers.

3.2.5. Customer Service

(Allowed €110.4mm Outturn €98m)

Table 6 - Customer Service Costs

DSO PR2 Operating Costs (€m 2009 Prices)	CER PR2 Allowed	DSO PR2 Projected Outturn	Var PR2 Outturn Vs CER Allowed
Customer Service	**110.4**	**98.3**	**-12.1**
Call Centre Charges	34.8	36.3	1.4
Area Operations	68.9	52.8	-16.1
Customer Relations	6.7	9.2	2.5

Customer service expenditure of €98m is under spent by €12m (11%) compared with the CER allowance of €110m, mainly due to an under spend on Area Operations of €16m due to rationalisation. The introduction of hand-held units and mobile data messaging has improved efficiency of customer driven work. Outage planning and live line work and system automation has improved productivity and reduced the need for switching.

Call Centre costs have increased from €6.1m per year to €7.9m per year during PR2 but are under spent overall in PR2 by €1.4m. It was found that the initial staffing levels gave unacceptable customer service, which has now improved following a customer service improvement programme.

3.2.6. Provision of Information

(Allowed €82.8m Outturn €74.9m)

Table 7 - Provision of Information Costs

Provision of Information (€m 2009 Prices)	CER PR2 Allowed	DSO PR2 Projected Outturn	Var PR2 Outturn Vs CER Allowed
DUOS	3.6	4.0	0.4
MRSO	7.9	6.2	-1.7
Market Systems	71.3	64.7	-6.6
Provision of Informatiion	**110.4**	**96.3**	**-14.1**

Market System costs are associated with information systems for operating the electricity market and data exchange with Suppliers. Activity has been monitored by CER throughout PR2 and allowed costs have been reduced by CER during PR2 from €112m to €71m to take account of activity levels.

3.2.7. Other Controllable Costs

(Allowed €82.8m Outturn €74.9m)

- **Table 8 -** Other Controllable Costs

Other Controllable Costs (€m 2009 Prices)	CER PR2 Allowed	DSO PR2 Projected Outturn	Var PR2 Outturn Vs CER Allowed
Corporate Charges	86.0	72.9	-13.1
Safety	13.1	15.3	2.2
Enviornmental	3.2	3.1	-0.1
Other Legal Revenue and Misc	18.0	12.4	-5.6
Pension	9.2	9.2	0.0
Insurance	15.1	15.1	0.0
Sustainability	0.0	7.9	7.9
Other Controllable Costs	144.6	135.9	-8.7

Corporate charges are €13m lower than those allowed by CER mainly due to the transfer of training and legal service costs from the Corporate Centre to the DSO and these are now absorbed under other headings.

Other costs include expenditure on health and safety and environment and these costs are increasing due to regulatory requirements and the need to maintain safety standards amongst staff and contractors and the general public.

3.2.8. Non Controllable Costs

Non controllable costs of €174.1m are costs which are driven by outside agencies, which are outside the control of the DSO and allowed by CER as pass through costs. €164.3m of the costs are for network rates and€9.8m is the CER levy.

3.2.9. Commercial Costs

Commercial excluded services costs of €168m are €78m higher than the allowed cost of €90m due to the high level of economic and new connections activity, which has led to an increase in repayable diversions and third party damage. Transaction Charges for services to Suppliers are approved by CER in a separate process and these have also increased. Commercial costs are not reflected in DUOS charges but are recovered direct from customers.

3.3. Operating Costs 2011 to 2015

3.3.1. Aims and Assumptions of the DSO

The DSO has indicated that it has responded to the current economic climate and believes that its submission is in keeping with the times. The objective of the DSO submission is to maintain the average unit price (AUP) of DUoS taking into account the €31m additional operating expenditure on sustainability and research and development. The new activities also include additional capital expenditure items, including €500m for smart meters, €187m for electric vehicles charging points and €102m for office moves. DSO has therefore been under some pressure to contain its forecast to provide headroom for this additional capex and opex.

DSO has provided details of the underlying assumptions behind its PR3 forecast.

Global Assumptions on growth of new connections and units distributed

The DSO accepts that forecasting new connections and demand has been difficult in current economic circumstances. Patterns of the past five years have been volatile and the past no longer can be used to predict the future.

The following assumptions are adopted by the DSO using ESRI data:

- That the economic recession will continue into 2010 but at a decelerating rate as forecast by ESRI, i.e. with a small net decline in 2010. See Reference 2 (DF 25).
- That the country will pull out of recession later in 2010 and start recovering from 2011 onwards.
- That stable growth will be re-established from 2011 onwards coming increasingly in line with long term growth rates on the system.
- The DSO predicts that the impact on GWh of electricity demand of Electric Vehicles is modest within this period and is assumed to be contained in the growth allowances.

Based on these assumptions a modest decline of just less than 1% is forecast for unit sales in 2010. 2011 and 2012 will show "recovery growth" of 1.6% and 3.2% respectively. Thereafter growth is expected to stabilise and to average just over 3% for the period 2013 to 2015.

Growth in units is forecast to increase by 2.85% compound from 23.1 TWh in 2010 to 25.5 TWh in 2015.

Customer numbers are forecast to increase by 1.35% pa compound from 2.26m in 2010 to 2.41 in 2015.

SKM Comment on Global Assumptions

The DSO's assumptions on growth are based on models which do not currently apply and must be treated with caution. There is a good deal of spare housing capacity in Ireland and the growth in new connections is likely to remain depressed.

We agree with the DSO's assumptions of a 1.35% per annum growth in connections during PR3. The DSO's assumption of an increase in units of 2.85% is considered to be high in view of the economic circumstances. However, operating costs and capital expenditure are more related to peak demand than unit growth and we agree with the DSO that there is likely to be no increase in peak demand throughout PR3.

DSO Modelling Assumptions

DSO has provided a summary of modelling inflation assumptions:

- **Table 9 -** DSO Modelling Assumptions.

Assumptions/Notes							
Latest ESRI Data		2011	2012	2013	2014	2015	
CPI		2.6%	2.6%	2.6%	2.6%	2.6%	avg 2.6% over 11-15 from ESRI based on "Pathway to Recovery" ESRI publication
		2011	2012	2013	2014	2015	
Contractor Rates							
OverHead Line Work							
	LVR	+3.5%	+3.5%	+3.5%	+3.5%	+3.5%	
	MV	+3.4%	+3.4%	+3.4%	+3.4%	+3.4%	
	38kV	+2.7%	+2.7%	+2.7%	+2.7%	+2.7%	
	110kV	+2.7%	+2.7%	+2.7%	+2.7%	+2.7%	
Stations Electrical Work							
	38kV & 110kV	+2.1%	+2.1%	+2.1%	+2.1%	+2.1%	
Civils Work		+2%	+2%	+2%	+2%	+2%	
Material Rates		CPI	CPI	CPI	CPI	CPI	
Wage Rates		CPI	CPI	CPI	CPI	CPI	

Overall the forecasts of input prices are 1% higher than CPI for Low voltage and Medium voltage line work and CPI or less in other areas.

The DSO has assumed a productivity improvement of 1% per annum.

This compares with Ofgem GB forecasts of RPI plus 1.4% per annum increase in input prices and 1% productivity improvement. However GB has not seen the level of deflation seen in Ireland in 2009.

DSO Stretch

The DSO has also indicated that after modelling to these assumptions it has included a €60m of stretch applied across the cost base, ie savings which have not yet been identified to specific initiatives. The DSO has also identified €15m additional revenue from commercial activities.

3.3.2. SKM Comment on Modelling Assumptions

There are a number of areas where we take a different view to DSO.

Productivity

The DSO has assumed a productivity increase of 1% per annum over PR3. The ESRI Medium Term Review 2008[5] forecasts that the average productivity of the Irish economy to be 2.5% per annum over the period 2011 to 2015. The DSO's activities are highly mechanised and are supported by a significant level of IT investment. There has also been significant reorganisation and staff reduction in PR2 and potential for more in PR3. Much of these developments have occurred in the latter part of PR2 and the full effect is not reflected in costs. We would therefore expect the DSO to achieve at least 2.5% productivity improvement over PR3.

[5] Economic and Social Research Institute Medium Term Review 2008 – May 2008

We have considered these factors in making our recommendations for allowed costs and we envisage a general increase in productivity of 2.5 % per annum and accept that on certain activities the productivity is offset by growth a 1% per annum growth in volumes, but this does not always apply.

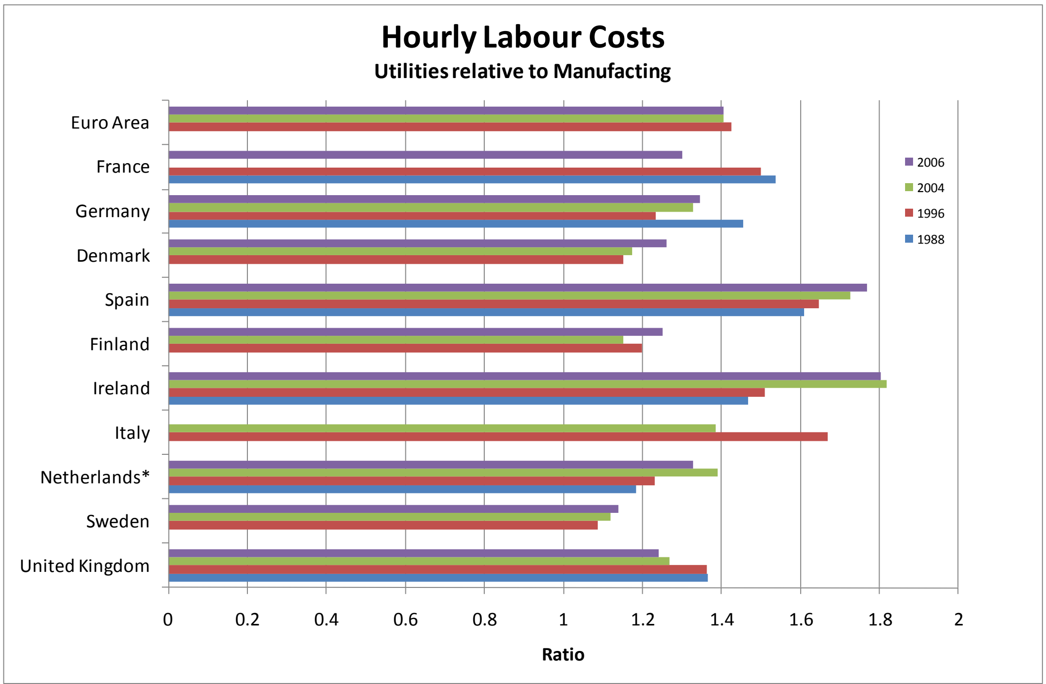
The DSO is operating a voluntary selective severance scheme in 2009 and 2010 and will lose 287 staff over the whole of PR2, while further staff reductions of 329 are forecast for PR3, which is equivalent to a saving of around €45m per year by 2015.

Payroll costs

The DSO's assumption that internal labour costs will be maintained at CPI is considered to be too conservative in the present economic climate and when compared with pay reductions elsewhere in the Irish economy Our recommendations are based on a reduction in DSO and ESB Group payroll costs of 5% in 2011, which is approximately a 2.5% reduction in controllable costs in 2011.

We have also considered relative payroll costs of the DSO. Figure 3 shows the hourly payroll costs for the Utilities sector in Ireland compared with manufacturing for a number of European countries and EU area average[6]. This shows that the ratio of Utilities to Manufacturing hourly payroll costs in Ireland is 1.8 compared with an EU Area average of 1.4. The gap is becoming wider in Ireland, whereas in many other countries exposure of Utilities to competition has reduced the gap over the last 20 years.

- **Figure 2 -** Utility Labour Costs Relative to Industry [7]



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[6] Eurostat statistics

[7] Data for 2004 and 2006 from Eurostat http://ec.europa.eu/eurostat/. Data for 1988 and 1996 Economic and Social Research Institute Ireland.

Services Provided from ESB Corporate and Other ESB Entities

The assumptions on input prices do not include the whole of the DSO cost base. 22% of DSO costs derive from other parts of ESB Group, including ESB Corporate, Supply Call Centre, ESB ITS, ESB Telecoms and ESBI.

The DSO has explained that it has made economies in its own costs during PR2; however, there is no evidence of the same level of efficiency improvement in these internal services. These services are provided at cost, or in many cases at market rates, and the ESB has not provided details of the margin on these services.

ESBI's own benchmarking indicates reasonable day rates but longer times to deliver services. In any event commercial day rates do not appear to be appropriate for enduring contracts for services that could equally be provided in-house with no added margin.

In addition, much of the costs from other parts of ESB Group consist of payroll costs which are now out of line with the Irish economy in the same way as the DSO business.

In making recommendations for allowed costs we have taken excess margin and payroll costs into account when assessing those costs which have a component of costs from other parts of ESB Group.

Cost Sources and Determination of Allowed Costs

- **Figure 3 -** Sources of DSO Operating Costs

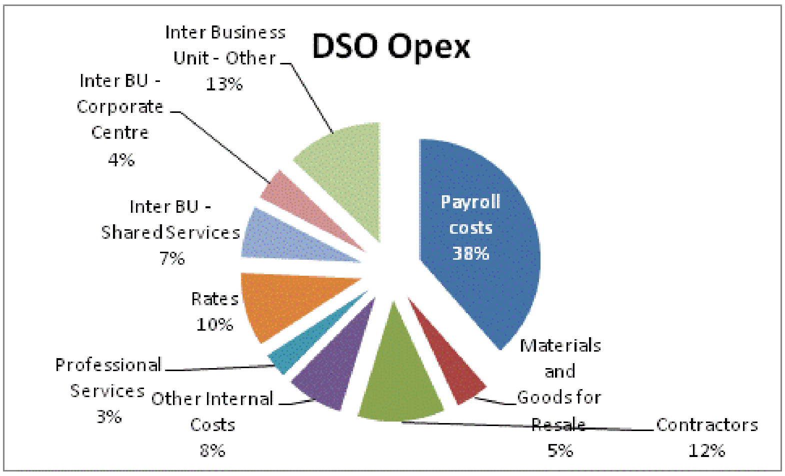


Figure 3 gives a breakdown of the sources of the DSO's operating costs, which we have used to allocate costs in making recommendations for allowed costs, and factoring in improvements in productivity, alignment of payroll cost and margin of ESB Group services.

We have also taken into account trends in PR2, in particular outturn costs in 2009 and the DSO's explanations of their forecasts.

Our recommendations indicate ongoing reduction in operating costs of 2% – 3% per annum over PR3 from a derived base Po costs in 2011. Taking into account that some costs are not

controllable, the overall reduction in costs from base level is around 2% per annum. This includes an allowance for growth in drivers such as customers where appropriate.

Our recommendation for allowed costs is an overall settlement tied to the delivery of outputs under incentives considered in Section 4. It is not dependent on individual line items and the recommendation is based on what is considered to be efficient overall.

Benchmarking

Benchmarking has been carried out by both DSO and SKM and is considered in more detail in Section 5.

Benchmarking of ESB Networks DSO and 110 kV TAO opex and non network capex for indicates that the DSO costs are 7.5% above the Upper Quartile of the GB DNO costs and 16 % above the efficiency frontier. This is consistent with our recommendations for allowed costs which give a reduction of 11% in controllable opex from €232m in 2009 to €207m in 2015.

There is no doubt that the DSO appears to be closing the efficiency gap with the GB DNOs and has implemented a number of measures adopted by the GB DNOs in the last 15 years. However there is insufficient evidence to conclude that the DSO is at the efficiency frontier and much evidence to indicate that significant further efficiency improvements are available.

It is evident that benchmarking becomes more difficult as the DSO approaches GB efficiency levels. Whereas it was easy to identify a large efficiency gap in PR1 and PR2 by benchmarking, this is now more difficult as the gap narrows.

Benchmarking carried out by the DSO and SKM follows to some extent practices adopted in GB, where cost adjustments and selection of benchmark drivers have become more sophisticated. However even amongst homogenous companies with strictly regulated reporting rules it is not possible to obtain consistent results. Benchmarking against GB costs may not be applicable to Ireland which has four times more line than GB companies of the same customer base. Bottom up benchmarking indicates that some repairs and maintenance costs in Ireland are inherently lower than in GB. The DSO's overhead line networks are simple and there is less urban cable network.

However, benchmarking against Utilities of other countries without this detailed knowledge of the cost allocations and network characteristics is unlikely to provide any more meaningful results. At least we are beginning to understand the real differences between Ireland and GB network, practices and costs. The DSO is also taking advantage of this knowledge by benchmarking activities and processes, which has led to the review of maintenance practices and PAS 55 asset management accreditation under the auspices of the accreditation authority for GB.

3.3.3. Summary of Operating Costs 2011 to 2015

Table 10 summarises the proposals of the DSO's for operating costs in PR3 and our recommendation for allowed costs.

- **Table 10 -** Summary of Operating Costs 2011 to 2015

	CER PR2 Allowed	Var PR2 Outturn Vs CER Allowed	DSO PR2 Projected Outturn	DSO PR3 Forecast	Var PR3 Forecast Vs PR2 Outturn	PR3 Recommended	Var Recommend Vs DSO Forecast
Diversions (Capex in PR3)	111.84	2.73	114.58		-114.58		
Operations and Maintenance	474.90	39.39	514.28	507.81	-6.47	445.63	-62.18
Asset Management	58.19	1.41	59.60	65.80	6.19	60.15	-5.64
Metering	102.63	-2.53	100.10	124.13	24.03	100.54	-23.59
Customer Service	110.43	-12.15	98.28	92.16	-6.12	82.28	-9.88
Provision of Data	82.84	-7.97	74.88	87.14	12.27	71.90	-15.24
Other	144.54	-8.63	135.91	166.29	30.38	136.47	-29.81
Controllable Costs Ex Diversions	973.53	9.52	983.05	1043.32	60.27	896.97	-146.35
Non Controllable Costs	174.08	0.00	174.08	189.96	15.88	189.96	0.00
Controllable + Non Controllable Excluding Diversions	1147.61	9.52	1157.13	1233.29	76.15	1086.94	-146.35
Commercial (Excluded Costs)	95.62	72.70	168.32	204.62	36.30	177.51	-27.11
Operating Costs Incl Commercial Excluding Diversions	1243.23	82.23	1325.45	1437.90	112.45	1264.45	-173.45

Further details are provided in Appendix C and in the analysis of individual cost headings in Section 3.3.3.

The DSO's forecast of operating expenditure in the PR3 period (2010 to 2015) is €1233.3m, which is €76m greater than the equivalent PR2 outturn of €1157.1m. This comparison excludes commercial costs and the cost of diversions, which it is proposed will be capitalised in PR3.

The additional costs of €76m include €31m for research and development and sustainability cost associated with future networks that will support wind generation and electric vehicles, using smart metering.

The net effect of capitalisation of diversions and the increased costs is a reduction in DUoS costs from PR2 to PR3 of €36.4m ie. The PR2 Outturn, including diversions, (€1155.1 + €114.6m diversions = €1269.7), is €36.4m greater than the PR3 forecast of €1233.3m, which excludes diversions.

Our recommendation is for allowed PR3 operating costs of €1086.9m, which is €146.3m lower than the DSO's PR3 forecast and €70.2m less than the equivalent PR2 outturn. Details of the derivation of our recommendations are set out below:

3.3.4. DSO Forecast of PR3 Operating Costs

The DSO forecasts of PR3 operating costs is summarised in Table 11.

The table shows cost increases particularly in Electricity Supplier related activities. Metering costs are forecast to increase by €24m (19.4%) over PR2 and Provision of Data to the Market costs are forecast to increase by €12.3 (14.1%). "Other" cost increases of €31m are due to the proposed new sustainability and R & D activities.

The DSO's proposed costs are considered in detail throughout this section of the report, which gives our recommendations on allowed costs and, where appropriate, adjustments to work programmes.

- **Table 11 -** Summary of DSO Forecast Operating Costs 2011 to 2015

	PR2 Outturn	2009 Actual	2011	2012	2013	2014	2015	DSO Forecast 2011 - 2015	Variance PR3-PR2	Variance %
Operations and Maintenance	514.28	103.6	102.7	101.6	101.3	100.8	101.5	507.8	-6.5	-1.3%
Asset Management	59.60	12.6	13.7	13.2	13.0	13.0	12.9	65.8	6.2	9.4%
Metering	100.10	21.3	24.8	24.7	24.8	24.9	24.9	124.1	24.0	19.4%
Customer Service	98.28	18.1	18.6	18.5	18.4	18.3	18.3	92.2	-6.1	-6.6%
Provision of Data	74.88	13.8	17.4	17.7	17.5	17.4	17.3	87.1	12.3	14.1%
Other	135.9	27.5	33.5	33.3	33.3	33.2	33.0	166.3	30.4	18.3%
Controllable Costs	983.1	196.9	210.7	209.0	208.2	207.5	207.9	1043.3	60.3	5.8%
Non Controllable Costs	174.1	34.5	37.3	37.3	37.3	37.3	40.8	190.0	15.9	8.4%
Controllable + Non Controllable	**1157.1**	**231.4**	**248.0**	**246.3**	**245.5**	**244.8**	**248.7**	**1233.3**	**76.2**	**6.2%**
Commercial Costs	168.32	35.6	39.3	39.6	41.0	41.5	43.2	204.6	36.3	17.7%
Total Operating Costs	**1325.5**	**267.0**	**287.3**	**286.0**	**286.5**	**286.3**	**291.9**	**1437.9**	**112.4**	**7.8%**
Diversions	114.58	14.2	11.5	11.7	11.9	12.1	12.4	59.7	-54.9	-92.0%
Controllable Non Controllable plus diversions	**1271.7**	**245.6**	**259.5**	**258.0**	**257.4**	**256.9**	**261.1**	**1293.0**	**21.2**	**1.6%**
Reduction in Operating Costs in Duos PR2 included diversions PR3 excludes diversions									**-38.4**	

3.3.5. Proposals for Allowed Operating Costs 2011 to 2015

In developing proposals for allowed costs consideration has been given to the range of efficiency factors highlighted as global assumptions in section 3.3.2. However the particular features of each cost heading have also been reviewed including the base level of costs appropriate in 2011, growth factors and potential efficiencies available. Efficiency factors have not been applied to non controllable pass through costs.

The proposals for PR3 operating costs are grouped and summarised below year by year and in comparison with historic costs and the DSO PR3 forecast.

- **Table 12 -** Summary of Operating Costs 2011 to 2015

	PR2 Outturn	2009 Actual	Recommended 2011	Recommended 2012	Recommended 2013	Recommended 2014	Recommended 2015	Recommended 2011 - 2015	DSO PR3 Forecast	Variance Recommend - DSO Forecast	Variance %
Operations and Maintenance	514.28	103.6	93.1	91.1	89.1	87.1	85.2	445.6	507.81	-62.2	-12.2%
Asset Management	59.60	12.6	12.4	12.2	12.0	11.8	11.7	60.2	65.80	-5.6	-8.6%
Metering	100.10	21.3	20.8	20.5	20.1	19.8	19.4	100.5	124.13	-23.6	-19.0%
Customer Service	98.28	18.1	17.3	16.9	16.4	16.0	15.6	82.3	92.16	-9.9	-10.7%
Provision of Data	74.88	13.8	14.8	14.6	14.4	14.2	14.0	71.9	87.14	-15.2	-17.5%
Other	135.9	27.5	28.2	27.7	27.3	26.8	26.4	136.5	166.3	-29.8	-17.9%
Controllable Costs	983.1	196.9	186.6	182.9	179.3	175.8	172.3	897.0	1043.3	-146.3	-14.0%
Non Controllable Costs	174.1	34.5	37.3	37.3	37.3	37.3	40.8	190.0	190.0	0.0	0.0%
Controllable + Non Controllable	**1157.1**	**231.4**	**223.9**	**220.2**	**216.6**	**213.1**	**213.2**	**1086.9**	**1233.3**	**-146.3**	**-11.9%**
Commercial Costs	168.3	35.6	37.3	36.4	35.5	34.6	33.7	177.5	204.62	-27.1	-13.2%
Total Operating Costs	**1325.5**	**267.0**	**261.2**	**256.6**	**252.1**	**247.7**	**246.9**	**1264.4**	**1437.9**	**-173.5**	**-12.1%**
Diversions	114.6	14.2	9.8	10.1	10.4	10.6	10.9	51.8	59.67	-7.9	-13.3%
Controllable Non Controllable plus diversions	**1271.7**	**245.6**	**233.7**	**230.3**	**227.0**	**223.7**	**224.0**	**1138.7**	**1293.0**	**-154.3**	-11.9%
Reduction in Operating Costs in DUoS - PR2 includes diversions PR3 excludes diversions								**-184.8**	**-38.4**		

It is proposed to capitalise diversions costs in PR3 and the footnote to the table shows the reduction in operating costs in DUoS of €38m for the DSO forecast and €184.8m for our recommended allowed costs.

