Decision on TSO and TAO transmission revenue for 2011 to 2015

<table>
<thead>
<tr>
<th>DOCUMENT TYPE:</th>
<th>Decision Paper</th>
</tr>
</thead>
<tbody>
<tr>
<td>REFERENCE:</td>
<td>CER/10/206</td>
</tr>
<tr>
<td>DATE PUBLISHED:</td>
<td>19th November 2010</td>
</tr>
<tr>
<td>QUERIES TO:</td>
<td>Jamie Burke (<a href="mailto:jburke@cer.ie">jburke@cer.ie</a>)</td>
</tr>
</tbody>
</table>


www.cer.ie
Abstract:

This paper outlines the decision on the revenue that EirGrid and ESB Networks will be allowed to recover from the Transmission Use of System (TUoS) customer over the period 2011 to 2015, to cover their costs as electricity Transmission System Operator (TSO) and Transmission Asset Owner (TAO), respectively.

The CER’s proposals regarding placing incentives on the TSO and TAO to increase the security, reliability and quality of the services provided by the transmission utilities, while operating in an increasingly efficient manner, will be consulted on with stakeholders in a separate CER paper in the coming weeks.

Target Audience:

This decision paper is for the attention of all members of the public and the energy industry. It will be of particular interest to parties that directly pay TUoS charges to EirGrid and end-user customers to whom these charges are passed onto.

Related Documents:

- **CER/10/207**  Response to comments received to CER/10/102.
- **CER/10/186**  Proposed decision on 2011 to 2015 distribution revenue for ESB Networks Ltd.
- **CER/10/199**  Response to comments received to CER/10/186.
- **CER/10/102**  Consultation on TSO and TAO revenue for 2011 to 2015.
- **CER/09/140**  Decision on 2010 Transmission revenue and TUoS tariffs.
- **CER/08/178**  Decision on 2009 Transmission revenue and TUoS tariffs.
- **CER/07/184**  Decision on 2008 Transmission revenue and TUoS tariffs.
- **CER/06/199**  Decision on 2007 Transmission revenue and TUoS tariffs.
- **CER/05/143**  Decision on TSO and TAO transmission revenue for the period 2006 to 2010.
- **CER/01/131**  Decision on TSO and TAO transmission revenue for the period 2001 to 2005.
Executive Summary

The Commission for Energy Regulation (the ‘CER’) is the independent body responsible for regulating the natural gas and electricity sectors in Ireland. Part of its responsibilities involves regulating the level of revenue which the monopoly electricity Transmission System Operator (TSO) EirGrid and the monopoly Transmission Asset Owner (TAO) ESB Networks in Ireland, can recover from the Transmission Use of System (TUoS) customer to cover their respective costs.

This paper outlines the CER’s decision on the TSO’s and TAO’s revenue for the 2011 to 2015 period.

The transmission network consists of the high voltage electricity wires that connect different parts of the country and ensures that electricity from Generators is transported to the distribution network, which in turn ensures it is delivered to end-users. As it would be wasteful and inefficient to have duplicate sets of transmission wires, the transmission network is a “natural monopoly”. Unregulated monopolies may be inefficient and impose prices that are too high so, as set-out in legislation, the CER regulates the TSO and TAO’s activities to protect the interest of electricity consumers, while ensuring that they can fulfil their obligations and deliver secure electricity supplies.

The nature of such regulation is that every five years the CER puts in place a revenue control that sets the transmission revenue that can be collected from the TUoS customer. This transmission revenue is collected by the TSO and distributed between the TSO and TAO as per SI 445 of 2000\(^1\) and the Infrastructure Agreement between the two bodies. Transmission revenue is set at a level that would allow an efficient business to finance its activities and is determined by a combination of benchmarking against organisations in other countries and examining the specific underlying costs of the TSO and TAO.

This five year revenue allowance approach is regarded as best international practice, and is used by nearly all other energy regulators (such as Ofgem in Great Britain\(^2\)) as well as in a number of other regulated sectors. It ensures that consumers are protected, while offering the regulated business a clear and stable environment to make the necessary investments to ensure a modern and efficient transmission system.

The CER also places incentives on the TSO and TAO to increase the security, reliability and quality of its service, while requiring the businesses to operate in an

---

2 Please see the following link for documentation on the current GB electricity transmission price control: [http://www.ofgem.gov.uk/Networks/Trans/PriceControls/Pages/PriceControls.aspx](http://www.ofgem.gov.uk/Networks/Trans/PriceControls/Pages/PriceControls.aspx)
increasingly efficient manner. Proposed transmission incentives for the next incentive period will be consulted on with stakeholders in a separate CER paper in the coming weeks.

The current price control expires on 31st December 2010. This decision paper sets out the CER’s decision for the revenue that the TSO and TAO, separately, should be allowed to earn from 1st January 2011 to 31st December 2015.

Financial data in this decision paper is expressed in 2009 price levels, unless otherwise stated.

The five-year period

The five years from 2011-2015 will require significant new investment in the transmission system. The Government target of ensuring 40% of Ireland’s electricity is generated by renewable sources by 2020 means a major expansion of the transmission network. This will allow these new renewable Generators to connect to the system. The transmission network also needs ongoing investment to ensure it operates securely and effectively. This necessary investment will mean that the overall revenues to be recovered by the TSO and TAO over the period of the review will rise from their current levels, and that the TUoS charges levied to consumers will rise somewhat. However, it should be noted that TUoS is a small overall element of a customer’s bill (approximately 7%) and that the revenues outlined in this paper will result in a minor increase per annum in a customer’s overall bill of about a half a percent.

While the CER is of the view that this investment is necessary and will deliver benefits to consumers, it is very aware of the need to ensure it is delivered as cost-effectively as possible. To that end, and mindful of the general economic difficulties in Ireland, it is deciding to require major efficiencies from the TSO and TAO. This is through cuts to the operating expenditure (Opex) required to run the system, as well as ensuring that capital expenditure (Capex) is fully scrutinised in terms of it being necessary (e.g. in terms of long term benefits outweighing costs), as well as being procured in an efficient manner.

These efficiencies will ensure that end-users are protected as much as is possible, while still allowing for the required level of investment to take place, and continues the pattern of the CER having implemented significant efficiencies in previous price reviews. In accordance with the principles of incentivising efficiencies, if the regulated companies manage to make even greater efficiency improvements over the review, they are allowed by the CER to keep some of the benefits for five years on a rolling basis.

The CER adopts an incentive based model to separately determine the TSO’s and TAO’s allowed revenues. Both utilities internal operating costs are fixed for a five year period. If either utility spends more than it is allowed, it bears the cost.
On the other hand if the utility spends below what it is allowed it can keep the surplus made any one year for a period of five years as a means of incentivising efficiency, as long as those savings have been made in an efficient manner and not simply through avoiding expenditure to the detriment of the transmission system. Customers benefit in the medium term by the progressive decrease in operating costs allowed at subsequent price reviews.

The process

This decision has been prepared following a lengthy period of engagement by the CER and its consultants with both the TSO and TAO as well as a previous consultation with industry\(^3\). This has involved the analysis of multiple submissions by the TSO and TAO on both their historic and forecast costs, multiple meetings with the TSO and TAO to clarify those submissions, site visits to transmission installations and the benchmarking of the TSO’s and TAO’s costs and performance against international best practice.

To provide advice and complete analysis over the course of the review, the CER engaged the services of Sinclair Knight Mertz (a leading international engineering, sciences and project delivery firm) to review efficiency levels, and both historic and forecast operating costs and capital investment. Europe Economics (a London based consultancy with expertise in economic regulation) has been engaged to provide advice on the allowed rate of return required on capital investments to ensure that the capital programme can be funded. The consultants’ reports are published alongside CER/10/102 and CER/10/103, with the substantive points and recommendations related to transmission summarised within this paper.

Performance

A historic period of underinvestment throughout the 1980’s and 1990’s in the transmission network in Ireland has been followed in recent years by an increased level of expenditure on capital, maintenance and network renewal programmes. This has been required to cater for new connections (both Demand and Generator) during the recent economic boom and to make up for a previous lack of work in this area. This expenditure, coupled with the TSO’s reaction to incentive mechanisms put in place by the CER, has greatly increased the quality of the electricity supply that the TUoS customer receives. Evidence of this can be seen in the annual Transmission System Performance reports published by EirGrid\(^4\). These reports show that system performance parameters such as System Minutes Lost and management of System Frequency levels have improved over the last number of years.

\(^3\) Please see the April 2009 PR3 scope consultation paper - CER/09/047.
\(^4\) Please see the following link: http://www.eirgrid.com/aboutus/publications/
It is proposed that the incentives relating System Frequency and System Minutes Lost will be continued into the forthcoming five-year period, as well as the introduction a “system availability” incentive. The CER is also proposing the introduction of a TSO network delivery incentive for both the TSO and TAO. Proposed transmission incentives for the next incentive period will be consulted on with stakeholders in a separate CER paper in the coming weeks.

The effective roll-out of Gate 3 and the Government’s target of 40% of Ireland’s electricity consumption coming from renewable generation by 2020 is key to the setting of these propose incentives for both TSO and TAO.

Review of 2006-2010 PR2 Costs

Capex

There has been a PR2 underspend of circa €78 million of network capex, which the CER can attribute to a number of reasons. Opposition from landowners to new construction, particularly of overhead lines, cost pressures encountered by the transmission utilities, uncertainty around defined roles and composition of the Infrastructure Agreement (IA) at the time of IA introduction all led to delays in projects during the PR2 period.

A non-network capex underspend of €13 million was largely associated with the TSO not utilising the allowed revenue for non-specified IT projects due to the diversion of resources to SEM establishment, allowed for in the PR2 transmission determination.

Both underspends were accounted for during the PR2 period through the reduction of transmission revenues over 2009 and 2010\(^5\).

Opex

A TAO underspend of €29.7 million has been identified due mainly to over-forecasting at the time of setting the PR2 determination. The CER is proposing that allowed TAO operating costs for PR3 be reduced by €25.04 million, as these savings have not been efficiently incurred.

A TSO underspend on internal operating costs of circa €18.3 million is considered to have arisen due to a combination of forecasting errors and efficiency savings. There has been a considerable amount of change to market and industry structures since the time of setting the PR2 determination. There was significant uncertainty on the TSO internal opex required to facilitate the start up of EirGrid as TSO. The CER has decided that the TSO should not receive a

\(^5\) Please refer to 2010 & 2009 transmission revenue determination papers [CER/08/178](#) and [CER/09/140](#).
windfall benefit from that uncertainty and that €8.48 million (just under 50% of the underspend) be deducted from allowed TSO PR3 costs.

In PR2 the CER used the Consumer Price Index (CPI) as the index to inflate revenue and it should be noted that in the last two years of the price control (2009 and 2010), allowed transmission costs have fallen in line with the CPI index (i.e. -4.5% for 2009)\(^6\). This has automatically insured that the TUoS charge has reacted to the falls in costs occurring elsewhere in the Irish economy.

**Costs for 2011-2015 PR3 period**

As outlined above the CER expects that the Opex for PR3 will be incurred as efficiently as possible by the transmission utilities over the PR3 period. The CER believes that the efficiencies we have built into the PR3 Opex will minimize the burden on the TUoS customer in the period.

**TAO**

CER/10/102 proposed TAO PR3 revenues of approximately €855 million. The CER has decided on total TAO PR3 revenues of approximately €921 million. This is a net increase of €66 million from that proposed in the consultation paper, or 7.7%. The reasons for this increase are outlined below.

The year by year revenue to cover the TAO’s costs during the 2011 to 2015 period is outlined in Table 1 below. These have been decided upon following a review of the TAO’s performance, both past and forecast, and benchmarking of its costs and performance against international best practice. Each of the components is discussed in turn below in the following chapters, where comparisons and analysis between proposed PR3 and actual PR2 are provided.

<table>
<thead>
<tr>
<th>TAO</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Opex</td>
<td>47,031,322</td>
<td>46,512,017</td>
<td>46,003,009</td>
<td>45,504,153</td>
<td>46,836,025</td>
<td>231,886,526</td>
</tr>
<tr>
<td>Clawbacks/Deferrals</td>
<td>-25,040,000</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>-25,040,000</td>
</tr>
<tr>
<td>Depreciation</td>
<td>33,698,398</td>
<td>38,474,653</td>
<td>44,316,653</td>
<td>50,665,653</td>
<td>57,260,653</td>
<td>224,416,011</td>
</tr>
<tr>
<td>Return on Capital + Incentives</td>
<td>111,978,993</td>
<td>78,746,492</td>
<td>78,630,249</td>
<td>105,378,706</td>
<td>131,316,100</td>
<td>506,050,541</td>
</tr>
<tr>
<td>Annual Revenue</td>
<td><strong>164,293,318</strong></td>
<td><strong>160,395,037</strong></td>
<td><strong>165,648,317</strong></td>
<td><strong>198,282,720</strong></td>
<td><strong>232,476,066</strong></td>
<td><strong>921,095,457</strong></td>
</tr>
</tbody>
</table>

---

\(^6\) Please refer to the [Central Statistics Office website](https://www.cso.ie/en/).
Additional TAO efficiencies

In addition, following the publication of the CER’s proposals on this matter the CER is requiring that the TAO deliver additional efficiency savings in Opex and Capex, the benefits of which will be given to customers within the 2011 to 2015 period. This reduction (€16.2 million) has been included in Table 1 and the TAO revenue table in section 13, but has not been broken down by line item within this paper; rather it is a reduction in overall revenue for Opex and Capex. The CER believes that given the current economic conditions that there are additional efficiencies to be realised by the TAO. The CER has not specified how these efficiency savings are to be delivered across the various line items. Rather the TAO is to determine how these reductions will be achieved across Opex and Capex.

TSO

CER/10/102 proposed TSO PR3 revenues of approximately €680 million. The CER has decided on total TAO PR3 revenues of approximately €696 million. This is a net increase of €16 million from that proposed in the consultation paper, or 2.4%. The reasons for this increase are outlined below.

The revenue to cover the TSO’s costs during the 2011 to 2015 period is outlined below in Table 2. These have been decided upon following a review of the TSO’s performance, both past and forecast, and benchmarking of its costs and performance against international best practice. Each of the components is discussed in turn below in the following chapters, where comparisons and analysis between proposed PR3 and actual PR2 are provided.
Table 2: TSO PR3 Costs (€m’s in 2009 prices)

<table>
<thead>
<tr>
<th>TSO</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Opex &amp; EWIC’ Charge</td>
<td>93,927,967</td>
<td>108,710,612</td>
<td>148,388,241</td>
<td>148,527,648</td>
<td>150,331,346</td>
<td>649,885,814</td>
</tr>
<tr>
<td>Clawbacks/Deferrals</td>
<td>-8,478,000</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>-8,478,000</td>
</tr>
<tr>
<td>Depreciation</td>
<td>7,271,156</td>
<td>7,550,051</td>
<td>6,787,772</td>
<td>5,884,060</td>
<td>5,447,506</td>
<td>32,940,545</td>
</tr>
<tr>
<td>Return on Capital +</td>
<td>751,947</td>
<td>1,828,966</td>
<td>1,872,008</td>
<td>2,239,981</td>
<td>2,612,023</td>
<td>9,304,926</td>
</tr>
<tr>
<td>Incentives</td>
<td>2,208,356</td>
<td>2,275,193</td>
<td>2,423,578</td>
<td>2,522,867</td>
<td>2,632,608</td>
<td>9,304,926</td>
</tr>
<tr>
<td>Working Capital</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Annual Revenue</td>
<td>95,681,426</td>
<td>120,364,822</td>
<td>159,471,600</td>
<td>159,174,556</td>
<td>161,023,483</td>
<td>695,715,888</td>
</tr>
</tbody>
</table>

Capex for 2011-2015 PR3 period

The purpose of the PR3 Capex review is to ensure that the correct, appropriate and fully justified level of network investment takes place in order to deliver the network capacity required for Gate 3\(^8\) and to meet Ireland’s 2020 renewable targets\(^9\). The CER’s approach, as detailed in section 8.0 of this paper, is to deliver increased network capacity in a multi-faceted approach involving enhancing capacity on existing networks, the development of new lines where justified and the operation of the network to deliver more.

As outlined above the CER believes that the significant PR3 capex investment in the Irish transmission system is necessary for consumer welfare and particularly so as to ensure the required transition to a more renewable-based electricity system. This will raise overall costs to the TUoS customer, but the CER believes that this is necessary to allow the level of renewable generation envisaged through Gate 3. It is worth noting that the Electricity Networks Strategy Group (ENSG) in the UK, which comprises of Ofgem and DECC, envisages a capex spend of €5.7 billion (£4.7 billion) over the next GB transmission price control to facilitate the GB renewable connection program\(^10\).

While the CER believes that a significant investment in the Irish transmission system is now necessary in order to meet Ireland’s renewable targets, we will do

---

\(^7\) The EWIC portion of this charge has been included for tariff profiling purposes. The charge incurred by the TSO will be subject to an annual ex-post review and any over/underspends will be reflected in the following year’s tariffs.

\(^8\) Please refer to the CER’s Gate 3 Decision paper which provides for 40% of Ireland’s electricity consumption coming from renewable generation by 2020. Gate 3 does so by including circa 3,900MW of renewable generator projects in Gate 3 through a defined rule set.

\(^9\) Please refer to the Government’s Energy White paper.

\(^10\) Please see ENSG’s March 2009 paper "Our Electricity Transmission Network: A vision for 2020".
all in our power to ensure that PR3 capex will be incurred as efficiently as possible. This will be done through use of an annual Capex monitoring program and a cost benefit analysis (CBA) template for all transmission projects over a certain level of expenditure.

The CER has decided to adopt a Sinclair Knight Merz (SKM) proposed ‘Stretched Network Needs’ scenario, which envisages €1.45 billion of transmission network capex over the 2011-2015 PR3 period.

PR3 Rate of Return (WACC)

The CER also sets the level of return allowed to the transmission utilities over the course of the review. The CER allows the transmission utilities this return on capital to remunerate the debt and equity required to finance capital investment. This return is known as the Weighted Average Cost of Capital (WACC).

Given the need for the capital investment programme, and further to CER/10/18611, the CER has decided to set a WACC for the TSO and TAO of 5.95% (real pre-tax). When applied to the TAO RAB, this equates to an allowance of €506.1 (after profiling). When applied to the TSO RAB this equates to an allowance of €9.2 (after profiling). This increase to return on capital is the most significant departure from the transmission consultation paper and was outlined in CER/10/186. The increase in the WACC reflects the increased costs that are faced by the transmission utilities to finance its business. This may be a temporary issue and if there is a significant change in circumstances, the CER will review, at the midterm of the review period, the level of WACC to see if an adjustment is required for the remaining period of the Price Review.

An adjustment, if required, could be an increase or a decrease depending on how circumstances have changed. However the CER believes that it is prudent at this stage to assume that circumstances will not change significantly and has modelled the PR3 transmission revenue on this basis. The CER recognises that the transmission utilities, TAO in particular, will need to access international capital markets to fund the capital investment programme and is conscious of the importance of providing regulatory certainty in that regard. Equally, it is important that the regulatory model can adapt to changing circumstances, particularly in times of significant uncertainty, in the interests of both consumers and investors. The CER believes that the WACC achieves an appropriate balance in this regard and should support strong credit quality and efficient funding of the investment programme.

During the consultation phase the CER also considered mechanisms that would have allowed the transmission utilities to earn a higher rate, or be rewarded

---

11 Please see the following link:
http://www.cer.ie/en/electricity-distribution-network-current-consultations.aspx?article=0b278e96-80f5-43e1-80ab-b23423c3c34c
through some other form of incentive mechanism through effective delivery of transmission network. Proposed transmission incentives for the next incentive period will be consulted on with stakeholders in a separate CER paper in the coming weeks.

**Transmission Revenue for 2011 & 2010/2011 AUP**

The CER has decided to allow the following revenue for the transmission businesses in 2011, which is to be €257.36 million in 2011 nominal prices\(^{12}\), as shown in the table below. This is the same amount as proposed in CER/10/102 – the only change has been the allocation of the €257.36 million between the TSO and TAO as a result of the change in the WACC. This transmission revenue amount of €257.36 million (TSO and TAO) feeds into the Demand transmission tariffs shown in the paper CER/10/102(j).

Table 3: Transmission Revenue for 2011

<table>
<thead>
<tr>
<th></th>
<th>2009 prices</th>
<th>2011 prices</th>
</tr>
</thead>
<tbody>
<tr>
<td>TSO Revenue</td>
<td>95,681,426</td>
<td>94,717,436</td>
</tr>
<tr>
<td>TAO Revenue</td>
<td>164,293,318</td>
<td>162,638,062</td>
</tr>
<tr>
<td><strong>Total 2011 Transmission Revenue</strong></td>
<td><strong>259,974,744</strong></td>
<td><strong>257,355,498</strong></td>
</tr>
</tbody>
</table>

Therefore, based on the allowed 2010\(^{13}\) and 2011 transmission revenue and the estimated consumption\(^{14}\), the transmission average unit price (AUP) for the tariff period of 1\(^{st}\) October 2010 to 30\(^{th}\) September 2011 is estimated to be 0.95 cent/kWh in 2011 nominal prices. This is an increase of 3% on the 2009/2010 tariff period transmission AUP\(^{15}\).

However due to tariff re-balancing measures, outlined in section 12.0, there will be a **45% decrease** on the transmission network charges applied to Large Energy Users (LEUs) for the tariff period 1\(^{st}\) October 2010 to 30\(^{th}\) September 2011.

---

\(^{12}\) 2011 prices are nominal and are based on inflation of the actual 2009 prices by assumed Ireland HICP rates of -1.5% in 2010 and 0.5% in 2011. Please see following link - latest ESRI Spring 2010 report: http://www.esri.ie/UserFiles/publications/QEC2010Spr/QEC2010Spr_ES_Summary%20Table.pdf

\(^{13}\) Please see 2010 transmission revenue determination paper – CER/09/140

\(^{14}\) Forecasting consumption is normally difficult. It is extremely difficult in the current economic climate with significant uncertainty around the timing of the return to economic growth and by extension growth in electricity consumption.