- **Figure 4 -** Operating Costs 2006 to 2015

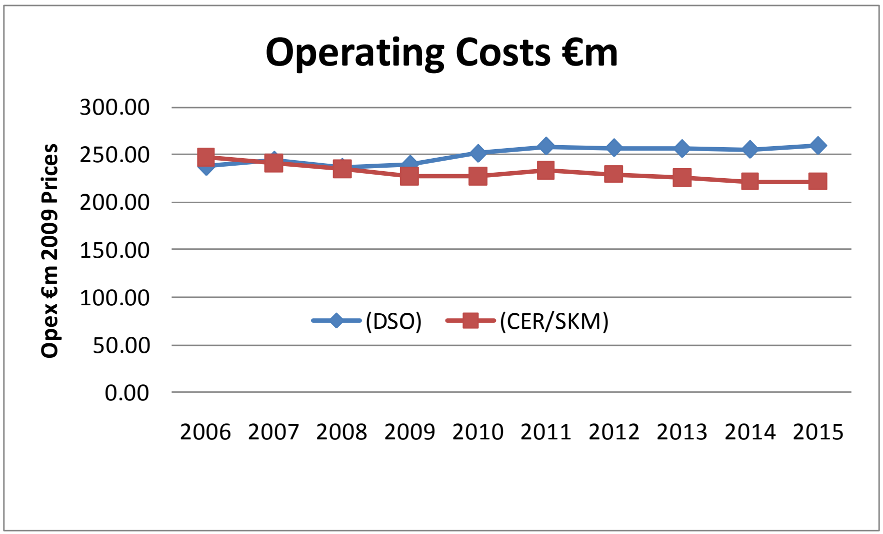


Figure 4 shows total operating costs excluding commercial costs, which are recommended to fall from €233m in 2009 to €213m in 2015.

3.3.6. Capital Driven Opex - Diversions

We agree with the proposal of the DSO to capitalise diversion of overhead lines associated with new connections, from PR3 onwards.

Undergrounding of overhead lines for new connections is already treated as capital expenditure. When lines are diverted, an old asset is retired and a new asset is created. It is therefore appropriate to capitalise these costs. The proposal is also consistent with the treatment of undergrounding costs. Diversion costs are therefore considered under the Report on Capital Expenditure.

3.3.7. Operations and Maintenance

(PR2 €514.3m DSO €507.8m Allowed €446.2m)

The DSO Forecast and Recommended Proposed Costs for Operations and Maintenance are summarised below.

- **Table 13 -** Operations and Maintenance Costs 2011 to 2015

Summary of Operation and Maintenance Costs 2011 to 2015 €m 2009 Prices

	2009 Actual	2011	2012	2013	2014	2015	DSO PR3 Forecast	PR2 Outturn	Variance PR3-PR2	Variance %
		DSO Forecast								
Control Centre	16.4	15.1	15.1	15.2	15.2	15.4	75.9	88.2	-12.3	-13.9%
Planned Maintenance	47.8	48.7	48.7	49.2	49.7	50.9	247.2	228.5	18.7	8.2%
Fault Maintenance	39.3	38.8	37.9	36.9	35.9	35.2	184.7	197.6	-12.9	-6.5%
Operations and Maintenance	**103.6**	**102.7**	**101.6**	**101.3**	**100.8**	**101.5**	**507.8**	**514.3**	**-6.5**	**-1.3%**
	2009 Actual	**2011**	**2012**	**2013**	**2014**	**2015**	**PR3 Recommended**	**DSO PR3 Forecast**	**Variance Recommend vs DSO Forecast**	**Variance %**
		Recommended								
Control Centre	16.4	14.7	14.4	14.0	13.7	13.3	70.1	75.9	-5.9	-7.7%
Planned Maintenance	47.8	41.0	40.3	39.6	38.9	38.2	198.0	247.2	-49.2	-19.9%
Fault Maintenance	39.3	37.3	36.4	35.5	34.6	33.7	177.5	184.7	-7.2	-3.9%
Operations and Maintenance	**103.6**	**93.1**	**91.1**	**89.1**	**87.1**	**85.2**	**445.6**	**507.8**	**-62.2**	**-12.2%**
Variance CER and DSO Forecast		-9.6	-10.6	-12.2	-13.7	-16.2	-62.2		-62.2	-12.2%

3.3.7.1. System Control

(PR2 €88.2m DSO €75.9m Allowed €70.1m)

- **Figure 5 -** System Control Costs 2006 to 2015

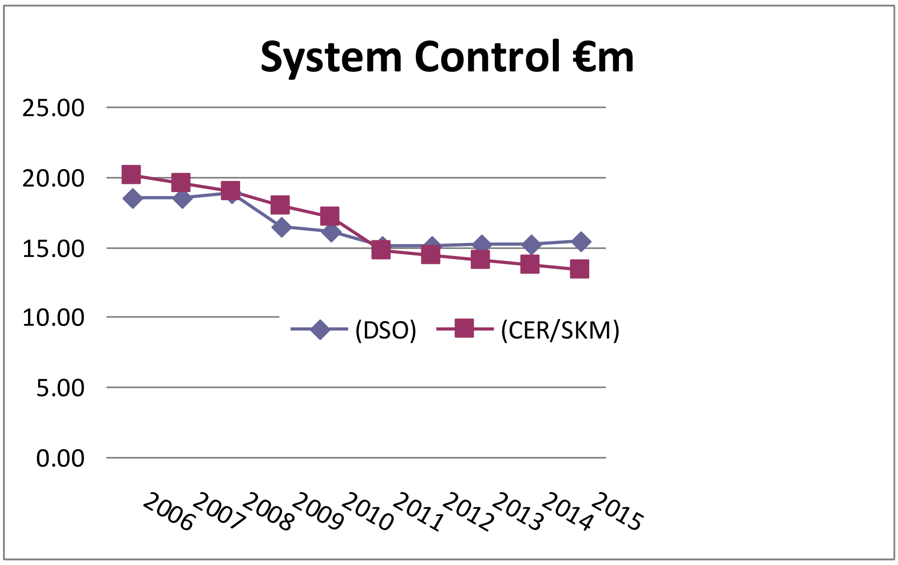


Figure 5 shows System Control costs, which are recommended to fall from €16.4m in 2009 to €13.3 in 2015.

During PR2 the DSO completed the implementation of the Outage Management IT System (OMS) and a programme of SCADA installations for those substations suitable for SCADA. The DSO is also in the process of transferring MV network control from 34 Areas to 2 centres in Dublin and Cork. These developments have led to the reduction in System Control costs from €18.5m in 2006 to €16.4m in 2009 and reductions in Area Operations Costs. There are further opportunities for cost reduction in PR3.

The application of IT and the penetration of wind generation should make it advantageous for DSO to further rationalise system control, with the potential for centralising on one control centre for all or part of the activity during PR3.

The installation of SCADA at main substations and remote control devices on the network gives better visibility of the state the network and enables the DSO to respond more quickly and efficiently to incidents. The DSO will continue to improve the facilities for system control in PR3 with a capital investment programme of €33.1m, upgrading existing IT and communications systems and extending SCADA.

The OMS system enables DSO to manage the day to day operation of the distribution system more effectively and efficiently. The OMS system provides a platform for managing planned outages and faults and improves the efficiency of its fault reporting systems to provide accurate data on the system performance incentive scheme.

The investment includes provision of €5.6m for a Power System Management (PSM) system to manage the wind generation connected to the distribution system. Over 1,500MVA of wind generation is now installed on the electricity system, 50% of it on the distribution networks. During the period of PR3 it is estimated that the amount of generation on the networks will increase to over 3,000MW, with approximately 1,500 MW embedded on the distribution system. Generation connected to the distribution system has until now been connected with firm capacity on a “fit and forget” basis. However this may change and it is accepted that a Power System Management System is likely to be required with some additional costs.

3.3.7.2. Planned Maintenance

(PR2 €228.5 DSO €247.2m Allowed €198.0m)

The DSO’s planned expenditure is presented in Table 14 and our recommended allowances in Table 15.

- **Table 14 -** DSO Forecast of Planned Maintenance 2011 to 2015 (€m 2009 prices)

	Actual 2009	Actual 2010	DSO Forecast 2011	2012	2013	2014	2015	DSO PR3 Forecast	PR2 Outturn	Variance DSO Forecast - PR2 Outturn
110kV Cables	0.01	0.24	0.38	0.38	0.38	0.38	0.38	1.92	0.31	1.60
110kV Lines	0.00	0.00	0.25	0.25	0.25	0.25	0.25	1.26	0.04	1.22
110kV/220kV Stations	3.09	3.15	4.77	4.81	4.84	4.92	5.05	24.40	15.24	9.16
110 kV Planned Maintenance	**3.10**	**3.39**	**5.41**	**5.45**	**5.48**	**5.56**	**5.68**	**27.57**	**15.59**	**11.98**
38kV Cables	0.41	0.73	1.47	1.46	1.47	1.47	1.67	7.54	2.26	5.28
38kV Stations	4.81	4.33	7.04	6.94	7.00	7.04	7.19	35.20	22.23	12.97
110kV/38Kv Line - Hazard maintenance	2.47	1.96	2.19	2.19	2.20	2.21	2.23	11.02	11.13	-0.11
110kV/ 38kV Line - Timber cutting	0.74	0.81	0.67	0.66	0.67	0.67	0.68	3.35	3.59	-0.24
38kV Planned Maintenance	**8.44**	**7.84**	**11.37**	**11.25**	**11.33**	**11.39**	**11.77**	**57.11**	**39.21**	**17.90**
Inspection & Follow-up	1.13	5.24	5.77	5.88	6.01	6.14	6.36	30.15	20.99	9.17
MV Sub & Minipillar Hazard Maintenance	6.64	3.18	1.89	1.97	2.07	2.12	2.26	10.31	19.13	-8.83
MV/LV Substations & Minipillars	**7.77**	**8.42**	**7.66**	**7.84**	**8.08**	**8.26**	**8.62**	**40.46**	**40.12**	**0.34**
Timber cutting - MV & LV Rural Lines	17.63	14.47	15.17	15.03	15.16	15.33	15.51	76.20	71.05	5.16
Timber cutting - LV Urban Lines	2.90	1.67	2.52	2.49	2.50	2.52	2.54	12.57	10.90	1.66
MV LV Rural Lines Hazard maintenance	6.97	9.08	5.26	5.27	5.30	5.32	5.41	26.56	40.21	-13.65
LV Urban Lines Hazard maintenance	0.96	1.60	1.33	1.33	1.34	1.34	1.36	6.70	11.36	-4.66
MV/LV Overhead Lines	**28.46**	**26.82**	**24.29**	**24.11**	**24.30**	**24.51**	**24.81**	**122.03**	**133.52**	**-11.49**
Total	**47.77**	**46.46**	**48.72**	**48.66**	**49.19**	**49.72**	**50.88**	**247.17**	**228.44**	**18.73**
Total Tree Cutting	**21.27**	**16.95**	**18.37**	**18.18**	**18.33**	**18.52**	**18.72**	**92.12**	**85.54**	**6.58**
% of work	44.53%	36.48%	37.70%	37.36%	37.27%	37.25%	36.80%	**37.27%**	**37.45%**	
Line Hazard Maintenance	**10.40**	**12.64**	**8.78**	**8.79**	**8.84**	**8.87**	**8.99**	**44.28**	**62.70**	**-18.42**
% of work	21.77%	27.20%	18.03%	18.06%	17.97%	17.85%	17.68%	17.91%	27.45%	

Table 15 – Recommended Planned Maintenance Costs 2011 to 2015 (€m 2009 prices)

Planned Maintenance Costs 2011 to 2015 €m 2009 Prices

Planned Maintenance	PR2 Outturn	2011	2012	2013	2014	2015	PR3 Recommend	DSO PR3 Forecast	Variance Recommend Forecast
DSO Forecast		48.72	48.66	49.19	49.72	50.88			
Recommended		41.04	40.31	39.59	38.88	38.19			
Variance		-7.68	-8.35	-9.60	-10.84	-12.69			
Recommended									
110 kV Substations	15.24	2.97	2.91	2.85	2.80	2.74	14.28	24.40	-10.12
38 kV Substations	22.23	4.33	4.25	4.16	4.08	4.00	20.82	35.20	-14.37
110 kV and 38 kV Cables	2.57	0.95	0.93	0.91	0.89	0.88	4.56	9.45	-4.89
MV SS Inspection and Follow Up	20.99	5.35	5.24	5.13	5.03	4.93	25.68	30.15	-4.47
MV SS and Minipillar Hazard Maintenance	19.13	1.75	1.71	1.68	1.64	1.61	8.40	10.31	-1.91
110 kV and 38 kV Lines Maintenance	11.17	1.91	1.87	1.83	1.80	1.76	9.17	12.28	-3.10
110kV and 38 kV Line Timber Cutting	3.59	0.64	0.63	0.62	0.61	0.60	3.10	3.35	-0.25
Timber Cutting MV LV Rural Lines	71.05	14.41	14.20	13.99	13.78	13.57	69.94	76.20	-6.26
Timber Cutting LV Urban Lines	10.90	2.40	2.36	2.33	2.29	2.26	11.63	12.57	-0.94
MV and LV Lines Hazard Maintenance	40.21	5.06	4.95	4.86	4.76	4.66	24.29	26.56	-2.27
LV Urban Lines Hazard Maintenance	11.36	1.28	1.25	1.23	1.20	1.18	6.14	6.70	-0.55
Total	**228.44**	**41.04**	**40.31**	**39.59**	**38.88**	**38.19**	**198.02**	**247.17**	**-49.15**

Comparison of planned and recommended are given in Figure 6

Figure 6 - Planned Maintenance Costs 2006 to 2015

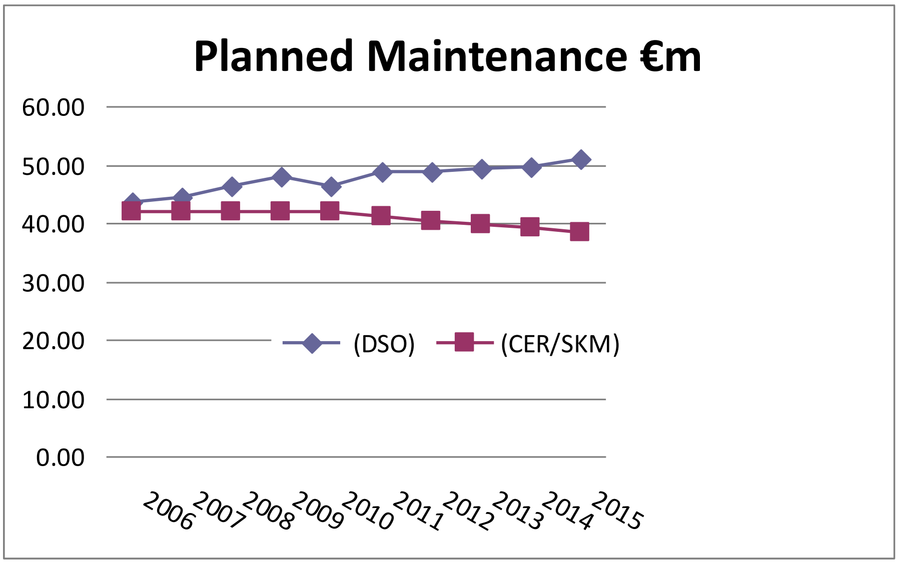


Figure 6 shows planned maintenance costs, which are recommended to fall from €47.8m in 2009 to €38.2m in 2015.

110kV and 38 kV (HV) Substation Maintenance PR2 €37.4m DSO €59.6m Allowed €35.1m

The main increase in expenditure in the DSO forecast relates to 110 kV and 38 kV substation maintenance costs which are forecast to increase by €22m compared with PR2.

As indicated in section 3.2.2 the DSO has under spent HV substation maintenance costs by €18m in PR2 and the forecasts for PR3 make provision for removing the backlog. This element of cost is removed from allowed costs as the DSO has already been paid for this work. Other savings are also available from the review of maintenance practices, reduction in payroll costs and other efficiency savings.

The maintenance policies have also been changed after the DSO benchmarked its practices with GB DNOs. This should yield savings and we would expect DSO to embark on a risk assessment of work to be done before increasing expenditure. No plan has been provided to indicate that the DSO requires such additional funding and we find it difficult to understand how this will be resourced and whether it will be completed.

110kV and 38 kV (HV) Cable Maintenance PR2 €2.56m DSO €9.46m Allowed €4.56m

Similarly there is a backlog in 38kV and 110 kV cable maintenance and these costs have been allowed on the basis of 2010 forecast costs, which are considered to reflect normal levels of required maintenance. The allowed costs represent a first year doubling of the present expenditure followed by efficiency savings.

MV Substation and Minipillar Maintenance PR2 €40.12m DSO €40.46m Allowed €34.1m

The DSO has spent significantly on replacement of oil switchgear and on minipillar refurbishment and it is expected that these costs will fall over PR3.

The programme of inspection and follow up maintenance and hazard maintenance on MV and LV substations and minipillars has fluctuated significantly in the past, which indicates some lack of consistency on what should be a steady programme. Inspection and hazard maintenance are considered together and are running at around €7.8m per year.

Tree Cutting All Voltages (PR2 €85.5m DSO €92.1m Allowed €84.7m)

Tree cutting represents around 37% of the planned maintenance costs and is important for quality of supply and safety reasons. We have investigated the method used by DSO to carry out this work and visited sites to understand how these contracts are applied in practice. The work is carried out by contractors who receive safety training from DSO. Contractors bid for specific “groups” of work and have an opportunity to put in site specific prices, which is important to obtain best value. We understand that recent contracts have a yielded a 7% reduction in costs.

Tree cutting intervals have been rationalised by DSO, three years for HV and MV lines, six years for LV rural lines and 4 years for LV urban lines. Clearing of LV lines represents 50% of the activity. Tree cutting is coordinated with inspection regimes with the same intervals. We do not consider coordination of intervals to be important for a programme of this magnitude and tree cutting intervals should be based on need.

We have accepted that the MV tree cutting programme should be organised on a three year cycle. However, we consider that efficiencies will be available in actively managing the programme to reflect need and risk. There will be some inevitable slippage in the programme due to site conditions and outage requirements. We have therefore applied 5% abatement. In addition we would expect a reasonable efficiency factor as the programme advances and less work is required on the next cut.

Overhead Line Hazard Maintenance (PR2 €62.7m DSO €45.5m Allowed €39.6m)

Overhead line hazard maintenance is reducing for two reasons. Firstly there is a dividend from the MV network renewal programme completed in PR1 and PR2 and the LV network renewal programme which is to be completed over PR2 and PR3. Secondly the DSO has changed its approach to overhead line maintenance and has moved to a strategy of refurbishing lines at an interval (DSO proposes 9 years). Refurbishing work should therefore anticipate requirements for the next 9 years, with limited work in between. This also avoids the need for repeated outages (and associated impact on customers CMLs and CLs) to carry out jobs which could otherwise be aggregated to the next refurbishment.

This strategy effectively capitalises much of the work required on overhead lines reducing, the level of operating costs.

We would expect the level of hazard maintenance to fall and this is reflected in DSO forecasts, and we have applied an additional efficiency factor to this work over PR3.

3.3.7.3. Fault Maintenance

(PR2 €197.6m DSO €184.7m Allowed €177.5m)

- **Figure 7 -** Fault Maintenance Costs 2006 to 2015

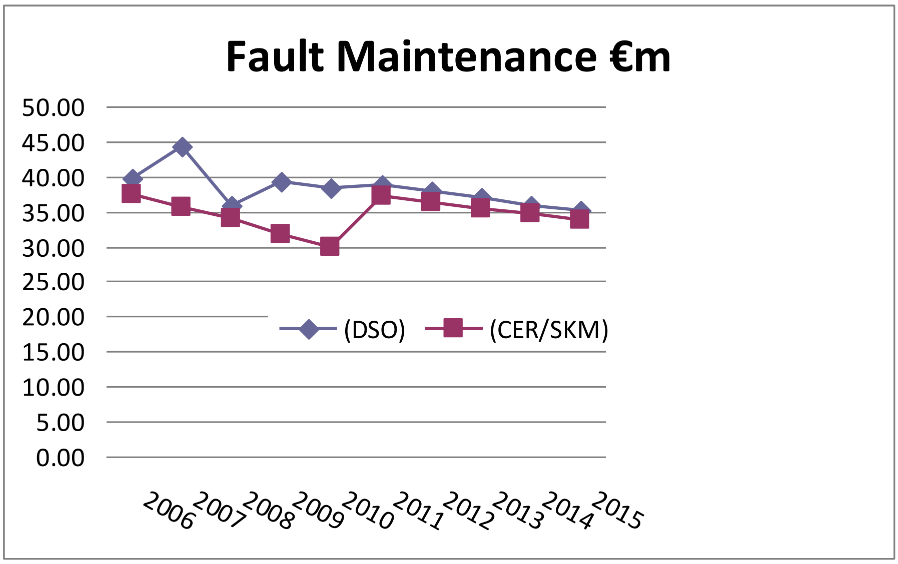


Figure 7 shows fault maintenance costs, which are recommended to fall from €39.3m in 2009 to €33.7m in 2015.

During PR2 fault costs rose significantly with an overspend of €29m, which has not wholly been accounted for, but which may be partly due to additional costs of achieving system performance and incentive payments. It is recommended that the additional annual costs incurred in PR2 and reflected in PR3 forecasts are accepted in part as a price worth paying for improvements in system performance.

The DSO forecast reflects the downward trend in fault rate. Our proposals for allowed costs are on a downward trend and we have also included efficiency savings, which should be achievable bearing in mind that the fault process benefits from many of the investments made for system control and remote control.

The performance of the network is mainly influenced by the performance of the medium voltage network which has recently been refurbished. The fault rate on the MV network may increase slightly during PR3 as more of the network is converted to 20 kV and becomes subject to greater electrical stresses. However in future it would be prudent for the DSO to renew suspect insulation as part of the uprating programme in order to reduce the risk of an increase in MV fault rate.

Most faults arise on the low voltage networks and, although these faults only contribute 10% to the system performance outputs, they account for 70% of the 37,000 separate incidents on the system and a similar proportion of fault costs.

The low voltage overhead line network is currently undergoing a renewal programme, with €69m invested in PR2 and a DSO forecast of €165m in PR3. The DSO indicates that this has been taken into account in developing its forecast for fault costs in PR3, together with improvements that come from the investment in Continuity measures forecast by the DSO at €23m and other renewal investments.

Section 4.1.4 provides details of the DSO forecast and recommendations for quality of supply targets and incentives.

3.3.8. Asset Management

(PR2 €59.6m DSO €65.8m Allowed €60.2m)

- **Table 16 -** Asset Management Costs 2011 to 2015

	2009 Actual	2011	2012	2013	2+F19014	2015	DSO PR3 Forecast	PR2 Outturn	Variance PR3-PR2	Variance %
		DSO Forecast					*DSO*			
Forestry and Wayleaves	4.9	5.1	5.1	5.0	5.0	5.0	25.3	19.5	5.8	29.8%
Asset Management	7.7	8.6	8.2	7.9	7.9	7.9	40.5	40.1	0.4	1.0%
Asset Management	**12.6**	**13.7**	**13.2**	**13.0**	**13.0**	**12.9**	**65.8**	**59.6**	**6.2**	**10.4%**
	2009 Actual	**2011**	**2012**	**2013**	**2014**	**2015**	**PR3 Recommended**	**DSO PR3 Forecast**	**Variance Recommend vs DSO Forecast**	**Variance %**
		Recommended								
Forestry and Wayleaves	4.9	4.9	4.9	4.9	4.9	4.9	24.5	25.3	-0.7	-2.9%
Asset Management	7.7	7.5	7.3	7.1	6.9	6.8	35.6	40.5	-4.9	-12.1%
Asset Management	**12.6**	**12.4**	**12.2**	**12.0**	**11.8**	**11.7**	**60.2**	**65.8**	**-5.6**	**-8.6%**
Variance CER and DSO Forecast		-1.3	-1.0	-1.0	-1.1	-1.2	-5.6		-5.6	-8.6%

Asset Management costs have risen during PR2 mainly due to the increase in payments to landowners for rights to place equipment on land and for forestry sterilisation costs. These costs have risen from €3.1m in 2006 to €4.9m in 2009. We recommend allowed costs remaining at 2009 levels. The DSO has proposed that these costs be treated as pass through costs but we disagree as they are to some extent negotiable and controllable.

The remaining asset management costs involve payroll and other costs such as ESBI and contracts for central technical services for the central management organisation. These costs do not include planning staff, which are mainly capitalised, and are considered to be relatively high for a networks organisation. Despite the likelihood of continuing centralisation we consider that asset management costs should decrease in line with our general efficiency savings.