\(^{15}\) TUoS costs roughly equate to 7% of the final end-user bill.
Conclusion

The CER believes that although TUoS charges levied to consumers will rise somewhat during PR3, its decision should allow for major new investments that will enable the transition to a renewables-based electricity system to be conducted effectively and at an efficient level of cost. To that end, the revenues contained in this paper suggest significant efficiencies that will benefit end-users, as well as provide the regulated companies with a stable environment and the chance to earn a good rate of return, given effective performance.
# Table of Contents

Executive Summary .................................................................................................................. 3

1.0 Introduction ........................................................................................................................................ 16
  1.1 The Commission for Energy Regulation ........................................................................................ 16
  1.2 Purpose of this paper ................................................................................................................... 16
  1.3 Structure of this paper .................................................................................................................. 16
  1.4 Queries on this paper .................................................................................................................... 18

2.0 Background, objectives & assumptions ...................................................................................... 19
  2.1 Introduction ....................................................................................................................................... 19
  2.2 The CER’s role in the determination of this control ............................................................................. 19
  2.3 Context of this revenue control ........................................................................................................ 19
  2.4 Objectives for this revenue control .................................................................................................. 21
  2.5 Effective unbundling of system operator and owner functions ......................................................... 22
  2.6 Key assumptions .............................................................................................................................. 23

3.0 The regulatory review process .................................................................................................... 25
  3.1 Introduction ....................................................................................................................................... 25
  3.2 Overview .......................................................................................................................................... 25
  3.3 Conduct of this project ..................................................................................................................... 27
  3.4 The expertise used .......................................................................................................................... 28
  3.5 Scope of this review .......................................................................................................................... 29
  3.6 April 2009 information note on preliminary proposals .................................................................. 29

4.0 The Regulatory Asset Base .......................................................................................................... 38
  4.1 Introduction ....................................................................................................................................... 38
  4.2 Composition of the RAB .................................................................................................................. 38
  4.3 Valuation of the Regulatory Asset Base .......................................................................................... 39
  4.4 Asset Lives Applied to the RAB ....................................................................................................... 42
  4.5 Depreciation method ....................................................................................................................... 44
  4.6 Replaced Assets ............................................................................................................................... 45
  4.7 Additions to TSO and TAO RABs .................................................................................................... 46
  4.8 Summary ......................................................................................................................................... 47

5.0 Cost of capital .................................................................................................................................. 49
  5.1 Introduction ....................................................................................................................................... 49
  5.2 Methodology for setting the cost of capital ..................................................................................... 50
  5.3 Europe Economics’ Point Estimate .................................................................................................. 51
  5.4 Incentives for delivery ..................................................................................................................... 52
  5.5 Uncertainty ....................................................................................................................................... 52
  5.6 Financeability ................................................................................................................................... 54
6.0 Performance & incentives ................................................................. 57
6.1 Introduction ..................................................................................... 57
6.2 Historical performance ................................................................... 57
6.3 2011-2015 PR3 Incentives ................................................................. 63

7.0 Review of historical capital expenditure .............................................. 64
7.1 Introduction & Objectives ................................................................. 64
7.2 Capex – Summary .......................................................................... 65
7.3 TAO Capex .................................................................................... 67
7.4 TSO Capex Non-Network ................................................................. 70
7.5 Difference between Capex approved and incurred ......................... 73

8.0 Review of forecast Capital expenditure .............................................. 75
8.1 Introduction ..................................................................................... 75
8.2 Objectives ...................................................................................... 78
8.3 Efficiencies built into capex allowances ............................................. 79
8.4 Network Capex ............................................................................. 80
8.5 PR3 Network Capex Approvals Program ......................................... 89
8.6 TSO Non-network Capex ................................................................. 90
8.7 Conclusions ................................................................................... 91

9.0 Review of historical operational expenditure ...................................... 93
9.1 Introduction ..................................................................................... 93
9.2 Objectives for the review of historic Opex ......................................... 93
9.3 Points of Note ................................................................................ 93
9.4 TAO Opex – Internal .................................................................... 94
9.5 TAO Opex - External ................................................................. 96
9.6 TSO Opex – Internal ................................................................. 97
9.7 TSO Opex – External ................................................................. 102
9.8 Conclusion .................................................................................. 105

10.0 Review of forecast operational expenditure ..................................... 108
10.1 Introduction .................................................................................. 108
10.2 Objectives for the Opex review ..................................................... 108
10.3 Efficiencies built into allowances ..................................................... 108
10.4 TAO Opex – Internal ................................................................. 117
10.5 TAO Opex – External ................................................................. 120
10.6 TSO Opex – Internal ................................................................. 121
10.7 TSO Opex – External ................................................................. 125
10.8 East-West Interconnector Charge ............................................... 128
10.9 TSO Working Capital Arrangements in PR3 .................................... 129
10.10 Conclusion ................................................................................ 137
11.0 Benchmarking ........................................................................................................... 139
  11.1 Introduction ........................................................................................................ 139
  11.2 Conclusion ........................................................................................................ 140

12.0 Tariff rebalancing .................................................................................................... 141
  12.1 Introduction ........................................................................................................ 141
  12.2 Details regarding tariff rebalancing ................................................................... 141
  12.3 Conclusion ........................................................................................................ 143

13.0 Form of the Control ............................................................................................... 144
  13.1 Structure of the Price Control .......................................................................... 144
  13.2 Base year revenue and profiling ...................................................................... 148
  13.3 Allowed Revenue ............................................................................................. 152
  13.4 TSO Revenue control formula ......................................................................... 155
  13.5 TAO Revenue control formula ......................................................................... 158

14.0 Tariffs for 1st October 2010 to 30th September 2011 ............................................. 161
  14.1 Introduction & background ............................................................................. 161
  14.2 Revenue related to the PR2 period .................................................................... 161

15.0 Conclusions ........................................................................................................... 163

Appendix A – Composition of the TAO RAB (1st Jan 09) ............................................. 165
1.0 Introduction

1.1 The Commission for Energy Regulation

The Commission for Energy Regulation (‘the CER’) is the independent body responsible for overseeing the regulation of Ireland's electricity and gas sector's. The CER was initially established and granted regulatory powers over the electricity market under the Electricity Regulation Act, 1999. The enactment of the Gas (Interim) (Regulation) Act, 2002 expanded the CER's jurisdiction to include regulation of the natural gas market, while the Energy (Miscellaneous Provisions) Act 2006 granted the CER additional powers in relation to gas and electricity safety. The Electricity Regulation Amendment (SEM) Act 2007 outlined the CER's functions in relation to the Single Electricity Market (SEM) for the island of Ireland. This market is regulated by the CER and the Northern Ireland Authority for Utility Regulation (NIAUR). The CER is working to ensure that consumers benefit from regulation and the introduction of competition in the energy sector.

1.2 Purpose of this paper

This decision paper sets out the CER's decision on the revenue that EirGrid (the Transmission System Operator, TSO) and ESB Networks (the Transmission Asset Owner, TAO) will be allowed to recover from the TUoS customer over the period 2011 to 2015. This revenue will allow the TSO and TAO to finance their activities as the monopoly electricity system operator and system owner in Ireland.

1.3 Structure of this paper

The structure of this decision paper is outlined in this section. It should also be noted that a separate overview paper which provides a high level summary of this paper:

- Section 1.0 details the purpose of this paper;
- Section 2.0 provides relevant background information. It also provides information on the CER's objectives for this review period and key assumptions;
- Section 3.0 outlines the process through which this review has been conducted to date. It also addresses comments received to the previous consultation on this project;
- Section 4.0 provides information on how the TSO and TAO Regulatory Asset Bases (RABs) have been derived for the 2011 to 2015 period;
- Section 5.0 provides information on the cost of capital for application to the TSO’s and TAO’s RAB over the 2011 to 2015 period;
- Section 6.0 provides information on incentives for the 2011 to 2015 period;
• Section 7.0 outlines a review of the TAO's and TSO's historical capital expenditure for the 2006 to 2010 period;
• Section 8.0 outlines a review of the TSO's forecast capital expenditure for the 2011 to 2015 period;
• Section 9.0 outlines a review of the TAO's and TSO's historic operational expenditure for the 2006 to 2010 period;
• Section 10.0 outlines a review of the TAO's and TSO's forecast operational expenditure for the 2011 to 2015 period;
• Section 11.0 provides information on benchmarking;
• Section 12.0 provides information on a change to the manner in which the TSO collects TUoS revenue from its customers;
• Section 13.0 provides information on how the decision outlined within the previous sections feed through into the TUoS revenue that would be collected each year by the TSO;
• Section 14.0 provides information the TUoS tariffs that will be in place for the 1\textsuperscript{st} October 2010 to 30\textsuperscript{th} September 2011 tariff period; and
• Section 15.0 provides a conclusion to the decisions outlined in this paper.

Reports provided by two consultancy advisors engaged by the CER to assist with this project have also been published alongside the consultation papers CER/10/102 and CER/10/103\textsuperscript{16}. These are:

• A report by Sinclair Knight Mertz recommending the appropriate level of revenue required to finance the technical aspects of the TSO's and TAO's activities, appropriate incentive mechanisms etc; and,
• A report by Europe Economics on the appropriate cost of capital for the TSO and TAO.

The CER position in this decision paper draw from the recommendations provided in these reports.

The following documents have also been published alongside this decision paper:

• A response-to-comments paper (CER/10/207);
• The ten responses received to the consultation on this matter; and,
• The PR3 transmission decision revenue model (CER/10/209).

\textsuperscript{16} Further information on the role of these advisors is provided in Section 3.4.
1.4 Queries on this paper

Queries on the decisions outlined in this paper should be sent to:

Jamie Burke  
Electricity Transmission  
Commission for Energy Regulation  
The Exchange  
Belgard Square North  
Tallaght  
Dublin 24  

Email: jburke@cer.ie  
Tel: 00353 (1) 4000800  
Fax: 00353 (1) 4000850
2.0 Background, objectives & assumptions

2.1 Introduction

This section provides the following information:

- Relevant areas of the CER’s role and the powers under which the CER will make its determination on the price control are outlined;
- The manner in which this price control follows on from previous controls is discussed;
- The CER’s objectives for the 2011 to 2015 revenue control are detailed;
- The changes to the structure of the transmission system in Ireland since the vesting of EirGrid as TSO in July 2006; and
- The key assumptions underpinning the review have been documented.

2.2 The CER’s role in the determination of this control

Under Section 35 of the Electricity Regulation Act 1999 (“the Act”), the CER approves charges for the use of the electricity transmission system in Ireland.

In accordance with Section 35 of the Act, this document outlines the CER’s decision on the revenue that the TSO and TAO will be allowed to recover from TUoS customers during the period from 2011 to 2015.

The rationale for the CER’s decision is explained in detail in the remainder of this paper. The level of revenue is detailed in section 13.0 of this paper.

Section 36 of the Act states that the TSO’s statement of charges, prepared in accordance with Section 35, must be submitted to the CER for approval and will not take effect until approved by the CER. In accordance with Section 36 of the Act, the TSO’s approved statement of charges for the 1st October 2010 to 30th September 2011 tariff period will be published alongside a decision paper on this matter.

2.3 Context of this revenue control

This paper sets out the CER’s decision on the revenue that the TSO and TAO will be allowed to recover from the TUoS customer over the period 2011 to 2015. This will be the third such transmission revenue control to be set by the CER.

---

17 Note that the TUoS tariffs for the 1st October 2010 to 30th September 2011 period have been approved by the CER. Please see document CER/10/102(j) and the 2010/2011 Statement of Charges published on the EirGrid website.
PR1: 2001 to 2005

The first five year control covered the period from 2001 to 2005\(^{18}\). This period saw many fundamental changes in the Irish electricity system relative to the preceding period. Load growth continued apace as the economy expanded. These developments followed on from a period from the mid eighties through the late nineties, which saw curtailed investment in the electricity network in Ireland. Against that background, the revenue control set in 2001 was intended to support the substantial new investment required while at the same time incentivising efficiency improvements in the transmission utilities.

At a general level, the CER believes that the revenue control was successful in providing the basis for system expansion and renewal. Significant improvements were achieved in addressing the effects of the historical lack of investment in the transmission system, with good progress made in increasing reliability and safety. The transmission network was extended and reinforced to accommodate rising demand and new connections.

PR2: 2006 to 2010

The second five year control covers the period from 2006 to 2010\(^{19}\). Again, when setting this control the CER’s objectives included ensuring that the transmission businesses were able to maintain the transmission network to an adequate standard to meet customers’ expectations. Coupled with this was the need to ensure that the interests of final customers were protected, in the short and long term, by delivering efficient network investment and containing tariffs to the maximum extent possible. During PR2 (and indeed previously in PR1) substantial levels of renewables and other new generation have connected, resulting in the need for significant expansion and reinforcement of the transmission system.

During PR2 load growth continued apace as the economy expanded. However, for both 2009 and 2010, due to the current economic circumstances, load growth and by extension energy throughput figures have been, and are expected to be, in the negative.

The CER’s objectives also included ensuring that the transmission businesses were able to attract the necessary level of capital investment to support the approved level of renewal and extension of the network. Appropriate incentives were included to encourage the TSO to improve both its efficiency and the quality of its service to customers\(^{20}\). The CER set incentives that were challenging but achievable.

---

\(^{18}\) The decision on transmission revenue for the period 2001 to 2005 is available [here](http://www.cer.ie/en/electricity-transmission-network-decision-documents.aspx?article=decf3b52-6d3d-4be1-b99d-efa0d186a3bb).

\(^{19}\) The decision on transmission revenue for the period 2006 to 2010 is available [here](http://www.cer.ie/en/electricity-transmission-network-decision-documents.aspx?article=decf3b52-6d3d-4be1-b99d-efa0d186a3bb).

The control was set in a manner that aimed to keep the day-to-day intervention by the CER in the TSO’s and TAO’s business to a minimum. This allows the TSO and TAO to manage its own costs in an efficient and independent manner while adhering to the principles and allowed revenues outlined in the PR2 decision paper and indeed this paper.

Generally, this revenue control has been successful in that the TSO has responded to the PR2 incentive mechanisms by increasing the quality of its service to customers. Details on improvements in System Minutes Lost, System Frequency, and Fault Clearance are provided in the TSO’s annual system performance reports. Further information on this is also provided in Section 6.0 of this paper.

PR3: 2011 to 2015

The PR2 revenue control ends on 31st December 2010. The next control period, PR3, will cover the period from 2011 to 2015. The decision in relation to this control is contained in this paper. The objectives of PR3 are outlined in the following section.

2.4 Objectives for this revenue control

The CER’s objectives for this revenue control are detailed below:

- To ensure that the work being carried out by the TSO and TAO in PR3 represents value for money for consumers;

- To complete this review and document the decision making process in a transparent manner with full and adequate consultation with interested parties;

- To maintain regulatory certainty;

- Ensure that the TSO and TAO are able to develop and maintain the transmission network to a high standard;

- Ensure that the interests of final customers are protected, in the short and long term. This involves ensuring that transmission costs and the tariffs set to recover these costs are contained to the maximum extent possible, while at the same time delivering efficient network investment;

- Ensure that ESB Networks as Transmission Asset Owner (TAO) and EirGrid as Transmission System Operator (TSO) are able attract the

---

21 Please refer to the EirGrid website for these performance reports.
necessary level of capital investment to support the approved level of renewal and extension of the network. In doing so, the CER wishes to ensure that the TSO’s investment plans provide value for money for customers in terms of the benefits they add. The CER also wishes to ensure the successful roll-out of Gate 3 and its ambitious renewables objectives, as per the CER’s 2008 direction. This direction provides for 40% of Ireland's electricity consumption coming from renewable generation by 2020. It is envisaged that this will come through the connection of circa 3,900MW of renewable generator projects in Gate 3 to the electricity system. PR3 will be crucial in determining the success of this scheme:

- Appropriate incentives are provided for the TSO and TAO to improve their efficiency and that appropriate savings gained through these incentives are passed through to consumers; and

- The day-to-day intervention by the CER in the TSO’s and TAO’s businesses is kept to a minimum.

2.5 Effective unbundling of system operator and owner functions

This section outlines the changes that took place to the structure of the transmission system during the PR2 period.

Pursuant to Statutory Instrument No. 445 of 2000, EirGrid is the statutory body licensed by the CER to act as the operator of Ireland’s electricity transmission system. The TSOs responsibilities include the operation, maintenance and development of Ireland’s electricity transmission system in a safe, secure, reliable, economical and efficient manner. The body which previously undertook the TSO’s functions prior to the establishment of EirGrid on 1st July 2006 was ESB National Grid.

Under this Statutory Instrument ESB Networks is licensed by the CER as the owner of Ireland’s electricity transmission system. The TAO is required to maintain the transmission system and carry out construction work for its development in accordance with the TSO’s Transmission Development Plan.

As a result of the structural split between the ownership and the operation of the transmission system, an Infrastructure Agreement has been drawn up between the TSO and TAO to govern the ongoing relationship between the two organisations. The agreement has been approved by the CER and came into effect on 1st July 2006 - the same date as the legal establishment of EirGrid as the TSO.

22 Please see following link: http://www.cer.ie/en/electricity-transmission-network-decision-documents.aspx?article=fb726a75-7365-4dfb-9e16-ff5c5d2d363a
Under the Infrastructure Agreement the responsibilities can be briefly summarised as follows:

Table 4: Breakdown of TSO and TAO responsibility as per IA.

<table>
<thead>
<tr>
<th>ACTIVITY</th>
<th>TSO RESPONSIBILITY</th>
<th>TAO RESPONSIBILITY</th>
</tr>
</thead>
<tbody>
<tr>
<td>Identification of Need</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Provision of Standard Costs</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>Selection of Optimal Solution</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Obtaining Planning Permission</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Obtaining Wayleaves</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Outage Planning</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Detailed Design</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>Procurement of Materials</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>Procurement of Resources</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>Management of Site Works</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>Commissioning</td>
<td></td>
<td>X</td>
</tr>
</tbody>
</table>

2.6 Key assumptions

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

2.6.1 Transmission system owner and operator structure

The transmission system operator and owner functions will continue to remain as a semi-state enterprise for the duration of the review and there will be no
substantial changes made to its structure. Therefore the transmission allowed revenues for 2011-2015 have been set on the basis of the current industry structure and the CER is assuming that this structure will be in place for the PR3 period. Should this position change over the five years of this revenue control period the CER will take the appropriate steps to review the regulatory structures and revenues in place for transmission.

Therefore, the policies outlined in this decision paper are on the basis that EirGrid will remain as TSO and ESB Networks will remain as TAO for the 2011-2015 PR3 period. For the assumptions outlined in sections 2.6.2 to 2.6.4, the process through which the revenue control will adapt to cover changes has been outlined.

Changes in the assumption outlined in this section would lead to a re-opening of the transmission revenue control.

2.6.2 TSO and TAO functions

There will be no substantial changes in the functions of the TSO and TAO.

2.6.3 PR2 outturn figures

Within this paper, the figures provided by the TSO and TAO on their respective expenditure during the PR2 period have been labelled as actual or outturn values. This is not strictly correct. The 2010 values are the TSO’s/TAO’s best estimate of the expenditure they will incur in 2010.

The final values for 2010 will be reviewed when these are available in 2011 and if necessary the revenue that the TSO and TAO should be allowed to collect from the TUsS customer will be adjusted at that time to reflect the outcome of the review.

2.6.4 Other

For the purposes of setting tariffs for the forthcoming period assumptions have been made regarding:

- the level of GWhs that will be consumed; and
- the 2010 and 2011 indexation values.

Revenue over or under-recoveries due to inaccuracy of these assumptions will be corrected through the use of a “k – factor” mechanism, which will be netted off the revenue to be collected in subsequent tariff periods. This process is detailed within Section 13 of this paper.
3.0 The regulatory review process

3.1 Introduction

This section provides information on the process that led to the decisions outlined in this paper. It provides:

• A high level overview of the process;
• Information on how the project has been conducted to date;
• A summary of the expertise used;
• Information on the scope of this review;
• Details of, and responses to comments received to, an information note that was published in April 2009 regarding this project;

3.2 Overview

This section provides a high level summary of the approach the CER has adopted to determining the revenue that the TSO and TAO can recover from TUoS customers during the period 2011 to 2015. Section 3.3 provides more detail on the steps taken as part of this process. Sections 7.0 to 10.0 provide more detail on how the TSO’s and TAO’s historic and forecast expenditure was reviewed; this includes information on benchmarking completed as part of the review.

The following documents have also been published alongside this decision paper:

• A response-to-comments paper (CER/10/207);
• The ten responses received to the transmission consultation on this matter; and
• The PR3 transmission decision revenue model (CER/10/209).

Review of historic Opex

The Opex incurred by the TSO and TAO over the period 2006 to 2010\textsuperscript{23} was reviewed. This involved assessing improvements in efficiency made by the TSO and TAO during that period, bearing in mind the significant changes that have taken place in the market structure, including vesting of EirGrid in July 2006, the implementation of the IA also in 2006 and the establishment of the Single Electricity Market (SEM) in November 2007.

\textsuperscript{23} It should be noted that 2010 values are currently forecast.
Review of forecast Opex

The Opex which the TSO and TAO forecasts they will incur respectively during the period 2011 to 2015 was reviewed, with particular focus on ensuring value for money and efficiency improvements.

Review of historic Capex

The Capex incurred by the TSO and TAO over the period 2006 to 2010\(^{24}\) was reviewed. The appropriateness and efficiency of the investments made during that period were assessed. This analysis included an assessment of actual versus planned Capex over the period, in terms of the volume of, unit cost of, and need for the investment. This review took account of the efficiency and value for money of the outturn expenditure compared to that forecast by the transmission businesses in advance of PR2.

Review of forecast Capex

The Capex program required for the PR3 period, as forecasted by the TSO was examined, with particular focus on ensuring value for money and the developing the transmission network towards reaching the Government's 2020 renewables target.

Determining the regulatory asset base

Following the above reviews of historic Capex any variances between the approved and actual expenditure which had been efficiently incurred by the TSO and TAO were reflected by adjusting the respective regulatory asset base (RAB). The original RABs had been put in place as part of the first five-year review (2001 to 2005) and adjusted for the second (2006 to 2010).