- **Figure 8 -** Asset Management Costs 2006 to 2015

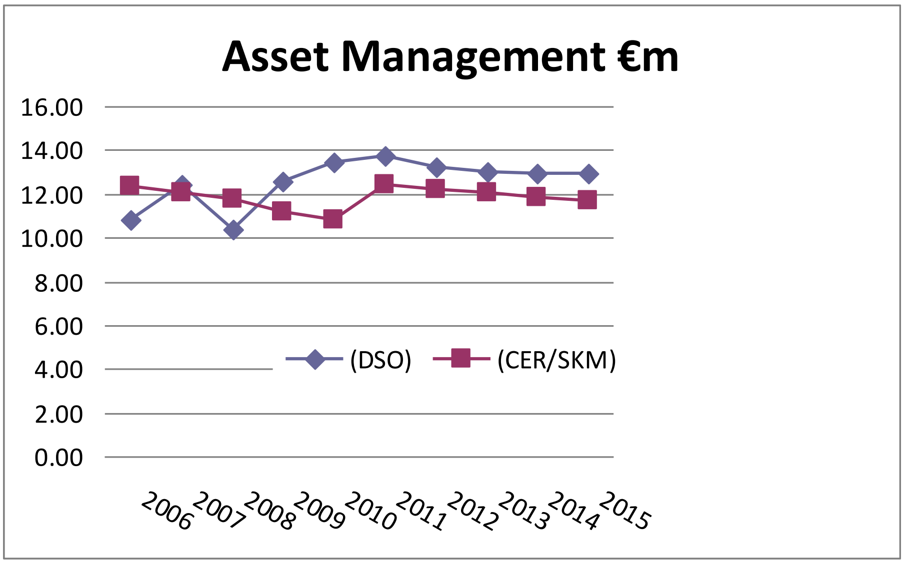


Figure 8 shows Asset Management costs, which are recommended to fall from €12.6m in 2009 to €11.7m in 2015

3.3.9. Metering

(PR2 €100.1m DSO €124.1m Allowed €100.5m)

- **Table 17 -** Metering Costs 2011 to 2015 (€m 2009 prices)

	2009 Actual	2011	2012	2013	2014	2015	DSO PR3 Forecast	PR2 Outturn	Variance PR3-PR2	Variance %
		DSO Forecast								
Meter reading	12.8	14.6	14.4	14.4	14.3	14.2	71.9	58.6	13.3	22.7%
NQH Data	1.6	1.9	1.9	2.0	2.0	2.0	9.7	6.8	2.9	43.2%
Customer meter operation	2.4	2.7	2.7	2.8	2.9	2.9	14.0	11.6	2.4	20.6%
Data Aggregation	4.6	5.6	5.6	5.7	5.7	5.8	28.5	23.1	5.4	23.3%
Metering	**21.3**	**24.8**	**24.7**	**24.8**	**24.9**	**24.9**	**124.1**	**100.1**	**24.0**	**24.0%**
	2009 Actual	**2011**	**2012**	**2013**	**2014**	**2015**	**PR3 Recommended**	**DSO PR3 Forecast**	**Variance Recomend vs DSO Forecast**	**Variance %**
		Recommended								
Meter reading	12.8	12.5	12.3	12.1	12.0	11.8	60.7	71.9	-11.1	-15.5%
NQH Data	1.6	1.5	1.5	1.5	1.5	1.4	7.4	9.7	-2.3	-23.6%
Customer meter operation	2.4	2.3	2.3	2.2	2.2	2.2	11.2	14.0	-2.8	-19.9%
Data Aggregation	4.6	4.4	4.3	4.2	4.1	4.0	21.1	28.5	-7.4	-25.9%
Metering	**21.3**	**20.8**	**20.5**	**20.1**	**19.8**	**19.4**	**100.5**	**124.1**	**-23.6**	**-19.0%**
Variance Recommended and DSO Forecast		-4.0	-4.2	-4.7	-5.1	-5.5	-23.6		-23.6	-19.0%

- **Figure 9 -** Metering Costs 2006 to 2015

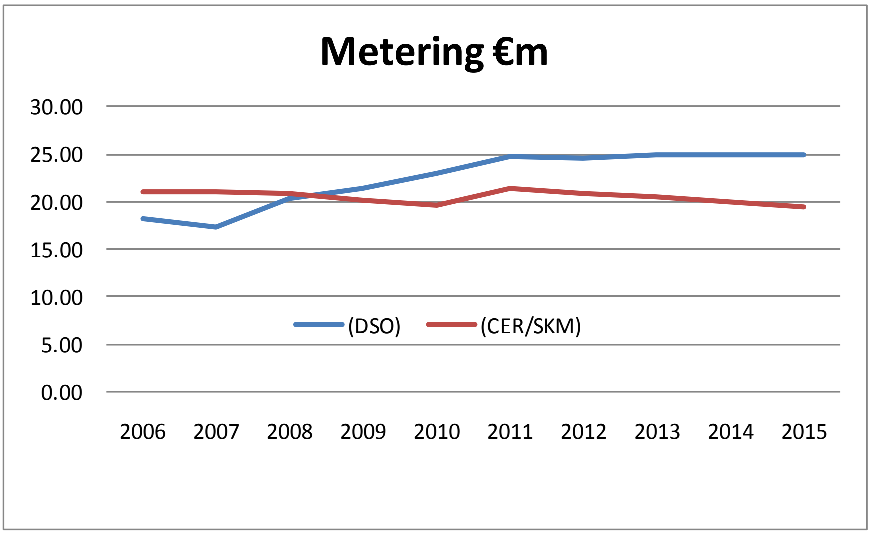


Figure 9 shows Metering costs, which are recommended to fall from €21.3m in 2009 to €19.4m in 2015.

Metering Reading (PR2 €58.6m DSO €71.9m Allowed €60.7m)

Almost 60% of Metering costs are associated with meter reading and 66% of meter reading costs are associated with contract meter readers. However meter reading also attracts €3.7m of internal DSO costs which appears to be a high overhead to carry above routine meter reading activities.

Meter reading costs are forecast by the DSO to increase from €12.8m per year in 2009 to €14.6m. We understand that this is mainly associated with the cost of achieving meter reading performance targets, particularly that which requires a 97% success rate for making 4 actual visits to each premise in each year, 92% being achieved at December 2009. There are no specialist skills for these activities and it should be possible to exert downward pressure on these costs during PR3.

Should DSO have difficulty meeting targets then it would be appropriate to revisit the targets in particular areas with CER and Suppliers and agree targets that are appropriate for credit control and to maintain complaints at an optimum level. There is potential for technology to be used for improving customer service by increasing customer own reads and making estimated accounts more acceptable.

We consider that the DSO forecast of metering costs does not reflect the prudence shown by the DSO in some other parts of the submission and we have little supporting information to justify these increases in costs.

- **Table 18 -** Meter Reading Targets

Analysis Month	Total No. of Accounts	Successful Visits %	Achieved % Accts with 4 Scheduled Visits	Achieved % Accts with 2 Scheduled Visits	Achieved % Accts w/out Actual Reading
	SLA Target	**80%**	**97%**	**99%**	**98%**
12.2009	2,209,232	84.999 %	92.207 %	99.964 %	98.320 %
12.2008	2,186,211	84.009 %	88.155 %	99.892 %	97.619 %
12.2007	2,135,674	83.657 %	80.971 %	98.987 %	96.830 %
12.2006	2,059,177	83.927 %	80.056 %	99.062 %	97.226 %
12.2005	1,970,353	83.678 %	84.382 %	98.827 %	96.311 %

NQH data is forecast to increase due to the additional work associated with wind generation and this is reflected in our proposal for allowed costs, whilst also applying efficiency savings.

Customer meter operation and Data aggregation allowed costs also include an efficiency factor.

3.3.10. Customer Service

(PR2 €98.3m DSO €92.2m Allowed €82.3m)

- **Table 19 -** Customer Service Costs 2011 to 2015

	2009 Actual	2011	2012	2013	2014	2015	DSO PR3 Forecast	PR2 Outturn	Variance PR3-PR2	Variance %
		DSO Forecast								
Call centre	7.9	7.1	7.0	7.0	7.0	7.0	35.0	36.3	-1.2	-3.3%
Area Operations	8.7	10.7	10.6	10.6	10.5	10.5	52.9	52.8	0.0	0.0%
Customer relations	1.5	0.9	0.9	0.9	0.8	0.8	4.3	9.2	-4.9	-53.6%
Customer Service	**18.1**	**18.6**	**18.5**	**18.4**	**18.3**	**18.3**	**92.2**	**98.3**	**-6.1**	**-6.2%**
	2009 Actual	**2011**	**2012**	**2013**	**2014**	**2015**	**PR3 Recommended**	**DSO PR3 Forecast**	**Variance Recomend vs DSO Forecast**	**Variance %**
		Recommended								
Call centre	7.9	6.9	6.7	6.6	6.4	6.2	32.8	35.0	-2.2	-6.3%
Area Operations	8.7	9.6	9.3	9.1	8.9	8.6	45.4	52.9	-7.4	-14.0%
Customer relations	1.5	0.8	0.8	0.8	0.8	0.8	4.0	4.3	-0.3	-6.1%
Customer Service	**18.1**	**17.3**	**16.9**	**16.4**	**16.0**	**15.6**	**82.3**	**92.2**	**-9.9**	**-10.7%**
Variance Recommended and DSO Forecast		-1.3	-1.7	-2.0	-2.3	-2.6	-9.9		-9.9	-10.7%

- **Figure 10 -** Customer Service Costs 2006 to 2015

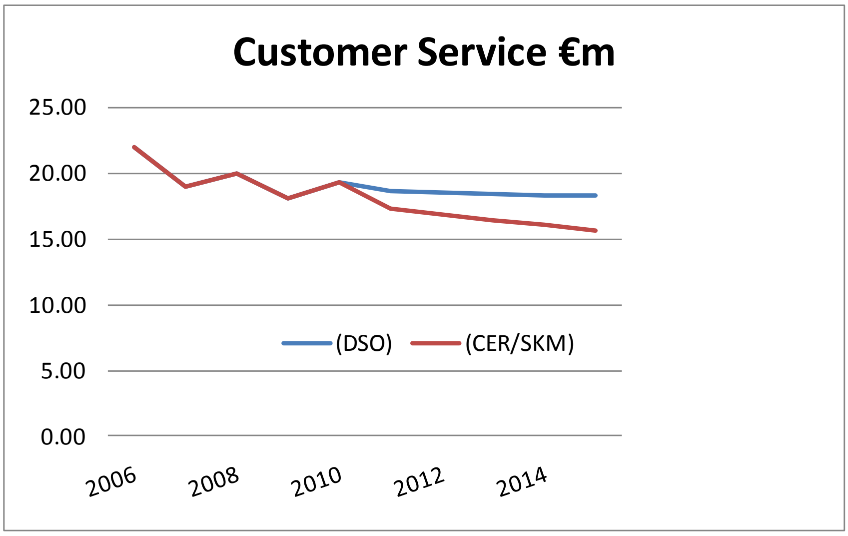


Figure 10 shows Customer Service costs, which are recommended to fall from €18.1m in 2009 to €15.6m in 2015.

Call Centre (PR2 €36.3m DSO €35.0m Allowed €32.8m)

At the PR2 review in 2005 CER had concerns over customer service performance levels and increased allowed costs and introduced targets and incentives to stimulate an improvement.

Penalties in the early part of PR2 put a focus on these targets and DSO implemented a customer service improvement plan. DSO has since delivered significant improvements in customer service during PR2 as highlighted in section 4.2.1 and in many areas now exceeds regulatory targets and industry norms and is at a high level by international standards.

From 2011 to 2015, competitiveness is an important national issue and DSO proposes to focus on consistently delivering cost-effective levels of service and this is reflected in the DSO's forecast.

Our view is that further efficiencies in Call Centre operations to reflect the level of investment in systems and future potential for exploitation of technology and in the alignment of labour costs with the Irish economy as a whole. There is also potential for the DSO to take a greater control of the Call Centre service provided by supply via the service agreements or by seeking direct control.

At the same time DSO has to maintain levels of service in order to drive down the number of calls and achieve success in dealing with calls on the first contact. The proposed allowed costs provide additional stretch and are considered to be achievable.

The incentive regime will also need to change to reflect the changed circumstances. Having reached target levels DSO needs to be incentivised to maintain that position. It is proposed to maintain the incentive measures SATRAT and to incentivise DSO to maintain ESATRAT performance at the present target levels of 85% as indicated in Section 4.2.2.

Area Operations (PR2 €52.8m DSO €52.9m Allowed €45.4m)

Area operations costs are those associated with the day to day operation of the network at the 34 areas. They are included in Customer Service as much of the work is immediate response to customers. Fault costs have been separated out and this has transferred costs to fault operations offset by transfer of reactive maintenance and tree cutting costs to area costs responsibility, giving rise to net increase of around €1m per year.

Savings of €18m were made in PR2 due to the impact of the network renewal programme, reducing the need for reactive work such as voltage complaints; better organisation of outages; work from OMS and mobile messaging systems; and less switching due to live working and remote control. Restructuring has also had an impact. In our view the savings arising in PR2 are likely to continue, as the IT systems are fully exploited and the mobile data system is extended to cover more field technicians. There is also the potential for further rationalising of the Area structure by centralising certain activities and reducing the number of depots.

Customer Relations (PR2€9.2m € DSO €4.3m Allowed €4.0m)

We have accepted the step change in customer relations costs proposed by DSO and applied an efficiency factor over PR3.

The DSO has advised that their submission is based on business as usual and if the Commission directs an information campaign associated with changes in the market, DSO would submit for additional allowance in respect of the associated cost.

3.3.11. Provision of Information

(PR2 €74.9m DSO €87.1m Allowed €71.9m)

- **Table 20 -** Provision of Information Costs 2011 to 2015

Summary Provision of Information Costs 2011 to 2015 €m 2009 Prices

	2009 Actual	2011	2012	2013	2014	2015	DSO PR3 Forecast	PR2 Outturn	Variance PR3-PR2	Variance %
		DSO Forecast								
DUoS Billing	0.7	0.7	0.8	0.8	0.8	0.8	3.8	4.0	-0.2	-4.8%
MRSO	1.1	2.0	2.0	2.0	2.0	2.0	10.1	6.2	3.9	62.5%
Market Opening	12.0	14.6	14.9	14.7	14.6	14.5	73.3	64.7	8.6	13.3%
Provision of Information	**13.8**	**17.4**	**17.7**	**17.5**	**17.4**	**17.3**	**87.1**	**74.9**	**12.3**	**16.4%**
	2009 Actual	**2011**	**2012**	**2013**	**2014**	**2015**	**PR3 Recommended**	**DSO PR3 Forecast**	**Variance Recommend vs DSO Forecast**	**Variance %**
		Recommended								
DUoS Billing	0.7	0.7	0.7	0.7	0.7	0.7	3.3	3.8	-0.5	-12.3%
MRSO	1.1	1.9	1.9	1.9	1.9	1.8	9.4	10.1	-0.6	-6.3%
Market Opening	12.0	12.2	12.0	11.8	11.6	11.5	59.1	73.3	-14.1	-19.3%
Provision of Information	**13.8**	**14.8**	**14.6**	**14.4**	**14.2**	**14.0**	**71.9**	**87.1**	**-15.2**	**-17.5%**
Variance Recommended and DSO Forecast		-2.6	-3.1	-3.1	-3.2	-3.3	-15.2		-15.2	-17.5%

- **Figure 11 -** Provision of Information Costs 2006 to 2015

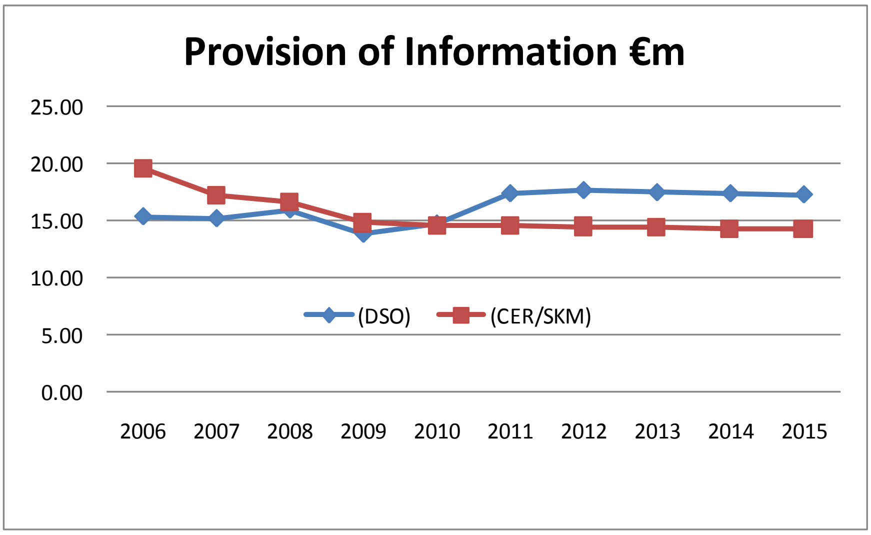


Figure 11 shows Provision of Information costs, which are recommended to increase slightly from €13.8m in 2009 to €14.0m in 2015.

DSO has explained that Market Systems Costs are expected to rise due to the need for more responsive IT systems and the need to handle larger volumes of market switching between Suppliers, which has risen from 54,479 in 2008 to 456,570 in 2009. We consider that level of switching is likely to stabilise at around 20%, which is the level of switching achieved in GB.[8]

DUOS (PR2 €4.0m DSO €3.8m Allowed €3.3m)

DUOS billing is maintained at 2009 levels with assumed efficiencies

MRSO (PR2 €6.2m DSO €10.1m Allowed €9.4m)

The DSO has included additional costs in the area of MRSO due to the level of churn and modifications associated with Free Electricity Allowances and global aggregation which require additional staff.

Market Systems (PR2 €64.7m DSO €73.3m Allowed €59.1m)

- **Table 21 -** Market Systems Costs 2006 to 2010

SPLIT OF MARKET SUPPORT (MOIP) COSTS							
	2006	2007	2008	2009	2010	Total	Allowance 04 €
Hosting and Data Storage	2.7	3.5	3.7	3.1	2.0	14.9	14.9
SAP Licences	0.4	0.5	1.3	0.7	0.6	3.6	5.5
Data Centre Infrastructure	0.3	0.7	0.2	0.1	0.2	1.5	3.1
Sub Total IT Infrastructure	3.4	4.7	5.3	3.9	2.8	20.0	23.4
Networks Direct Cost MOIP Support	1.1	2.0	1.6	1.4	1.7	7.7	
ITS MOIP Support Charges	7.0	4.6	6.0	5.1	6.3	29.0	
Sub total MOIP Support Operating Costs	8.1	6.5	7.6	6.5	8.0	36.7	33.0
MOIP Incremental Costs (€)	***11.5***	***11.2***	***12.9***	***10.4***	***10.8***	***56.7***	***56.4***
No. of FTEs	***49***	***33***	***36***	***36***	***36***	***191***	***192.0***
Industry Co-ordination and Design	1.4	1.6	1.1	1.3	1.3	6.8	8.2
Contact centre Supplier Support	0	0.4	0.4	0.4	0.4	1.6	1.7
Sub Total Other costs (€)	***1.4***	***2.0***	***1.5***	***1.7***	***1.7***	***8.4***	***9.9***
Total MOIP Opex (€)	**12.9**	**13.2**	**14.4**	**12.1**	**12.5**	**65.1**	**66.2**

[8] Ofgem Domestic Retail Market Report 2007.

- **Table 22 -** DSO Forecast of Market Systems Costs 2006 to 2015

SPLIT OF MARKET SUPPORT (MOIP) COSTS 2010 to 2015						
	2011	**2012**	**2013**	**2014**	**2015**	**Total**
Hosting and Data Storage	2.3	2.3	2.3	2.3	2.3	11.5
SAP Licences	0.8	0.8	0.8	0.8	0.7	3.8
Data Centre Infrastructure	0.2	0.2	0.2	0.2	0.2	1.2
Sub Total IT Infrastructure	3.3	3.3	3.3	3.3	3.3	16.5
						0
Networks Direct Cost MOIP Support	2.0	2.0	2.1	2.0	2.0	10.2
ITS MOIP Support Charges	7.3	7.3	7.5	7.3	7.3	36.7
Sub total MOIP Support Operating Costs	9.4	9.4	9.5	9.4	9.3	47.0
MOIP Costs (€)	***12.7***	***12.7***	***12.9***	***12.7***	***12.6***	***63.5***
						-
No. of FTEs	***36***	***36***	***36***	***36***	***36***	***182***
						0
Industry Co-ordination and Design	1.5	1.5	1.5	1.5	1.5	7.6
Contact centre Supplier Support	0.5	0.5	0.5	0.5	0.5	2.3
Sub Total Other costs (€)	***2.0***	***2.0***	***2.0***	***2.0***	***2.0***	***10.0***
						0
Total MOIP Opex (€)	**14.6**	**14.6**	**14.9**	**14.7**	**14.6**	**73.5**

The forecasting of Market Systems Costs in PR2 was poor and the allowed costs were reduced downwards throughout PR2. It is recognised that this activity is not wholly under the control of the DSO, but it is part of the DSO's responsibilities to deliver efficient market systems. These costs have therefore been subject to the same level of efficiency savings and the 2011 costs have been fixed at the 2009 level. We do not accept the rationale for the increase in the Market Systems forecasts; in particular there is no justification for increase in support by ESB ITS from €29m in PR2 to €37m in PR3. It is recognised that any new activities required by the market may lead to a request for adjustments, higher of lower as has been the case in the past.

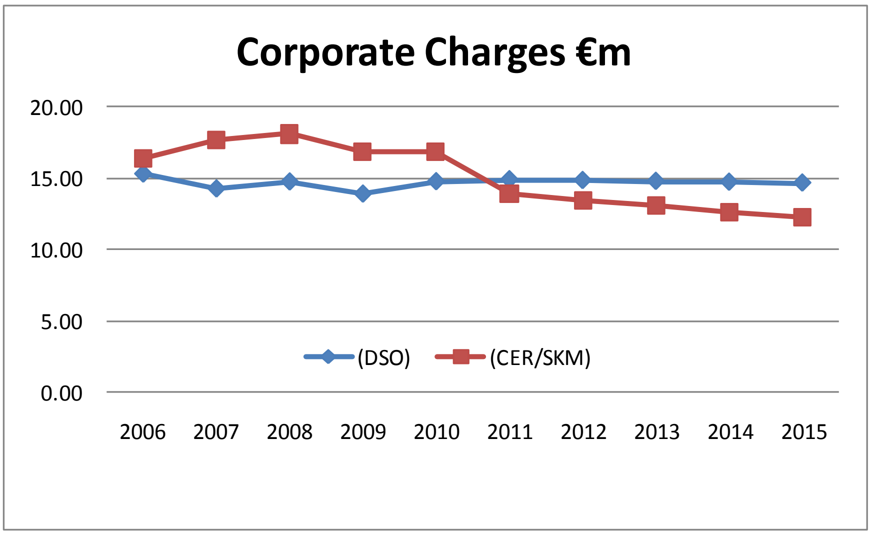
3.3.12. Corporate Costs

(PR2 €72.9m DSO €73.8m Allowed €64.3m)

- **Table 23 -** Corporate Costs 2011 to 2015

	2009 Actual	**2011**	**2012**	**2013**	**2014**	**2015**	**DSO PR3 Forecast**	**PR2 Outturn**	**Variance PR3-PR2**	**Variance %**
		DSO Forecast								
Company Wide Costs	2.0	2.9	2.9	2.9	2.9	2.9	14.5	11.1	3.4	30.4%
Corporate Centre & Corp Affairs	11.9	12.0	11.9	11.9	11.8	11.8	59.4	61.8	-2.4	-3.9%
Corporate Costs	**13.9**	**14.9**	**14.8**	**14.8**	**14.7**	**14.7**	**73.8**	**72.9**	**1.0**	**1.4%**
	2009 Actual	**2011**	**2012**	**2013**	**2014**	**2015**	**PR3 Recommended**	**DSO PR3 Forecast**	**Variance Recommend vs DSO Forecast**	**Variance %**
		Recommended								
Company Wide Costs	2.0	1.9	1.9	1.8	1.8	1.7	9.2	14.5	-5.3	-36.5%
Corporate Centre & Corp Affairs	11.9	11.6	11.3	11.0	10.7	10.5	55.2	59.4	-4.2	-7.1%
Corporate Costs	**13.9**	**13.5**	**13.2**	**12.9**	**12.5**	**12.2**	**64.3**	**73.8**	**-9.5**	**-12.9%**
Variance Recommended and DSO Forecast		-1.4	-1.6	-1.9	-2.2	-2.4	-9.5		-9.5	-12.9%

- **Figure 12 -** Corporate Charges 2006 to 2015



Graph 9 shows Corporate Costs, which are recommended to decrease from €13.9m in 2009 to €12.2m in 2015.

Corporate costs reduced during PR2 from €15.2m in 2006 to €14.7m in 2010. However, it is considered that these costs should have reduced by more than this due to transfer to DSO of legal services (€2.2m per year) and training centres (€2.8m per year). No explanation has been provided for the forecast increase in corporate costs of €1m from 2009 to 2010 and this increase has been rejected and efficiency savings applied.

Corporate costs are allocated on a basket of measures across the ESB businesses with a few services being charged on usage.

3.3.13. Other Controllable Costs

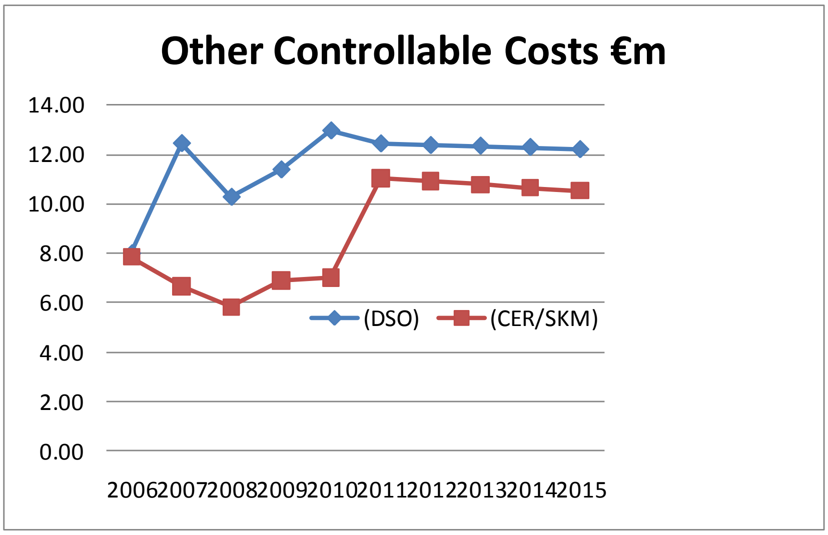
(PR2 €55.1m DSO €61.7m Allowed €53.9m)

▪ **Table 24 -** Other Controllable Costs 2011 to 2015

Summary of Proposed Other Costs 2011 to 2015 €m 2009 Prices

	2009 Actual	2011	2012	2013	2014	2015	DSO PR3 Forecast	PR2 Outturn	Variance PR3-PR2	Variance %
		DSO Forecast								
Safety	3.0	3.3	3.3	3.3	3.3	3.3	16.3	15.3	1.0	6.6%
Environmental	0.7	1.5	1.5	1.5	1.5	1.5	7.4	3.1	4.3	136.9%
Legal	2.6	2.3	2.3	2.3	2.3	2.3	11.5	12.8	-1.3	-10.3%
Pension	2.5	1.7	1.7	1.7	1.7	1.7	8.5	9.2	-0.7	-7.7%
Revenue	0.6	0.8	0.7	0.7	0.7	0.7	3.5	2.8	0.8	28.4%
Insurance	1.9	2.9	2.9	2.9	2.9	2.9	14.4	15.1	-0.7	-4.6%
Misc	0.1	0.0	0.0	0.0	0.0	0.0	0.1	-3.1	3.2	-101.9%
Other Controllable Costs	**11.4**	**12.4**	**12.4**	**12.3**	**12.3**	**12.2**	**61.7**	**55.1**	**6.5**	**11.9%**
	2009 Actual	**2011**	**2012**	**2013**	**2014**	**2015**	**PR3 Recommended**	**DSO PR3 Forecast**	**Variance Recommend vs DSO Forecast**	**Variance %**
		Recommended								
Safety	3.0	2.9	2.8	2.7	2.7	2.6	13.7	16.3	-2.6	-18.8%
Environmental	0.7	1.1	1.1	1.1	1.1	1.1	5.5	7.4	-1.9	-34.9%
Legal	2.6	2.3	2.3	2.3	2.3	2.3	11.3	11.5	-0.2	-1.6%
Pension	2.5	1.7	1.6	1.6	1.5	1.5	7.9	8.5	-0.6	-7.8%
Revenue	0.6	0.6	0.6	0.6	0.6	0.6	2.9	3.5	-0.6	-21.0%
Insurance	1.9	2.5	2.5	2.5	2.5	2.5	12.5	14.4	-1.9	-15.0%
Misc	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	49.6%
Other Controllable Costs	**11.4**	**11.0**	**10.9**	**10.8**	**10.7**	**10.5**	**53.9**	**61.7**	**-7.7**	**-12.5%**
Variance Recommended and DSO Forecast		-1.4	-1.5	-1.6	-1.6	-1.7	-7.7		-7.7	-12.5%

▪ **Figure 13 -** Other Controllable Costs 2006 to 2015



Graph 10 shows Other Controllable Costs, which are recommended to fall from €11.4m in 2009 to €10.5m in 2015.

Other controllable costs consist of safety, environmental, and central services such as pension administration and revenue collection.

Safety costs stabilised over PR2 and the DSO has met the challenge to improve contractor safety. There appears to be no justification for the step change in 2011 and an efficiency factor has been applied as for most other activities. There is a balance to be struck between central coordination of safety policy and the role of individual line managers.

DSO proposals for increase in environmental costs are associated with three additional staff on activities related to recycling and fluid filled cables. In our view the fluid filled cables are a matter for maintenance managers and the increase in costs is not wholly justified. Costs rose from €0.3 to €0.7m from 2006 to 2009 and the DSO forecasts another rise to €1.5m in 2010 and into PR3. We have proposed a rise to €1.1m in 2011 to be maintained at that level through PR3.

Legal costs have been held at 2009 levels and efficiency factors have been applied to revenue and pension administration costs.

3.3.14. Sustainability and Research and Development

(PR2 €7.9m DSO €30.8m Allowed €18.2m)

- **Table 25 -** Sustainability and R & D Costs 2011 to 2015

Summary of Proposed Sustainability Costs2011 to 2015 €m 2009 Prices

	2009 Actual	2011	2012	2013	2014	2015	DSO PR3 Forecast	PR2 Outturn	Variance PR3-PR2	Variance %
		DSO Forecast								
Research and Development	0.0	1.0	1.0	1.0	1.0	1.0	5.0	0.0	5.0	
Sustainability	2.3	5.1	5.1	5.2	5.2	5.2	25.8	7.9	17.8	225.2%
Sustainability	**2.3**	**6.1**	**6.1**	**6.2**	**6.2**	**6.2**	**30.8**	**7.9**	**22.8**	**288.3%**
	2009 Actual	**2011**	**2012**	**2013**	**2014**	**2015**	**PR3 Recommended**	**DSO PR3 Forecast**	**Variance Recommend vs DSO Forecast**	**Variance %**
		Recommended								
Research and Development	0.0	0.7	0.7	0.7	0.7	0.7	3.4	5.0	-1.6	-32.0%
Sustainability	2.3	3.0	3.0	3.0	3.0	3.0	14.8	25.8	-11.0	-42.6%
Sustainability	**2.3**	**3.6**	**3.6**	**3.6**	**3.6**	**3.6**	**18.2**	**30.8**	**-12.6**	**-40.8%**
Variance Recommended and DSO Forecast		-2.5	-2.5	-2.5	-2.5	-2.5	-12.6		-12.6	-40.8%

ESB Networks faces major technical challenges to support Government targets for renewable generation, introduction of electric vehicles and carbon reduction, whilst ensuring cost competitiveness is maintained. Government targets include:

- 40% of Ireland's electricity from renewable sources requiring over 6,000MW of renewable generation connected to the national network.
- 10% penetration of electric vehicles, representing 230,000 vehicles by 2020
- Meeting CO2 emission targets nationally may require a significant move to direct electric heating in the residential sector, possibly involving the more widespread use of heat pumps.

The R & D projects are linked to capital investment programmes for smart networks and metering and provision of electricity supplies for electric vehicle charging points.

The DSO sees this as an integrated infrastructure project. Smart meters will permit dynamic control of the loading of the network to balance a future direct heating load and electric vehicle charging load with the variable wind generation.

There is a question as to whether it is appropriate for the DSO to be involved in areas which do not appear to be directly linked to its licence obligations and we have not recommended capital expenditure of €187.5m in electric vehicle charging points. However, the DSO does need to understand and develop plans to integrate wind generation and electric vehicles into the distribution network.

The sustainability expenditure makes provision for €14.2m of identified expenditure of which €8.2m involves subsidy for microgeneration, ie €6m of R & D projects, and a further unspecified €17m of R & D projects.

R & D can produce success and failure and we have reservations that participation in collaborative research of this type will identify the viability of this project or provide solutions and we recommend sustainability and research and development expenditure of €18.2m.

We recommend that tariff support for microgeneration should be provided outside of DUoS, possibly using a PSO mechanism.

3.3.15. Non Controllable Costs

(PR2 €189.5m DSO €204.3m CER €199.5m)

- **Table 26 -** Non Controllable Costs

Summary of Proposed Non Controllable Costs 2011 to 2015 €m 2009 Prices

	2009 Actual	2011	2012	2013	2014	2015	DSO PR3 Forecast	PR2 Outturn	Variance PR3-PR2	Variance %
		DSO Forecast								
ESI Levy	1.4	1.9	1.9	1.9	1.9	1.9	9.5	9.8	-0.3	-2.8%
Rates	33.2	35.4	35.4	35.4	35.4	38.9	180.5	164.3	16.2	9.8%
Non Controllable Costs	**34.5**	**37.3**	**37.3**	**37.3**	**37.3**	**40.8**	**190.0**	**174.1**	**15.9**	**9.1%**
	2009 Actual	**2011**	**2012**	**2013**	**2014**	**2015**	**PR3 Recommended**	**DSO PR3 Forecast**	**Variance Recommend vs DSO Forecast**	**Variance %**
		Recommended								
ESI Levy	1.4	1.9	1.9	1.9	1.9	1.9	9.5	9.5	0.0	0.0%
Rates	33.2	35.4	35.4	35.4	35.4	38.9	180.5	180.5	0.0	0.0%
Non Controllable Costs	**34.5**	**37.3**	**37.3**	**37.3**	**37.3**	**40.8**	**190.0**	**190.0**	**0.0**	**0.0%**
Variance Recommended and DSO Forecast		0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0%

Non- Controllable costs are normally allowed as pass through, subject to them being efficiently incurred, and consist of rates and CER levy.

Local Authority Rates were set in 2008 for a period up to 2014; a provision has been made by DSO for a 10% increase in 2015, which is reasonable.

DSO support for market design administration costs are included in Market Systems and are recognised as being treated as pass through costs, although controllable.

We have not accepted that forestry payments and wayleaves costs included in Asset Management costs are non controllable pass through items. To do so would set a precedent for many other costs that are subject to negotiation.

3.3.16. Impact of Allowed Operating Costs on DUoS

The impact of operational costs excluding depreciation, commercial costs and exceptional costs on the unit cost of electricity per customer and per kWh is shown in the table below:

- **Table 27 -** Trends in Unit Costs

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Customers (m) (Actual / DSO Forecast	2.070	2.151	2.204	2.234	2.259	2.287	2.317	2.348	2.381	2.416
GWh DSO Forecast	22903	23457	24043	23084	22902	23269	24014	24758	25526	26317
DSO Operating Costs €m	259.4	265.3	249.5	245.6	251.9	248.0	246.3	245.5	244.8	248.7
Actual / Allowed Operating Costs €m	259.4	265.3	249.5	245.6	251.9	223.9	220.2	216.6	213.1	213.2
Cost per customer (DSO Forecast)	125.3	123.3	113.2	110.0	111.5	108.4	106.3	104.5	102.8	102.9
Cost per customer (Allowed)	125.3	123.3	113.2	110.0	111.5	97.9	95.0	92.2	89.5	88.2
DSO Cost per kWh (cents)	1.13	1.13	1.04	1.06	1.10	1.07	1.03	0.99	0.96	0.95
Actual / Allowed Cost per kWh (cents)	1.13	1.13	1.04	1.06	1.10	0.96	0.92	0.87	0.83	0.81

There has been a reduction in unit costs per kWh of 3.7% 2006 to 2010.

The DSO forecasts of cost and increase in units distributed of 2.85% per year give rise to a reduction in unit costs per kWh of 13.4% 2010 to 2015. The reduction in cost per kWh based on recommended costs and the DSO forecast of units is 25.8% from 2010 to 2015.

4. DSO Performance

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

- The duration and frequency of customer interruptions defined by the key international measures:
  - System Average Interruption Frequency Index (SAIFI), measured by the Number of Customer Interruptions per 100 customers per year.
  - System Average Interruption Duration Index (SAIDI), measured by the average minutes customers are off supply per year
- System Electrical Losses
- Performance against the Customer Charter and Other Customer Service Measures

4.1. System Performance

The DSO's network performance was analysed according to:

- Assessment of historical performance against incentivised targets
- Recommendations for system performance for the period 2011 to 2015.

4.1.1. Measures of System Performance

The two international measures of system performance SAIFI, SAIDI are explained below:

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 one minute[9]) 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.

$$SAIFI = \frac{\sum N_i}{N_T}$$ where,

N_i is the number of customers interrupted in fault i

N_T is the total number of customers served

[9] Note the CER PR2 decision paper defined interruptions as being of five minutes duration whereas DSO has used one minute in PR2. DSO proposes to change the definition of SAIDI and SAIFI in the future period to apply to those interruptions lasting three minutes or more, in line with common European practice.

SAIFI is measured by of the Number of Interruptions per 100 Customers per year, referred to in this report as CIs.

System Average Interruption Duration Index (SAIDI)

SAIDI is the average duration of interruptions for all customers during the year. It is determined by dividing the sum of all durations of service interruptions to customers by the total number of customers.

It is calculated as:

$$\text{SAIDI}^{10} = \frac{\sum r_i N_i}{N_T} \quad \text{where,}$$

r_i is the duration of fault I

SAIFI is measured by the Average Customer Minutes Lost per customer per year, referred to in this report as CMLs.

System performance is disaggregated between planned and unplanned interruptions. Planned interruptions are those which have been pre-arranged by giving notice to customers under Customer Charter G2. Unplanned interruptions are those which occur due to failure of equipment, or error, including failures initiated by third parties.

4.1.2. Review of Historic System Performance 2006 to 2010

CER set incentivised targets for system performance for the period 2006 to 2010 and the DSO received incentive payments for exceeding targets and was penalised where targets were not met.

- **Table 28 -** System Performance 2006 to 2010

	2005	2006	2007	2008	2009	2010
Customer Interruptions/100 Customers						
Unplanned Outages	186	143	148	128	110	122
Planned Outages	89	68	28	24	24	25
Total CIs	**275**	**211**	**177**	**152**	**134**	**147**
Target CIs	0	201	178	175	173	171
Variance - ive good	**0**	**11**	**-1**	**-23**	**-39**	**-23**
Customer Minutes Lost CMLs						
Unplanned Outages	155	124	115	94	79	88
Planned Outages	375	269	79	61	62	65
Total CMLs	**530**	**393**	**194**	**155**	**141**	**153**
Target CMLs	275	379	230	215	208	201
Variance - ive good	**255**	**14**	**-36**	**-60**	**-67**	**-48**

Targets and performance exclude exceptional storm days (13 from 2006 to 2008) to ensure that performance is measured on a consistent basis over time and with comparator countries.

[10] Note SAIDI was incorrectly described in CER PR2 decision paper, although the formula was correct. CAIDI is not used in this paper to avoid confusion as it is not an incentivised measure.

Outages on the MV network give rise to the majority of Customer Interruptions and Customer Minutes Lost. The targets and performance for 2005 and 2006 took account of the considerable number of planned outages required for Medium Voltage network renewal, which was completed in 2006. In future planned outages are expected to remain at the lower levels achieved from 2007 onwards.

There was a sharp decrease in CIs and CMLs in 2009 which the DSO attributes to benign weather particularly in the spring.

The underlying network performance is best represented by the performance for unplanned interruptions which has improved from 2005 to the 2010 forecast as shown in the table below:

- **Table 29 -** Improvement in network performance Unplanned Outages 2005 to 2010

Unplanned Outages	2005	2010	Improvement%
Customer Interruptions CIs	186	122	34%
Customer Minutes Lost CMLs	155	88	43%

Much of the MV network has been uprated from 10 kV to 20 kV, which has led to a temporary increase in the number of faults (400 in PR2) due to the higher electrical stresses. This effect will diminish as weaknesses are revealed and rectified and as equipment is replaced with modern insulation. However there is no doubt about the overall benefit of uprating the network to 20 kV which provides 4 times the capacity and ¼ of the electrical losses of a 10 kV system.

The DSO has responded to the incentives to improve system performance and received incentive payments for improvement in CMLs and CIs of €55m during PR2.

The improvement has been achieved by speeding up the response to incidents and rationalising system control and by the introduction of the IT system OMS. The OMS system is the IT system for managing outages and recording network performance figures. The system gives some confidence in the accuracy of data, although an independent audit could be considered, as required in GB.

CMLs and CIs associated with unplanned interruptions have also reduced significantly due to:

- Capital investments programmes at a cost of €23.7m:
    - Installation of remote controlled switches on rural networks so that 1100 devices will be installed by 2010.
    - Splitting MV feeders to reduce the number of customers affected by each fault.
    - Installing SCADA in 77 HV substations, completing SCADA in 441 of the 489 substations, suitable for SCADA.

- Completion of the MV network renewal programme.

- Management initiative to set targets for each area and focus on the cost benefit of incentivised performance.

- The impact of planned outages has been reduced by adopting live working techniques at MV and by the use of generators where appropriate.

We have reviewed a number of these investments and found that they are commensurate with the incentive rate, currently €8 per CML saved. Over time the incremental benefits of additional investment is likely to diminish.

4.1.3. International Benchmarking

Network performance has been monitored and incentivised on a consistent basis by Ofgem the regulator in Great Britain for over ten years. Targets are set for each company taking into account inherent and inherited differences in the network and by characterising the network according to the proportion of overhead lines and underground cables and the sparseness of customers.

- **Table 30 -** GB Network Performance

Table A2.5: Incentive Scheme - 2008/09 Customer Interruptions & Customer Minutes Lost as a Percentage of Respective 2008/09 Targets

DNO	2008/09 CI Target	2008/09 Incentive Scheme CIs	2008/09 Incentive Scheme CIs as % of 2008/09 Target		2008/09 CML Target	2008/09 Incentive Scheme CMLs	2008/09 Incentive Scheme CMLs as a % of 2008/09 Target
CN West*	104.6	92.8	89		91.0	79.3	87
CN East	76.7	68.5	89		70.0	58.4	83
ENW*	57.1	48.3	85		54.7	50.8	93
CE NEDL	74.5	64.2	86		68.4	76.3	112
CE YEDL*	68.5	76.4	112		63.4	73.0	115
WPD S Wales*	95.3	66.1	69		72.2	36.8	51
WPD S West*	84.5	58.4	69		62.2	43.9	71
EDFE LPN	36.2	28.7	79		40.1	44.2	110
EDFE SPN	84.5	82.7	98		68.2	99.8	146
EDFE EPN*	85.7	84.8	99		69.1	88.3	128
SP Distribution	60.8	55.7	92		54.0	48.5	90
SP Manweb*	46.7	49.3	106		46.1	54.8	119
SSE Hydro*	95.2	75.8	80		93.0	75.1	81
SSE Southern*	88.3	64.3	73		77.4	65.6	85
GB average		66.6				66.1	

The Quality of Service Report[11] for 2008/09 shows the range of targets and performance between companies, which is summarised in the table above.

[11] 2008/2009 Electricity Distribution Quality of Service Report

- **Table 31 -** Comparison of DSO and GB Performance 2008/09

Note: Excludes London which is an all underground network designed with enhanced security	**CIs**	**CMLs**
DSO Total	152	155
DSO Unplanned	128	94
GB Average Total	69	68
GB Average Unplanned	64	56
GB Highest	93	93
GB Lowest	48	46

The table above shows the relative performance of DSO and GB, excluding London. Scottish Hydro has CIs and CMLs of 76 and 75 respectively but it should be noted that in 2001/02 Scottish Hydro had CIs of 120 against a target of 135 CIs and CMLs of 142 against a target of 195 CMLs, which demonstrates the scale of improvements that are possible.

The distribution network in Ireland is significantly different to that of GB. The average length of network in GB is 27 metres per customer and 75 metres per customer in Ireland. Scottish Hydro has 64 metres per customer but the proportion of overhead network is 5:1 whilst it is 9:1 in Ireland and the GB average is 1:1. The settlement pattern in Ireland is different to GB with over 640,000 customers living in rural areas. Many are served by individual radial circuits protected by fuses and with no possibility of interconnection to provide an alternative supply in the event of a fault.

Only 7% of CIs and 17% of CMLs are due to planned interruptions in GB. Whereas in Ireland 16% of CIs and 39% of CMLs are due to planned outages. This may be partly due to the extent of live working in GB, but much of the difference is due to inherent differences in the network.

DSO has carried out some benchmarking of their performance relative to GB, taking into account the type of the settlement patterns and topography of their network. The methodology is to model how GB DNOs would perform on DSO networks by applying GB fault rates and average fault duration to the DSO network.

On this comparison DSO CMLs are at the top end of performance due to their superior response times. DSO retains 34 areas and 61 depots which provides a relatively good response to network faults. This analysis brings DSO at mid range for CIs due to the relatively lower level of penetration of network reclosers and the large number of fused spurs. However the DSO is applying an innovative solution to this by replacing fuses with “tripsaver” devices which will reduce nuisance operation of fuses in future.

We have examined the DSO’s benchmarking of quality of supply performance against GB DNOs and have concluded that it is not intended to be an exhaustive model but it is illustrative of the sensitivity of system performance to network topography, customer dispersion, fault rates and the level of system automation.

The work carried out in GB has demonstrated the difficulty of modelling and benchmarking even similar networks in order to set non discriminatory targets. There are many other factors to take into account. For example GB has considerably more lightning than Ireland. Fault duration may be relatively longer in GB because it has less short time faults that can be restored by replacing fuses or reclosing a switch. (This feature was noted as GB networks were automated)

The rate of improvement of DSO network performance demonstrates the effectiveness of incentives but also indicates that there is some way to go for DSO to achieve optimum network performance.

This is recognised by DSO in their proposals for the PR3 period 2011 to 2015.

4.1.4. Determination of Network Performance Targets and Incentives

DSO has made proposals for improvement in network performance for the period 2011 to 2015 including operational improvements, network renewal and specific continuity improvement projects.

DSO will also continue to develop operational initiatives and live working and by the end of 2011 MV network control will have been transferred to Dublin and Cork, whilst retaining local presence for management of incidents.

Table 32 below summarise the balance of improvements and degradation DSO has forecast over PR3.

- **Table 32 -** DSO Proposals for Network Performance Improvement

Programme	CI	CML
Ageing / Degradation of Networks	13.8	15.3
Refurbishment Programmes	-14.4	-18.1
20kV Conversion (15,000)	8.7	6.1
Continuity Initiatives	-20.2	-21
Overall impact on Fault performance	**-12.1**	**-17.8**

The renewal of the MV network is largely completed but will commence again towards the end of PR3 on a 9 year refurbishment cycle to maintain performance. A further 15000 km of network will be uprated to 20 kV with the attendant potential for a temporary increase in fault rate which has been taken into account in establishing system performance targets.

Network renewal will be focussed on low voltage networks and, although this will reduce the number of faults, the impact on CMLs and CIs is not so great. The low voltage network incurs 70% of the 37,000 incidents per year, many on individual services, but only contributing 12% of CMLs.

DSO modelling assumes an overall degradation and this is considered to be pessimistic for a network which has been recently renewed to improve mechanical strength, particularly as the degradation due to the 20 kV uprating is separately accounted for.

DSO proposes to invest further in network continuity projects. These initiatives provide a relatively quick return and are mainly focussed on restoring customers quicker by remote control devices. The benefits of these initiatives are shown in Table 33:

- **Table 33 -** Proposed Continuity Investments

Programme	CI	CML	Number	Cost €m
Rural Recloser/LBFM	0.17	15.3	700	9.5
Centralised control of MV	-	1.09		
Tripsavers	0.013	1.55	500	1.9
High Impedance Earthing	0.012	0.76	10	3.8
38kV LBFM	-	0.73	70	2.5
SCADA extension	-	1.07	38	2
Remote Control of Urban RMUs	0	0.28	250	1.9
Replacement of Obsolete Reclosers & Sw. Gear	0.005	0.15		
Splitting of feeders	0.002	0.15		
Total	**0.202**	**21.09**		**23.2***

* Total cost from capital programme

The major benefit comes from providing remote controllable switching devices on the network such as rural reclosers and extension of SCADA (remote control) to the remaining 38 major substations that remain to be equipped.

Tripsavers are devices that replace fuses and allow source circuit breakers to go through a reclose cycle for a transient fault, thus avoiding an unnecessary sustained interruption due to unwanted operation of fuses.

There is relatively lower value from the use of High Impedance Earthing and this does not appear to be justified on continuity grounds alone.

The DSO Proposals for Network Performance for unplanned outages for PR2 are shown below.

- **Table 34 -** DSO Proposal for Network Performance Improvement (Unplanned Outages)

Unplanned Outages	2005	2010	Improvement 2005 - 2010	2015	Improvement 2010 - 2015
Customer Interruptions	186	122	34%	110	10%
Customer Minutes Lost	155	88	43%	70	20%

This appears to be a conservative forecast. There is no evidence that network fault rates are increasing and it would be abnormal for networks to degrade during a period of major network renewal. Reliable historic fault rates are not available from DSO but in GB where similar investment programmes are in place fault rates are remarkably stable[12]. We do not accept an overall degradation in performance.

[12] 2007 08 Electricity Distribution Quality of Supply Data (Ofgem website)

We would also expect the MV network to improve over the period as the problems of uprated 20 kV network abate. The 20 kV conversion programme should recognise the problem and re-insulation should be provided to reduce this effect. The effect of the 20 kV uprating should be reduced by 20%.