The TAO and TSO RABs were also adjusted to allow for the approved forecast Capex. It has been decided that these adjusted RABs will be used for the forthcoming review period (2011 to 2015) and have been published alongside this paper.

Determining the appropriate cost of capital

A cost of capital for application to both the TSO's and TAO's regulatory asset base has been developed and this has been addressed in section 5.0 of this paper.

\(^{24}\)It should be noted that 2010 values are currently forecast.
Determining appropriate incentives

Transmission incentives for both the TSO and TAO for the forthcoming incentive period are currently being consulted on. Proposed transmission incentives for the next incentive period will be consulted on with stakeholders in a separate CER paper in the coming weeks.

Determining the allowed revenue

The output of the above analysis was fed through to develop revenue for the TSO and TAO (which will be recovered from the TUoS customer) for each calendar year within the period 2011 to 2015. This revenue feeds through into the setting of TUoS tariffs for each tariff period, 1\textsuperscript{st} October to 30\textsuperscript{th} September.

Determining TUoS tariffs

This paper includes information on demand TUoS tariffs for the next tariff period, from 1\textsuperscript{st} October 2010 to 30\textsuperscript{th} September 2011. They are based on three months (demand weighted) of the 2010 calendar year revenue (please see CER/09/140) and nine months of 2011 calendar year revenue. It is intended that the same methodology, for allocation of calendar year revenue for recovery during tariff periods, will be used for subsequent tariff periods.

Generator TUoS tariffs for the period 1\textsuperscript{st} October 2010 to 30\textsuperscript{th} September 2011 were published by the CER during the consultation phase – please refer to CER/10/102(k).

3.3 Conduct of this project

In order to ensure that there is clarity as to the underlying data and assumptions as well as the analysis itself, this project has involved a high level of interaction with the TSO and TAO\textsuperscript{25}. In addition, information on this review has previously been published for consultation. The high level steps associated with this process are provided here.

The first phase of public consultation was undertaken in April 2009, when the CER published an information note (CER/09/047) requesting comments on the proposed scope of its forthcoming electricity transmission and distribution revenue reviews\textsuperscript{26}. Further detail on the content of, and comments received to, that information note is provided below in Section 3.6.

\textsuperscript{25} Some aspects of the TAO’s costs relate to services shared with other ESB business units. Separate information was sought and received from ESB Corporate in respect of those costs.

\textsuperscript{26} The information note/consultation paper published by the CER in April 2009 regarding the scope of this review is available here.
In parallel with the above consultation the CER acquired consultancy support for the provision of technical and financial advice over the course of the project. Detail on this is provided above in Section 3.4.

To ensure that the CER and its advisors attained an adequate understanding of the TSO’s and TAO’s business, the CER engaged with both parties to ensure that relevant data was provided in a useable format. A questionnaire was issued to the TSO and TAO outlining the technical, economic and financial data required by the CER. The TSO and TAO then separately completed the questionnaire in two stages: providing historic data first and then progressing to forecast information. Following submission there was a period of interaction between the CER and the TSO and TAO during which clarifications and further information were sought. A number of site visits to key installations were also completed.

This interaction allowed the CER, with the assistance of its advisors, to complete a comprehensive review of the TSO’s and TAO’s historic and forecast performance, leading to the development of the decisions outlined in this paper. Prior to publication of these proposals for consultation in CER/10/102, they were discussed with both parties and reviewed for technical accuracy.

Following consideration of all comments received to that consultation, the CER is now publishing its decision on this matter. All comments received have been published alongside this paper. In addition, a CER response-to-comments paper which summarises and responds to all comments received has also been published alongside this decision.

3.4 The expertise used

The CER has completed numerous reviews of regulated utilities since its foundation in 1999 and has developed its internal abilities over that period. To augment these skills, and reflecting the range of analysis required, the CER has acquired the services of economic and engineering experts to assist in the review of the TSO’s and TAO’s historic and forecast costs as well as their respective performances in PR2.

Sinclair Knight Mertz (SKM) was procured to provide advice on the technical aspects of the review. This includes reviewing the TSO’s and TAO’s capital and operational expenditure and providing advice on an efficient level which should be approved by the CER for recovery from the TUoS customer. This role includes completing the benchmarking studies necessary to provide relevant and well founded advice.

Europe Economics was procured to provide advice on the financial aspects of the review. The main body of work being completed by Europe Economics is the provision of advice on the appropriate cost of capital for the TSO and TAO for the five year period 2011 - 2015.
The advice put forward by the CER’s consultancy support has fed through into this consultation paper. In addition, the reports put forward by both SKM and Europe Economics were published alongside the consultation papers (CER/10/102 and CER/10/103).

3.5 Scope of this review

The review and decisions outlined in this paper relate to the regulated aspects of the TSO’s and TAO’s activities. With regard specifically to the TAO, this work forms part of a wider review process in which each of ESB’s regulated business units have been assessed\(^\text{27}\). With relevance to the current review, to set the costs to be recovered from the TUoS customer, the CER has also taken into account:

- Transfers of costs and revenue between separate ESB business units, for example in respect of ESBI; and,
- The allocation of corporate centre costs and overheads to the regulated business units. Separate information was sought from ESB and EirGrid Corporate in respect of those costs.

3.6 April 2009 information note on preliminary proposals

3.6.1 Introduction

This will be the third revenue control to be put in place for the TAO and the first full price control for EirGrid since it assumed the role of TSO in July 2006. The previous reviews allowed some treatments (for example, depreciation methodologies) to become established practice. As a result, the CER stated its intent to continue using some of the methodologies established during the previous reviews, and to focus on other areas that would ensure that the TSO and TAO businesses are operated and developed in a cost-effective manner. In April 2009 an information note was published to this effect\(^\text{26}\). Sections 3.6.2 to 3.6.3 provide a summary of the main points of that information note, the comments received and the CER’s responses.

3.6.2 Summary of April 2009 information note

In April 2009, the CER published an information note highlighting and requesting comments on some initial high level proposals regarding the review of the TSO’s and TAO’s performance and costs. The CER proposed that the project undertaken by the CER would focus on reviewing and setting the TSO’s and TAO’s businesses:

---

\(^{26}\) Please also refer to the PR3 Distribution consultation paper (CER/10/103) published on 5\(^{\text{th}}\) July 2010.
• Opex;
• Capex;
• weighted average cost of capital (WACC);
• regulatory asset bases (that is, adjusting for the level of expenditure incurred by the TSO and TAO); and
• financial performance incentives.

The CER stated its belief that focusing on the above areas would allow for the continued protection of electricity customers by ensuring that the electricity network businesses are operated and developed to meet customer needs in a cost-effective and efficient manner.

The information note outlined the CER’s proposal that, on the basis of regulatory certainty and maintaining regulatory precedent, certain methodologies which have become established during the previous control periods, would not be reviewed as part of this project. These are as follows:

• The length of the review would not be changed. That is, it would continue to be a multi-annual revenue review covering a 5 year period;
• The Capital Asset Pricing Model (CAPM) would continue to be used to aid the determination of a WACC which would be applied to the TSO’s and TAO’s RAB;
• The CPI-X model would continue to be used to set the level of revenue to be recovered from the TUoS customer; and,
• The existing methodologies used for valuation and depreciation of the businesses assets would continue to be applied.

The CER also stated that it continued to believe that the revenue controls for the transmission and distribution businesses should be set using a common set of principles. However, in developing the controls for each business, the CER committed to taking into account their specific features.

The CER noted that it would consider all submissions to that information paper and respond as appropriate in the relevant consultation papers. Comments were invited from stakeholders on the scope of the review and alternative methodologies that could be taken with respect to the currently adopted approaches listed above.

A summary of the comments received is provided in the following section. The CER’s position is also provided on each. In addition the original responses provided to the information note are published alongside this paper.
3.6.3 Comments & responses

Three respondents provided comments on the information note. These responses are published alongside this paper. The main points of each and the CER’s position on these points are provided below.\(^{28}\)

**Consistency of methodology**

One respondent supported the CER’s objective of using a common set of principles for the transmission utilities and Distribution System Operator (DSO) where possible. The respondent also stated its belief that continuity of methodology is important and emphasised the need for incremental development of the methodology, rather than abrupt changes to accommodate new ideas.

Another respondent, while welcoming the CER’s commitment to regulatory certainty, stated that a degree of flexibility is required and items should not be precluded from further consideration during the review.

The CER has borne these comments in mind during the PR3 project.

**Five-Year review**

Two respondents stated that they supported the CER’s intention to continue with the existing five-year review period. It was recognised that this timeframe balanced the need for a length over which costs would be relatively predictable while also allowing time for utilities to respond to the incentives placed on them. It also allowed a reasonable level of planning certainty.

The third respondent did not comment on this aspect of the information note. The CER intends to continue the practice of setting transmission revenue on a five-year basis. This control period will cover 2011 to 2015.

**The use of CAPM**

**Comments**

One respondent agreed that CAPM should continue to be used, but that it should be used in a transparent manner and supplementary tools, such as the dividend growth model and market return analysis, should be used to check that the model is providing robust answers.

Regarding transparency, they stated that it should be clear how;

---

\(^{28}\) It should be noted that the information note provided proposals on both the transmission and distribution reviews. Consequently, responses covered both transmission and distribution. This consultation paper responds to comments that are relevant to transmission.
the proxy cost of equity is to be derived in the absence of real shareholders;
international utility comparators are used; and,
adjustments are made for business scale and interest rate differentials, etc.

They stated that it is important that the progression from input data to final conclusion is presented in a way that maximises use of objective data and noted that if current financial conditions persist into the review timescale, then it would also be important to define the treatment of any anomalies in the interest rate spread between official rates and the cost of borrowing.

A second respondent similarly supported the use of CAPM, but noted that estimating a cost of equity through the CAPM is not a precise science, and this is particularly so in the case of state owned and unlisted businesses. This respondent stated that it is therefore important that other information sources and approaches are not precluded from consideration in estimating the cost of equity.

The third respondent did not comment on this aspect of the information note.

Response

When developing proposals on the appropriate cost-of-capital for the transmission utilities, the CAPM model was used. Crosschecks with other information sources have been used to check the robustness of the proposals. However, dividend growth models and market return analysis were not specifically used as crosschecks.

Information on this is provided within a report by the CER’s advisors on this aspect of the control. This was published alongside the transmission consultation paper.

The report by the CER’s advisors, together with the information provided in Section 5.0 of this paper, should address the concerns regarding the provision of a clear view of the process through which the CER’s decisions have been developed.

CPI-X

CPI-X is a regulatory mechanism used to promote efficiency while taking account of inflationary/deflationary economic pressures. The ‘X-factor’ is an efficiency target. The two respondents that commented on this aspect of the information note were in favour of continuing this methodology. It was noted that the basis on which the X-factor was set should be as clear and objective as possible.
The CER has borne these comments in mind during the PR3 project. This aspect of the review is commented on further in Section 13.1.1 of this consultation paper.

Incentives

A general theme highlighted within responses was the importance of having appropriate incentives in place to reward performance, drive change and business efficiencies, rule out ‘gold-plating’, etc. It was stated that the review should ensure that performance mechanisms would incentivise state enterprises as effectively as they would a private firm.

The CER has borne these comments in mind during the PR3 project. Proposed transmission incentives for the next incentive period will be consulted on with stakeholders in a separate CER paper in the coming weeks.

Valuation and depreciation

Comment

One respondent stated that there was a lack of detailed information on how the CER calculates transmission and distribution charges, specifically on the exact methods of valuation of existing ESB Networks infrastructure. The respondent stated that without accurate detail as to how the CER is valuing ESB Networks’ asset base it is impossible to determine whether the consumer is being taken advantage of. The respondent requested that the CER:

- publish its detailed calculations on its valuation of ESB networks’ assets,
- extend its public consultation period to allow a full analysis by independent experts and interested parties and
- to appear before the Joint Oireachtas Committee on Communications, Energy and Natural Resources before committing to PR3.

Another party, while not providing a formal response, also requested additional information on the valuation methodology applied by the CER for previous revenue controls.

Response

To allow for the first request detailed above, and a previous request by the Joint Oireachtas Committee on Communications, Energy and Natural Resources, in June 2009 the CER published its detailed calculations behind the valuation of both the electricity TAO and distribution RABs for the first and second revenue reviews29. Similar calculations for the electricity transmission RAB (both TSO and

29 Calculations behind the valuation of the electricity transmission and distribution regulated asset bases for the first and second price reviews are available here.
TAO) for the 2011 to 2015 period have been published alongside this decision paper.

The respondent also requested an extension of the consultation period to allow a full analysis by independent experts and interested parties. The response date for the earlier consultation on this project was May 2009. Following publication of details on the asset base calculations no further submissions were received from any interested parties. However, interested parties were given a further opportunity to comment on the proposals for the 2011 to 2015 revenue period in CER/10/102. The CER believes that the publication of this data covered off the second request for additional information as detailed above.

The same respondent also requested that the CER appear before the Joint Oireachtas Committee on Communications, Energy and Natural Resources before committing to this project. As noted in the consultation paper the CER has appeared in front of this committee and others a number of times in 2009 and 2010. The CER continues to be available to attend further sessions as required.

**Comment**

One respondent stated that it supported the proposed approach, but added that the review should not preclude consideration of other items such as the approach for providing return on the asset base. They stated that it is important that a degree of flexibility is maintained on this and all other aspects of the review.

**Response**

The CER has borne these comments in mind during the PR3 project.

**Comment**

One respondent stated that international yardsticks should be used to validate the valuation.

**Response**

The methodology used by the CER has been validated as part of previous reviews and the CER did not move from this methodology as part of this review.

**The approval of expenditure for recovery**

**Comment**

One respondent stated that it is important that capital expenditure be subject to a robust and expert challenge process, both as to necessity and cost.
Response

As per previous price reviews the CER has employed technical advisors to challenge all requested capital expenditure submitted by the TSO. The CER intends to further build and refine the capex monitoring program that was put in place in the PR2 period. This will involve the addition of a formal Capex approvals process as well as refinements and improvements to the monitoring process. The refined PR3 Capex monitoring and approvals process will be outlined in conjunction with the PR3 transmission incentives workstream.

Comment

One respondent stated that there must be scope for including directed expenditure, for example, full metering on the distribution system to improve the measurement of losses and customer demand or implementation of transmission IT systems, to improve transparency and accuracy in the Single Electricity Market.

Response

The CER has reviewed all proposed expenditure put forward by the TSO, TAO (and DSO) and has also included incentives for improvement in the TSO’s and TAO’s performance in some areas. However, the CER has not provided specific directions on the manner in which improvements should be brought about. It is the TSO’s and TAO’s responsibility to respond to those incentives in an efficient, cost effective manner.

Information on assets transferred to the TAO

Comment

One respondent stated that those who build connection assets (and hand them over to the networks businesses for minimal cost) believe that information on the nature and valuation of this asset group should be part of the standard published dataset.

The respondent stated that as part of this project, there should be a consultation on the valuation, treatment and balance sheet benefits attributable to these assets and means whereby these could be retained by the investors repaying the associated debt.
**Response**

The CER understands that this refers to assets built contestably for the connection of Generators to the electricity network. In response to a request by the CER, ESB Networks provided the following regarding the treatment of such assets:

**Numbers**

*Three contestably built generator transmission connection assets have transferred to the Transmission Asset Owner (TAO). Four more are currently in the process of transferring.*

**Treatment**

*As mentioned by the respondent, these assets transfer at a nominal sum of €1. There is effectively no return on these assets. For this reason, the correct accounting treatment for them is not straightforward and is currently being discussed with the external auditors of ESB and a resolution is expected in the near future.*

While not specifically part of this project, a consultation on matters related to distribution contestability and further development of transmission contestability was initiated and completed following publication of the information note, and receipt of the above response. This consultation considered the second comment outlined above. The CER does not intend to undertake further consultation on this matter as part of this revenue control project.

**Alignment of revenue year with tariff year**

**Comment**

One respondent maintained that the tariff year and revenue year should be aligned, consistent with the Regulatory Authorities’ (RAs) decision paper AIP/SEM/07/0931. This respondent believed that in the absence of alignment, there is no defined revenue on which to base tariffs and that the interim solution creates a layer of complexity to the annual tariff and revenue setting process.

---

30 Please refer to CER/10/056
31 Please see the following link: http://www.allislandproject.org/en/generation.aspx?page=3&article=5acbc469-e103-4962-b30f-6dd2e31a404c
32 Demand weighted breakdown – please refer to section 14.0 of this paper for further detail.
Response

The CER acknowledges the decision made by the RAs in AIP/SEM/07/093 and is also aware that the TSO has already adjusted its accounting year to align with the tariff year on the basis of the RAs stated intention in that decision paper.

Post receipt of responses to CER/09/047 the CER requested the other two licensees involved in the electricity networks price control (ESBN as DSO and TAO) to comment on the proposed shift to allow alignment. Considering that ESBN is transmission and distribution network asset owner, the CER felt it was important that ESBN outlined any specific issues or complexities, with such an alignment.

ESB Networks’ response outlined the following. ESB Networks’ statutory accounting or regulatory reporting periods are aligned with the price control revenue year. These, in turn, are aligned with the income tax year set by government. By license ESB Networks Ltd. is required to reconcile their regulatory accounts with its statutory accounts. ESB Networks’ maintained that compliance with this requirement in a transparent manner would be very challenging if a new, distinct timeline were introduced and reconciliation was required across two different annual periods.

ESB Networks’ also maintained that the new arrangement would entail additional cost. The task of preparing regulatory accounts to a different reporting period than the statutory accounts would cause a significant additional administrative burden and cost, for instance two different closing periods and two different audits by external auditors.

In light of the above, the CER is not aligning the revenue tariff with the tariff year for PR3, at the present time. Although AIP/SEM/07/093 specified that an alignment should occur, it did not outline timelines for such a move. This is not to say that the issue will not be reviewed in the future, especially if any significant industry changes were to occur. Also, the CER does not feel that the current system of calculating tariffs across two revenue years, i.e. the demand weighted breakdown, is overly onerous and complex and believes that the current system is transparent to stakeholders and to the TUoS customer.
4.0 The Regulatory Asset Base

4.1 Introduction

The revenue that is recovered from the TUoS customer during each review period can be divided into three separate categories:

1. Revenue to cover the TSO’s and TAO’s operational costs during that period;
2. A return on capital invested in the TSO’s and TAO’s assets; and
3. Revenue to cover depreciation of the TSO’s and TAO’s assets.

The Regulatory Asset Base (RAB) plays a key role in the determination of the amount of depreciation that the TSO and TAO receives (item 3 above), and is the base to which the rate-of-return is applied when determining the return on capital for the TSO and TAO (item 2 above).

This section provides information on a number of interrelated issues that determine the TSO’s and TAO’s RAB. Specifically, this section provides information on:

- the type of assets within the TSO’s and TAO’s RAB;
- the methodology used to value the assets within the TSO’s and TAO’s RAB;
- the length of asset lives applied to the assets within the TSO’s and TAO’s RAB;
- the depreciation methodology applied to the TSO’s and TAO’s RAB;
- the regulatory practice when an asset is physically replaced prior to being fully depreciated; and
- the regulatory treatment of (1) additions to the TSO’s and TAO’s RAB and (2) clawback of revenue earned on assets that were not put in place (i.e. the PR2 Capex underspend).

Finally, Section 4.8 provides a summary.

4.2 Composition of the RAB

Please see Appendix A in this paper for composition of the TAO’s regulated asset base at 1st January 2009. Information on the value of the assets is provided within the TSO and TAO asset base, which have been published in the accompanying transmission revenue model.
4.3 Valuation of the Regulatory Asset Base

4.3.1 Introduction & decision to continue current approach

The preceding section provides information on the composition of the TAO and TSO RAB. However, the approach to valuing the assets within the RABs is also an important decision within the revenue control process.

In an information note published in April 2009 (CER/09/047), the CER stated its intention to continue its current approach for valuation of the RABs through into the next review period. The information note stated that on the basis of regulatory certainty and maintaining regulatory precedent the methodology for valuation of the RABs, which has become established practice during the first two control periods, would not be reviewed as part of this project.

This approach allows the CER to focus on reviewing other aspects of the TSO’s and TAO’s performance to ensure that the electricity network businesses are operated and developed in a cost-effective and efficient manner.

None of the respondents raised any specific issues to the continuation of this approach but some requested further information. This request was met through the publication of the DSO’s and TAO’s RAB in June 2009. The CER has also published the TSO and TAO PR3 RABs in the accompanying transmission revenue model.

The CER is now restating its intention to continue with the current methodology for the valuation of the TSO’s and TAO’s RAB. The following sections provide further information on this issue.

4.3.2 Background

The core issue regarding the valuation of the TSO’s and TAO’s RAB is whether the RAB should reflect the value of the assets now (replacement value) or when they were built (acquisition cost). A number of variations on these approaches are outlined below. The advantages and disadvantages of each are detailed in Table 5.

Acquisition cost

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

33 Please see the following link: http://www.cer.ie/en/electricity-transmission-network-decision-documents.aspx?article=cbcc1883-95aa-429e-8dcc-cc562c9e38e6
Replacement cost

Assets are valued at what it would cost to replace existing assets. There are two approaches to replacement cost: (a) indexing the acquisition cost of the assets to allow for inflation; and (b) revaluing the asset based using a modern equivalent asset value (MEAV) approach.

Replacement cost less stranded assets

This is as per replacement cost (above) but those assets that are not utilised in the current system would be excluded. Effectively, this would be the cost of building a replacement system.

Deprival value

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

Table 5: Advantages and disadvantages of valuation approaches.