The calculations of improvements from the continuity initiatives appear to be reasonable on average, although we would expect the investment to be targeted on the most advantageous parts of the network first and the improvements give a 15% improvement on the DSO forecast of CML improvement.

Our proposals for system improvement are based on the assumptions on network performance improvements below:

- **Table 35 -** SKM Improvement from Performance Initiatives

Programme	**CI**	**CML**
Ageing / Degradation of Networks	13.8	15.3
Refurbishment Programmes	-13.8	-15.3
20kV Conversion (15,000)	6.96	4.88
Continuity Initiatives	-20.2	-24.15
Overall impact on Fault performance	**-13.24**	**-19.27**

The DSO has based the forecast on the 2010 forecast which is based on a trend that excludes the 2009 figures that the DSO considers to be abnormally low due to a benign spring. Basing the target on a simple regression including 2009 gives a starting point for 2010 of 101 CIs and 64 CMLs. These are not considered to be credible starting points and it is proposed to adopt the average of 2008 and 2009 as the starting point for CIs (119 compared with the DSOs figure of 122) and for CMLs (87 compared with 88).

The overall target performance for unplanned outages applied linearly over the period is set out below:

- **Table 36 -** Recommendations for Network Performance Improvement (Unplanned Outages)

Unplanned Outages	**2005**	**2010**	**Improvement 2005 - 2010**	**2015**	**Improvement 2010 - 2015**
Customer Interruptions	186	119	34%	106	11%
Customer Minutes Lost	155	87	43%	68	22%

The DSO has established models for deriving targets for unplanned outages and has forecast further improvements in CIs of 10% and CMLs of 20% during PR3. We have examined the models and have modified the target to 11% for CIs and 22% for CMLs. These targets are considered to be stretching and yet provide sufficient opportunity for the DSO to achieve incentive payments, which we recommend should continue at the existing levels. We also agree

that the targets should be based on interruptions of three minutes or more, which is a technical change from the one-minute threshold adopted up to 2010.

This is a technical change to accommodate automatic switching schemes some of which may take up to three minutes to operate.

Planned Outages

The DSO has proposed that targets for planned interruptions are set annually based on the workload in any one year, which will avoid windfall gains from uncompleted work programmes. We agree with this approach and have examined the models which appear to have a sound theoretical basis and include a proportion of live work. However performance should be monitored and the incentive rate adjusted if the gains appear to be out of line with customer benefits.

It is particularly important to incentivise improvement in planned outage performance in Ireland which has a relatively high level of planned outages due to the nature of the network.

- **Table 37 -** Proposed and Recommended Network Performance Targets

	2005	2010	% Decrease 2005 to 2010	2011	2012	2013	2014	2015	% Decrease 2010 to 2015
DSO Forecast									
Unplanned Interruptions									
CIs	186.2	122.2	34.4%	121.3	118.6	115.7	112.9	110.1	9.9%
CMLs	154.9	88.0	43.2%	85.7	81.5	77.7	74.0	70.2	20.2%
Planned Interruptions									
CIs	89.0	25.3	71.5%	22.6	22.6	22.6	22.6	22.7	10.5%
CMLs	375.4	65.3	82.6%	55.8	55.8	55.7	55.8	55.8	14.5%
Recommended									
Unplanned Interruptions									
CIs	186.2	119.0	36.1%	120.48	116.91	113.28	109.64	106	10.9%
CMLs	154.9	87.0	43.8%	85.30	80.60	76.40	72.20	68	21.8%
Planned Interruptions									
CIs	89.0	25.3	71.5%	22.6	22.6	22.6	22.6	22.7	10.5%
CMLs	375.4	65.3	82.6%	55.8	55.8	55.7	55.8	55.8	14.5%

Worst Served Customers

Incentives on average network performance can mean that customers receiving multiple interruptions in a year are disadvantaged as there is currently no incentive to improve the performance to a minority group. Customer Surveys show that there is a section of the customer base that does receive multiple interruptions and a mechanism is required to identify these customer groups and manage appropriate improvement.

Experience elsewhere indicates that some multiple interruptions are random but others are often due to neglect of parts of the network or repeated faults for the same case that are easily put right.

Various methods are used Guaranteed Standard in GB provides a payment of £50 for customers having four or more interruptions per year each lasting 3 hours or more (1 April to 31 March).

GB is also introducing a national fund for worst served customers of £42m with a cap of £1000 per customer. It is understood that CER favours the introduction of a similar fund.

The DSO has proposed a fund of €10m over PR3 for worst served customers and we recommend that this approach is explored further and that thresholds are set to fairly identify beneficiaries. The scale of the fund should be set at £10m for the whole of PR3, with particular targets in mind, based on network performance data.

To introduce this standard there is a need to be able to identify customers affected in the OMS system and to gain some knowledge before setting the threshold. It is recommended that DSO investigate whether information is currently available from OMS to identify individual or groups of customers that experience multiple interruptions and come forward with proposals ready for implementation in 2012.

4.2. Customer Service Performance and Incentives

4.2.1. Review of Customer Service Performance 2006 – 2010

At PR2 review in 2005 CER had considerable concerns over customer service performance levels and a number of incentives and targets were introduced to stimulate an improvement. CER allowed a higher level of operating costs for the contact centre than the DSO requested to facilitate improvement.

Penalties in the early part of PR2 put a focus on these targets and DSO implemented a customer service plan. DSO has since delivered significant improvements in customer service during PR2 and in many areas now exceeds regulatory targets and industry norms and is considered to be at very high level by international standards.

This was achieved by introducing a customer service improvement plan and working closely with ESB Customer Supply which operates the central call centre based at Cork on behalf of distribution. Particular emphasis is placed on training and retention of staff and quality of service provided, telephone response and successfully answering calls on first contact, which is around 80%.

The improvement in customer service is evident throughout the organisation but the customer experience is initially via the call centre in Cork. The Call Centre handles calls for supply and distribution. The distribution service deals with no supply calls, meter reading enquiries and general enquiries. (The DSO has introduced a separate central bureau for new connections closely supported by good liaison with locally based staff).

Technology has been adopted to provide automatic facilities for recording meter reading and to provide feedback for no supply calls, where in the event of an outage or multiple outages thousands of customers may call at any time. The call centre is sized but not fully staffed to handle a major emergency affecting 500,000 customers.

- **Table 38 -** NCCC Number of Contacts 2008

	Meter Reading	No Supply	Total inc Supply	Response
Operator Answered	75060		784562	85% < 3 sec
Recorded Message		306378	306378	20 secs
Automated Response	295733		295733	
Total	370793	306378	1386673	
Letters			45661	

DSO has provided information on the Service Level Agreement for Call Centre charges and the annual review arrangements. This SLA requires updating and this has been recognised and is being addressed by the DSO.

DSO was faced with an increasing level of complaints in the period 2003 to 2005 and a Customer Service Improvement Plan was implemented in 2006. The expected outturn KPIs are compared with the improvement plan target in Table 33 below. Most targets are being met except meter reading complaints, "pay to authorise" for connections and the high standard of 95% of supplier jobs meeting SLA.

- **Table 39 -** Customer Service Targets and Performance

Key Performance Indicator		2005	2009 Outturn	2009 Target
NCCC Telephone answering (20 sec.) inc. IVR	(%)	63%	90%	80%
NCCC Calls Abandoned	(%)	13%	1%	5%
Referrals cleared in 2 days	(%)	50%	93%	95%
Complaints cleared in 5 days	(%)	60%	96%	94%
No. of Customer Complaints	(no.)	8978	4032	4000
Customer Satisfaction (Red C / MORI Survey)	(%)	68%	78%	76%
New Connection -Pay to Authorise	(weeks)	7.6	4	4
New Connection -Pay to Connect	(weeks)	21	12	
New Connection Charter Payments (NG5 & NG6)	(no.)	2612	1,003	2000
Supplier jobs within SLA	(%)	65%	93%	95%
Meter Reading Complaints*	(no.)	1300*	700	700
Planned Outage Charter Payments (NG2)	(no.)	5924	1,250	2000

* metric became available in 2006

- **Table 40 -** Customer Service Incentivised Performance against targets

	2006	2007	2008	2009	2010
	Targets				
Speed of Tel Response	70%	75%	80%	83%	83%
Abandonment Rate	5%	5%	5%	5%	5%
Mystery Caller	67%	72%	75%	80%	80%
Callback Survey	77%	78%	80%	80%	80%
ESATRAT (Performance Target)	78%	81%	84%	85%	85%
	Outcome				
Speed of Tel Response	78%	82%	85%	88%	
Abandonment Rate	4%	3%	2%	1%	
Mystery Shopper	76%	79%	83%	87%	
Callback Survey	73%	79%	81%	85%	
SATRAT *(Actual Performance)*	82%	85%	88%	90%	

In 2006 CER introduced an incentive mechanism on the NCCC incorporating four separate measures to evaluate the level of customer service provided[13], (ESATRAT):

- Speed of Telephone Response
- Call Abandonment Rate
- Customer Call-Back survey results
- Mystery Caller survey results

The penalty/reward (ESATRAT) applies to both the PES and the DSO and is capped at a certain percentage (1.0% (penalty); 0.25% (reward)) of each business's Allowed Revenue each year. It is noted that the DSO bears a larger proportion of the reward/penalty (€650,000) than the PES (€150,000), although the PES has a greater influence on performance and the DSO generally handles more straightforward calls with IVR and recorded message facilities.

IVR has a significant impact on telephone response and there are two measures adopted.

• **TSF 20 (incl IVR)** is the percentage of calls to the Call Centre answered (either by an Agent or IVR) within 20 seconds.

• **TSF 30 (excl IVR)** is the percentage of calls that are in a queue waiting to speak to an Agent (after being placed in the queue either via the IVR or by an Agent) that are answered by an Agent within 30 seconds

4.2.2. Determination of Customer Performance Targets and Incentives 2011 to 2015

From 2011 to 2015, competitiveness is an important national issue and DSO proposes to focus on consistently delivering cost-effective levels of service and this is reflected to some extent in the forecast.

DSO has indicated that with full exploitation of new technology and reducing the need for customer calls, there should be a continuing improvement in customer service and containment of cost increases.

The DSO has proposed performance targets for the period 2011 to 2015 as follows:

Table 41 - DSO Proposed Contact Service Performance Targets

KPI	2009 Actual	2010 Target	2011	2012	2013	2014	2015
NCCC TSF (20 sec.) inc. IVR	90%	80%	80%	80%	80%	80%	80%
NCCC Abandoned	1%	<5%	<5%	<5%	<5%	<5%	<5%
Referrals cleared in 2 days	93%	95%	98%	98%	98%	98%	98%
Complaints cleared in 5 days	96%	95%	95%	95%	95%	95%	95%
No. of Customer Complaints	4032	3500	3,200	2,900	2,600	2,300	2,000
Red C Survey (Customer Satisfaction)	78%	78%	80%	80%	80%	80%	80%

[13] Decision Paper CER06107 2006

▪ **Table 42 -** DSO Proposed Customer Contact Performance Targets

KPI	2009 Actual	2010 Target	2011	2012	2013	2014	2015
Speed of Tel Response	88%	83%	83%	83%	83%	83%	83%
Abandonment Rate	1%	5%	5%	5%	5%	5%	5%
Mystery Caller	87%	80%	80%	80%	80%	80%	80%
Callback Survey	85%	80%	80%	80%	80%	80%	80%
ESATRAT (Performance Target)	90%	85%	85%	85%	85%	85%	85%

The DSO approach is to broadly maintain performance at current target levels rather than at actual levels of performance and indicates that its plans and costs are consistent with this approach.

The DSO has indicated that customer expectations are increasing all the time and a number of initiatives are being implemented to maintain performance levels

- increased interaction with NCCC management
- support for increased staff numbers and resource management
- technology enhancements
- support for process re-engineering to improve NCCC agent call handling
- Changes to NCCC Interactive Voice Response (IVR) and customer waiting messages to request MPRN number for ESB Networks queries

We accept that performance targets are currently at a reasonable level and that the incentive scheme has been valuable in incentivising the DSO to make improvements.

We recommend that the incentive scheme be modified to incentivise the DSO to maintain existing target levels of performance as proposed by DSO throughout PR3 and that the DSO will be rewarded for over and under achievement of the ESATRAT target of 85% under existing incentive arrangement. CER should consider the benefit of applying a dead band apply between 82.5% and 87.5% to further incentivise maintaining existing levels of performance, which was 90% in 2009.

The measurement of customer satisfaction using the RED C survey has been successful in improving overall customer satisfaction levels. It is recommended that a new inventive be adopted based on the Red C performance to ensure that customer satisfaction levels are maintained.

4.3. System Losses Incentives

4.3.1. DSO Proposals for Losses Incentives

ESBN’s proposals for a losses incentive scheme can be summarised as follows:

- The incentive will be based on losses as a percentage of GWh distributed.

- The target for each year will be set by adjusting the actual 2010 losses by the expected improvement in losses from the reinforcement and 20kV conversion programmes in the PR3 determination, based on a network losses model.
- The 2010 losses is to be calculated as the average of the measured losses over the three years 2009, 2010 and 2008, after adjustments for the calculated effects of the system improvements completed in each year.
- Use of a three-year average will reduce the risk of penalties or rewards due to an error in the starting point for the PR3 target.
- The reward/penalty each year is to be based on the variance between the rolling 3 year average of the target losses and the rolling 3-year average of the measured losses. This will reduce the variability in reward/penalty due to the inherent stochastic error in any one year's reading.
- The calculations of the target level of losses and the reported losses will be based on the method of measuring distribution losses that utilises the bulk supply point metering, (not calculated transmission losses, which have proved to be inaccurate).
- The amount of revenue per GWh distributed that ESBN be allowed to retain (/forego) compared with allowed losses will be based on the current long-run cost of generation.

DSO Assumptions and Modelling

The model proposed by the DSO is based on the following assumptions.

- Adopts GWh assumed by DSO growth rate (2.3% per year)
- Losses are adjusted for change in load flows due to distributed generation added each year
- Assumes no increase in peak demand on individual substations over PR3
- Uses average network parameters such as power factor, plant load factors, loss load factors and other parameters.
- Transformer losses are adjusted for HV transformer capacity installed as per PR3 programme and average MV transformer capacity per customer connected.
- Efficiency of 38 kV and 110 kV lines and cable remain the same
- Models the increase in efficiency of MV network converted from 20 kV to 10 kV
- Assumes commercial losses remain as present percentage of LV units distributed.

4.3.2. SKM Comment on DSO Proposals for Losses Incentives

The DSO proposes to convert 15,000 km of 10 kV network to 20 kV operation, mainly due to reinforcement drivers. The saving in losses will amount to 20-25MW at the times of system peak, which will offset the expenditure over a 25 year period.

Network losses are a combination of fixed losses in transformers and heating losses which are proportional to I^2R in each element of the network. Any method based on averages is inherently susceptible to inaccuracies in these averages, either due to inherent bias in parameters selected or due to annual variations in load patterns and inaccuracies from periodic meter reading cycles.

It is not possible to determine the accuracy of the model proposed but it is likely that variances between the model and actual readings are as likely to be due to modelling and measurement inaccuracies as resulting from actions to reduce losses by the DSO.

The proposal to run the incentive scheme on a three year rolling average may eliminate some but not all inaccuracies.

Apart from the investments already built into the capital programme, the DSO has few options of reducing system losses by operational means and any reductions available will be small compared with modelling inaccuracies.

The DSO's approach to measuring the outcome of investments to reduce system losses using a network model and averaging results over a three-year period is a reasonable basis for estimating system losses. However our experience is that any theoretical model of network losses is likely to have significant inaccuracies due to the assumptions made and simplifications inherent in such models and may not be suitable for calculating incentives. Any gains or losses from the method proposed by the DSO are likely to be of a windfall nature and not due to additional initiatives taken by the DSO. It is noted that the DSO has not proposed any initiatives to reduce losses beyond the investments in the capital programme. Such initiatives generally lead to only small reductions in losses that are not measureable against background errors.

It is recommended that CER should proceed with modelling system losses as proposed by the DSO but incentives should not be paid until the model has been shown to be accurate and that any real[14] reductions in technical losses beyond that built into the capital programme can be identified as being as a direct result of actions by the DSO.

4.4. Incentive for Generation Connections

The DSO has proposed incentives for connecting generators to the network based on achievements in relation to each of three milestones - planning stage, detailed design stage and

[14] The recent losses incentive introduced in GB by Ofgem in DPCR4 resulted in windfall gains by DNO's mainly by addressing the non technical losses associated with meter reading times and did not achieve the intended result of reducing technical system losses

construction stage. The DSO proposes adjustments to target dates due to matters considered to be outside the DSO's control. We recommend an incentive linked to MW of connected generation based on overall target dates based on the project timescales agreed with CER. This approach avoids sub optimisation over the various stages and encourages catch up where there is slippage in any one stage.

5. Benchmarking DSO Costs

5.1. Introduction and Summary

This section summarises benchmarking studies we have undertaken for CER, which are set out in a report in Appendix D. ESB Networks DSO costs and TAO 110 kV costs have been benchmarked against GB DNO costs, excluding Scottish DNOs, which are not responsible for 132 kV assets.

We have also carried out bottom up benchmarking of tree cutting costs and fault costs on a per km basis and explain some of the apparent differences in performance.

Our findings are as follows:

Benchmarking of ESB Networks DSO and 110 kV TAO opex and non network capex for indicates that the DSO costs are 7.5% above the Upper Quartile of the GB DNO costs and 16 % above the efficiency frontier. This is consistent with our recommendations for allowed costs which give a reduction of 11% in controllable opex from €232m in 2009 to €207m in 2015.

Our benchmarking shows a smaller efficiency gap when benchmarking opex costs alone. However we consider that it is necessary to include all inputs and note that in the recent DPCR5 price review Ofgem benchmarked GB DNOs opex plus non network capex costs.

A model of fault costs based on our standard unit costs and the fault data for GB DNOs and the DSO indicates that DNO costs of faults per km are inherently 1.5 times that of the DSO. This is because the DNOs have a higher proportion of underground cable, and hence cable faults, which are more expensive to repair. The model corresponds with actual outturn cost data. Whilst this indicates that the DSO is as efficient as the average DNO in respect of fault costs, the DNOs carry a cost penalty in the top down benchmarking.

Tree cutting costs have been benchmarked and the DSO's costs of €107 per km are lower than the DNO costs of €251 per km. This may be partly due the relative tree cover and the temporary increase in tree cutting in GB due to new safety regulations.

We compared IT and Telecoms costs and System Control support costs and found them to be relatively high. This corresponds with the findings of one of the DSO's benchmarking studies, which indicates that some technical costs such as fault and maintenance (cost per km) are considered to be best in class or low, whereas support costs leave room for improvement. The study indicates that ESBN may have some unfavourable characteristics. Our view is that the ESB network is atypical and has characteristics which mean that costs per km may be inherently lower than companies with a more typical mix of overhead line and underground cable.

5.2. Benchmarking ESB Networks Costs against GB DNOs

5.2.1. Top Down Benchmarking

The studies include top down benchmarking using various regression analysis methods adopted by Ofgem in the price reviews of DNOs. Our studies compare operating costs plus non network capex, as these latter costs are in support of operations. Omitting these cost can lead to errors. For example DNO leased transport charges show in operating costs, whereas ESBN purchase transport at €7.5m per year and costs are reflected depreciation so are not included in benchmarking on opex alone.

ESBN networks are very different from those of GB DNOs. GB network is 64% cable and network length is 27m per customer, whereas the DSO's network is only 13% cable and has a network length of 75m per customer. Much of the ESBN MV and LV overhead networks are simple single phase networks. ESBN's unit costs (opex plus non network capex) are €96 per customer and €1274 per km, whereas the average DNO unit costs are €60 per customer and €2139 per km. Comparison on a per km basis favours companies with a higher relative network length.

For this reason top down benchmarking is carried out against a composite scale variable (CSV) which is a composite index based on, customer numbers; length of network; and unit distributed. CSVs adopted by Ofgem in the DPCR3 and DPCR4 price reviews have been used for comparison. The differences in the CSVs have a small impact on the relative positions of GB DNOs, but have a significant impact on the relative position of ESBN because it is an outlier in network characteristics.

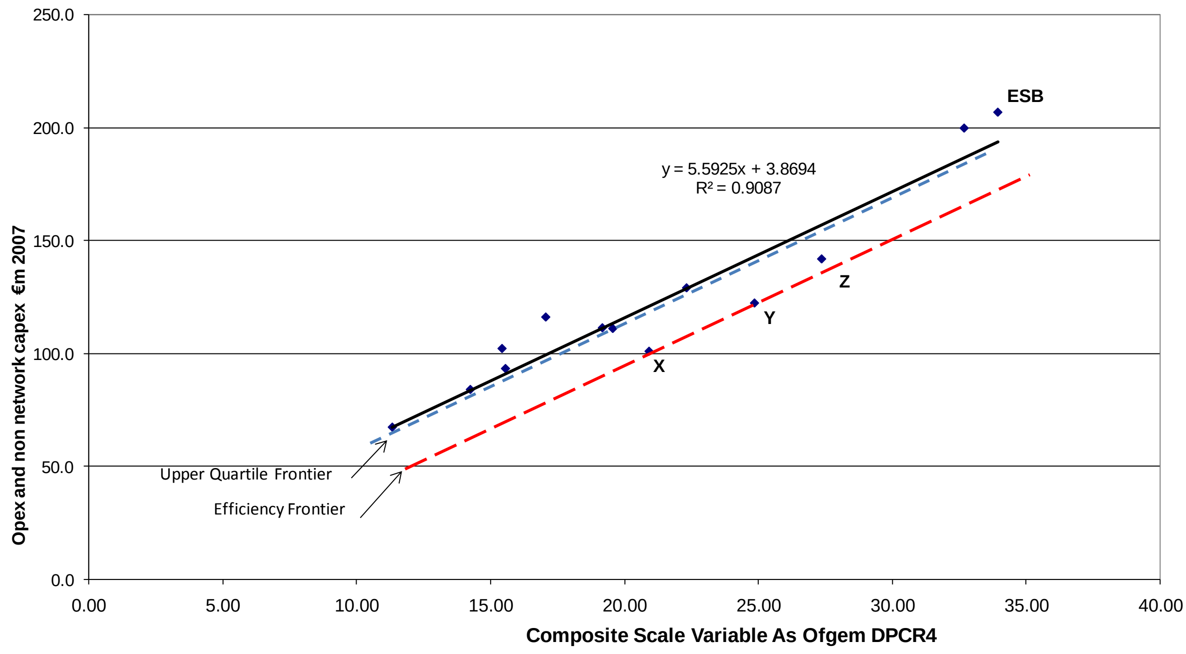
As ESBN move closer to the efficiency frontier it becomes more important to have all the information required to ensure that only comparable activities are included and that costs are correctly normalised. Ofgem has instituted a cost reporting regime for DNOs which gives considerable insight into their costs. No such equivalent information is available outside GB. GB DNOs are also considered to be efficient by worldwide standards. Despite the difference in network characteristics, GB is considered to be the only benchmark that provides reliable results, within the limits of precision now required. We consider benchmarking against other companies to be of limited value.

- **Table 43 -** Results of Benchmarking

Regression	**Costs**	**Ofgem CSV**	**€m from Efficiency Frontier**	**€m from Upper Quartile Frontier**	**Correlation R^2**
Regression 1	Opex + Non Network Capex	DPCR 3	€63m	€46m	0.83
Regression 2	Opex + Non Network Capex	DPCR 4	€33m	€15m	0.91
Regression 3	Opex	DPCR 3	€40m	€26m	0.90
Regression 4	Opex	DPCR 4	€16m	€5m	0.94

The most representative study is considered to be Regression 2 as shown in the Figure 14 below. This indicates that ESBN Distribution and 110 kV opex plus non network capex is around €33m from the efficiency frontier and €15m from the upper quartile frontier. The upper quartile is commonly used benchmark, recognising that there may be inaccuracies in the methodology that create outliers.

- **Figure 14 -** Benchmarking ESBN and GB DNO Opex plus Non Network Capex – DPCR4 CSV



In 2007 ESBN's opex, (including an allowance for 110 kV costs) and non network capex was €207m. This was €33m (16%) from the efficiency frontier and €15.5m (7.5%) from the upper quartile efficiency frontier.

The DSO's total operating costs plus non network capex, (excluding diversion and commercial cost) were €279m in 2007 and fell to €267m in 2008 and 2009, but are forecast to increase to around €284m throughout PR3, including €42m of non controllable costs in 2015.

Controllable opex and non network capex is €244m in 2015. Our recommendations on opex and capex indicate reductions in controllable opex plus non network capex to €207m in 2015. This is a reduction of €25m (11%) on the equivalent costs of €232m in 2009.

This reduction would represent a level of efficiency at around the mid-point of the upper quartile and efficiency frontier. This is considered to be achievable, as there are opportunities to reduce payroll costs in real terms in addition to other productivity and efficiency gains.

5.2.2. Bottom-Up Benchmarking

It is possible to benchmark certain costs directly, eg where costs are mainly fixed costs or where a simple driver can be identified. This section shows results of bottom -up benchmarking of certain maintenance activities, IT/ and Telecoms costs and System Control Costs.

5.2.2.1. Tree Cutting Costs

Using the same cost source used for top down benchmarking we have carried out benchmarking of tree cutting costs for 2007/08.

Tree cutting costs are a significant part of planned maintenance costs 35% in GB and 31% for the DSO.

GB tree cutting costs are €196m for 780,482 km of overhead line or €251 per km of overhead line.

DSO tree cutting costs in 2007 were €14m, but more typical costs are €17.5m per year for 163,203 km of line so tree cutting costs are €107 per km of overhead line.

Tree coverage in Ireland[15] is 669,000 hectares or 4.7 hectares per km of line. Tree coverage in the UK is 2845,000 hectares or 10 hectares per km of line. Tree cutting costs may therefore be expected to be higher in GB than in Ireland.

In addition revised UK Electricity Safety, Quality and Continuity Regulations (Regulation 4 (2)) places additional obligations on electricity companies to ensure that clearance between trees and lines is maintained to avoid contact and interruptions in supply. This is backed up by new industry standards. There is an amount of work required to achieve these safety standards in GB and this has led to an increase in tree cutting.

This demonstrates a significant limitation in benchmarking where local factors, sometimes of a temporary nature, can frustrate a like for like comparison. However, we accept that DSO's tree cutting activities appear to be efficient but are not entirely comparable with GB.

5.2.2.2. Fault Costs

From the top down benchmarking data sources, total fault costs in Ireland are €46.8m (€329 per km) and total fault costs in GB are €384m (€492 per km), a ratio of 1:1.5.

However, GB network is 64% cable and network length is 27m per customer, whereas the DSO's network is only 13% cable and has a network length of 75m per customer. Much of the MV and LV overhead networks are simple single phase networks.

Underground cable faults are more expensive to repair than overhead line faults and the mix of faults is different.

Table 44 gives the results of modelling LV and MV fault costs based on unit costs from a GB DNO source.

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[15] Provided by the World Resources Institute (http://www.wri.org)

- **Table 44 -** Model DSO and GB DNO MV and LV Underground and Overhead Fault Costs

Faults	Prime Unit Cost €m 2008	DSO Faults	DSO Fault Rate (per 100 km)	DSO Fault Cost €m	DSO Faults	DSO Fault Rate (per 100 km)	DSO Fault Cost €m
20 kV Overhead Lines	947	4238	16.38	4.0			
10 kV Overhead Lines	947	6287	11.35	6.0	1177	11	1.11
Low Voltage Overhead Lines (Ex Services)	518	19769	35.62	10.2	946	19	0.49
Overhead LV Services	224	2276	n/a	0.5	210		0.05
							0.00
20 kV Underground Cables	5460	18	5.46	0.1		5	0.00
10 kV Underground Cables	5460	446		2.4	633		3.46
Low Voltage Underground Cables (Ex Services)	1930	1650	12.52	3.2	3546	11	6.84
Underground LV Services	806	2374	n/a	1.9	6848		5.5
Total				**28.36**			**17.47**

Length of LV and MV Network km		156531		63931
Faults Cost per €/km		**181.2**		**273.34**

The results shows that cable faults dominate in GB DNOs and these are more expensive to repair than overhead line faults. GB DNO fault costs of €273/per km are 1.5 times higher than the DNO costs of €181/km. This matches the higher fault costs found in practice.

It can be concluded that GB fault costs per km are inherently higher than in Ireland and that the DSO is as efficient as the average DNO in respect of fault costs.

5.2.2.3. IT, Telecoms and System Control Costs

Other costs have characteristics that allow direct comparison for companies of the same customer base and demand. A comparison of the GB average annual IT and Telecom costs and System Control costs against DSO costs indicates that the DSO is less efficient in these areas.

	GB Average	DSO Costs
System Control*	€9m p.a.	€18.6m p.a.
IT Costs/Telecoms	€12.2m p.a.	€26.2m p.a.

* Note EirGrid is responsible for 110 kV system control, except for Dublin and small pockets outside Dublin and the EirGrid system control costs are not included.

5.3. ESBN Benchmarking

DSO has provided summary details of three benchmarking studies carried out by their consultants, which are summarised below with our comments:

5.3.1. Benchmarking of ESBN opex costs against GB DNO for 2007/08

This study is based on the Ofgem DPCR 4 methodology and gives results that are €5m more favourable than our equivalent study, showing the DSO close to the efficiency frontier

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- Adjustment for Purchasing Power Parity is not a significant factor in 2007/08. In any event it obscures the difference due to high payroll costs in Ireland and a more absolute benchmark is required.
- We consider that insufficient costs may have been included for Market Systems and the110 kV adjustments may have been insufficient.

5.3.2. Benchmarking of DSO opex costs GB DNO costs for 2005 to 2009

This study uses Ofgem DPCR 5 price review data for five years, using the Ofgem DPCR 4 benchmarking methodology.

The results show ESBN as being within 1% of the Upper Quartile Frontier.

- Our results for the study based on 2007 data show ESBN as €5m above the upper quartile and the results are very similar, within the accuracies of such studies.
- It is noted that the Scottish Companies are included and it is not known whether the costs have been adjusted for 132 kV. Our studies exclude Scottish Companies.
- 110kV adjustments may have been insufficient.
- Benchmarking over 5 years and adjusting for Purchasing Power Parity in a climate of fluctuating exchange rates and deflation is questionable but does not appear to have produced significantly different results.

5.3.2.1. Benchmarking of DSO opex costs with 17 European regional and national DSOs based on 2008 data

The participants were not selected on the basis of comparability or efficiency and small urban companies were excluded from some of the comparisons with the DSO.

- Adjustments for activities and costs appears to have been restricted due, as the study was based on limited data and limited interaction with the companies.

The consultant reports with our observations are set out below:

The data suggest that ESBN has best-in- class performance with regard to technical activities costs in its regional/nationwide peer group. ESBN`s fault & maintenance costs amount to €340/km compared to the average fault & maintenance costs in the regional/nationwide peer group of €1,649/km.

- We have commented above that the cost of ESBN’s network may be low due to inherent difference in proportion of overhead line and the relatively simple nature of much of the MV and LV single phase networks.

ESBN customer activities and operational metering costs are at a low level, though a more detailed examination of the scope of activities compared to other participants in both of these areas would be required to support these findings.

Support activities costs and the percentage of grid losses show potential room for improvement based on the survey data. ESBN also displays an average continuity of supply value in the regional/nationwide peer group. ESBN's support activities costs of €4.4/MWh are somewhat greater than the average support activities costs of €3.8/MWh.

- This is an area where we have also noted that ESB Networks is high costs and where costs are not falling. This may be due to the lack of direct control of services provided from other parts of ESB Group.

6. Conclusions

6.1. PR2 Operating Costs

The DSO's PR2 operating costs of €1272m are €12m[16] higher than the allowed costs of €1260m, excluding commercial costs and exceptional costs, indicating that the DSO has met the targets set by CER. It is important to note that the DUoS tariffs over the period are based only on the allowed expenditures.

The DSO met all of the incentivised performance targets for network performance and customer service set out in Sections 4.1.2 and 4.2.1, including a reduction in average minutes lost per customer of 43 % and in customer interruptions of 34%. The DSO has also exceeded the overall customer satisfaction target (ESATRAT) of 85% (actual performance of 90% in 2009).

The under spend on System Control costs of €5.4m is mainly due to reorganisation of the Areas and centralisation of MV network control from 34 Areas to two control centres at Cork and Dublin. The development of the Control Centre IT systems (OMS), and SCADA for the remote control of the network, has also reduced costs**.**

Planned maintenance costs of €228.5m are €16.1m higher than the allowed costs of €212.3m. Table 4 shows that there has been an overspend of €37.7m on overhead line maintenance and an under spend of €21.4m on maintenance of substations and cables.

Benchmarking indicates that tree cutting costs are lower per km than in Great Britain, (see Section 5.2.2.1 and we consider that the expenditure on tree cutting, although overspent by around €30m, has been efficiently incurred.

It is recommended that the under spend of €18m and the non completion of the HV substation maintenance programme is taken into account in the review of planned maintenance costs for PR3. The PR3 forecast includes provision for reducing backlog and customers should not be expected to pay for planned maintenance twice.

Fault maintenance costs of €197.6m were €28.6m higher than the CER allowed costs of €169m. The overspend arose partly because fault numbers did not reduce as much as was anticipated, due to a delay in the low voltage network refurbishment programme. There were 400 more MV faults on the uprated 20 kV network than anticipated.

The DSO received incentive payments of €55m for improvements in system performance and some of the overspend may be attributed to changes in working practice to meet performance targets. Consideration has been given to deducting part of the overspend from allowed revenue. However, the

[16] In 2006 the CER decided (CER/06/207) to allow the ESB to recover, over five years, a portion of its pension deficit. This has not been taken into account in this report which considers normal operating costs. Pension deficit is still under separate consideration. The impact of this adjustment would result in an under spend.

DSO has met overall performance targets at close to its forecast costs.. The price control is an overall settlement and it is not appropriate to deduct revenue for this individual line item. However the DSO will forfeit any overspend if the outturn costs are greater than allowed costs at the end of 2010.

Metering costs of €100m are under spent by €2.5m. However meter reading costs have increased from €10.5m per year to a forecast €13.6m in 2010, since it has proved expensive to meet the meter reading performance targets, in particular the requirement for 97 per cent of accounts with four scheduled visits per year. (Performance has improved from 84% in 2005 to 92% in 2009).

Customer service expenditure of €98m is under spent by €12m (11%) compared with the CER allowance of €110m, mainly due to an under spend on Area Operations of €16m due to rationalisation. Hand held terminals and a mobile data messaging system has been introduced which has improved the efficiency of customer driven work. Outage planning and live line work and system automation has improved productivity and reduced the need for switching.

Call Centre costs have increased from €6.1m per year to €7.9m per year during PR2 but are under spent overall in PR2 by €1.4m. It was found that the initial staffing levels gave unacceptable customer service, which has now improved following a customer service improvement programme.

Market System costs are associated with the operation and development of a customer information system for operating the electricity market and data exchange with Suppliers. Activity has been monitored by CER throughout PR2 and allowed costs have been reduced by CER during PR2 from €112m to €71m to take account of activity levels.

Corporate charges are €13m lower than those allowed by CER mainly due to the transfer of training and legal service costs from the Corporate Centre to the DSO, and these are now absorbed under other headings.

6.2. PR3 Assumptions

We agree with the DSO’s assumptions of a 1.35% per annum growth in connections during PR3. The DSO’s assumption of an increase in units of 2.85% is considered to be high in view of the economic circumstances. However, operating costs and capital expenditure are more related to peak demand than unit growth and we agree with the DSO that there is likely to be no increase in peak demand throughout PR3**.**

The DSO has assumed a productivity increase of 1% per annum over PR3. The ESRI Medium Term Review 2008[17] forecasts that the average productivity of the Irish economy to be 2.5% per annum over the period 2011 to 2015. The DSO’s activities are highly mechanised and are supported by a significant level of IT investment. There has also been significant reorganisation and staff reduction in PR2 and potential for more in PR3. Much of these developments have occurred in the latter part of PR2 and the full effect is not reflected in costs. We would therefore expect the DSO to achieve at least 2.5% productivity improvement over PR3**.**

[17] Economic and Social Research Institute Medium Term Review 2008 – May 2008

The DSO's assumption that internal labour costs will be maintained at CPI is considered to be too conservative in the present economic climate and when compared with pay reductions elsewhere in the Irish economy. Our recommendations are based on a reduction in DSO and ESB Group payroll costs of 5% in 2011, which is approximately a 2.5% reduction in controllable costs in 2011.

In making recommendations for allowed costs we have taken excess margin and payroll costs into account when assessing costs which have a component of those costs from other parts of ESB Group.

Our recommendations indicate ongoing reduction in operating costs of 2% – 3% per annum over PR3 from a derived base Po costs in 2011. Taking into account that some costs are not controllable the overall reduction in costs from base level is around 2% per annum. This includes an allowance for growth in drivers such as customers, where appropriate.

Our recommendation for allowed costs is an overall settlement tied to the delivery of outputs under incentives considered in Section 4. It is not dependent on individual line items and the recommendation is based on what is considered to be efficient overall.

Benchmarking of ESB Networks DSO and 110 kV TAO opex and non network capex for indicates that the DSO costs are 7.5% above the Upper Quartile of the GB DNO costs and 16 % above the efficiency frontier. This is consistent with our recommendations for allowed costs which give a reduction of 11% in controllable opex from €232m in 2009 to €207m in 2015.

There is no doubt that the DSO appears to be closing the efficiency gap with the GB DNOs and has implemented a number of measures adopted by the GB DNOs in the last 15 years. However, there is insufficient evidence to conclude that the DSO is at the efficiency frontier and much evidence to indicate that significant further efficiency improvements are available.

It is evident that benchmarking becomes more difficult as the DSO approaches GB efficiency levels. Whereas it was easy to identify a large efficiency gap in PR1 and PR2 by benchmarking, this is now more difficult as the gap narrows.

6.3. PR3 Operating Costs

The DSO's forecast of operating expenditure in the PR3 period (2010 to 2015) is €1233.3m, which is €76.2m greater than the equivalent PR2 outturn of €1157.1m. This comparison excludes commercial costs and the cost of diversions, which it is proposed will be capitalised in PR3.

The additional costs of €76m include €31m for research and development and sustainability costs associated with future networks that will support wind generation and electric vehicles, using smart metering.

Our recommendation is for allowed PR3 operating costs of €1086.9m, which is €146.3m lower than the DSO's PR3 forecast and €80.2m less than the equivalent PR2 outturn.

During PR2 the DSO completed the implementation of the Outage Management IT System (OMS) and a programme of SCADA installations for those substations suitable for SCADA. The DSO is also in the process of transferring MV network control from 34 Areas to 2 centres in Dublin and Cork.

These developments have led to the reduction in System Control costs from €18.5m in 2006 to €16.4m in 2009 and reductions in Area Operations Costs. There are further opportunities for cost reduction in PR3**.**

As indicated in section 3.2.2 the DSO has under spent HV substation maintenance costs by €18m in PR2 and the forecasts for PR3 make provision for removing the backlog. This element of cost is removed from allowed costs as the DSO has already been paid for this work. Other savings are also available from the review of maintenance practices and payroll and other efficiency savings.

The DSO has spent significantly on replacement of MV oil switchgear and on minipillar refurbishment and it is expected that these costs will fall over PR3.

We have accepted that the MV tree cutting programme should be organised on a three year cycle. However, we consider that efficiencies will be available in actively managing the programme to reflect need and risk. There will be some inevitable slippage in the programme due to site conditions and outage requirements. We have therefore applied 5% abatement. In addition we would expect a reasonable efficiency factor as the programme advances and less work is required on the next cut.

During PR2 fault costs rose significantly with an overspend of €29m, which has not wholly been accounted for, but which may be partly due to additional costs of achieving system performance and incentive payments. It is recommended that the additional annual costs incurred in PR2 and reflected in PR3 forecasts are accepted in part as a price worth paying for improvements in system performance.

Asset Management costs have risen during PR2 mainly due to the increase in payments to landowners for rights to place equipment on land and for forestry sterilisation costs. These costs have risen from €3.1m in 2006 to €4.9m in 2009. We recommend allowed costs remaining at 2009 levels. The DSO has proposed that these costs be treated as pass through costs but we disagree as they are to some extent negotiable and controllable.

Meter reading costs are forecast by the DSO to increase from €12.8m per year in 2009 to €14.6m. We understand that this is mainly associated with the cost of achieving meter reading performance targets particularly that which requires a 97% success rate for making 4 actual visits to each premise in each year, 92% being achieved at December 2009. There are no specialist skills for these activities and it should be possible to exert downward pressure on these costs during PR3.

Our view is that further efficiencies are possible in Call Centre operations to reflect the level of investment in systems and future potential for exploitation of technology, and in the alignment of labour costs with the Irish economy as a whole. There is also potential for the DSO to take a greater control of the Call Centre service provided by supply via the service agreements or by seeking direct control.

At the same time DSO has to maintain levels of service in order to drive down the number of calls and achieve success in dealing with calls on the first contact. The proposed allowed costs provide additional stretch and are considered to be achievable.

Savings of €16m were made in PR2 due to the impact of the network renewal programme, reducing the need for reactive work such as voltage complaints; better organisation of outages; work from OMS and mobile messaging systems; and less switching due to live working and remote control. Restructuring has also had an impact. In our view the savings arising in PR2 are likely to continue, as the IT systems are fully exploited and the mobile data system is extended to cover more activities. There is also the potential for further rationalising of the Area structure by centralising certain activities and reducing the number of depots.

We have accepted the reduction in customer relations costs proposed by DSO and applied an efficiency factor over PR3.

The DSO has included additional costs in the area of MRSO due to the level of churn and modifications associated with Free Electricity Allowances and global aggregation which require additional staff.

Corporate costs reduced during PR2 from €15.2m in 2006 to €14.7m in 2010. However it is considered that these costs should have reduced by more than this due to transfer to DSO of legal services (€2.2m per year) and training centres (€2.8m per year). No explanation has been provided for the forecast increase in corporate costs of €1m from 2009 to 2010 and this increase has been rejected and efficiency savings applied.

The sustainability expenditure makes provision for €14.2m of identified expenditure of which €8.2m involves subsidy for microgeneration, ie €6m of R & D projects, and a further unspecified €17m of R & D projects.

R & D can produce success and failure and we have reservations that participation in collaborative research of this type will identify the viability of this project or provide solutions so we recommend sustainability and research and development expenditure of €18.2m.

We recommend that tariff support for microgeneration should be provided outside of DUoS, possibly using a PSO mechanism.

6.4. DSO Performance and Incentives

We have examined the DSO’s benchmarking of quality of supply performance against GB DNOs and have concluded that it is not intended to be an exhaustive model but it is illustrative of the sensitivity of system performance to network topography, customer dispersion, fault rates and the level of system automation.

The rate of improvement of DSO network performance demonstrates the effectiveness of incentives but also indicates that there is some way to go for DSO to achieve optimum network performance.

The DSO has based the forecast on the 2010 forecast which is based on a trend that excludes the 2009 figures that the DSO considers to be abnormally low due to a benign spring. Basing the target on a simple regression including 2009 gives a starting point for 2010 of 101 CIs and 64 CMLs. These are not considered to be credible starting points and it is proposed to adopt the average of 2008 and 2009 as the starting point for CIs (119 compared with the DSOs figure of 122) and for CMLs (87 compared with 88).

The DSO has established models for deriving targets for unplanned outages and has forecast further improvements in CIs of 10% and CMLs of 20% during PR3. We have examined the models and have modified the target to 11% for CIs and 22% for CMLs. These targets are considered to be stretching and yet provide sufficient opportunity for the DSO to achieve incentive payments, which we recommend continue at the existing levels. We also agree that the targets should be based on interruptions of three minutes or more, which is a technical change from the one-minute threshold adopted up to 2010.

The DSO has proposed that targets for planned interruptions are set annually based on the workload in any one year, which will avoid windfall gains from uncompleted work programmes. We agree with this approach and have examined the models which appear to have a sound theoretical basis and include a proportion of live work. However performance should be monitored and the incentive rate adjusted if the gains appear to be out of line with customer benefits.

The DSO has proposed a fund of €10m over PR3 for worst served customers and we recommend that this approach is explored further and that thresholds are set to fairly identify beneficiaries. The scale of the fund should be set at £10m for the whole of PR3, with particular targets in mind, based on network performance data.

We recommend that the incentive scheme be modified to incentivise the DSO to maintain existing target levels of performance as proposed by DSO throughout PR3 and that the DSO will be rewarded for over and under achievement of the ESATRAT target of 85% under the existing incentive arrangement. CER should consider the benefit of applying a dead band apply between 82.5% and 87.5% to further incentivise maintaining existing levels of performance, which was 90% in 2009..

The measurement of customer satisfaction using the RED C survey has been successful in improving overall customer satisfaction levels. It is recommended that a new inventive be adopted based on the Red C performance to ensure that customer satisfaction levels are maintained.

6.5. Benchmarking

Benchmarking of ESB Networks DSO and 110 kV TAO opex and non network capex for indicates that the DSO costs are 7.5% above the Upper Quartile of the GB DNO costs and 16 % above the efficiency frontier. This is consistent with our recommendations for allowed costs which give a reduction of 11% in controllable opex from €232m in 2009 to €207m in 2015.

Our benchmarking shows a smaller efficiency gap when benchmarking opex costs alone, and are similar to the results of the ESBN studies. However we consider that it is necessary to include all inputs and note that in the recent DPCR5 price review Ofgem benchmarked GB DNOs opex plus non network capex costs.

A model of fault costs based on our standard unit costs and the fault data for GB DNOs and the DSO indicates that DNO costs of faults per km are inherently 1.5 times that of the DSO. This is because the DNOs have a higher proportion of underground cable, and hence cable faults, which are more expensive to repair. The model corresponds with actual outturn cost data. Whilst this indicates that the DSO is as efficient as the average DNO in respect of fault costs, the DNOs carry a cost penalty in the top down benchmarking.

Tree cutting costs have been benchmarked and the DSO's costs of €107 per km are lower than the DNO costs of €251 per km. This may be partly due the relative tree cover and the temporary increase in tree cutting in GB due to new safety regulations.

We compared IT and Telecoms costs and System Control support costs and found them to be relatively high. This corresponds with the findings of one of the DSO's benchmarking studies, which indicates that some technical costs such as fault and maintenance (cost per km) are considered to be best in class or low, whereas support costs leave room for improvement. The study indicates that ESBN may have some unfavourable characteristics. Our view is that the ESBN network is atypical and has characteristics which mean that costs per km may be inherently lower than companies with a more typical mix of overhead line and underground cable.

6.6. Losses

The DSO proposes to convert 15,000 km of 10 kV network to 20 kV operation during PR3, mainly due to reinforcement drivers. The saving in losses will amount to 20-25MW at the times of system peak, which will offset the expenditure over a 25 year period.

The DSO's approach to measuring the outcome of investments to reduce system losses using a network model and averaging results over a three-year period is a reasonable basis for estimating system losses. However our experience is that any theoretical model of network losses is likely to have significant inaccuracies due to the assumptions made and simplifications inherent in such models and may not be suitable for calculating incentives. Any gains or losses from the method proposed by the DSO are likely to be of a windfall nature and not due to additional initiatives taken by the DSO. It is noted that the DSO has not proposed any initiatives to reduce losses beyond the investments in the capital programme. Such initiatives generally lead to only small reductions in losses that are not measureable against background errors.

It is recommended that CER should proceed with modelling system losses as proposed by the DSO but incentives should not be paid until the model has been shown to be accurate and that any reductions in losses beyond that built into the capital programme can be identified as being as a direct result of actions by the DSO.

6.7. Generation Connection Incentive

The DSO has proposed incentives for connecting generators to the network based on achievements in relation to each of three milestones - planning stage, detailed design stage and construction stage. The DSO proposes adjustments to target dates due to matters considered to be outside the DSO's control. We recommend an incentive linked to MW of connected generation based on overall target dates based on the project timescales agreed with CER. This approach avoids sub optimisation over the various stages and encourages catch up where there is slippage in any one stage.

Appendix A Efficiency and Service Initiatives PR2

ESB Networks has undertaken a number of initiatives to improve efficiency and performance during PR2 which can be expected to decrease costs during the remainder of PR2 and in PR3.

- Implementation of significant re-organisation 9 – 7 directors and 7 – 5 divisions and Depot Rationalisation – 81 to 60 depots
- Implementation of a significant voluntary severance (VS) programme, costs of which are not funded through regulatory allowances. Loss of 287 staff in networks; target for network technicians of 1700 to 1800 from 2250.
- Flexible resource model and use of contractors; single portfolio for networks overheads, performance pay, pressure on expenses.
- Implementation of Performance Improvement Programmes for Overtime etc.
- Focus on cost efficiencies through technical innovations and effective KPI reporting
- Leveraging maximum efficiencies from IT systems
    - Asset Register and Maintenance Management (ARM)
    - Work Management System
    - Operation Management System – to promote centralisation of System Control
    - Mobile data Management (MDMS) – for metering
- Reduce inter business unit charges since 2006. Market Pricing Board to market test all IT services and brings charges in line with delivery of comparable services to the Irish market.
- Manage and control directly, Legal Services and Training by integrating both functions into the ESB Networks Organisation, services that were previously bought in.
- Strategic procurement
- DSO achieved PAS 55 accreditation for its asset management practices in 2009
- Customer service improvement plan to ensure virtually all targets will be achieved in PR2.