<table>
<thead>
<tr>
<th>Approach</th>
<th>Advantages</th>
<th>Disadvantages</th>
</tr>
</thead>
<tbody>
<tr>
<td>(1) Acquisition cost</td>
<td>This is the simplest approach to valuing the RAB. It requires no adjustments to the RAB, other than for new capital expenditure and depreciation.</td>
<td>It does not reflect the economic values of the assets and therefore is likely to reduce incentives to invest in the network. It may not provide sufficient cashflow to fund network investment.</td>
</tr>
</tbody>
</table>
| (2) Replacement cost | There are two variations of this:  
(a) Modern Equivalent asset  
This ensures the RAB is directly linked to the costs of constructing a new transmission system.  
It provides a better indication of changes in market values.  
(b) Indexed acquisition cost  
This is simpler to apply than MEAV, as it does not require | Modern Equivalent asset  
Complex, as in principle all assets within the RAB must be reviewed and valued.  
Assessment of networks used for valuation is controversial – specifically whether this should be the existing or an ‘optimal network’.  
This approach risks deterring new investment if some existing assets are stranded when the RAB is revalued.  
Indexed acquisition cost  
Simple indexation means that some assets may be |
| (3) Replacement cost less stranded assets | The advantages are as per those listed above for replacement cost. In addition, it has the benefit that any assets that are considered stranded – that is, where there is an unambiguous case that they are not required – would be removed from the RAB. This is correct as, in principle, these should be removed as they do not form part of the operational base of networks. | Identifying stranded assets is somewhat judgmental. It would need to be demonstrated that a specific asset should not have been built based on reasonable assumptions. Excluding stranded assets from the RAB may deter investment. That is, the TSO/TAO may not invest in some cases if there is a risk that the asset may become stranded, for example, through expected load not appearing. |
| (4) Deprival value | Provides most accurate economic valuation of the network | Highly complex to apply as requires detailed modeling of system to determine asset values |

Having balanced and considered all of the above, the CER decided that the TSO’s and TAO’s RAB would be valued using a replacement cost approach for the period 2001 to 2005. It was subsequently decided that the approach would be continued for the period 2006 to 2010.

While it is recognised that there are advantages and disadvantages associated with each methodology, the replacement cost approach was taken as it is more likely to result in the correct level of network investment.

As documented above there are a number of variations of replacement cost that could be used. The version used by the CER is 2 (b) above - indexed acquisition cost, (i.e. acquisition costs indexed upwards to allow for inflation, as a proxy for the replacement cost).

### 4.3.3 Decision

The CER will continue using this methodology to value the TSO and TAO RABs for the 2011 to 2015 period. Maintaining regulatory certainty by continuing this
methodology, which has become established practice over the past two control periods, was a significant factor in this decision. However, it should also be noted that, if this was not a factor, the transparency and superior investment signals, etc. related to the current approach would still provide valid arguments for its continuation.

4.4 Asset Lives Applied to the RAB

4.4.1 Introduction

The assets lives applied to assets within the RAB feeds through into the level of depreciation that the TSO and TAO receive separately on those assets within each control period (or indeed year).

In an information note published in April 2009\textsuperscript{26} (CER/09/047), the CER stated its intention to continue using average assets lives of 50 years for the TAO’s network assets\textsuperscript{34}. CER/09/047 stated that on the basis of regulatory certainty and maintaining regulatory precedent this methodology, which has become established practice during the first two control periods, would not be reviewed as part of this project.

This approach allows the CER to focus on reviewing other aspects of the TSO’s and TAO’s performance to ensure that the electricity network businesses are operated and developed in a cost-effective and efficient manner.

No respondents raised any issues to the continuation of this approach. The CER is now restating its intention to continue using average assets lives of 50 years for the TAO’s network assets. The asset lives applied during PR2 other types of assets within the TAO’s and TSO’s RAB are detailed below. It is intended that these will also be applied through the 2011 to 2015 period.

The following sections provide further information on this topic.

4.4.2 Background

There have been some changes in the length of the asset lives applied to the TAO’s assets when moving from pre 2001, into PR1, and through into PR2. The assets lives applied during each period are detailed in Table 6.

\textsuperscript{34} Network assets, depreciated over 50 years, make up the vast majority of the TAO’s RAB.
In PR1 a uniform network asset life of 40 years was applied by the CER. When setting the revenue control period for 2006 to 2010 (PR2), the CER decided that transmission network assets contained in the RAB should be depreciated over an average lifetime of 50 years. Most of the other asset lives have not changed between the price control periods.

Regarding the change from 40 to 50 year asset lives for the network assets, the PR2 decision paper (CER/05/143) noted that internationally in recent years there has been a general trend towards extending the lifetimes of electricity transmission assets. This is based on the experience of efficient network operators, who have found that equipment that has properly specified, installed and maintained will last longer than had previously been assumed. Performance of older assets is generally adequate, not least due to the modest pace of technological advance in electricity transmission, and the risks of purely age-related failure are considered to be low. In addition, condition monitoring has replaced age-based techniques in determining effective asset lifetimes.

The PR2 decision paper (CER/05/143) provided a specific example of these trends in the UK. Table 6.2 of CER/05/143 shows the average lifetimes and the standard deviation for a selection of UK electricity assets.

That decision paper stated that from these data it can be clearly seen that the present treatment of ESB’s TAO RAB assets (depreciating the network plant types over 40 years) should be modified.

The PR2 decision paper went on to note that a consequence of the average asset lifetimes assumed by a utility is that assets older than this age may be automatically considered to be unreliable, dangerous and urgently in need of replacement. While as part of the work leading up to that decision paper ESB has stated that the criteria for asset replacement are based on asset condition rather than age, the figure of 40 years was generally mentioned by ESB staff when explaining the need for an asset’s replacement. The paper noted that asset condition with the transmission network generally appears good, and in line with the expected condition of well-maintained assets according to their age and

### Table 6: Asset lives applied to transmission assets

<table>
<thead>
<tr>
<th>Asset</th>
<th>Pre PR1</th>
<th>PR1</th>
<th>PR2</th>
</tr>
</thead>
<tbody>
<tr>
<td>HV network assets</td>
<td>25</td>
<td>40</td>
<td>50</td>
</tr>
<tr>
<td>IT</td>
<td>5</td>
<td>5</td>
<td>5 or 7</td>
</tr>
<tr>
<td>Office equipment</td>
<td>10</td>
<td>10</td>
<td>10</td>
</tr>
<tr>
<td>Fixtures &amp; fittings</td>
<td>5</td>
<td>5</td>
<td>10</td>
</tr>
<tr>
<td>Scada telecoms</td>
<td>15</td>
<td>15</td>
<td>10</td>
</tr>
<tr>
<td>Vehicles</td>
<td>7</td>
<td>7</td>
<td>7</td>
</tr>
<tr>
<td>Premises</td>
<td>50</td>
<td>50</td>
<td>50</td>
</tr>
<tr>
<td>Tools</td>
<td>5</td>
<td>5</td>
<td>5</td>
</tr>
<tr>
<td>Telecoms</td>
<td>15</td>
<td>15</td>
<td>10</td>
</tr>
</tbody>
</table>
environment. Site visits conducted by the CER and its engineering advisers during the course of the PR2 review provided considerable evidence of this.

CER/05/143 stated that the use of average lifetimes more in line with current international practice would reduce the amount of annual depreciation, and realign ESB’s perception of asset age with current expectations.

Having considered the above, the CER decided that network assets contained in the RAB should be depreciated over an average lifetime of 50 years. The CER also decided that the changes in an asset’s life should be implemented in accordance with paragraph 93 of FRS 15, that is, the carrying amount (Net Book Value) of an asset at the time of the change should be depreciated over the revised remaining useful economic life of that asset.

The CER sees no reason to change this treatment for the 2011 to 2015 period.

4.4.3 Decision

For the control period covering 2011 to 2015, the CER will continue applying the assets lives used during PR2. These are detailed above in Table 6. Maintaining regulatory certainty by continuing this methodology was a factor in this decision. However, it should also be noted that these asset lives are generally in line with international benchmarks, and regulatory certainty aside, there would still be a valid rationale for applying these values.

4.5 Depreciation method

4.5.1 Introduction

In the information note published in April 2009, the CER stated its intention to continue using the same depreciation methodology for the period 2011 to 2015 as was employed in PR2. The information note stated that on the basis of regulatory certainty and maintaining regulatory precedent this methodology would not be reviewed as part of this project.

This approach allows the CER to focus on reviewing other aspects of the TSO’s and TAO’s performance to ensure that the electricity network businesses are operated and developed in a cost-effective and efficient manner.

No respondents raised any issues to the continuation of this approach. The CER is now restating its intention to continue using straight line depreciation during the period 2011 to 2015.

---

35 FRS 15 sets out the principles of accounting for tangible fixed assets, such as electricity transmission assets.
36 FRS 15 is available [here](http://www.ukfrc.org.uk) on the UK Financial Reporting Council’s website.
The following sections provide further information on this topic.

4.5.2 Background

Economic depreciation profiles allocate the original capital cost of a project over its useful life. There are a number of possible methods through which asset bases may be depreciated; common relevant examples are straight-line, sum-of-years-digits and declining balance depreciation.

When setting the first revenue control, covering the period 2001 to 2005, the CER chose the straight-line method. The following benefits were noted:

- Straight-line fully depreciates the assets over a period of time. The declining balance method does not as it is calculated as a portion of the declining value of the asset.
- Due to the nature of the design life of network assets and the load profile of the use of network assets, the straight-line method was considered to be a reasonable representation of depreciation for network assets.

The straight-line approach to depreciation was then continued when setting the second revenue control, covering the period 2006 to 2010.

4.5.3 Decision

For the control period covering 2011 to 2015, the CER will continue applying the straight-line method of depreciation used during PR2. Maintaining regulatory certainty by continuing this methodology was a factor in this decision. However, regulatory certainty aside, the rationale that led to this approach being chosen in the first instance would still provide relevant arguments for choosing straight-line depreciation for the forthcoming period.

4.6 Replaced Assets

When setting the current revenue control covering the period from 2006 to 2010, the CER noted that a significant amount of expenditure had taken place in the last decade on replacing assets in ESB’s networks. This could possibly lead to a situation where an asset and its subsequent replacement would both be included in the RAB at the same time, that is, the asset has been replaced before its value in the RAB has been fully depreciated.

In that decision paper the CER stated its belief that assets included within the RAB that have been replaced should be removed from the RAB at the time of their replacement.

The CER has decided that this policy will apply during the next revenue control period.
4.7 Additions to TSO and TAO RABs

4.7.1 Introduction

The regulatory treatment of additions to the TSO and TAO RAB’s is an important issue in a revenue control. This section explains the decision to continue the current regulatory approach to treatment of additions to the TSO and TAO RAB’s for:

- Interest During Construction (IDC);
- Capital contributions and grants; and,
- Variations between allowed and actual expenditure during PR2.

4.7.2 Interest During Construction (IDC)

In both PR1 and PR2, assets were added to the RABs as costs were incurred, not on the date of commissioning. The TSO and TAO received a return on the assets from the middle of the year in which the costs were incurred, rather than when the asset was commissioned. For this reason the CER did not allow IDC to be added to the respective RAB’s.

Depreciation was also provided as expenditure on assets is incurred. This means that expenditure on assets still under construction during any given year will be included in the calculation of that year’s annual depreciation charge.

The CER has decided to continue this policy during the forthcoming revenue control period, covering 2011 to 2015.

4.7.3 Capital contributions and grants

In both the first and second revenue controls, capital contributions and grants were subtracted from capital expenditure in the relevant year.

The CER has decided to continue this policy during the forthcoming revenue control period.

4.7.4 Variations between allowed and actual PR2 Capex

PR2 Capex Underspend

The information provided jointly by the TSO and TAO has indicated that there will be an underspend on Capex during the PR2 period relative to the amount allowed. The reasons for this underspend are detailed fully in the accompanying SKM transmission report. However, the high-level reasons include land access and planning delay issues, as well as some delays while making the transition to the new TSO / TAO structure. These issues are further discussed in section 7.0 below.
As outlined in the 2009 and 2010 Transmission revenue determination papers\textsuperscript{37} the CER employs a process to monitor the Capex incurred by the TAO and TSO. As a result of the reporting on the Capex the CER requested the transmission utilities to report specifically on the actual transmission Stage 1 and Stage 2 capex (for years 2006 to 2008). The expenditure reported by them for 2006 to 2008 indicated that there had been a significant underspend of transmission network related Capex.

In CER/08/178 the CER decided to reduce the 2009 transmission revenue by \(\text{€}11.85\) million (2008 prices) to account for this Capex underspend on an annual basis from 2006 to 2008. Further to examination of the Capex undertaken by the TAO for 2006 to 2008, in CER/09/140 CER decided to reduce the transmission revenue for 2010 by an additional \(\text{€}5.94\) million (2008 prices) to account for an additional over-recovery relating to the depreciation of network assets and the return (at 5.63\%) on the capital employed in the transmission network.

In addition, as indicated in Table 14 of Section 7.2 there has been (and will be) an overspend of Capex in the last two years of PR2 period, 2009 and 2010. The CER has reviewed this overspend as detailed in Section 7.5 of this paper and is satisfied that this specific overspend has been efficiently incurred and has added this to the TAO RAB for the forthcoming period. The CER will review the final out-turn position of Capex for the final two years of PR2 as this information becomes available in 2011.

However, even allowing for the 2009 and 2010 overspends, there has still been a gross network Capex underspend of approximately \(\text{€}78\) million and gross non-network Capex underspend of approximately \(\text{€}13\) million in the entire PR2 period. This has been taken into account by the CER when shaping its views on transmission network and non-network capex for the PR3 period.

\textbf{4.8 Summary}

This section provides a summary of the CER’s decisions on a number of interrelated areas that impact on the setting of the TSO’s and TAO’s RAB and the level of revenue that the TSO and TAO are allowed to collect during each control period (or year) to cover their depreciation costs separately.

No changes in methodology relative to that employed during the 2006 to 2010 period are being introduced for the 2011 to 2015 period.

\textsuperscript{37} CER/08/178 and CER/09/140 respectively.
**Valuation methodology**

The CER will continue using the methodology employed during previous control periods. This is a variation of replacement cost approach, which uses the inflation cost, indexed upwards to allow for inflation, as a proxy for replacement cost.

**Asset lives**

The CER will continue using the methodology employed during the previous control period, PR2, which covered 2006 to 2010. Under this approach an average life of 50 years is applied to transmission network assets. These make up the majority of the TAO’s asset base. The lifetimes applied to other assets, including that of the TSO’s (e.g. IT), are detailed in Table 6 of this paper.

**Depreciation methodology**

The CER will continue using the methodology employed during previous control periods. This is straight-line depreciation.

**Capex Underspend & Overspend**

The CER has already taken account of the Capex underspends for years 2006 to 2008. It has been decided that the overspend by the TAO on capital projects for 2009 and projected for 2010 will be added to the RAB. This has been reviewed by the CER and its consultants and is deemed to be efficiently incurred. However, the CER will still review the final out-turn position of Capex for the final two years of PR2 as this information becomes available in 2011.
5.0 Cost of capital

5.1 Introduction

Like any other business the TSO and TAO separately compete for capital (finance) on national and international markets to finance their respective capital projects e.g. transmission infrastructure construction (Stage 1 and Stage 2). In line with common practice, the amount of revenue to be collected from the TUoS customer to cover this cost is set by applying a cost of capital to the TSO’s and TAO’s RAB.

This is a critical element of the revenue control. For the period 2006 to 2010 the TSO’s and TAO’s cost of capital was set to 5.63%\(^{38}\). This meant that the TAO was allowed to recover €283 million (2004 prices) over the five year period to cover its cost of capital. The amount of this figure, relative to the other revenue collected by the TAO is demonstrated in Table 7 below.

Due to the limited size of the TSO RAB (mostly IT infrastructure), applying the same cost of capital has a significantly lesser impact on TUoS tariffs. It is evident from Table 8 that Operating Costs make up the vast majority of revenues associated with the TSO. Nonetheless, it was allowed to recover circa €11 million (2004 prices) over the five year period to cover its cost of capital. The amount of this figure, relative to the other revenue collected by the TSO is demonstrated in Table 8 below.

<table>
<thead>
<tr>
<th>Table 7: TAO allowed revenue for 2006 to 2010</th>
</tr>
</thead>
<tbody>
<tr>
<td>€m’s</td>
</tr>
<tr>
<td>Operating costs</td>
</tr>
<tr>
<td>Depreciation</td>
</tr>
<tr>
<td>Cost of capital</td>
</tr>
<tr>
<td><strong>Total</strong></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Table 8: TSO allowed revenue for 2006 to 2010</th>
</tr>
</thead>
<tbody>
<tr>
<td>€m’s</td>
</tr>
<tr>
<td>Operating costs</td>
</tr>
<tr>
<td>Depreciation</td>
</tr>
<tr>
<td>Cost of capital</td>
</tr>
<tr>
<td><strong>Total</strong></td>
</tr>
</tbody>
</table>

It is important that the cost of capital is set at a level that allows the TSO and TAO to finance their respective activities. Setting the cost of capital at a lower

\(^{38}\) This is a real pre-tax rate.

\(^{39}\) All figures are in 2004 terms and are as listed in the PR2 decision paper. They have not been adjusted for outturn, yearly updates or inflation. Please see the PR2 decision for further details.

\(^{40}\) Ibid.
level could result in both transmission utilities being unable or possibly unwilling to finance their operations\footnote{Due to debt funding obligations.}, including necessary maintenance and repair. It has been argued that while there is a risk that if the cost of capital is set too high consumers may pay marginally more than is necessary for the service received, the consequences of setting too low a cost of capital may be more severe. This is discussed further below.

Setting the costs of capital too low may result in necessary projects (such as those designed to facilitate the Government’s 2020 renewables target) not being completed, with the result being that the consumer would be worse off in the long run. However, this must be balanced against the obvious disadvantage of setting the cost of capital at a level that is too high and allowing the transmission utilities to recover too much revenue from the TUoS customer.

The following sections provide:

- a brief outline of the model that has been used to derive the cost of capital for the TSO and TAO; and
- detail on the cost of capital for the TSO and TAO.

It is important to note that during the review process the CER considered whether to apply a different cost of capital to the TSO from that of the TAO. Subsequent to this review the CER has decided against such a move and that the same cost of capital is applied to both transmission utilities. The justification for such is provided in the Europe Economics report published alongside the consultation paper.

This decision paper only provides a high level summary of the work that was completed when deriving a cost of capital. As detailed in Section 3.4 of this paper, the CER has employed Europe Economics to provide advice on the appropriate cost of capital for the TSO and TAO. The report provided by Europe Economics has been published alongside the consultation paper and interested parties should refer to that document for further information on this decision.

\section*{5.2 Methodology for setting the cost of capital}

At a theoretical level, there is considerable academic controversy surrounding the most appropriate approach to setting the cost of capital. Consistent with many other regulators in similar environments, when setting the appropriate cost of capital for the two previous control periods the CER used the weighted average cost of capital (WACC) methodology. Within this, the cost of debt was set using the Capital Asset Pricing Model (CAPM).
As detailed in Section 3.6, in April 2009 the CER published an information note (CER/09/047) outlining its intention to continue using the same methodology for the period 2011 to 2015 as was employed in PR2. The information note stated that on the basis of regulatory certainty and maintaining regulatory precedent this methodology would not be reviewed as part of this project.

This approach allows the CER to focus on reviewing other aspects of the TSO’s and TAO’s performance to ensure that the electricity network businesses are operated and developed in a cost-effective and efficient manner.

No respondents raised any specific issues to the continuation of this approach. It was stated that while the CAPM should continue to be used, it should be used in a transparent manner and supplementary tools, for example, the dividend growth model and market return analysis, should be used to check that the model is providing robust answers.

While market return analysis and dividend growth models were not specifically used as crosschecks, other information sources have been examined to ensure that the CER’s decision is robust. Details on this are provided in the separate cost of capital report, which has been published alongside the consultation paper. That report also addresses a request that transparent information be provided on the building blocks that led to the final value.

The cost of capital value detailed in this paper has been derived using the WACC model and the CAPM, and as such this paper is restating the CER’s intention to continue using these methodologies to calculate the appropriate cost of capital for both the TSO and TAO for the 2011 to 2015 period.

5.3 Europe Economics’ Point Estimate

This section lists the cost of capital cost of capital recommendations provided by Europe Economics to the CER for the period 2011 to 2015. It also lists the values of the factors that underpin this value. For further information on these values, interested parties should refer to the separate Europe Economics cost of capital report, which has been published alongside this transmission consultation paper.

Section 3.3 of this consultation paper outlines the process through which the TSO and TAO provided information to the CER and its advisors regarding their activities. As part of that process, both the TSO and TAO provided reports containing their own proposals on an appropriate cost of capital.42 These figures are also included in Table 9 below.

42 Please note that as part of the TSO submission, EirGrid argued that a different WACC should be applied to it in PR3 from that of the TAO. This matter is addressed in the accompanying EE report and the recommendations/justifications for not doing so are also outlined.
It should be noted that while the TAO’s underlying figures led to a real pre-tax WACC of 6.3%, its submission requested that the CER approve a pre-tax real value of 6.0%. Similarly, the TSO requested that the CER approve a pre-tax real value of 6.26%.