Appendix B Distribution Cost Pressures PR2

- Historically significant economic growth up to 2008 and its impact on activity levels and ESB Networks' cost base.
- Costs of land access/wayleaving, outage planning in particular in cities (weekday restrictions) and stringent environmental legislation.
- Significant creep in 3rd Party fees and charges (eg local authority development fees, path opening fees and water charges etc.)
- Access problems and work practice requirements around environmentally sensitive areas (Protected woodlands, bogs, marshes and waterways)
- Substantial increases in worldwide commodity prices for key materials until the current year.
- Acceleration in wind generation connections and enhanced service to generators called for by regulatory decisions.
- Landowner insistence on Tree surgeon as opposed to timber contractor in some circumstances.
- Road safety requirements.
- Local authority and Garda compliance in road closure planning, Signage plan and equipment needed to deploy road works + associated fees. Increased spend in disposable equipment / losses in equipment associated with road works.
- Full lane reinstatement (Can be very expensive in Fault clearance/repair circumstances)
- Charge culture - DSO now have to pay or compensate 3rd parties where previously some services/help was given free.
- Customers more demanding and aware of their rights, can result in refusal of access been 1st position rather than acceptance, causes significant delays and downtime.
- On-going and emerging Health, Safety and Environmental Regulations.

Appendix C DSO Operating Costs PR2 and PR3

	CER PR2 Allowed	Var PR2 Outturn Vs CER Allowed	DSO PR2 Projected Outturn	DSO PR3 Forecast	Var PR3 Forecast Vs PR2 Outturn	PR3 Recommended	Var Recommend Vs DSO Forecast
Diversions (Capex in PR3)	**111.84**	**2.73**	**114.58**		**-114.58**		
Operations and Maintenance	**474.90**	**39.39**	**514.28**	**507.81**	**-6.47**	**445.63**	**-62.18**
System Control	93.60	-5.39	88.21	75.95	-12.26	70.08	-5.86
Planned Maintenance	212.33	16.12	228.45	247.17	18.72	198.02	-49.15
Fault Maintenance	168.96	28.66	197.62	184.69	-12.93	177.53	-7.17
Asset Management	**58.19**	**1.41**	**59.60**	**65.80**	**6.19**	**60.15**	**-5.64**
Metering	**102.63**	**-2.53**	**100.10**	**124.13**	**24.03**	**100.54**	**-23.59**
Meter reading	54.97	3.59	58.55	71.87	13.31	60.74	-11.12
NQH Data	8.74	-1.95	6.80	9.73	2.94	7.44	-2.30
Customer meter operation	25.01	-13.40	11.61	14.00	2.39	11.22	-2.78
Data Aggregation	13.91	9.23	23.14	28.53	5.39	21.14	-7.39
Customer Service	**110.43**	**-12.15**	**98.28**	**92.16**	**-6.12**	**82.28**	**-9.88**
Call Centre Charges	34.83	1.42	36.25	35.04	-1.21	32.83	-2.21
Area Operations	68.90	-16.07	52.83	52.85	0.02	45.45	-7.40
Customer Relations	6.69	2.50	9.19	4.27	-4.92	4.01	-0.26
Provision of Data	**82.84**	**-7.97**	**74.88**	**87.14**	**12.27**	**71.90**	**-15.24**
DUOS	3.64	0.36	4.00	3.81	-0.19	3.34	-0.47
MRSO	7.93	-1.74	6.19	10.06	3.87	9.43	-0.64
Market Systems	71.27	-6.58	64.68	73.27	8.59	59.14	-14.14
Other	**144.54**	**-8.63**	**135.91**	**166.29**	**30.38**	**136.47**	**-29.81**
Corporate Charges	86.00	-13.14	72.86	73.85	0.98	64.33	-9.52
Safety	13.05	2.26	15.31	16.33	1.02	13.75	-2.58
Environmental	3.19	-0.06	3.13	7.42	4.29	5.50	-1.92
Other Legal Revenue Misc	18.03	-5.61	12.42	15.07	2.65	14.33	-0.74
Insurance	15.07	0.00	15.07	14.37	-0.69	12.50	-1.87
Pension	9.19	0.00	9.19	8.48	-0.71	7.87	-0.62
R & D	0.00	0.00	0.00	5.00	5.00	3.40	-1.60
Sustainability	0.00	7.92	7.92	25.77	17.84	14.80	-10.97
Controllable Costs Excl Diversions	**973.53**	**9.52**	**983.05**	**1043.32**	**60.27**	**896.97**	**-146.35**
ESI Levy	9.78	0.00	9.78	9.50	-0.28	9.50	0.00
Rates	164.31	0.00	164.31	180.46	16.16	180.46	0.00
Non Controllable Costs	**174.08**	**0.00**	**174.08**	**189.96**	**15.88**	**189.96**	**0.00**
Operating Costs Excluding Diversions and Commercial Costs	**1147.61**	**9.52**	**1157.13**	**1233.29**	**76.15**	**1086.94**	**-146.35**
Commercial	**95.62**	**72.70**	**168.32**	**204.62**	**36.30**	**177.51**	**-27.11**
Operating Costs Incl Commercial Excluding Diversions	**1243.23**	**82.23**	**1325.45**	**1437.90**	**112.45**	**1264.45**	**-173.45**

Non Controllable Costs include Rates and CER Levy, shown as pass through

Appendix D Benchmarking

Benchmarking ESB Networks Costs against GB Distribution Network Operators.

D.1 Introduction

This report sets out the methodology and results of benchmarking ESBN distribution and 110 kV transmission costs with the costs of Distribution Network Operators (DNO) of Great Britain. The study is based on the linear regression methodology adopted by Ofgem in the GB DPRC3 and DPCR4 price reviews.

Adjustments are required in respect of the DSO's 110 kV operations and GB DNO's 132 kV operations. GB DNOs have full responsibility for 132 kV activities, except Scottish companies, which have been excluded from the studies.

Following the DPCR 4 review Ofgem adopted a regulatory cost reporting regime to provide better data for benchmarking DNOs. A brief description of Ofgem cost reporting and the benchmarking adopted in DPCR3 and DPCR4 is provided in Annex 1.

The methodology compares costs against a composite scale variable CSV, which is a weighted index based on, customers numbers; units distributed; and network length. A CSV approach is required because comparison of costs on a "cost per customer" or "cost per km" basis gives contradictory results. For example the ESBN's unit costs (opex plus non network capex) are €96 per customer and €1274 per km, whereas the average DNO unit costs are €60 per customer and €2139 per km. Comparison on a per km basis favours companies with a higher relative network length. The GB DNOs have an average of 26 m network per customer, whereas the DSO has 75 m per customer, three times more network relative to its customer base.

Ofgem used a more sophisticated model in DPCR5 and it has not been possible to replicate this model. (We are informed that the DSO's consultants also found they had insufficient information to replicate the Ofgem DPCR5 model). The Ofgem DPCR5 approach benchmarked costs over a 5 year time frame and compared opex plus non network capex together, although only opex was compared in DPCR 3 and DPCR4. We have included opex and non network capex in our benchmarking.

It is reasonable to include non network capex, since these costs are business support costs, most of which are which are depreciated over short timeframes. Omitting them can distort comparisons. For example some companies lease transport in operating costs and others purchase transport, so that financing costs do not appear in opex but in depreciation. IT capex also contributes to improvements in efficiency and it is right to benchmark all inputs.

ESB Networks spent €35m per year on non network capex in 2007, of which €7.5m was for transport. DNOs spent €7m on non network capex in 2007 on average.

Use of non network capex is sometimes questioned because it can fluctuate from year to year. The DSO's non network capex ranges between €32m and €40m from 2006 to 2015. The €35m non network capex in 2007 is a typical and ongoing cost. The DNOs' non network capex of €7m is an average of 12 companies, which takes out volatility.

Our benchmarking studies are based on the two different CSVs used by Ofgem in DPCR3 and DPCR4, with and without non network capex, for the single year 2007. We have not attempted to benchmark costs over a longer time frame as any distortions in the GB DNOs costs are averaged out and ESBN's costs are reasonably constant. Exchange rates, inflation and Purchasing Power Parity indices fluctuated considerably in the period from 2008 to 2010, so a benchmark in 2007 is considered to be more reliable. ESBN's costs have not changed significantly since 2007.

D.2 Normalisation of ESB Networks and GB DNO Costs for Benchmarking

GB DNO and ESBN's costs need to be normalised to ensure that only comparable activities and costs are benchmarked and to take account of differences in capitalisation policies.

GB DNOs costs for 2007/08 are shown in Annex 2. DNOs report activity costs as direct costs only and these costs have been adjusted to include appropriate indirect costs based on information from Ofgem's rules for cost reporting.

GB DNOs capitalise more costs than ESBN, particularly fault costs and a proportion of support activities. ESBN has retained a more traditional capitalisation policy and we have confirmed these practices through a questionnaire.

ESB Networks report operating costs on an activity basis, and these costs include indirect costs fully absorbed into the main activity headings. ESBN distribution and transmission costs for are shown as Annex 3.

GB DNO's costs are normalised to the DSO's costs taking account of the following.

- DNO capitalise 23.5% of operating costs but these normally capitalised costs are retained in operating costs in this analysis as these costs are not capitalised by ESBN.
- DNOs would capitalise part of System Control costs and Health and safety costs and these are all included in operating costs, since such costs do not appear to be capitalised by ESBN.
- ESBN costs exclude line diversions as these are capitalised in GB.
- All ESBN and DNO metering costs are excluded from the benchmarking. ESBN has full meter operator obligations, whereas the DNO remaining meter operations are separately regulated.
- DNO call centres take mainly no supply calls whereas ESBN call centres handle meter reading calls and no supply calls. Customer Call Centre costs are therefore excluded from benchmarking. Other ESBN and DNO customer service costs are included.
- ESBN and DNOs both have responsibility for DUoS billing and meter point registration so DUoS and MRSO costs are included.
- ESBN market systems IT costs are included at 25% of total costs, which is an estimate of those IT costs supporting the MRSO meter registration activity, which is the proportion adopted by DSO in its benchmarking.
- Corporate costs, Safety, Environment, Insurance costs and Pension administration costs are included.
- ESI/licence fees, network rates and commercial excluded services costs are excluded from benchmarking.

- ESBN 110 kV costs (transmission and distribution) are equivalent to DNO 132 kV costs. TAO 110 kV fault and planned maintenance costs are included. Other transmission operating costs relate to 400 kV 220 kV and 110 kV costs and are included in proportion to the 110 kV maintenance costs. Equivalent TAO 110 kV costs of €6.6m are therefore included for 2007.
- EirGrid also has responsibility for some 110 kV activities carried out by GB DNOs, including network planning and system operation and control. These activities are integrated into 220 kV, 400 kV and generation planning and control activities. The 110 kV component of these costs is significant and includes, operating costs of SCADA equipment in substations and associated telecommunications. The total internal operating costs of TSO were €38m in 2007 and it would be reasonable to assume that an equivalent GB DNOs would carry additional €3m corresponding to the TSO's 110 kV activities. The GB DNOs' cost base has been reduced by €3m pro- rata to the number of customers.

D.3 Benchmarking ESBN Distribution + 110 KV against Equivalent GB DNO Costs

D.3.1 Benchmarking Data

Annex 4 shows comparable costs for ESBN and GB DNOs considered in the benchmarking for 2007/08 (DNOs) and 2007 (ESBN), using the normalisation principles above. Currency conversion has been carried out with 75% of GB DNO 2007/08 costs being converted to euro using the 2007 average £/€ exchange rate of 1.46, and 25% of GB DNO 2007/08 costs have converted to euro using the 2008 average £/€ exchange rate of 1.25.

Annex 4 also shows the derivation of the composite scale variables for the two methods of benchmarking adopted by Ofgem in DPCR3 and DPCR4

Regression Analysis

The linear regression analysis based on the Ofgem DPCR3 and DPCR4 CSVs, with and without non network capex is shown in Charts 1 to 4. The results are summarised Table 1

Table 1: Results of Regression Analysis

Regression	Costs	Ofgem CSV	€m from Efficiency Frontier	€m from Upper Quartile Frontier	Correlation R^2
Chart 1	Opex + NN Capex	DPCR 3	€63m	€46m	0.83
Chart 2	Opex + NN Capex	DPCR 4	€33m	€15m	0.91
Chart 3	Opex	DPCR 3	€40m	€26m	0.90
Chart 4	Opex	DPCR 4	€16m	€5m	0.94

NN Capex is Non Network Capital Expenditure

The R^2 correlation factor shows reasonable correlation for all studies. However, the two CSV factors give very different results, which indicate the difficulty designing suitable studies.

Ofgem was of the opinion that the DPCR3 methodology may have disadvantaged DNOs with long networks. The use of DPCR3 or DPCR4 methodology has a marginal impact on GB DNOs. As can be seen the relative positions of the three most efficient companies are similar for all studies. However the efficiency gap for ESBN varies from €63m to €5m.

The most representative study is considered to be shown as Chart 2, which indicates that ESBN Distribution and 110 kV opex plus non network capex is around €33m from the efficiency frontier and €15m from the upper quartile frontier. The upper quartile is commonly used recognising that there may be inaccuracies in the methodology that create outliers.

A €207m sample of the ESBN's opex and non network capex is therefore €33m (16%) from the efficiency frontier and €15.5m (7.5%) from the upper quartile efficiency frontier.

The DSO's total operating costs plus non network capex, (excluding capital driven costs) were €279 in 2007 and fell to 267 in 2008 and 2009, but are forecast to increase to around €284m throughout PR3, including €42m of non controllable costs in 2015.

Controllable opex and non network capex is therefore around €244m in 2015. Our reports on opex and capex indicate reductions in controllable opex plus non network to €207m in 2015. This is a reduction of €25m (11%) on the equivalent costs of €232m in 2009, which points to a level of efficiency at around the mid-point of the upper quartile and efficiency frontier. This is considered to be achievable as there are opportunities to reduce payroll costs in real terms, in addition to other productivity and efficiency gains.

D.3.2 Consideration of Benchmarking Results

The analysis is dependent on the assumptions and data used and the following observations are relevant:

ESBN is an outlier in terms of "cost per customer" and "cost per km" and it is not certain which of the Ofgem methodologies are appropriate. The range of results places ESBN's costs between €63m to €5m above the efficiency frontier. By comparison the three most efficient DNOs are placed close to the efficiency frontier for all studies.

Errors can arise due to choice of comparable costs and normalisation for capitalisation policy. CSVs are dependent on the accuracy of, numbers of customers; units distributed; and length of network.

Benchmarking has been carried out for 2007, which is considered to be more stable than later in PR2. Ireland had negative inflation of -4.6% in 2009. The £/€ exchange rate has fallen reflecting the relative weakness of the pound against the whole of Europe.

Benchmarking results have not been adjusted for PPP, as this was not a significant factor in 2007. In any event benchmarking is seeking difference in absolute terms, since much of the cost base is subject to common international prices.

ESBN 110 kV transmission costs are included in the comparison with GB DNOs and in making adjustments we have endeavoured to take account of the inefficiencies inherent in the industry structure.

Chart 1 GB DNOs and ESBN Opex and Non Network Capes - DPCR3 Methodology

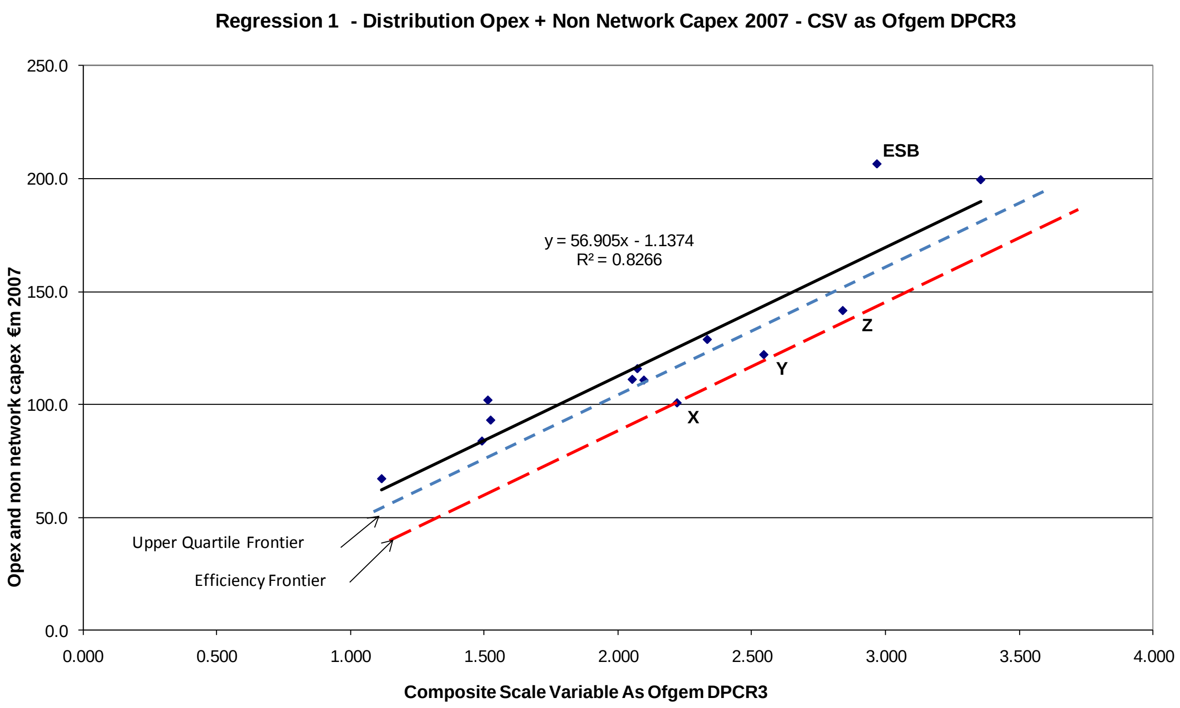


Chart 2 GB DNOs and ESBN Opex and Non Network Capex - DPCR4 Methodology

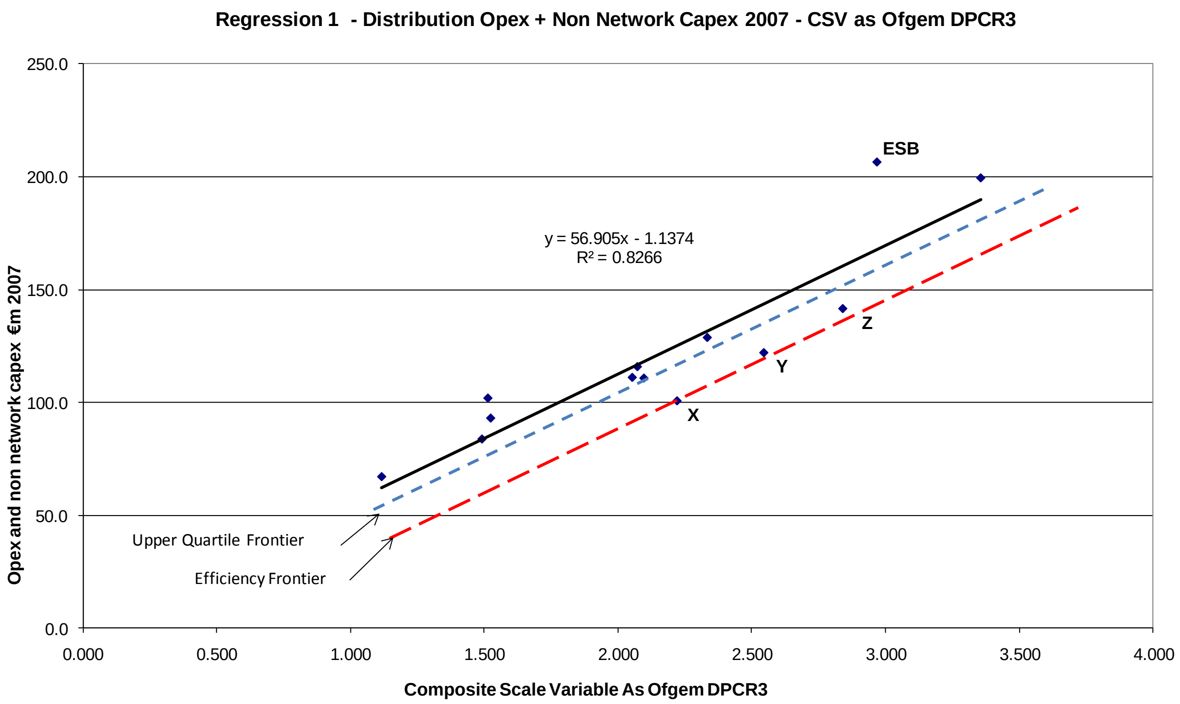


Chart 3 Regression of GB DNOs and ESBN Opex - DPCR3 Methodology

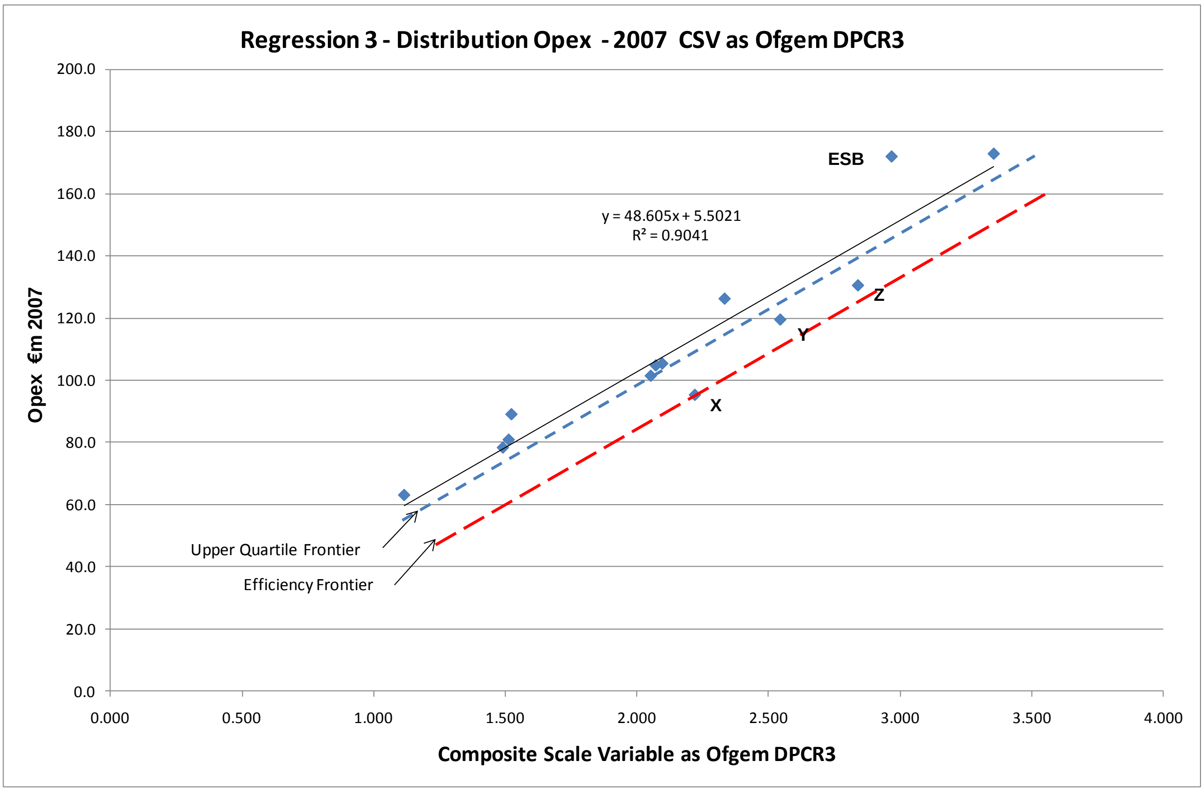
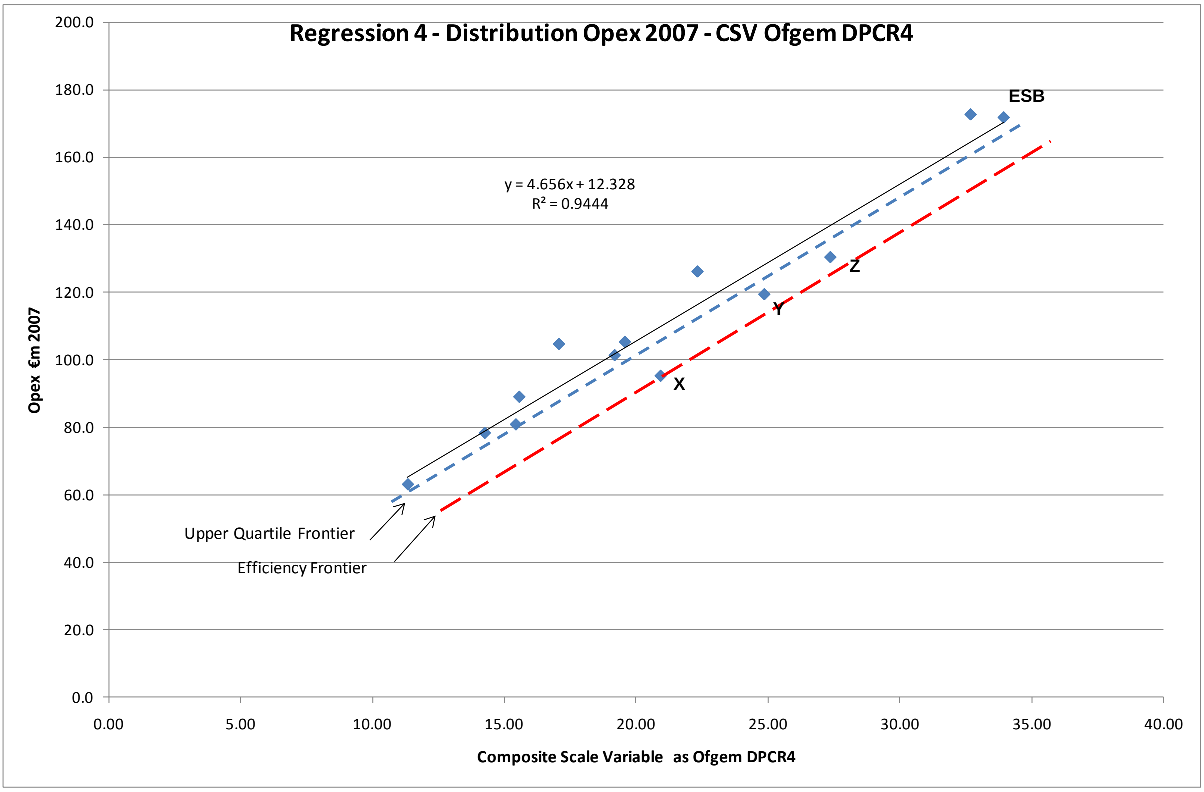


Chart 4 Regression of GB DNO and ESBN Opex - DPCR4 Methodology



D.4 Bottom Up Benchmarking

It is possible to benchmark certain costs directly, eg where costs are mainly fixed costs or where a simple driver can be identified. This section shows results of bottom -up benchmarking of certain maintenance activities, IT/Telecoms costs and System Control Costs.

D.4.1 Tree Cutting Costs

Using the same costs used for top down benchmarking we have carried out benchmarking of tree cutting costs for 2007/08.

Tree cutting costs are a significant part of planned maintenance costs 35% in GB and 31% for the DSO.

GB tree cutting costs of £63m prime costs, with overheads give a total cost with overheads of €196m for 780,482 km of overhead line or <u>€251 per km</u> of overhead line.

DSO tree cutting costs in 2007 were €14m but more typical costs are €17.5m per year for 163,203 km of line and tree cutting costs of <u>€107 per km</u> of overhead line.

Tree coverage in Ireland[18] is 669,000 hectares or 4.7 hectares per km of line. Tree coverage in the UK is 2845,000 hectares or 10 hectares per km of line. Tree cutting costs may therefore be expected to be higher in GB than in Ireland.

In addition revised UK Electricity Safety, Quality and Continuity Regulations (Regulation 4 (2)) places additional obligations on electricity companies to ensure that clearance between trees and lines is maintained to avoid contact and interruptions in supply. This is backed up by new industry standards.

There is an amount of work required to achieve these safety standards in GB and this has led to an increase in tree cutting.

This demonstrates a significant limitation in benchmarking where local factors, sometimes of a temporary nature, can frustrate a like for like comparison. However, we accept that DSO's tree cutting activities appear to be efficient but not entirely comparable with GB.

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[18] Provided by the World Resources Institute (http://www.wri.org)

D.4.2 Fault Costs

From the top down benchmarking data sources, total fault costs in Ireland are €46.8m (€329 per km) and total fault costs in GB are €384m (€492 per km), a ratio of 1:1.5.

However, GB network is 64% cable and network length is 27m per customer, whereas the DSO's network is only 13% cable and has a network length of 75m per customer. Much of the MV and LV overhead networks are simple single phase networks.

Underground cable faults are more expensive to repair than overhead line faults and the mix of faults differs.

Table 2 gives a model of LV and MV fault costs based on unit costs from a GB DNO source. GB DNO data is for a DNO with a similar customer base to the DSO and typical DNO proportion of overhead line and underground cable.

Table 2 Model DSO and GB DNO MV and LV Underground and Overhead Fault Costs

Model of MV and LV Undeground Cable and Overhead Line Fault Costs DSO and GB DNO

Faults	Prime Unit Cost €m 2008	DSO Faults	DSO Fault Rate (per 100 km)	DSO Fault Cost €m	DSO Faults	DSO Fault Rate (per 100 km)	DSO Fault Cost €m
20 kV Overhead Lines	947	4238	16.38	4.0			
10 kV Overhead Lines	947	6287	11.35	6.0	1177	11	1.11
Low Voltage Overhead Lines (Ex Services)	518	19769	35.62	10.2	946	19	0.49
Overhead LV Services	224	2276	n/a	0.5	210		0.05
							0.00
20 kV Underground Cables	5460	18	5.46	0.1		5	0.00
10 kV Underground Cables	5460	446		2.4	633		3.46
Low Voltage Underground Cables (Ex Services)	1930	1650	12.52	3.2	3546	11	6.84
Underground LV Services	806	2374	n/a	1.9	6848		5.5
Total				**28.36**			**17.47**
Length of LV and MV Network km				156531			63931
Faults Cost per €/km				**181.2**			**273.34**

Table 2 shows that cable faults dominate in GB DNOs and these are more expensive to repair than overhead line faults. The modelled fault costs using the same unit cost data shows that GB DNO fault costs of €273/per km are 1.5 times higher than the DNO costs of €181/km. This matches the higher fault costs found in practice.

It can be concluded that GB fault costs per km are inherently higher than in Ireland and that the DSO is as efficient as the average DNO in respect of fault costs.

D.4.3 IT, Telecoms and System Control Costs

Other costs have characteristics that allow direct comparison for companies of the same customer base and demand. A comparison of the GB average IT and Telecom costs and System Control costs against DSO costs indicates that the DSO is less efficient in these areas.

	GB Average	DSO Costs
System Control*	€9m p.a.	€18.6m p.a.
IT Costs/Telecoms	€12.2m p.a.	€26.2m p.a

* Note EirGrid is responsible for 110 kV system control and these costs are not included.

D.5 DSO Other Costs

ESBN costs include other costs not carried by GB DNOs including, non-repayable diversions €31.7m , meter operator costs €17.5, and higher call centre costs due to metering activities €3m say; total €52m. In addition DSO pays rates of €34m compared with average DNO average rates of €25m. Total additional operating costs of the DSO compared with GB DNOs of the same size is around €60m in €300m or 20%. Add the impact of differences in capitalisation policies (a further 20%) and the total impact on DUoS is significant.

Connection policies and depreciation also have an impact on DUOS. GB DNOs pay transmission exit charges on average of around €10m per year which reflects the full shallow cost of transmission connections, whereas the DSO carries 50% of the shallow transmission connection costs. ESBN also carries 50% of the cost of all connections to the distribution system, via depreciation charges.

D.6 ESBN Benchmarking Studies

ESBN has provided summary details of benchmarking carried out by their consultants as follows:

a) Benchmarking of ESBN opex and non network capex against comparable GB DNO costs based on Ofgem 2007/08 data from DNO cost reporting, using the Ofgem DPCR 4 methodology and adjusting for Purchasing Power Parity. The study shows DSO close to the efficiency frontier.
   - Adjustment for Purchasing Power Parity is not a significant factor in 2007/08. In any event it obscures the difference due to high payroll costs in Ireland and a more absolute benchmark is required.
   - We consider that insufficient costs may have been included for Market Systems and the110 kV adjustments may have been insufficient.

b) Benchmarking of ESBN opex costs against comparable GB DNO costs based on data from the DPCR 5 price review for five years but using the Ofgem DPCR 4 benchmarking methodology. The results show ESBN as being within 1% of the Upper Quartile Frontier.
   - Our results for the study based on 2007 data show ESBN as €5m above the upper quartile and the results are very similar, within the accuracies of such studies.
   - It is noted that the Scottish Companies are included and it is not known whether the costs have been adjusted for 132 kV. Our studies exclude Scottish Companies.
   - 110kV adjustments may have been insufficient.
   - Benchmarking over 5 years and adjusting for Purchasing Power Parity in a climate of fluctuating exchange rates and deflation is questionable but does not appear to have produced significantly different results to the one year studies.

c) Benchmarking of ESBN opex costs with 17 European regional and national Utilities based on 2008 data
   The participants were not selected on the basis of comparability or efficiency and included small urban companies, which were excluded from some of the comparisons.

   - Adjustments for activities and costs appears to have been restricted due, as the study was based on limited data and limited interaction with the companies.

   The consultant reports as follows:

The data suggest that ESBN has best-in- class performance with regard to technical activities costs in its regional/nationwide peer group. ESBN`s fault & maintenance costs amount to €340/km compared to the average fault & maintenance costs in the regional/nationwide peer group of €1,649/km.

- We have commented above that the cost of ESBN's network may be low due to inherent difference in proportion of overhead line and the relatively simple nature of much of the MV and LV single phase networks.

ESBN customer activities and operational metering costs are at a low level, though a more detailed examination of the scope of activities compared to other participants in both of these areas would be required to support these findings.

Support activities costs and the percentage of grid losses show potential room for improvement based on the survey data. ESBN also displays an average continuity of supply value in the regional/nationwide peer group. ESBN's support activities costs of €4.4/MWh are somewhat greater than the average support activities costs of €3.8/MWh.

- This is an area where we have also noted that ESB Networks is high cost and where costs are not falling. This may be due to the lack of direct control of services provided from other parts of ESB Group.

GB Distribution Network Operator Costs Annex 1

A 1.1 Ofgem Treatment of Costs in DPCR4

As part of the GB price control DPCR4 2005 to 2010 Ofgem carried out an analysis of GB DNO capital expenditure and operating costs in order to normalise DNO opex and capex so that for regulatory purposes companies were compared on a common basis. Normalisation was required because of the differing capitalisation policies of DNOs. Some companies capitalised a significant proportion of fault costs as they argued that fault repair included a high replacement element.

The classification of DNO costs is described in Appendix 1 of Ofgem Final Proposals for DPCR4[19], costs being classified on an activity basis as either direct or indirect costs.

The principal activities include:

> Net "non fault capital expenditure" consists of new connections net of customer contributions, reinforcement and non load related expenditure, excluding faults, plus 38% of indirect costs.
>
> "Opex plus fault costs" include inspection and maintenance, tree cutting storm repairs and insurance, non network capex and fault costs plus 62% of indirect costs.
>
> These non fault capex and opex + fault categories comprise essentially controllable costs and exclude non controllable costs such as business rates, transmission exit charges, excluded services, certain costs subject to incentives such as IFI and distributed generation, licence fees and re-opener items. Pension deficit costs are also treated separately.
>
> Indirect costs are all other controllable costs but do not include any direct labour, materials and contractors which are in the above categories.
>
> To ensure a standard approach to capitalisation of faults, Ofgem allowed 23.5% of "opex plus fault costs" (including the associated 62% of directs) to be capitalised into the RAV.
>
> Pension costs for the period 2005/06 to 2009/10 were considered to be uncertain and were to be taken out of all costs and 57.7% of pension costs were to be capitalised.

A 1.2 Ofgem Cost Reporting

Following DPCR4 Ofgem established an annual cost reporting regime under common rules so that DNO costs could be monitored on a continuing basis. The methodology for cost monitoring is published annually as cost reporting rules and an associated spreadsheet.

The cost reporting rules include definitions of all direct and indirect costs which essentially form the typical controllable costs of the DNOs. Other costs include non controllable costs, and atypical items which are not part of the core price control costs being treated as pass through, excluded services, part of the incentive scheme or disallowed from the revenue calculation.

The Ofgem cost reporting rules[20] and associated spreadsheet[21] for 2007/08 are also available on the Ofgem website, together with the financial model for DPCR5[22] which contains historic data, including

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[19] Ofgem Paper 265/04 Electricity Distribution Price Control Final Proposals November 2004.

[20] Ofgem Cost Reporting Rules 2007/08

units distributed and 2007/08 Quality of Supply data spreadsheet which[23] includes fault data and system statistics such as length of network.

A 1.3 Ofgem Benchmarking DPCR3, DPCR4 and DPCR5

Ofgem has used the analysis of controllable costs to provide a better understanding of DNO cost base. In considering DNO operating costs in DPCR 5 2010/11 – 2014/15 Ofgem has used a number of methods of benchmarking.

The principle drivers of network length, customer numbers and units distributed, individually do not provide a suitable benchmark for operating costs and Ofgem has used various weighted composite variables to benchmark costs.

In DPCR 3 Ofgem adopted a linear regression benchmarking method described in Annex 2 of the Consultation Paper dated May 1999. This involved benchmarking against a composite scale variable (CSV), using a weighted average of customer numbers, units distributed and network length. A similar methodology was used by CER in PR2[24], as follows:

The composite scale variable for a company i = (1 + dUi/Ui +dLi/Li) x Ci

Where dUi/Ui is the proportional deviation in units distributed from the overall average.

Where dLi/Li is the proportional deviation in network length from the overall average.

Ci is customer numbers in millions.

In DPCR4 Ofgem adopted a similar regression benchmarking methodology but one that gave more weight to network length set out in DPCR4 initial proposals[25]

$$CSV = A^{0.5} \times B^{0.25} \times C^{0.25}$$

Where A = length of network ‘000 km

B = Customer numbers (Million)

C = Units distributed GWh

In DPCR5 Ofgem adopted more direct modelling of individual direct and indirect costs against specific drivers such as number of faults and network length. This is described in Ofgem initial proposals cost assessment paper[26] and associated Appendix.[27]

[21] Ofgem RRP Data Tables 2007/08 – pro forma only
[22] Ofgem DPCR5 Financial Model – October letter.
[23] Ofgem 200708 Quality of Supply Data
[24] CER 2006 – 2010 Distribution Price Control Review CER Decision on Distribution System Operator Revenues Appendix B
[25] Ofgem Electricity Price Control Review Initial Proposals June 2004.

[26] Ofgem DPCR5 Initial Proposals 3 Allowed Revenue and Cost Assessment

[27] Ofgem DPCR5 Initial Proposals 3 Allowed Revenue and Cost Assessment Appendix.

GB Distribution Company Activity Costs 2007/08 Nominal Prices

Annex 2

	All GB DNOs Inc Scottish	A	Y	X	B	C	D	E	F	G	H	I	Z
Direct Activities	**1529**	**142**	**154**	**102**	**88**	**105**	**53**	**88**	**110**	**113**	**194**	**104**	**140**
Load Related New Connections Net	192	11	46	10	12	2	-1	1	18	8	35	5	36
Non load related non fault and replacement	793	87	63	64	43	55	32	45	51	63	80	68	52
Non operational capex	85	2	2	4	4	4	3	15	8	7	19	3	8
Faults	273	24	27	16	17	29	8	14	23	22	40	13	23
Inspection and Maintenance	115	12	12	5	5	7	6	7	10	8	12	6	14
Tree Cutting	63	5	3	2	6	7	4	5	0	5	8	8	7
Network Policy and R & D	8	1	1	1	1	1	1	1	0	0	0	1	0
Indirect Activities	**855**	**76**	**67**	**71**	**43**	**50**	**41**	**49**	**67**	**60**	**101**	**56**	**79**
Network Design and Engineering	69	6	5	9	4	4	4	5	7	4	7	6	3
Project Management	60	4	2	4	2	4	3	5	6	4	8	5	7
Engineering Management and Clerical Support	202	23	17	15	9	11	7	10	15	14	27	11	20
Control Centre	40	4	4	3	2	3	2	2	3	3	5	2	3
System mapping and cartography	17	2	2	1	1	2	1	1	2	1	2	1	1
Customer Call Centre inc compensation claims	20	1	1	1	1	2	1	1	1	2	3	1	3
Stores and procurement	20	1	2	1	1	1	1	1	2	2	3	1	2
Vehicles and transport	70	5	6	2	3	3	3	4	3	4	7	5	12
IT and telecoms	121	11	10	13	7	7	7	7	9	8	12	8	8
Property management	62	6	5	7	2	3	2	3	6	6	8	4	4
HR and non op training	28	1	1	3	2	2	1	1	3	3	4	2	3
Health and Safety and Op training	21	2	2	1	1	1	1	1	1	1	2	2	2
Finance and Regulation	98	8	8	9	6	6	6	6	8	7	11	6	9
CEO Group Legal secretary and community	26	2	2	2	2	1	2	2	1	1	2	2	2
Total Activity Costs	**1443**	**80**	**92**	**103**	**88**	**102**	**69**	**106**	**84**	**72**	**118**	**103**	**207**
Atypical cash costs	52	2	1	15	0	5	4	7	2	3	3	1	3
Pension deficit payments	143	8	10	0	22	6	13	21	15	16	4	0	27
Metering (separate price control)	78	1	1	1	3	5	2	6	2	3	6	12	13
Excluded services and de minimus activities	236	12	10	15	13	11	9	25	45	10	31	9	27
Distributed Generation less contributions	-2	0	0	0	0	0	0	0	0	0	0	1	0
IFIs (Innovation Incentives)	11	1	1	1	0	1	0	0	2	1	2	0	1
Disallowed related party margins	44	-5	4	12	3	2	0	1	0	0	1	10	4
Statutory depreciation	600	39	42	59	32	47	25	34	42	40	56	36	68
Network Rates	282	20	27	17	14	18	15	18	23	10	26	16	38
Transmission Exit Charges	113	8	4	9	5	10	4	5	12	8	9	12	10
Pension deficit payments - related parties	-46	-8	-10	0	0	0	0	0	0	0	0	0	-27
Non activity costs and reconciliation	-69	2	2	-26	-4	-3	-3	-11	-59	-19	-20	6	43
Total annual opex and capex per Reg Accounts	**3827**	**298**	**313**	**276**	**219**	**257**	**163**	**243**	**261**	**245**	**413**	**263**	**426**

ESBN Distribution and 110 kV Transmission Operating Costs Annex 3

ESB Distribution and 110 kV Transmission Operating Costs
(€m Nominal Prices)

Activity	DSO 2007	TAO 110 kV 2007
Non repayable line diversions	31.7	
System Control^	18.6	
Planned Maintenance^	44.6	3.0
Fault Maintenance^	44.5	1.0
Asset Management^	12.5	0.2
Metering DSO	**17.5**	
Meter reading	10.2	
NQH Data	1.3	
Customer meter operation	2.0	
Data Aggregation	4.0	
Customer Service Sub Total	**19.0**	
Call Centre Charges	6.2	
Area Operations/Operations^	10.4	2.4
Customer Relations^	2.4	
Provision of Data	**15.3**	
DUOS & MRSO^	2.1	
Market Systems Support*^	13.2	
Corporate Charges^	14.3	
Safety^	3.8	
Environmental^	0.4	
CER Levy*	2.5	
Sub Total	**224.6**	**6.6**
Commercial*	**31.5**	
External Repayable*	21.5	
Supply Repayable*	8.5	
Other Inter ESB*	1.5	
Network Rates*	33.9	16.5
Insurance*^	4.2	0.2
Pension*	1.1	0.2
Other Legal Revenue Misc*	2.9	1.8
Subtotal	**73.7**	**18.7**
Total Excluding exceptionals	**298.4**	**25.3**
Controllable Costs	**209.0**	**6.6**
Non Controllable Costs*	**89.4**	**18.7**

DSO Comparable Opex^	**165.2**
TAO 110 kV Comparable Opex	6.6
Total Opex Comparable with GB	**171.8**
Non Nework Capex	34.9
Comparable Opex and Non Network Capex	**206.7**

Benchmarking of GB DNO and ESBN DSO + 110 kV Comparable Operating Costs Annex 4

Comparable Operating Costs and Non Network Capex

Benchmarking of Comparable Operating Costs + Non Network Capex (ESB DSO + 100 kV Costs 2007 and GB DNO Costs 2007/08)

	All GB DNOs Ex Scottish	A	Y	X	B	C	D	E	F	G	H	I	Z	ESB
Comparable Opex + Non Network Capex £m 2007/08	998.3	93.4	88.8	73.5	60.8	80.5	48.6	73.5	84.1	80.7	144.3	67.2	102.9	
Comparable Opex + Non Network Capex €m 2007	**1378.7**	**129.0**	**122.3**	**100.9**	**84.0**	**111.0**	**67.3**	**102.1**	**116.1**	**111.3**	**199.7**	**93.3**	**141.8**	**206.7**
Number of Customers	25968777	2433482	2576436	2342770	1558187	2234349	1079585	1504598	2206090	2214187	3469255	1473411	2876427	2151285
Length of Circuit (km)	671658	61964	70948	56520	39530	52141	34757	49612	35920	51815	94439	48562	75450	162203
Length of Circuit (km/customer)	0.0259	0.0255	0.0275	0.0241	0.0254	0.0233	0.0322	0.0330	0.0163	0.0234	0.0272	0.0330	0.0262	0.0754
dL1/Li	-0.1278	-0.1413	-0.0714	-0.1864	-0.1445	-0.2130	0.0857	0.1120	-0.4509	-0.2108	-0.0820	0.1115	-0.1154	1.5426
Units Distributed (GWh)	291246	26576	29446	25605	16934	24136	12657	15316	29797	22759	36896	16875	34249	23456
Units/Customer	11.215	10.921	11.429	10.929	10.868	10.802	11.724	10.179	13.507	10.279	10.635	11.453	11.907	10.903
dUi/Ui	0.002	-0.024	0.021	-0.023	-0.029	-0.035	0.048	-0.090	0.207	-0.082	-0.050	0.023	0.064	-0.026
Cost per customer (€/Customer)	**53.1**	**53.0**	**47.5**	**43.1**	**53.9**	**49.7**	**62.4**	**67.9**	**52.6**	**50.3**	**57.6**	**63.3**	**49.3**	**96.1**
Cost per km (€/km)	**2053**	**2081**	**1723**	**1785**	**2125**	**2129**	**1937**	**2059**	**3231**	**2148**	**2114**	**1921**	**1879**	**1274**
Scale Variable (Ofgem DPCR3 and CER PR2)		2.333	2.544	2.220	1.491	2.096	1.116	1.513	2.071	2.052	3.355	1.523	2.839	2.967
CSV Ofgem DPCR4		22.32	24.86	20.92	14.25	19.57	11.33	15.43	17.07	19.18	32.69	15.56	27.37	33.94
Cost/CSV DPCR4	#DIV/0!	5.78	4.92	4.82	5.89	5.67	5.94	6.62	6.80	5.80	6.11	5.99	5.18	6.09
Comparable Opex + Non Network Capex €m 2007	**1378.7**	**129.0**	**122.3**	**100.9**	**84.0**	**111.0**	**67.3**	**102.1**	**116.1**	**111.3**	**199.7**	**93.3**	**141.8**	**206.7**

Comparable Operating Costs

	All GB DNOs (Excluding Scottish	A	Y	X	B	C	D	E	F	G	H	I	Z	ESB
Comparable Opex £m 2007/08	919.3	91.4	86.8	69.5	56.8	76.5	45.6	58.5	76.1	73.7	125.3	64.2	94.9	
Comparable Opex GB DNO 2007/08* ESB €m 2007	1266.5	**126.1**	**119.4**	**95.2**	**78.3**	**105.3**	**63.1**	**80.8**	**104.7**	**101.4**	**172.7**	**89.0**	**130.4**	**171.8**
Number of Customers	25968777	2433482	2576436	2342770	1558187	2234349	1079585	1504598	2206090	2214187	3469255	1473411	2876427	2151285
Length of Circuit (km)	671658	61964	70948	56520	39530	52141	34757	49612	35920	51815	94439	48562	75450	162203
Length of Circuit (km/customer)	0.0259	0.0255	0.0275	0.0241	0.0254	0.0233	0.0322	0.0330	0.0163	0.0234	0.0272	0.0330	0.0262	0.0754
dL1/Li	-0.1278	-0.1413	-0.0714	-0.1864	-0.1445	-0.2130	0.0857	0.1120	-0.4509	-0.2108	-0.0820	0.1115	-0.1154	1.5426
Units Distributed (GWh)	291246	26576	29446	25605	16934	24136	12657	15316	29797	22759	36896	16875	34249	23456
Units/Customer	11.215	10.921	11.429	10.929	10.868	10.802	11.724	10.179	13.507	10.279	10.635	11.453	11.907	10.903
dUi/Ui	0.002	-0.024	0.021	-0.023	-0.029	-0.035	0.048	-0.090	0.207	-0.082	-0.050	0.023	0.064	-0.026
Cost per customer (€/Customer)	**48.8**	**51.8**	**46.4**	**40.6**	**50.3**	**47.1**	**58.4**	**53.7**	**47.5**	**45.8**	**49.8**	**60.4**	**45.3**	**79.9**
Cost per km (€/km)	**1886**	**2036**	**1683**	**1685**	**1981**	**2020**	**1815**	**1629**	**2915**	**1956**	**1829**	**1833**	**1728**	**1059**
Scale Variable (Ofgem DPCR3 and CER PR2)		2.333	2.544	2.220	1.491	2.096	1.116	1.513	2.071	2.052	3.355	1.523	2.839	2.967
CSV Ofgem DPCR4		22.32	24.86	20.92	14.25	19.57	11.33	15.43	17.07	19.18	32.69	15.56	27.37	33.94
Cost/CSV DPCR4	#DIV/0!	5.65	4.80	4.55	5.50	5.38	5.56	5.24	6.13	5.29	5.28	5.72	4.77	5.06
Comparable Opex comparable with ESB €m 2007*	**1266.5**	**126.1**	**119.4**	**95.2**	**78.3**	**105.3**	**63.1**	**80.8**	**104.7**	**101.4**	**172.7**	**89.0**	**130.4**	**171.8**