Table 9: WACC (cost of capital) calculations and data inputs

<table>
<thead>
<tr>
<th></th>
<th>PR1</th>
<th>PR2</th>
<th>TSO view</th>
<th>TAO view</th>
<th>EE</th>
<th>EE point estimate</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Cost of debt</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Risk free rate</td>
<td>3.05</td>
<td>2.38</td>
<td>2.25%</td>
<td>1.9 – 2.2</td>
<td>1.6 – 2.2</td>
<td>2.0</td>
</tr>
<tr>
<td>Debt premium</td>
<td>1.50</td>
<td>1.35</td>
<td>2.05%</td>
<td>1.3 – 2.1</td>
<td>1.0 – 1.4</td>
<td>1.2</td>
</tr>
<tr>
<td>Pre tax cost of debt</td>
<td>4.55</td>
<td>3.73</td>
<td>4.30%</td>
<td>3.2 – 4.3</td>
<td>2.6 – 3.6</td>
<td>3.2</td>
</tr>
<tr>
<td><strong>Cost of equity</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Real risk free rate</td>
<td>3.05</td>
<td>2.38</td>
<td>2.25%</td>
<td>1.9 – 2.2</td>
<td>1.6 – 2.2</td>
<td>2.0</td>
</tr>
<tr>
<td>Equity risk premium</td>
<td>5.4</td>
<td>5.25</td>
<td>5.5%</td>
<td>5.0 – 7.0</td>
<td>4.5 – 5.4</td>
<td>5.2</td>
</tr>
<tr>
<td>Asset beta</td>
<td>0.41</td>
<td>0.40</td>
<td>0.45</td>
<td>0.34 – 0.46</td>
<td>0.2 – 0.4</td>
<td>0.3</td>
</tr>
<tr>
<td>Equity beta</td>
<td>0.80</td>
<td>0.80</td>
<td>0.85 – 0.92</td>
<td>0.4 – 1.0</td>
<td>0.47</td>
<td>0.67</td>
</tr>
<tr>
<td>Cost of equity</td>
<td>6.58</td>
<td>7.2%</td>
<td>6.2 – 8.6</td>
<td>3.4 – 7.6</td>
<td>5.5</td>
<td></td>
</tr>
<tr>
<td><strong>WACC</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Effective tax rate</td>
<td>0.125</td>
<td>0.125</td>
<td>0.125</td>
<td>0.125</td>
<td>0.125</td>
<td>0.125</td>
</tr>
<tr>
<td>Gearing</td>
<td>0.5</td>
<td>0.50</td>
<td>50%</td>
<td>0.5 – 0.6</td>
<td>0.5 – 0.6</td>
<td>0.55</td>
</tr>
<tr>
<td>Pre-tax WACC</td>
<td>6.5</td>
<td>5.63</td>
<td>6.26%</td>
<td>4.7 – 7.1</td>
<td>3.2 – 5.6</td>
<td>4.6</td>
</tr>
</tbody>
</table>

As highlighted by the CER’s consultants the estimation of the true value of WACC is inherently uncertain, perhaps more so in the current economic climate. The standard approach to setting an allowed WACC figure is to set a rate at the start of the period which applies for the entire period. The allowed WACC provides for the uncertainty.

5.4 Incentives for delivery

The TSO has put forward a significant capital programme for the PR3 period. The network Capex allowance is €1.45 billion (please see section 8.0), which will facilitate achievement of the Government’s 2020 renewable targets. Proposed transmission incentives for the next incentive period will be consulted on with stakeholders in a separate CER paper in the coming weeks.

5.5 Uncertainty

In CER/10/102 the CER highlighted that the estimation of the true value of WACC is inherently uncertain, perhaps more so in the current economic climate. The standard approach to setting an allowed WACC figure is to set a rate at the start of the period which applies for the entire period. The allowed WACC
provides for the uncertainty. The CER sought the views or proposals of respondents on the CERs approach or alternative methods that may cater for the uncertainty. Those respondents that did provide comments in response generally acknowledged the uncertainty in the current economic climate, but did not provide specific proposals for consideration by the CER.

Europe Economics approach takes account of country risk issues in the calculation of the WACC recommended in the original consultation paper in the following ways. First, in estimating the cost of equity, Europe Economics based its range estimate of the Equity Risk Premium (ERP) on Irish data rather than on international data, and chose a point figure towards the top end of the range to reflect the potential for the ERP to be temporarily elevated during periods of recession. Second, on the cost of debt, Europe Economics analysis is based on the assumption that the CERs financeability analysis targets a rating in the A category and factors country risk into the ratings assessment. Its analysis also assumes that A rated corporate bonds are internationally comparable. Third, the set of comparators that Europe Economics examined when estimating both the equity beta and the debt premium included some comparators from countries facing sovereign debt problems on the periphery of the eurozone.

However, it is not possible to replicate all the factors that rating agencies take into account in its financeability assessment. In particular, it is difficult to fully factor in the effect that country risk may have on ESBs credit rating. In addition, Europe Economics analysis was only based on data up to the end of February 2010, and developments since then underline the persistence of the sovereign debt crisis, and might suggest that corporate bonds of equivalent ratings may now be less comparable within the eurozone than was the case even seven months ago.

The cost of borrowing has increased substantially in Ireland in recent months. The CER believes that the increase to the cost of debt to the Irish government is a good indication of the changing circumstances generally. There is evidence from other European countries that the cost of debt for utilities has some correlation to the cost of debt faced by the state. Ireland has a small open economy and intuitively one would assume that the combined effects of a recession, a banking crisis and increased Government borrowing will have significant impacts on the Irish economy as a whole. Further evidence of this is provided by the revised outlooks for another State-owned company by Standard and Poor’s and Moody’s which linked the reviews to the sovereign position.

Therefore the cost of capital of 5% included in the consultation paper would not be appropriate given what is now known about the extent of the financial difficulties and necessity of the large capital investment program. The CER has engaged SKM to review the capital investment plans for the transmission network. EirGrid has proposed significant investment in the network. While our advisors have recommended some reductions in expenditure, they recommend
that the majority of this investment is needed over the course of the review period to ensure reliable and secure electricity supplies for customers and to allow Ireland to reach its 2020 targets. Therefore the CER does not believe that the deferring of significant investment is an option. The CER will allow the transmission utilities a real pre-tax WACC of 5.95%.

The increase in the WACC reflects the increased costs that are faced by the transmission utilities to finance their businesses. This may be a temporary issue and if there is a significant change in circumstances, the CER would propose to review, at the midterm of the review period, the level of WACC to see if an adjustment is required for the remaining period of the Price Review. An adjustment, if required, could be an increase or a decrease depending on how circumstances have changed. However the CER believes that it is prudent at this stage to assume that circumstances will not change significantly and has modelled the PR3 transmission revenues on this basis.

The CER recognises that the transmission utilities, the TAO in particular, will need to access international capital markets to fund the capital investment programmes and is conscious of the importance of providing regulatory certainty in that regard. Equally, it is important that the regulatory model can adapt to changing circumstances, particularly in times of significant uncertainty, in the interests of both consumers and investors. The CER believes that the WACC proposal achieves an appropriate balance in this regard and should support strong credit quality and efficient funding of the investment programme.

### 5.6 Financeability

The CER has an obligation to ensure that all licensees are capable of financing their operations as specified by Section 9(4)(c) of the ERA, which states that:

“9(4) In the carrying out the duty imposed by subsection (3), the Minister and the CER shall have regard to the need:

……

(c) to secure that licence holders are capable of financing the undertaking of the activities which they are licensed to undertake;”

The CER interprets this clause such that the obligation is to ensure that an efficient licence holder, in this case the TSO and TAO, are capable of financing their activities. The CER has made a number of assumptions in this respect which are that the

- the TSO and TAO does not exceed the allowance for operating costs;
- the financeability assessment is based on the notional capital structure assumed by the CER; and
- the effects of any pension deficit are ignored.
The CER believes these assumptions are reasonable given that (a) the allowed operating costs are set at the level an efficient company can achieve, (b) it is not the function of the CER to specify the capital structure of the TSO or the TAO, to the extent the actual differs from the notional any costs should be borne by the shareholder and not the final customer and (c) it has been decided that the treatment of the pension deficits within both utilities will not be dealt with as part of the PR3 process.

The calculation of the cost of capital is based on the TSO and TAO achieving an A credit rating. The rating agencies take a number of factors into consideration when determining the rating of a company. ESB and EirGrid do not have a credit rating and it is not possible for the CER to replicate all the factors that the credit ratings agencies take into consideration. However, the rating agencies do publish their methodologies for rating regulated utilities and this gives guidance on what factors are taking into consideration, importantly the financial metrics associated with the different credit ratings. Rating agencies look at a similar range of financial ratios, Table 10 sets out the ratios which are broadly consistent with an A credit rating.

<table>
<thead>
<tr>
<th>Table 10: Financial Ratios consistent with an A credit rating</th>
</tr>
</thead>
<tbody>
<tr>
<td>FFO interest cover</td>
</tr>
<tr>
<td>Net Debt/RAV</td>
</tr>
<tr>
<td>FFO/Net Debt</td>
</tr>
</tbody>
</table>

Ofgem assesses financeability using a similar set of ratios, albeit with differing limits, which are set out in the table below. Ofgem has used these ratios in its assessment of financeability for DPCR4 and DPCR5.

<table>
<thead>
<tr>
<th>Table 11: Financial ratios used by Ofgem in financeability assessment</th>
</tr>
</thead>
<tbody>
<tr>
<td>FFO interest cover</td>
</tr>
<tr>
<td>Retained Cash Flow/Debt</td>
</tr>
<tr>
<td>Debt/Regulatory Asset Base</td>
</tr>
</tbody>
</table>

Ofgem does not have a specific credit rating target, rather that companies should have an investment grade rating. This can be interpreted to mean an investment rating from BBB+ to A. In its initial proposals for DPCR5 it outlined its view that a financial profile that meets their target ratios is broadly consistent with an A-credit rating.

43 In its recent review, DPCR5, Ofgem concluded that a higher level of debt to RAV - 70% - was consistent with an investment grade credit rating.

44 Please see following link:
The CER believes that regulatory regime in Ireland is comparable to that in Britain, providing a stable and transparent framework within which both the TSO and TAO operates. In terms of the financial profile, we have assessed the TSO and TAO against the financial ratios set out above and believe that the allowed revenues provide for an A credit rating.
6.0 Performance & incentives

6.1 Introduction

This chapter provides information on the PR2/PR3 incentive mechanisms. The next section of the chapter provides details of the previously used incentives in transmission during the PR2 period. Proposed transmission incentives for the next incentive period will be consulted on with stakeholders in a separate CER paper in the coming weeks.

6.2 Historical performance

6.2.1 Introduction

The PR2 decision paper (CER/05/143) provided for incentivisation of the TSO for the continued improvement of transmission system performance and of the management of external costs. Incentives were set for 2006, 2008 and jointly for 2009 and 2010.

Incentives were not set for the calendar year 2007. At the time in 2006 there was still uncertainty regarding the particular roles of the TSO and TAO, which were subsequently defined in the IA of June 2006. The uncertainty of roles meant that it would have been inappropriate of the CER to attribute an incentive mechanism to a particular body, which may not have subsequently been given the control under the IA to affect that particular incentive measure.

For both 2008 and 2009/2010 the TSO submitted for review to the CER possible parameters for system performance revenue incentives. In both instances, the CER responded to EirGrid’s proposal with draft revenue System Performance Incentives (SPIs), which were further discussed with the TSO before being decided upon by the CER.

In the case of 2009/2010 the CER deemed it appropriate to set revenue/performance targets that applied for the two years of 2009 and 2010 rather than separately negotiating new targets for 2010 at the end of 2009. The CER believed that a longer incentivisation period provided a stronger incentive to the TSO to improve performance because: (i) it incentivised the implementation of more long-term performance improvement measures in addition to “quick-fixes”; and (ii) made the TSO aware that the targets could not be relaxed in the following year if performance in any of the agreed categories deteriorated.
6.2.2 Previously used TSO performance measures

2006

Following the determination of the 2006-2010 price control the CER put in place incentives relating to the TSO’s management of system performance in 2006 in the areas of constraint and ancillary services costs, system frequency, system minutes lost and fault clearance rates.

The System Minutes Lost (SML) is an index that measures the severity of each system disturbance relative to the size of the system. It is determined by calculating the ratio of unsupplied energy during an outage to the energy that would be supplied during one minute, if the supplied energy was at its peak value.

The National Control Centre (NCC) in the TSO offices aims to maintain the frequency of the system within a target operating range of 50 ±0.1 Hz. The frequency, however, may deviate outside the normal operating range under fault or abnormal operating conditions. It was previously argued that fault clearance rates better indicates the system’s ability to respond satisfactorily to whatever faults occur in any particular year.

The targets for SML and for fault clearance rates were met and resulted in a revenue increase for the TSO of €113,800 and €94,940 respectively. The TSO maintained the system frequency in the band 49.9Hz to 50.1Hz for 90.3% of the time. This did not meet the target of 93% and therefore it incurred a penalty of €139,630.

The CER decided that a penalty should not be levied upon the TSO in relation to constraints and ancillary services as some of the factors which contributed to the high cost of constraints were largely outside of the TSO’s control. The incentives which applied for 2006 resulted in an overall incentive award of €69,000 to the TSO out of a possible €520,000.

2008

The areas of incentives for the TSO in 2008 remained largely the same from 2006, i.e. ancillary services (excluding constraint costs), system minutes lost, system frequency and fault clearance rates. However, the targets published in CER/09/00445, for the most part, became more stringent.

It was decided by the CER that constraint costs would not be incentivised for 2008 due to the new all-island SEM and the lack of historical benchmark data. It

---

Please see following link:
http://www.cer.ie/en/electricity-transmission-network-decision-documents.aspx?article=decf3b52-6d3d-4be1-b99d-efa0d186a3bb
was not expected at the time of drafting the 2008 SPIs paper that ancillary services would be provided on an all-island basis in 2008. Accordingly, for 2008, the CER decided that a target for ancillary services would only apply with a central target based on the CER’s determination of the ex-ante allowed revenue for ancillary services for 2008 of €40.5 million (2006 prices).

With respect to SML the TSO submitted for a central target of 4.0 SML to apply in 2008 with a cap and collar of +/- 2.0 system minutes. The CER considered that the TSO’s proposed target of 4.0 SML, which also applied in 2006, did not present to the TSO a sufficiently challenging target considering that the average SML outturn for the previous five years was 0.75 minutes. However, at the time the CER also noted the additional challenges associated with increasing amounts of wind on the system. Accordingly, the CER decided on a central target of 3.5 SML to apply in 2008 with a cap and collar of +/- 2.0 system minutes.

For 2008, the CER decided to slightly relax the central target from 93% in 2006 to 92.5% in 2008 within the System Frequency SPI. This was in view of the increasing challenge caused by rising wind penetration on the system. The CER also widened the upper and lower bounds of the target to +/-2% of the central target of 92.5% so as to provide a strong incentive for the TSO to improve on the previous years’ performance. With regards to Fault Clearance, the CER decided on a more stringent central target for fault clearance of 0.15 to apply compared with 0.3 in 2006, with a cap and collar of +/- 0.1.

The CER decided to apply an equal weighting of 25% to each of the above four criteria and also chose to increase the revenue incentive to circa 2% of internal costs for 2008. Based on an ex-ante allowed revenue of €43.66 million for 2008’s internal costs (CER/07/184), the maximum incentive amounted to €872,000 (in 2006 prices). As detailed in CER/09/140, the TSO reached its targets successfully in each category for 2008. Therefore, the CER allowed this €872,000 adjustment to be added to TSO revenue for 2008.

2009/2010

For 2009/2010 the areas of incentives and targets decided upon for the TSO remained largely the same from 2008, i.e. for SML, system frequency and fault clearance rates. The CER also decided to allow one other form of incentivisation into the SPI programme, namely timeframes for the lodgement of planning permission. In addition a separate incentive applied for the roll-out of transmission-related Gate 3 offers.

In respect of ancillary services and constraint costs, the CER believed that it was not appropriate to apply incentives for 2009, in light of the move towards all-island harmonisation of these costs. This issue is discussed below in section 6.3.
With the addition of the planning permission category into the SPIs for the TSO and to ensure that the total amount available to the TSO stayed approximately within the 2% threshold of internal opex, the CER decided to apply a similar weighting to those set in 2008. SML, System Frequency and Fault Clearance were all kept at 0.25 over the two year SPI period so as to allow for the introduction of the fourth SPI relating to lodgement of planning permission on the part of EirGrid.

The CER decided for 2009 and 2010 that the parameters and associated weighting for SML remain the same as those set in 2008, i.e. 3.5 SML for 2009 and 3.5 SML for 2010. The CER believed that this represented a challenging but realistic target for the TSO.

The CER felt it important to clarify that this would not be an average target of 3.5 SML over the two years because the CER wanted to avoid setting an incentive target which could lead to large fluctuations in SML performance over 2009 and 2010. With this target for SML the CER tried to ensure that the TSO maintained the highest possible levels of system performance, not just an average over the two years, but consistently over each year.

The roll-out of Gates 1, 2 and 3 renewable Generators over the coming years will result in more wind being connected to the system, which will be a challenge from a system frequency perspective. However, the CER believes that the TSO has, and will have, the necessary systems and models in place to accommodate increased levels of wind penetration.

In its correspondence with the CER in 2008, EirGrid proposed that it be incentivised to manage system frequency in the range of 49.9Hz to 50.1Hz for 94% of the time. The CER welcomed this initiative by EirGrid and deemed that the 2008 central target of 92.5% would be revised up to 94% for 2009/2010. The CER decided that a central target for fault clearance of 0.15, with a cap and collar of +/- 0.1 as applied in 2008, would apply over 2009/2010 period.

As noted above another form of incentivisation was introduced into the SPI programme for 2009/2010, namely the lodgement of planning permission by the TSO for shallow connections assets for both Generators and Demand customers. This issue is of significant important to Generators and Demand customers seeking to connect to the system in a timely fashion. Therefore, the CER deemed it appropriate to incentivise the TSO in this area. For the TSO to receive monies under this SPI, it will need to improve on the standard timelines for lodgement of planning permission, which were approved and published by the CER in CER/09/077 in late 2008.\(^{46}\)

---

\(^{46}\) Please see the following link: http://www.cer.ie/en/electricity-transmission-network-decision-documents.aspx?article=7ab5d769-38ba-450c-b772-74751011d83e

60
With equal weightings attached to all four 2009/2010 SPIs, the total amount that could be rewarded to or subtracted from the TSO over the two year period is €1.8 million.

In addition, as stated in CER/09/004 the effective and timely implementation of transmission-related Gate 3 is one of the key targets of both the CER and the TSO. Therefore, the CER decided to include a category of incentivisation for the TSO in an attempt to achieve this key workplan efficiently and effectively. This will be a once-off SPI paid or penalised to or from the TSO, as the case may be, in 2012. The parameters were based on the timelines included in the final Gate 3 direction which was published in December 2008\(^\text{47}\) by the CER. Any subsequent modifications to these timelines will be taken into account upon the outturn review of this once-off SPI. This specific SPI is further outlined in section 4 of CER/09/004.

Please see below Table 12 outlining the system performance parameters for 2009, their respective targets, and EirGrid’s performance against each.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Target</th>
<th>Outturn Performance</th>
<th>Financial gain/ (loss) in 2009 prices</th>
</tr>
</thead>
<tbody>
<tr>
<td>System Frequency in range 50Hz +/- 0.1Hz</td>
<td>94% +/- 2%</td>
<td>98%</td>
<td>€224,000</td>
</tr>
<tr>
<td>System Minutes Lost</td>
<td>3.5 SML +/- 2 SML</td>
<td>0.006</td>
<td>€224,000</td>
</tr>
<tr>
<td>Fault Clearance Rate</td>
<td>0.15 +/- 0.1</td>
<td>0.0303</td>
<td>€224,000</td>
</tr>
<tr>
<td>Lodgement of Planning Permission</td>
<td>Lodged in standard timeframes</td>
<td>N/A</td>
<td>N/A</td>
</tr>
</tbody>
</table>

As is evident from the table above, the TSO performed well against all of the system performance targets for 2009 (first three parameters in table). Further details of these three parameters, and the TSO’s performance, is presented in the TSO 2009 System Performance Report\(^\text{48}\).

In terms of the fourth parameter in the table above – lodgement of planning permission – this parameter is not applicable for 2009 since there were no applications required to be lodged for planning permission for shallow connections. The TSO was therefore entitled to a SPI amount of €672k for 2009.

\(^\text{47}\) Please see the following link: http://www.cer.ie/en/electricity-transmission-network-decision-documents.aspx?article=fb726a75-7365-4dfb-9e16-ff5c5d2d363a

\(^\text{48}\) Please see following link and Transmission System Performance Reports subsection http://www.eirgrid.com/aboutus/publications/
and this has been reflected in the revenue allowance for 2011 (please see section 9.8).

Although the parameters listed above are open to fluctuation and occurrences of such are largely outside the control of the TSO, the CER notes that the TSO has achieved all of its performance objectives where applicable for 2009 (and 2008). This will be kept in mind by the CER when setting performance targets for the PR3 period.

6.2.3 Assessment of historical performance

The table below sets out the parameters of the SPIs in the PR2 period. SKM note in their report that the TSO had some difficulty in influencing system performance in the short term. This was due to the relatively weak incentive to invest in system improvement and to the adverse impact on system performance of higher levels of volatile wind generation. This latter effect has been overcome to some extent by greater North-South coordination and transmission system monitoring.

However, as evident from the table below, overall the TSO has improved system performance despite some contrary influences brought about by the increase in wind generation and the complexity of system operation.

Table 13: PR2 Transmission System Parameters

<table>
<thead>
<tr>
<th>Performance Measure</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td>Frequency Violations Outturn</td>
<td>90.4%</td>
<td>94.0%</td>
<td>97.0%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Frequency Violations Target Upper</td>
<td></td>
<td></td>
<td>94.5%</td>
<td>96.0%</td>
<td>96.0%</td>
</tr>
<tr>
<td>Frequency Violations Target Central</td>
<td></td>
<td></td>
<td>92.5%</td>
<td>94.0%</td>
<td>94.0%</td>
</tr>
<tr>
<td>Frequency Violations Target Lower</td>
<td></td>
<td></td>
<td>90.5%</td>
<td>92.0%</td>
<td>92.0%</td>
</tr>
<tr>
<td>System Minutes Lost Outturn</td>
<td>2.3</td>
<td>3.4</td>
<td>0.7</td>
<td></td>
<td></td>
</tr>
<tr>
<td>System Minutes Lost Target Upper</td>
<td></td>
<td></td>
<td>5.5</td>
<td>5.5</td>
<td>5.5</td>
</tr>
<tr>
<td>System Minutes Lost Target Central</td>
<td>3.5</td>
<td>3.5</td>
<td>3.5</td>
<td></td>
<td></td>
</tr>
<tr>
<td>System Minutes Lost Target Lower</td>
<td>1.5</td>
<td>1.5</td>
<td>1.5</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fault Clearance Rate Outturn</td>
<td>0.08</td>
<td>0.09</td>
<td>0.03</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fault Clearance Rate Target Upper</td>
<td></td>
<td></td>
<td>0.25</td>
<td>0.25</td>
<td>0.25</td>
</tr>
<tr>
<td>Fault Clearance Rate Target Central</td>
<td></td>
<td></td>
<td>0.15</td>
<td>0.15</td>
<td>0.15</td>
</tr>
<tr>
<td>Fault Clearance Rate Incentive Lower</td>
<td></td>
<td></td>
<td>0.05</td>
<td>0.05</td>
<td>0.05</td>
</tr>
<tr>
<td>System Availability</td>
<td>97.1%</td>
<td>95.3%</td>
<td>97.2%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>System Availability Target</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Planning Consent Lodgements</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Planning Consent Target Upper</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Planning Consent Target Central</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Planning Consent Target Lower</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

62
6.3 2011-2015 PR3 Incentives

The CER is keen to continue the appropriation of incentive mechanisms to the TSO (and now to the TAO) into the PR3 period. Improvements in transmission system performance, grid infrastructure build and achievement of the Government’s 2020 renewables targets will be fundamental to the setting of transmission incentive mechanisms in PR3.

It is the CER’s view that the targets proposed for the PR3 period should be even more challenging than PR2\(^49\) - yet still achievable. The CER believes that incentives with such characteristics will encourage both the TSO and TAO to improve their performance. As noted in the introduction to this section proposed transmission incentives for the next incentive period will be consulted on with stakeholders in a separate CER paper in the coming weeks.

\(^{49}\) Especially in light of the fact that EirGrid successfully reached all of its performance targets in both 2008 and 2009.
7.0 Review of historical capital expenditure

This section examines the historical Capex undertaken by the TAO and TSO. The outturn expenditure is assessed, looking at the output in terms of delivery and efficiency. As mentioned above, a more detailed breakdown and explanation of historic Capex is provided in the SKM transmission report published alongside the consultation paper CER/10/102.

7.1 Introduction & Objectives

Both the TAO and TSO have undertaken a significant programme of investment during PR2. The CER allowed, in the PR2 determination, €524 million of net Capex related to network and non-network investments for the TAO. With respect to the TSO, the PR2 determination allowed for nearly €30 million of Capex spend, the vast majority of TSO Capex being IT related. The subsequent vesting of EirGrid as TSO on 1st July 2006 and the commencement of the SEM on 1st November 2007 resulted in a revision of allowed TSO Capex. This is discussed below in section 7.4.

In the PR2 determination the CER looked to keep pace with the continued domestic economic expansion through the significant level of allowed transmission Capex, the result of which was considerable investment in new generator and demand connections, reinforcement, network renewal and IT by the TSO and TAO.

The main objectives in the PR3 review of the TAO’s and TSO’s historical Capex are to assess whether the expenditure has been incurred efficiently and the expected benefits for customers have been achieved. In other words has the TSO and TAO delivered what it said it would and at the cost which had been forecast. The following areas were examined in detail:

- Comparing the outturn expenditure (and currently projected for 2010) with the allowed expenditure;
- Understanding the differences between the allowed expenditure and the outturn expenditure; and

It is important to clarify the respective roles of the TAO and the TSO in relation to transmission system development, and the implications of these roles for network Capex in the context of a price control. EirGrid, as TSO, plans the future development of the transmission network on an independent basis. Project design and initiation is the TSO’s responsibility and this is referred to as Stage 1. Projects called for by the TSO must be funded efficiently and constructed in a timely manner by the TAO, which does not have a decision-making role in terms
of the transmission projects to be undertaken. The construction and energisation of projects by the TAO is referred to as Stage 2.

The TSO, in accordance with SI 445 of 2000⁵⁰ and its licence conditions, is required to prepare a Transmission System Development Plan relating to a period of five years to ensure security of supply. This plan is to be updated or revised on an annual basis, issued for public consultation and submitted to the CER for approval. The TAO is then responsible for the implementation of that plan⁵¹.

Given the unique structure of the Irish transmission business (i.e. the separation of the operator and ownership functions), combined with the sizeable scale of many transmission projects, the CER has assumed a monitoring role in the rollout of significant transmission projects. While the CER currently reviews capital projects in detail at the end of the five-year review period, an active and ongoing annual Capex monitoring process has been put in place over the PR2 period. This ongoing process is of particular merit in relation to transmission projects, which by their very nature can span more than a single revenue review period.

### 7.2 Capex – Summary

Table 14 below sets allowed versus actual Network and Non-Network Capex for the PR2 period, which has been allowed for and incurred by the TAO. As can be seen from this table the TAO has underspent on the allowed net Capex of €524 million by circa €78 million. It should be noted that a negative number in the variance categories indicate an underspend, while a positive number indicate an overspend. Please also note that the 2010 figures provided are current best projected.

---


⁵¹ A more detailed breakdown of respective actions, timelines and charges between the TSO and TAO can be found in CER/09/077, published last year by the CER.
Table 14: Transmission PR2 TAO Network and Non-Network Capex (€m’s 2009 prices)

<table>
<thead>
<tr>
<th>Year</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
<th>Totals</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gross (after allowing for IDC)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CER Allowed</td>
<td>145.30</td>
<td>114.32</td>
<td>96.82</td>
<td>103.83</td>
<td>118.53</td>
<td>578.80</td>
</tr>
<tr>
<td>Actual</td>
<td>71.79</td>
<td>86.28</td>
<td>106.67</td>
<td>141.36</td>
<td>144.80</td>
<td>550.90</td>
</tr>
<tr>
<td>Interest During Construction (IDC)</td>
<td>-3.86</td>
<td>-4.27</td>
<td>-4.58</td>
<td>-5.05</td>
<td>-5.80</td>
<td>-23.56</td>
</tr>
<tr>
<td>Actual (less IDC)</td>
<td>67.94</td>
<td>82.01</td>
<td>102.09</td>
<td>136.31</td>
<td>139.00</td>
<td>527.34</td>
</tr>
<tr>
<td>Variance $^{52}$</td>
<td>-77.36</td>
<td>-32.32</td>
<td>5.27</td>
<td>32.48</td>
<td>20.47</td>
<td>-51.45</td>
</tr>
<tr>
<td>Customer Cont.</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CER Assumed</td>
<td>-17.14</td>
<td>-11.78</td>
<td>-10.62</td>
<td>-7.75</td>
<td>-7.79</td>
<td>-55.08</td>
</tr>
<tr>
<td>Actual</td>
<td>-10.32</td>
<td>-14.71</td>
<td>-11.27</td>
<td>-38.01</td>
<td>-6.90</td>
<td>-81.21</td>
</tr>
<tr>
<td>Variance $^{53}$</td>
<td>6.83</td>
<td>-2.93</td>
<td>-0.65</td>
<td>-30.26</td>
<td>0.89</td>
<td>-26.13</td>
</tr>
<tr>
<td>Net (after Customer Cont.)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CER Allowed</td>
<td>128.15</td>
<td>102.54</td>
<td>86.20</td>
<td>96.08</td>
<td>110.74</td>
<td>523.71</td>
</tr>
<tr>
<td>Actual</td>
<td>57.62</td>
<td>67.29</td>
<td>90.82</td>
<td>98.29</td>
<td>132.10</td>
<td>446.13</td>
</tr>
<tr>
<td>Variance $^{54}$</td>
<td>-70.53</td>
<td>-35.24</td>
<td>4.62</td>
<td>2.22</td>
<td>21.36</td>
<td>-77.58</td>
</tr>
</tbody>
</table>

Table 15 below sets allowed versus actual Non-Network Capex for the PR2 period, which has been allowed for incurred by the TSO. As can be seen from this table the TSO has underspent on the allowed Non-Network Capex of €53 million by circa €13 million. A further breakdown of this table below is provided in section 7.4. It should be noted that a negative number in the variance categories indicate an underspend, while a positive number indicate an overspend. Please also note that the 2010 figures provided are current best projected.

$^{52}$ Actual minus Allowed.
$^{53}$ ibid
$^{54}$ ibid
Table 15: Transmission PR2 TSO Non-Network Capex (€m’s 2009 prices)

<table>
<thead>
<tr>
<th>Services</th>
<th>CER PR2 Allowed</th>
<th>CER Adjusted Allowed</th>
<th>Actual</th>
<th>Variance⑤5</th>
</tr>
</thead>
<tbody>
<tr>
<td>Accommodation and Facilities</td>
<td>0.9</td>
<td>12.3</td>
<td>11.7</td>
<td>-0.6</td>
</tr>
<tr>
<td>Control / Operations</td>
<td>1.6</td>
<td>3.5</td>
<td>3.0</td>
<td>-0.5</td>
</tr>
<tr>
<td>Corporate IT Infrastructure</td>
<td>4.9</td>
<td>7.4</td>
<td>7.7</td>
<td>0.3</td>
</tr>
<tr>
<td>Enterprise Applications</td>
<td>17.3</td>
<td>17.3</td>
<td>3.4</td>
<td>-13.9</td>
</tr>
<tr>
<td>Market Systems</td>
<td></td>
<td></td>
<td>6.7</td>
<td>3.3</td>
</tr>
<tr>
<td>Telecoms</td>
<td>6.8</td>
<td>9.1</td>
<td>7.7</td>
<td>-1.4</td>
</tr>
<tr>
<td><strong>Net Non Network Capex</strong></td>
<td><strong>31.5</strong></td>
<td><strong>53.0</strong></td>
<td><strong>40.2</strong></td>
<td><strong>-12.8</strong></td>
</tr>
</tbody>
</table>

7.3 **TAO Capex**

This section examines the historical capital expenditure undertaken by the TAO, with the outturn expenditure assessed. A deeper review, looking at the output in terms of delivery and efficiency, is contained in the accompanying SKM transmission report.

The TAO has undertaken a significant programme of investment in the transmission system during PR2. The CER allowed, in the PR2 transmission determination, €524 million of capex related to network and non-network investments. Over the period there was significant expenditure on new connections (demand and generation), reinforcement, network renewal and IT. However, the outturn/2010 forecast figures as outlined in Table 14 above has not been in line with figures allowed by the CER. There are a number of reasons for this which is also discussed below in section 7.5. It should be noted that a negative number in the variance categories indicate an underspend, while a positive number indicate an overspend. Please also note that the 2010 figures provided are current best projected.

⑤5 Actual minus allowed.
### 7.3.1 TAO Capex – Load

Table 16: Load Related Expenditure (€m’s 2009 prices)

<table>
<thead>
<tr>
<th>Year</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
<th>Totals</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gross</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CER Allowed</td>
<td>108.88</td>
<td>79.09</td>
<td>70.94</td>
<td>85.57</td>
<td>104.04</td>
<td>448.51</td>
</tr>
<tr>
<td>Actual</td>
<td>38.97</td>
<td>61.03</td>
<td>66.18</td>
<td>108.15</td>
<td>123.20</td>
<td>397.53</td>
</tr>
<tr>
<td>Variance</td>
<td>-69.91</td>
<td>-18.06</td>
<td>-4.75</td>
<td>22.58</td>
<td>19.16</td>
<td>-50.98</td>
</tr>
</tbody>
</table>

| Customer Contributions |
| CER Assumed | -17.14 | -11.78 | -10.62 | -7.75 | -7.79 | -55.08 |
| Actual | -10.32 | -14.71 | -11.27 | -38.01 | -6.90 | -81.21 |
| Variance | 6.83 | -2.93 | -0.65 | -30.26 | 0.89 | -26.13 |

| Net (after Customer Contributions) |
| CER Allowed | 91.74 | 67.31 | 60.32 | 77.82 | 96.25 | 393.43 |
| Actual | 28.66 | 46.32 | 54.91 | 70.13 | 116.30 | 316.32 |
| Variance | -63.08 | -20.99 | -5.41 | -7.69 | 20.05 | -77.11 |

Note: The figures above do not include Interest During Construction (IDC) which has been taken into account in the overall capital expenditure (see Table 14).

Load related Capex is mainly related to the connection of new business and new generators to the transmission system. Gross Load Related expenditure of €397.5 million was €50.9 million lower than the CER allowed costs of €448.5 million. Net Load Related Expenditure of €316.3 million was €77.1 million lower than the allowed costs of €393.4 million.

As outlined in the accompanying SKM Transmission report, a number of Load Related projects which required the construction of new overhead lines were significantly delayed due to problems with obtaining permission for access to the land, which partly explains the shortfall against forecast. Delaying factors, such as land access issues, are discussed further in section 7.5 below.
7.3.2 TAO Capex – Non Load

Table 17: Non-Load Related Expenditure (€m's 2009 prices)

<table>
<thead>
<tr>
<th>Year</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
<th>Totals</th>
</tr>
</thead>
<tbody>
<tr>
<td>CER Allowed</td>
<td>35.31</td>
<td>35.23</td>
<td>25.89</td>
<td>18.26</td>
<td>14.49</td>
<td>129.17</td>
</tr>
<tr>
<td>Actual</td>
<td>32.61</td>
<td>25.05</td>
<td>40.11</td>
<td>33.21</td>
<td>21.60</td>
<td>152.58</td>
</tr>
<tr>
<td>Variance</td>
<td>-2.69</td>
<td>-10.18</td>
<td>14.22</td>
<td>14.95</td>
<td>7.11</td>
<td>23.41</td>
</tr>
</tbody>
</table>

Note: The figures above do not include Interest During Construction (IDC) which has been taken into account in the overall capital expenditure (see Table 15).

Network non-load related Capex is investment needed to refurbish or replace old and faulty equipment on the network. The projects included under this heading include refurbishment or replacement of substations, transformers, switchgear, overhead lines and underground cables. Non-load related expenditure also covers expenditure to improve network performance, such as remote control and automation.

Non-load related expenditure of €152.6 million exceeded the CER allowed costs €129.2 million by €23.4 million. Increases in the costs of materials and labour have contributed to this overspend and the percentage overspend is reasonably consistent with the analysis provided by SKM in their transmission report. It should be noted that a negative number in the variance categories indicate an underspend, while a positive number indicate an overspend. Please also note that the 2010 figures provided are current best projected.

7.3.3 Capex Monitoring Program

The CER, in agreement with the TSO and TAO, put in place a capex monitoring program during the PR2 period. It was agreed that a Capital Expenditure Report would be submitted to the CER on an annual basis (referred to as Capex Monitoring Report).

The 2009 Capex monitoring submission made jointly by the TSO and TAO can be broken into three categories; (a) projects over €1 million identified at PR2, (b) possible projects over €1 million identified at PR2 as provisional and which are now being undertaken and (c) aggregated figures for undertaken projects under €1 million. Within each of those categories there are informational columns, e.g. identifying project agreement dates (Stage 1 moving into Stage 2), expected Stage 1 spend (TSO), expected Stage 2 spend (TAO) etc.

The CER also requested ‘commentary’ associated with a reason(s) behind delays or large differences in estimated versus actual costs for certain projects. These drivers are broken down into ‘Internal’ and ‘External’ factors. Severe delays and/or large over/under actual costs are of primary concern to the CER,

56 Please refer to section 8.8 of the accompanying PR3 TSO SKM report.
whether due to internal or external factors. A detailed explanation from the TSO, the TAO or indeed both, was required to be provided to the CER in the following circumstances;

- Delays of 6 months or greater to project completion to any projects with associated costs of €1 million or above.

- Actual project spend is significantly different as to what was forecasted in PR2, 20% or above of total estimated project spend at PR2. This figure of 20% relates to both an overspend or underspend for a project. However, the CER reserves the right to query any over or under spend, of any percentage, that it believes requires further investigation.

- Internal or external problems that arose in a specific project, which could affect other project of similar characteristics (i.e. location /similar material requirements/delay in obtaining planning permission etc); will be highlighted to the CER upon request. Remedies taken by the TSO and TAO to such problems under their control, will also be provided to the CER upon request.

As SKM recommend, the Capex Monitoring Report should become a fully functional (i.e. formula based) tool that is a shared document between the three main stakeholders, albeit with some improved clarity and quality control of inputs. As such it will act to highlight project issues and if updated regularly (at least monthly) by the responsible project managers it will allow additional management focus on problematic issues.

The CER will be looking to further refine this Capex Monitoring Model as per the SKM recommendations for the PR3 period and this is discussed further in section 8.5 below.

### 7.4 TSO Capex Non-Network

This section examines the historical Capex undertaken by the TSO, with the outturn expenditure assessed. As with the TAO a deeper review, looking at the output in terms of delivery and efficiency, is contained in the accompanying SKM transmission report.

The Capex allowed by CER at the outset of PR2 was adjusted by the CER after public consultation during PR2. This was done in order to provide resources for EirGrid to relocate to new offices at the Oval in Ballsbridge and develop IT systems in readiness for the Single Electricity Market. The annual transmission revenue determination papers[^57] detail the various cost revenue items included, such as those mentioned above.

[^57]: Please see PR2 transmission revenue determination papers: CER/06/199, CER/07/184, CER/08/178 and CER/09/140
Even though the CER permitted these extra costs to be included in the transmission revenue the TSO was still expected to ensure that allowed additional “uncertain costs”, were incurred in an efficient manner, i.e. the fit-out of the offices in the Oval.

As per Table 18 below, the TSO has underspent on the revised allowed Non-Network capex of €53 million by €12.8 million. This underspend was largely associated with the TSO not utilising the €13 million for non specified IT projects, allowed for in the PR2 determination due to the diversion of resources to SEM establishment. A more detailed analysis of this is provided in the accompanying SKM transmission report.

It should be noted that a negative number in the variance categories indicate an underspend, while a positive number indicate an overspend. Please also note that the 2010 figures provided are current best projected.
Table 18: Non-Network related Expenditure (€m's 2009 prices)

<table>
<thead>
<tr>
<th>Category</th>
<th>CER Allowed</th>
<th>Adjusted CER Allowed</th>
<th>PR2 Actual</th>
<th>Variance</th>
</tr>
</thead>
<tbody>
<tr>
<td>Premises Relocation</td>
<td>0.0</td>
<td>11.2</td>
<td>10.8</td>
<td>-0.4</td>
</tr>
<tr>
<td>Fixture and Fittings</td>
<td>0.9</td>
<td>1.1</td>
<td>0.9</td>
<td>-0.2</td>
</tr>
<tr>
<td>Accommodation and Facilities</td>
<td>0.9</td>
<td>12.3</td>
<td>11.7</td>
<td>-0.6</td>
</tr>
<tr>
<td>Control Facilities and Wall</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Diagrams</td>
<td>0.0</td>
<td>1.2</td>
<td>0.4</td>
<td>-0.8</td>
</tr>
<tr>
<td>Control Centre Systems</td>
<td>1.6</td>
<td>2.3</td>
<td>2.6</td>
<td>0.3</td>
</tr>
<tr>
<td>Economic Despatch and Unit commitment</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>TSO Interconnector integration</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Control / Operations</td>
<td>1.6</td>
<td>3.5</td>
<td>3.0</td>
<td>-0.5</td>
</tr>
<tr>
<td>PC Peripherals and Servers</td>
<td>3.8</td>
<td>3.9</td>
<td>4.8</td>
<td>0.9</td>
</tr>
<tr>
<td>Oval relocation - networking</td>
<td>2.4</td>
<td>2.4</td>
<td>2.4</td>
<td>0.0</td>
</tr>
<tr>
<td>Business Continuity</td>
<td>0.6</td>
<td>0.6</td>
<td>0.0</td>
<td>-0.6</td>
</tr>
<tr>
<td>Corporate data management</td>
<td>0.5</td>
<td>0.5</td>
<td>0.4</td>
<td>-0.1</td>
</tr>
<tr>
<td>Website</td>
<td></td>
<td>0.1</td>
<td>0.1</td>
<td></td>
</tr>
<tr>
<td>Other projects</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Corporate IT Infrastructure</td>
<td>4.9</td>
<td>7.4</td>
<td>7.7</td>
<td>0.3</td>
</tr>
<tr>
<td>Unspecified Projects</td>
<td>12.9</td>
<td>12.9</td>
<td>-12.9</td>
<td></td>
</tr>
<tr>
<td>Other</td>
<td>4.4</td>
<td>4.4</td>
<td>-4.4</td>
<td></td>
</tr>
<tr>
<td>Planning - Power Systems</td>
<td></td>
<td>1.9</td>
<td>1.9</td>
<td></td>
</tr>
<tr>
<td>TUoS and Ancillary Settlement</td>
<td></td>
<td>1.6</td>
<td>1.6</td>
<td></td>
</tr>
<tr>
<td>TSO Business Application</td>
<td></td>
<td></td>
<td></td>
<td>0.0</td>
</tr>
<tr>
<td>Project Management</td>
<td></td>
<td></td>
<td></td>
<td>0.0</td>
</tr>
<tr>
<td>General IS Applications</td>
<td></td>
<td></td>
<td></td>
<td>0.0</td>
</tr>
<tr>
<td>Other Applications</td>
<td></td>
<td></td>
<td></td>
<td>0.0</td>
</tr>
<tr>
<td>Enterprise Applications</td>
<td>17.3</td>
<td>17.3</td>
<td>3.5</td>
<td>-13.8</td>
</tr>
<tr>
<td>TSO Readiness</td>
<td></td>
<td>3.4</td>
<td>3.4</td>
<td>0.0</td>
</tr>
<tr>
<td>Day 1 B - TSO</td>
<td></td>
<td>2.1</td>
<td>2.1</td>
<td></td>
</tr>
<tr>
<td>Electronic Interface to system users</td>
<td></td>
<td>0.2</td>
<td>0.2</td>
<td></td>
</tr>
<tr>
<td>Implementation of New Trading</td>
<td></td>
<td>0.4</td>
<td>0.4</td>
<td></td>
</tr>
<tr>
<td>Settlement systems</td>
<td></td>
<td>0.1</td>
<td>0.1</td>
<td></td>
</tr>
<tr>
<td>Replacement Systems</td>
<td></td>
<td>0.6</td>
<td>0.6</td>
<td></td>
</tr>
<tr>
<td>Market Systems</td>
<td></td>
<td>3.4</td>
<td>6.7</td>
<td>3.3</td>
</tr>
<tr>
<td>SCADA/Metering &amp; Hardware</td>
<td>5.4</td>
<td>5.4</td>
<td>5.2</td>
<td>-0.2</td>
</tr>
<tr>
<td>Oval Telecoms</td>
<td>2.4</td>
<td>2.4</td>
<td>2.4</td>
<td>0.0</td>
</tr>
<tr>
<td>Telecoms Other/ Telephony</td>
<td>1.3</td>
<td>1.3</td>
<td>0.1</td>
<td>-1.2</td>
</tr>
<tr>
<td>Telecoms</td>
<td>6.8</td>
<td>9.1</td>
<td>7.7</td>
<td>-1.4</td>
</tr>
<tr>
<td>Net Non Network Capex</td>
<td>31.5</td>
<td>53.0</td>
<td>40.2</td>
<td>-12.7</td>
</tr>
</tbody>
</table>
7.5 Difference between Capex approved and incurred

The PR2 transmission determination provided for a five-year rolling retention of efficiency savings for both Opex and Capex. Where the TSO and TAO can show that avoided Capex is due to efficiencies on their part, they are allowed to retain the revenue associated with the unspent Capex for a period of five years. The transmission determination specified that reduction of volumes of investment (or indeed forecasting error) would not be accepted as efficiency, as appears to be case for the PR2 period. The CER has decided to reset both the TAO and TSO RAB in line with outturn PR2 costs. The opening TSO and TAO RABs for the PR3 period are contained in sections 8.4.4 and 8.6.1 of this paper.

As stated in section 4.7.4 above the CER has already reduced the allowed transmission revenue for both 2009 and 2010 to reflect the TAO underspend.

The remainder of this section briefly addresses the reasons as to why there was an underspend for PR2 TAO Capex and TSO Capex. It should be noted that the CER and its consultants have invested significant time into investigating the cause of the Capex underspends and have reflected the findings of these investigations in the Capex amounts for the PR3 period (please see section 8.0). A more detailed account of the Capex underspends is provided in the accompanying SKM transmission report; however the key reasons from the CER’s perspective are outlined below.

**TAO**

As outlined above and detailed in Table 14 the TAO underspend of approximately €78 million can be attributed to a number of issues. Opposition from landowners to new construction, particularly of overhead lines has led to lengthy delays or even the inability to build transmission projects. This has meant projects identified as part of PR2 and accounted for through allowed PR2 Capex were simply not completed or were severely delayed.

The TAO has identified a number of cost pressures over the PR2 period which impacted on project outturn costs. These include increases in basic material and equipment costs as well as increases in labour rates. This, in combination with land access issues, led to a number of significant projects overspends and heavy delays, which in turn led to resources (financial and manpower) being diverted away from other listed projects.

The Infrastructure Agreement (IA) came into force on 1st July 2006, upon the vesting of EirGrid. It defines the working relationship between EirGrid in its role as TSO, and ESB Networks in its role as TAO. It is clear that uncertainty around defined roles and composition of the IA following the introduction of the IA led to delays in projects in the early years of the PR2 period, most notably in 2006.
However, while there may have been teething problems with the implementation of the IA at the time of the establishment and transfer of responsibilities to EirGrid. Nonetheless these have since been resolved and the IA processes have evolved and have worked well since 2006. Where opportunities have been identified to improve IA processes, they are being continually taken. For example proposals were made to the CER to allow paralleling processes in the case of IPP projects, by allowing work to progress in parallel on projects whilst planning permission is being sought. Please refer to CER/09/077 for further detail on the matter.

Please also refer to Appendix E of the accompanying SKM TAO report for a more detailed explanation of the delaying factors discussed above.

**TSO**

As detailed in Table 15 the TSO underspend was largely associated with it not utilising the €13 million for non specified IT projects, allowed for in the PR2 transmission determination.

In CER/09/140 a repayment of €4.5 million of the depreciation and return associated with elements of non-network Capex not expended up to 2010 was brought forward by the TSO. This repayment amounted to a once off reduction in 2010 of €4.5 million based upon the underspend of the non-network Capex in the PR2 period.
### 8.0 Review of forecast Capital expenditure

#### 8.1 Introduction

In response to the CER’s Price Review Questionnaire, the TSO submitted three network Capex projections in spreadsheet format, each set against somewhat different development scenarios respectively referenced as ‘Network Needs’, ‘Deliverability’ and ‘Affordability’. The Capex associated with each of these scenarios are presented in tabular format below:

Table 19: PR3 EirGrid Capex scenarios

<table>
<thead>
<tr>
<th>Network Needs Scenario - €2109 Million</th>
<th>PR3 Period</th>
<th>Total in the PR3 period</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2011</td>
<td>2012</td>
</tr>
<tr>
<td>Ongoing projects</td>
<td></td>
<td></td>
</tr>
<tr>
<td>EirGrid</td>
<td>€22.1</td>
<td>€9.2</td>
</tr>
<tr>
<td>ESB</td>
<td>€210.4</td>
<td>€290.3</td>
</tr>
<tr>
<td>Total</td>
<td>€232.5</td>
<td>€299.5</td>
</tr>
<tr>
<td>Under Consideration - System Reinforcements</td>
<td></td>
<td></td>
</tr>
<tr>
<td>EirGrid</td>
<td>€1.1</td>
<td>€7.2</td>
</tr>
<tr>
<td>ESB</td>
<td>€16.9</td>
<td>€48.1</td>
</tr>
<tr>
<td>Total</td>
<td>€18.0</td>
<td>€55.3</td>
</tr>
<tr>
<td>Under consideration - Shallow Connection - Non LCTA works</td>
<td></td>
<td></td>
</tr>
<tr>
<td>EirGrid</td>
<td>€2.1</td>
<td>€2.3</td>
</tr>
<tr>
<td>ESB</td>
<td>€2.3</td>
<td>€9.4</td>
</tr>
<tr>
<td>Total</td>
<td>€4.4</td>
<td>€11.7</td>
</tr>
<tr>
<td>Provisions - System Reinforcements</td>
<td></td>
<td></td>
</tr>
<tr>
<td>EirGrid</td>
<td>€0.0</td>
<td>€0.0</td>
</tr>
<tr>
<td>ESB</td>
<td>€5.2</td>
<td>€3.4</td>
</tr>
<tr>
<td>Total</td>
<td>€5.2</td>
<td>€3.4</td>
</tr>
<tr>
<td>Provisions - Asset Refurbishment</td>
<td></td>
<td></td>
</tr>
<tr>
<td>EirGrid</td>
<td>€0.6</td>
<td>€0.7</td>
</tr>
<tr>
<td>ESB</td>
<td>€23.0</td>
<td>€49.0</td>
</tr>
<tr>
<td>Total</td>
<td>€23.6</td>
<td>€49.7</td>
</tr>
<tr>
<td>Provisions - Minor Capital &amp; Conflicts (Minus 75% Contribution)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>EirGrid</td>
<td>€0.1</td>
<td>€0.1</td>
</tr>
<tr>
<td>ESB</td>
<td>€7.8</td>
<td>€8.9</td>
</tr>
<tr>
<td>Total</td>
<td>€7.9</td>
<td>€9.0</td>
</tr>
<tr>
<td>Under consideration - DSO - 50% contribution</td>
<td></td>
<td></td>
</tr>
<tr>
<td>EirGrid</td>
<td>€1.5</td>
<td>€0.4</td>
</tr>
<tr>
<td>ESB</td>
<td>€3.3</td>
<td>€2.3</td>
</tr>
<tr>
<td>Total</td>
<td>€4.8</td>
<td>€2.6</td>
</tr>
<tr>
<td>Total</td>
<td>€296.4</td>
<td>€431.1</td>
</tr>
</tbody>
</table>

PR3 Total €2,109 Million
<table>
<thead>
<tr>
<th>Deliverability Scenario - €1733 Million</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>Total in the PR3 period</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>€ million</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Ongoing projects</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EirGrid</td>
<td>€21.0</td>
<td>€8.7</td>
<td>€3.7</td>
<td>€3.3</td>
<td>€0.6</td>
<td></td>
</tr>
<tr>
<td>ESB</td>
<td>€199.9</td>
<td>€275.8</td>
<td>€212.3</td>
<td>€138.2</td>
<td>€27.2</td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>€220.8</td>
<td>€284.5</td>
<td>€216.0</td>
<td>€141.5</td>
<td>€27.8</td>
<td>€890.7</td>
</tr>
<tr>
<td><strong>Under Consideration - System Reinforcements</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EirGrid</td>
<td>€1.0</td>
<td>€6.8</td>
<td>€54.3</td>
<td>€36.5</td>
<td>€21.0</td>
<td></td>
</tr>
<tr>
<td>ESB</td>
<td>€10.1</td>
<td>€28.9</td>
<td>€78.5</td>
<td>€129.9</td>
<td>€150.2</td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>€11.1</td>
<td>€35.7</td>
<td>€132.8</td>
<td>€166.4</td>
<td>€171.2</td>
<td>€517.3</td>
</tr>
<tr>
<td><strong>Under consideration - Shallow Connection - Non LCTA works</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EirGrid</td>
<td>€2.1</td>
<td>€2.3</td>
<td>€4.9</td>
<td>€2.3</td>
<td>€0.4</td>
<td></td>
</tr>
<tr>
<td>ESB</td>
<td>€2.3</td>
<td>€9.4</td>
<td>€11.7</td>
<td>€12.4</td>
<td>€16.4</td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>€4.4</td>
<td>€11.7</td>
<td>€16.7</td>
<td>€14.7</td>
<td>€16.8</td>
<td>€64.3</td>
</tr>
<tr>
<td><strong>Provisions - System Reinforcements</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EirGrid</td>
<td>€0.0</td>
<td>€0.0</td>
<td>€0.0</td>
<td>€0.4</td>
<td>€0.4</td>
<td></td>
</tr>
<tr>
<td>ESB</td>
<td>€2.6</td>
<td>€1.7</td>
<td>€1.7</td>
<td>€0.0</td>
<td>€3.6</td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>€2.6</td>
<td>€1.7</td>
<td>€1.7</td>
<td>€0.4</td>
<td>€4.0</td>
<td>€10.4</td>
</tr>
<tr>
<td><strong>Provisions - Asset Refurbishment</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EirGrid</td>
<td>€0.5</td>
<td>€0.5</td>
<td>€0.3</td>
<td>€0.4</td>
<td>€0.0</td>
<td></td>
</tr>
<tr>
<td>ESB</td>
<td>€18.4</td>
<td>€39.2</td>
<td>€48.8</td>
<td>€44.0</td>
<td>€36.8</td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>€18.9</td>
<td>€39.7</td>
<td>€49.1</td>
<td>€44.4</td>
<td>€36.8</td>
<td>€189.0</td>
</tr>
<tr>
<td><strong>Provisions - Minor Capital &amp; Conflicts (Minus 75% Contribution)</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EirGrid</td>
<td>€0.1</td>
<td>€0.1</td>
<td>€0.1</td>
<td>€0.1</td>
<td>€0.1</td>
<td></td>
</tr>
<tr>
<td>ESB</td>
<td>€7.8</td>
<td>€8.9</td>
<td>€9.0</td>
<td>€9.6</td>
<td>€10.3</td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>€7.9</td>
<td>€9.0</td>
<td>€9.1</td>
<td>€9.8</td>
<td>€10.4</td>
<td>€46.1</td>
</tr>
<tr>
<td><strong>Under consideration - DSO - 50% contribution</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EirGrid</td>
<td>€1.5</td>
<td>€0.4</td>
<td>€0.0</td>
<td>€0.0</td>
<td>€0.0</td>
<td></td>
</tr>
<tr>
<td>ESB</td>
<td>€3.3</td>
<td>€2.3</td>
<td>€2.8</td>
<td>€3.6</td>
<td>€1.8</td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>€4.8</td>
<td>€2.6</td>
<td>€2.8</td>
<td>€3.6</td>
<td>€1.8</td>
<td>€15.6</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>€270.6</td>
<td>€384.9</td>
<td>€428.2</td>
<td>€380.8</td>
<td>€268.9</td>
<td>€1,733.5</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>PR3 Total</td>
<td>€1,733 Million</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
The TSO identified the “Network Needs” scenario (€2.109 billion expenditure forecast) as its view of the total Capex investment needed over the five years of the PR3 period. This, the TSO, argued was the investment needed to deliver network capacity sufficient to continue progress towards meeting Ireland’s 2020 renewable targets, delivery of Gate 3 and long-term Grid25 objectives. The other two scenarios – “Deliverability” (€1.733 billion expenditure forecast) and “Affordability” (€1.329 billion expenditure forecast) – were derived from the Network Needs scenario. The Deliverability scenario represents the TSO’s view of a realistic level of expenditure which could be delivered over the five year period (bearing in mind that a significant ramp-up in expenditure and activity would be required between PR2 and PR3). The Affordability scenario represents the TSO’s view of an expenditure programme which limits the impact on transmission tariffs in the PR3 period.
Each of the three TSO Capex submissions contain a significant programme of capital expenditure for the PR3 period, especially when compared against the total PR2 Capex allowed by the CER (€524 million). The TSO has stated that renewable generation connection is the main driver of the PR3 Capex program, through the accommodation of the CER’s Gate 3 program\(^{58}\) and the TSO’s Incremental Transfer Capability (ITC) program\(^{59}\). Furthermore, the PR3 Capex submission made by the TSO is a reflection of the anticipated needs contained within its long-term \textit{Grid25}\(^{60}\) strategy, which it is argued by the TSO will facilitate the reaching of the Government’s 2020 renewables target. \textit{Grid25} outlines a requirement for total expenditure in the region of €4 billion in the transmission network.

With respect to non-network Capex, the TSO has indicated that it will adopt a reasonable policy towards replacement of IT systems in the PR3 period. Its PR3 forecast non-network Capex submission of €30.3 million gross (€23.5 million net) is €16.6 million lower than the PR2 net expenditure of €40.2 million. This net figure also takes account of €6.8 million of customer contributions.

The following sections review and assess the requested network and non-network Capex submissions and detail the CER’s decision on the matter.

\subsection*{8.2 Objectives}

The objective of the review of the PR3 network and non-network Capex programmes submitted by the TSO is to ensure that the Capex is necessary and represents value for money for the consumer. In order to achieve this objective the CER, assisted by our advisors, reviewed:

- The policies and standards adopted by the TSO that underpin the network and non-network capex programme;
- The strategies adopted by the TSO to ensure that planning expenditure is needed, represents best value for the customer and can be delivered in the timeframe;
- The benefits that Capex will bring to the system and whether these benefits are valued by the customer.

The CER believes that the significant PR3 Capex investment in the Irish transmission system is necessary for consumer welfare and particularly so as to ensure the required transition to a more renewable-based electricity system. This

\footnotesize{\(^{58}\) Please see the following link: http://www.cer.ie/en/electricity-transmission-network-decision-documents.aspx?article=fb726a75-7365-4dfb-9e16-ff5c5d2d363a

\(^{59}\) Please see the following link: http://www.eirgrid.com/media/ITC%20Programme.pdf

\(^{60}\) Please see the following link: http://www.eirgrid.com/media/Grid%2025.pdf}
will raise overall costs to the TUoS customer, but the CER believes that this is necessary to allow the level of renewable generation envisaged through Gate 3.

### 8.3 Efficiencies built into Capex allowances

As outlined in section 10.3 below in the discussion on the expected efficiencies for opex, the CER believes that there are opportunities for the TSO (and TAO) to achieve savings. Some of these savings may be achieved in the areas of payroll, reorganisation or in bought in services that reflect the increased value that the economic recession has brought to the economy as a whole. It is also expected that general productivity increases are achievable.

This is also true in the area of Capex. The SKM report recommends efficiency savings can be made in Capex although to a lesser extent than in Opex as a larger portion of Capex costs are related to materials and contractors. The world market for electrical plant such as transformers and switch gear is buoyant, with underlying commodity prices also driving costs which seem to have only been temporarily affected by the recession. Similarly the labour element of electrical and IT contractor costs is set by industry wide agreements which have not seen the reductions experienced by the wider economy. However, the CER believes that there are efficiencies that can be achieved, primarily by reductions in the TSO’s and TAO’s directly incurred costs.

Furthermore, SKM have reviewed the necessity of each of the submitted Capex programmes and have highlighted potential improvements and innovations with little or no risk to the system to the delivery of necessary additional capacity. The CER has accepted SKM’s recommendations in this respect and the allowances in this section align with these recommendations.

Finally, the CER indicated with the consultation on this matter in July of this year that it was minded to approve the levels of revenue as recommended by SKM within its reports. However, the CER now believes that the TAO should be able to make further efficiency savings in capital (and operating) costs within the 2011 to 2015 period with regard to Stage 2 costs. It is noted that the December 2009 TSO submission already reflected an expected 10% reduction in Stage 1 costs over the PR3 period.

These Stage 2 efficiency savings have been included within the approved revenue detailed in the Executive Summary and section 13 of this paper but have not been broken down by line item within this paper. Rather it is a reduction in overall revenue for capital and operating costs. The TAO is to determine how these reductions in costs will be achieved across the various line items. The benefit of the Capex efficiencies in terms of avoided asset related costs, that is, reductions in depreciation and return, will be given to customers within the PR3 period.
8.4 Network Capex

As outlined above the TSO submitted three separate network development scenarios. As part of their submission to the CER, the TSO advised that if all Grid25 new build projects were commenced over the next 18-24 months and network uprates scheduled according to their deliverability then the Capex spend in PR3 would have required about €3.5 billion. In order to establish the Network Needs for PR3, the above programme of €3.5 billion was adjusted to take account of the following:

- current, lower demand projections for the PR3 period,
- the more limited number of new thermal generation plants which will be provided under Gate 3, and
- the advancement in the first instance of only one major project, where two or more largely parallel projects had been previously identified.

Taking account of the above, the scenario was subsequently adjusted to €2.1 billion by the TSO in its final submission to the CER.61

In response to the CER’s request that consideration be given to both alternative scenarios and flexibility as part of the approach to forecasting for the forthcoming period, two further scenarios were adopted namely, ‘Deliverability’ and ‘Affordability’.

The ‘Deliverability’ scenario was described as the TSO’s best assessment of what proportion of the ‘Network Needs’ scenario could actually be delivered in the PR3 2011-2015 period. The ‘Deliverability’ equates to €1.7 billion.

With regard to the third scenario ‘Affordability’, the TSO stated that it was essentially based upon delaying Capex to minimise any early impact on tariffs, albeit inevitably resulting in higher overall costs in terms of constraints, losses and in the extreme load shedding. The ‘Affordability’ scenario equates to a PR3 period 2011-2015 spend of €1.3 billion. This is in part constrained by the fact that almost €900 million of transmission projects are already underway. The TSO indicated that these could only be reversed at considerable cost and the risk of stranding of assets.

To allow for context the ‘Network Needs’ scenario is presented below against the PR2 Allowed and Outturn/2010 forecast network Capex. This indicates a need for a significant ‘ramping-up’ in expenditure and activity between PR2 and PR3.

As can be seen from the table below, the necessitated jump in investment from the end of the current price control into PR3 is quite significant (approximately

61 It should be noted that this submission reflected an expected 10% reduction in Stage 1 costs over the PR3 period, which was proposed by EirGrid.
€180 million) and would require considerable changes to the current work practices of both TSO and TAO.

Table 20: ‘Network Needs’ set against PR3 Capex allowed & outturn

<table>
<thead>
<tr>
<th>Year</th>
<th>PR2 Spend and forecast</th>
<th>CER PR2 Allowed</th>
</tr>
</thead>
<tbody>
<tr>
<td>2006</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2007</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2008</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2009</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2010</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2011</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2012</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2013</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2014</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2015</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

8.4.1 Network Capex – Background

In their review of the EirGrid submission, SKM have highlighted a number of efficiencies and innovations that are expected to occur in the PR3 period, which will have a significant impact on the level of PR3 network Capex investment. This review takes account of the previous work and publications by both the CER and the TSO, which focus on reaching the Government’s 2020 40% renewables target.

Published in 2008, EirGrid’s Grid25 document is intended to provide a detailed strategy for developing the grid to facilitate meeting Ireland’s target of 40% of electricity generation from renewable energy by 2020. Grid25 reflects the output of the All Island Grid Study\(^{62}\), which indicates that to meet the 40% renewable energy target, a total of circa 4600 MWs of wind-based generation will need to be developed within Ireland.

In the case of the CER’s Gate 3 process, the transmission capacity that can be made available to allow the connection of new Generation to the transmission network is quantified by the use of EirGrid’s ITC program. The results of a recent “ITC program run”\(^{63}\) have been provided to the CER as part of this review.

\(^{62}\) Please see the following link: http://www.dcenr.gov.ie/NR/rdonlyres/1B7ED484-456E-4718-A728-97B82D15A92F/0/AllIslandGridStudyStudyOverviewJan08.pdf

\(^{63}\) Final ITC runs for submission to CER as issued 22.01.10
process. The ITC study was based upon delivering the maximum practical transmission capacity taking account of agreed ‘project delivery time lines’, within the constraints imposed by network access issues.

The results of the study, which identifies both wind and conventional generation capacity that will be granted Firm Access under “Gate 3”, are presented in graphical format in Table 21. This table also present the existing and ongoing Gate 2 renewable connections and also a renewable capacity “target” line if the 40% renewable targets for 2020 and beyond are to be met.

Table 21: Gate 3 ITC Programme Firm Access results

It can be seen from this table that the Gate 3 connections will allow the 40% renewables target to be met in 2020. Although some slippage against the target line is evident at times and, under ideal conditions additional transmission reinforcement works would be undertaken, if practical to allow for some earlier connections. As SKM note an alternative conclusion would be that if the TSO’s ‘Network Needs’ investment program is not adopted (or the network capacity which the programme aims to deliver is not achieved), there will be a risk that Ireland will not meet its 40% renewables target by 2020, or alternatively that there will need to be a significant “catch-up” exercise to be undertaken during the next price control PR4.

However, in their report SKM have identified a number of areas which, if implemented, should be beneficial to the accommodation of renewables, and which do so in a less costly and quicker manner than that proposed by the TSO under the Network Needs scenario, while still ensuring network security. For a more in-depth analysis of these areas please refer to the accompanying SKM report.
Gate 3 Non-Firm Capacity

Due to compliance with the existing transmission planning criteria\textsuperscript{64} (N-1 firm), it is a reasonable expectation that for significant periods of time the transmission system will operate under somewhat more benign conditions and transmission capacity will be available to allow for additional generation to connect and operate, particularly wind based generation with its lower load factor and variable output. By accepting the modest volume of generation constraint (1% to 2%) approximately 50% more wind-based generation can connect.

Wind enhanced line ratings

When investigating the provision of network capacity to allow the connection of high levels of wind generation, the cooling effects of the wind as it blows along the lines invariably increases overhead line capacity ratings. Essentially this suggests that when the wind is blowing and wind generators are exporting to the grid, there is an associated increase in the capacity of the network carrying this wind output, due to the cooling affect of the wind on the overhead lines. Due to potential savings in network investment requirements, there has been considerable recent electricity supply industry interest in the use of enhanced circuit ratings at times of higher wind speeds and also the provision of appropriate monitoring equipment, often referred to as Dynamic Line Rating (DLR) to allow for the safe use of any such available capacity.

It has been concluded by SKM in its report that significant additional network capacity may be available to the TSO by the making use of DLR. Based upon delivering the challenging 40% renewable target in an efficient manner it is reasonable to expect the TSO to invest in such facilities as an alternative/complement to network reinforcements. However, the PR3 network investment proposals submitted by the TSO do not indicate this to be the case, other than a relatively low key pilot project basis which is more focused on reducing equipment risk under low wind conditions.

SKM has therefore recommended that the TSO initiates significant investigations into the potential application of DLR within potentially stressed parts of the network as an alternative to certain of the proposed network reinforcements.

\textsuperscript{64} ESB National Grid Transmission Planning Criteria October 1998. “The system shall be designed to operate within normal operating ranges for credible load and generation patterns for base case operation. The system shall be designed to withstand the more probable contingencies without widespread system failure and instability, maintaining power quality within specified voltage and frequency fluctuation ranges and maintaining voltage and thermal loadings within operating limits. The more probable contingencies are comprised of single contingency (N-1), overlapping single contingency and generator outage (N-G-1) and trip - maintenance (N-1-1) disturbances”. Also “Several base cases may be required to model the necessary range of load levels and generation patterns.”
N-1 Security

SKM has argued in its report that when applied to circuits that connect high load-factor (efficient) conventional generation to the main electricity grid, and hence through to Demand customers, the application of an N–1 firm criteria has a sound basis. This was particularly the case in the days of central planning where, in the majority, only sufficient generation was installed to meet peak demand.

However, when planning the development of a system with significant capacity in excess of peak demand (one which would accommodate 40% renewables), where the load centres may be inherently “secured” by more local conventional generation there may be significant opportunities to operate parts of the network outside on the N-1 parameter and on an “opportunistic basis” as “energy - MWh” rather than “capacity - MW” corridors.

8.4.2 Network Capex – ‘Stretched Network Needs’

Taken together, the work referenced by SKM in their report indicates that there may be significant existing capacity and/or potential new network capacity that can be made available in a cost effective and timely manner to network users, particular wind based renewable generation. This should off-set the need for the full programme of network investment identified by the TSO in its Network Needs scenario, yet still deliver the required network capacity and not compromise the achievement of Gate 3 and the national renewable targets.

It should be noted that the additional, albeit marginally constrained network capacity identified and the enhanced rating identified in the SKM report are not necessarily fully additive and may be best considered as somewhat complementary approaches. However, in unison, the overall benefits can be reasonably assessed as likely to be equivalent to more than 50% increase in the network capacity that has already been identified as available for renewable generation via the ongoing Gate 2 works and also the proposed ITC (Gate 3) related works. Applying a 50% increase to the renewable capacity figures presented in Table 21, results in Table 22 below.
SKM believe that on the basis that the scope for releasing network capacity by means other than traditional network reinforcements is fully adopted, the extent of network reinforcements focused on allowing the connection of renewable and used in the ITC program can be reduced to only about 40% of the original program. However, this will still allow the 2020 renewables targets to be met, as evident in Table 23 below.
The above observations have been investigated by SKM using the PR3, Network Needs scenario spreadsheet and the associated savings, both with respect to “Ongoing Projects” and “UC – System reinforcements” categories identified.

The adjusted network investment profile resulting from the above assessments are presented in Table 24 below in what is described as a ‘Stretched Network Needs’ scenario. This sums to about €1.45 billion over the PR3 period 2011-2015. The basis of the ‘Stretched Network Needs’ scenario is considered to be aligned with the cost effective delivery of the network capacity required to allow the 40% renewable energy target to be met by 2020 and to also be aligned with the Grid25 strategy for the development of Ireland’s electricity grid for a sustainable and competitive future.

Table 24: Stretched Network Needs Scenario as proposed by SKM

<table>
<thead>
<tr>
<th>Stretched Network Needs Scenario</th>
<th>PR3 Period</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2011</td>
</tr>
<tr>
<td>Ongoing projects</td>
<td></td>
</tr>
<tr>
<td>EirGrid</td>
<td>7.1</td>
</tr>
<tr>
<td>ESB</td>
<td>158.9</td>
</tr>
<tr>
<td>Total</td>
<td>166.1</td>
</tr>
<tr>
<td>Under Consideration - System Reinforcements</td>
<td></td>
</tr>
<tr>
<td>EirGrid</td>
<td>9.1</td>
</tr>
<tr>
<td>ESB</td>
<td>11.7</td>
</tr>
<tr>
<td>Total</td>
<td>20.8</td>
</tr>
<tr>
<td>Under consideration - Shallow Connection - Non LCTA works</td>
<td></td>
</tr>
<tr>
<td>EirGrid</td>
<td>1.4</td>
</tr>
<tr>
<td>ESB</td>
<td>6.1</td>
</tr>
<tr>
<td>Total</td>
<td>7.5</td>
</tr>
<tr>
<td>Provisions - System Reinforcements</td>
<td></td>
</tr>
<tr>
<td>EirGrid</td>
<td>0.0</td>
</tr>
<tr>
<td>ESB</td>
<td>0.3</td>
</tr>
<tr>
<td>Total</td>
<td>0.3</td>
</tr>
<tr>
<td>Provisions - Asset Refurbishment</td>
<td></td>
</tr>
<tr>
<td>EirGrid</td>
<td>0.1</td>
</tr>
<tr>
<td>ESB</td>
<td>6.8</td>
</tr>
<tr>
<td>Total</td>
<td>6.9</td>
</tr>
<tr>
<td>Provisions - Minor Capital &amp; Conflicts (Minus 75% Contribution)</td>
<td></td>
</tr>
<tr>
<td>EirGrid</td>
<td>0.0</td>
</tr>
<tr>
<td>ESB</td>
<td>3.0</td>
</tr>
<tr>
<td>Total</td>
<td>3.1</td>
</tr>
<tr>
<td>Under consideration - DSO - 50% contribution</td>
<td></td>
</tr>
<tr>
<td>EirGrid</td>
<td>0.2</td>
</tr>
<tr>
<td>ESB</td>
<td>1.6</td>
</tr>
<tr>
<td>Total</td>
<td>1.8</td>
</tr>
<tr>
<td>Total</td>
<td>18.0</td>
</tr>
<tr>
<td>ESB</td>
<td>253.5</td>
</tr>
<tr>
<td>Total</td>
<td>206.4</td>
</tr>
</tbody>
</table>

Additional to the total PR3 Capex investment requirements, the expenditure profile carried out by SKM has also been adjusted to better reflect likely sustainable outcomes. This is noting the project delivery issues that have been

---

65 An “Ongoing Project” refers to projects that have been approved by EirGrid’s Board for the level of Capex necessary to progress the project towards Stage 2, i.e. the point when the project will be progressed onto the TAO to begin detailed engineering and construction.

66 Under Consideration Projects are those at a relatively early, pre-feasibility stage within EirGrid’s planning group.
encountered in the past (please refer to section 7.5 above) and also the clear linkage with further expenditure during PR4 that will be needed to deliver the Grid25 objectives. The resulting expenditure profile is presented in Table 25 below.

Table 25: Stretched Network Needs proposal by SKM - profiled

Based upon the assessment presented above and also the information contained in EirGrid’s submissions relating to the three scenarios that they outlined, the underlying split between load and non-load related Capex lines, customer contributions and the associated build up of the net network Capex is presented in a more conventional format in the below table.

This table also lists the network capex associated with the three EirGrid scenarios for comparison purposes.
Table 26: SKM PR3 capital expenditure (€m’s 2009 prices)

<table>
<thead>
<tr>
<th>SKM PR3 Capex (€m’s)</th>
<th>Year</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>Totals</th>
</tr>
</thead>
<tbody>
<tr>
<td>Load related</td>
<td></td>
<td>184.8</td>
<td>251.0</td>
<td>288.4</td>
<td>303.5</td>
<td>307.6</td>
<td>1335.3</td>
</tr>
<tr>
<td>Non-Load related</td>
<td></td>
<td>32.1</td>
<td>30.3</td>
<td>29.2</td>
<td>30.0</td>
<td>27.6</td>
<td>149.1</td>
</tr>
<tr>
<td>Gross Network capex</td>
<td></td>
<td>216.9</td>
<td>281.3</td>
<td>317.6</td>
<td>333.5</td>
<td>335.2</td>
<td>1484.4</td>
</tr>
<tr>
<td>Customer contributions</td>
<td></td>
<td>-10.5</td>
<td>-6.3</td>
<td>-8.4</td>
<td>-7.8</td>
<td>-1.4</td>
<td>-34.4</td>
</tr>
<tr>
<td>Net Network Capex</td>
<td></td>
<td>206.4</td>
<td>275.0</td>
<td>309.2</td>
<td>325.7</td>
<td>333.8</td>
<td>1450.0</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>EirGrid PR3 Capex subs.</th>
<th>Network Needs</th>
<th>296.4</th>
<th>431.1</th>
<th>508.8</th>
<th>488.3</th>
<th>384.8</th>
<th>2,109.4</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Deliverability</td>
<td>270.6</td>
<td>384.9</td>
<td>428.2</td>
<td>380.8</td>
<td>268.9</td>
<td>1,733.5</td>
</tr>
<tr>
<td></td>
<td>Affordability</td>
<td>249.04</td>
<td>333.22</td>
<td>339.05</td>
<td>265.81</td>
<td>142.18</td>
<td>1,329.3</td>
</tr>
</tbody>
</table>

8.4.3 CER’s position

SKM was requested by the CER to undertake a detailed analysis of the PR3 network Capex submission made by the TSO, focusing on the objectives outlined in 2.4 above. Based on the analysis and recommendations provided in this section and the accompanying SKM transmission report, the CER has decided to adopt the ‘Stretched Network Needs’ scenario for the purposes of the PR3 capex spend and tariff profiling.

However this is not to say that the allowed amount of €1.45 billion is fixed. As noted by SKM in their report, the CER will request the TSO to undertake cost-benefit analysis for projects with total projected spend (i.e. Stage 1 and Stage 2) of over a certain amount. This issue is further discussed in section 8.5 below.

The purpose of this is to ensure that the correct, appropriate and fully justified level of network investment takes place in order to deliver the network capacity required for Gate 3 and to meet Ireland’s renewable targets. The CER’s approach to deliver increased network capacity is a multi-faceted approach involving enhancing capacity on existing networks, the development of new lines where justified and the operation of the network to deliver more.

The CER believes this approach will deliver the required levels of network capacity at minimal additional cost to the customer and will ensure that the network is operated in the most efficient and cost effective manner. It should be noted that there is no specific list of projects associated with network Capex allowed under PR3; rather each proposed project (e.g. over €10 million) will
undergo a rigorous cost-benefit analysis to determine the most appropriate mechanism to deliver the required capacity.

The annual PR3 Capex for the purposes of tariff profiling will be that as contained in Table 26.

In conclusion, the CER has decided to adopt the ‘Stretched Network Needs’ scenario which envisages **€1.45 billion** of transmission network capex over the 2011-2015 PR3 period. This figure of €1.45 billion is not fixed and should not be viewed as a ‘target’ for transmission network capex. Rather, the CER is adopting a more flexible approach to allowed Capex, in light of the current uncertainty for PR3, e.g. energy growth levels, Gate 3 Generation take-up etc.

### 8.4.4 TAO RAB 2011 to 2015

Based on the above profiled spend of €1.45 billion, the TAO’s RAB PR3 is set out in Table 27 below.

<table>
<thead>
<tr>
<th></th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Opening Net Book Value</strong></td>
<td>1,208.7</td>
<td>1,381.4</td>
<td>1,618.0</td>
<td>1,882.8</td>
<td>2,157.9</td>
</tr>
<tr>
<td><strong>Capex</strong></td>
<td>206.4</td>
<td>275.0</td>
<td>309.2</td>
<td>325.7</td>
<td>333.8</td>
</tr>
<tr>
<td><strong>Depreciation</strong></td>
<td>-33.7</td>
<td>-38.5</td>
<td>-44.3</td>
<td>-50.7</td>
<td>-57.3</td>
</tr>
<tr>
<td><strong>Closing Net Book Value</strong></td>
<td>1,381.4</td>
<td>1,618.0</td>
<td>1,882.8</td>
<td>2,157.9</td>
<td>2,434.4</td>
</tr>
</tbody>
</table>

The PR3 TAO RAB is published in the accompanying transmission revenue model.

### 8.5 PR3 Network Capex Approvals Program

As discussed in section 7.3.3, the CER intends to further build and refine the capex monitoring program that was put in place in the PR2 period. This will involve the addition of a formal Capex approvals process as well as refinements and improvements to the monitoring process. The CER agrees with the TSO that individual projects must pass individual economic evaluation and must still stand on their own merit in order to be brought forward, and is therefore still proposing this additional procedure in the Capex monitoring program.

SKM have recommended that the report/approvals process should become a fully functional (i.e. formula based) tool that is a shared document between the three main stakeholders, albeit with some improved clarity and quality control of inputs.
The CER has discussed with the TSO the appropriate CBA template, format and timings of submission to the CER during the PR3 consultation period. The new PR3 Capex monitoring and approvals process will be outlined in conjunction with the PR3 transmission incentives workstream. It should be noted that the CER will still require the transmission utilities to submit the Capital Expenditure Report on an annual basis\(^\text{67}\), the format of which is outlined in section 7.3.3.

### 8.6 TSO Non-network Capex

Considerable uncertainty exists over the TSO’s future non-network Capex, principally due to bedding down of the SEM and possible further harmonisation with SONI IT systems. Moreover, for many other IT developments an accurate prediction of hardware and software requirements for five years hence is problematic. Consequently, the SKM’s approach to assessing this aspect of the TSO’s costs has been to determine whether the TSO’s planned Capex – and the justification for that expenditure - is robust. In general terms, in their report SKM is of the view that the TSO’s projections are reasonable.

The investment in IT and Telecoms Capex forecast for PR3 is substantially driven by the need to provide new facilities for the increased number of staff and transmission and renewable generation sites. The TSO forecasts twenty-five Remote Terminal Units (RTUs) per year (new and replacement) and expects customer contributions of €1.35 million per year for the fifteen RTUs which are required in all power stations over 5 MWs. The TSO also intends to review the technology for providing these services.

The TSO is proposing to invest €2.8 million on replacement of the TUoS system and €0.8 million on integration of the East-West Interconnector (EWIC) into existing systems. €1.5 million of unidentified projects is included in the forecast and this appears to be conservative bearing in mind the level of change likely to affect EirGrid.

The TSOs PR3 forecast non-network Capex of €30.3 million gross (€23.5 million net), which is €16.6 million lower than the PR2 net expenditure of €40.2 million. This net figure of €23.5 million takes account of €6.8 million of customer contributions for SCADA RTUs. This programme is considered to be reasonable subject to an efficiency stretch of 2% and SKM have therefore recommended non-network capital expenditure of €29.7 million gross, circa €23.1 million net spend.

The CER has decided to accept this SKM recommendation of non-network Capex spend over the 2011-2015 PR3 period, which Table 4Table 28 below sets out.

---

\(^{67}\) Which will include a report on Stage 1 costs, projects within Stage 1 and the size of the proposed 'side' RAB.
Table 28: CER PR3 non-network capex (€m’s 2009 prices)

<table>
<thead>
<tr>
<th></th>
<th>Year</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>Totals</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>CER PR3 Non-</strong></td>
<td><strong>Gross Spend</strong></td>
<td>8.45</td>
<td>5.72</td>
<td>5.22</td>
<td>5.74</td>
<td>4.61</td>
<td>29.74</td>
</tr>
<tr>
<td><strong>Network Capex</strong></td>
<td><strong>Customer contributions (SCADA)</strong></td>
<td>-1.32</td>
<td>-1.32</td>
<td>-1.32</td>
<td>-1.32</td>
<td>-1.32</td>
<td>6.6</td>
</tr>
<tr>
<td></td>
<td><strong>Net Non-</strong></td>
<td>7.13</td>
<td>4.4</td>
<td>3.9</td>
<td>4.42</td>
<td>3.28</td>
<td>23.13</td>
</tr>
<tr>
<td></td>
<td><strong>Network Capex</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

| **EirGrid PR3 Capex** | **Gross Spend** | 8.6  | 5.8  | 5.5  | 5.9  | 4.7  | 30.35  |

8.6.1 TSO RAB 2011 to 2015

Based on the above profiled spend of €23.13 million, the TSO’s RAB for PR3 is set out in Table 29 below. It should be noted that a number of amendments were made to the TSO RAB during the PR3 consultation phase, on light of TSO submissions concerning PR2 non-network Capex spend. This has resulted in the 2011 OAV from the consultation paper, €33.3 million, being amended to €36.5 million.

Table 29: CER TSO RAB for PR3 period (2011 to 2015)

<table>
<thead>
<tr>
<th></th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Opening Net Book Value</strong></td>
<td>36.5</td>
<td>36.3</td>
<td>33.2</td>
<td>30.3</td>
<td>28.8</td>
</tr>
<tr>
<td><strong>Capex</strong></td>
<td>7.13</td>
<td>4.4</td>
<td>3.9</td>
<td>4.42</td>
<td>3.28</td>
</tr>
<tr>
<td><strong>Depreciation</strong></td>
<td>-7.3</td>
<td>-7.6</td>
<td>-6.8</td>
<td>-5.9</td>
<td>-5.4</td>
</tr>
<tr>
<td><strong>Closing Net Book Value</strong></td>
<td>36.3</td>
<td>33.2</td>
<td>30.3</td>
<td>28.8</td>
<td>26.7</td>
</tr>
</tbody>
</table>

The PR3 TSO RAB is published in the accompanying transmission revenue model.

8.7 Conclusions

The purpose of the PR3 Capex review is to ensure that the correct, appropriate and fully justified level of network investment takes place in order to deliver the network capacity required for Gate 3 and to meet Ireland’s 2020 renewable targets.

As outlined above the CER believes that the significant PR3 capex investment in the Irish transmission system is necessary for consumer welfare and particularly
so as to ensure the required transition to a more renewable-based electricity system. The CER will adopt the SKM ‘Stretched Network Needs’ scenario, which envisages **€1.45 billion** of transmission network capex over the 2011-2015 PR3 period.

The CER intends to further build and refine the Capex monitoring program that was put in place in the PR2 period. This will involve the addition of a formal Capex approvals process as well as refinements and improvements to the monitoring process. The new PR3 Capex monitoring and approvals process will be outlined in conjunction with the PR3 transmission incentives workstream.

Considerable uncertainty exists over the TSO’s future non-network Capex, principally due to bedding down of the SEM and possible further harmonisation with SONI IT systems. Moreover, for many other IT developments an accurate prediction of hardware and software requirements for five years hence is problematic. The TSOs PR3 forecast non-network capital expenditure of €30.3 million gross is considered to be reasonable subject to an efficiency stretch of 2% and SKM have therefore recommended non-network capital expenditure of €29.7 million gross, circa **€23.1 million** net spend.
9.0 Review of historical operational expenditure

9.1 Introduction

This section examines the historical Opex undertaken by the TAO and TSO over the PR2 2006 to 2010 period. The outturn expenditure is assessed and compared to the revenue allowed by the CER as part of the PR2 determination.

It should be noted that there has been significant changes in the market structure since the PR2 determination, including vesting of the TSO in July 2006 and the opening of the SEM in November 2007. This has resulted in a number of Opex cost categories being re-opened during the PR2 period to take account of the market developments and industry structure. These changes are referred to below from sections 9.4 to 9.7 and the accompanying SKM transmission report.

9.2 Objectives for the review of historic Opex

The main objective of the review of the TAO’s and TSO’s historical Opex is to assess whether the expenditure that has been incurred by the two utilities has been done so efficiently, while delivering the expected benefits for customers in line with the package agreed as part of the PR2 determination and the subsequent annual revenue determinations68.

This review of historic performance also assisted in the CER’s determination of the appropriate allowed Opex for the PR3 2011 to 2015 period, as detailed within Section 10.0 of this paper.

9.3 Points of Note

With respect to both TAO and TSO external costs, although these costs were allowed as pass through in PR2, as they are (in the most part) outside the control of the utilities, the CER undertook an annual ex-post adjustment to take account of actual outturn costs. This ex-post adjustment was subsequently reflected in the following year’s allowed revenue.

Hence the reason why allowed external costs for PR2 closely mirrors that of outturn figures provided by the utilities.

---

68 Please see CER/06/199, CER/07/184, CER/08/178 and CER/09/140
9.4 TAO Opex – Internal

Table 30 below provides a high level summary of:

- the internal Opex approved by the CER for 2006 to 2010, which incorporates the subsequent internal operational costs approved by the CER reflecting market and industry structure changes;69
- the internal operational costs incurred by the TAO during 2006 to 2010; and
- the variance between the two.

Table 39 excludes the depreciation associated with the TAO.

Sections 9.4.1 to 9.4.7 below provide a narrative of the items included within the table. It should be noted that a negative number in the variance categories indicate an underspend, while a positive number indicate an overspend. Please also note that the 2010 figures provided are current best projected.

9.4.1 Operations (Allowed €16.1; Outturn €10.95)

This cost item includes operational switching, station attendance, fault location, and a range of other services. SKM have concluded that the underspend in this category is due to the over-provision of allowed costs in PR2 and not due to efficiency savings. This largely reflected the uncertainty at the time of the split of responsibilities and costs between the TAO and TSO, which were later clarified under the IA.

9.4.2 Planned & Fault Maintenance (Net Allowed €70.63m; Outturn €60.94m)

As set out in the IA the TSO is responsible for setting the maintenance policy, which includes the frequency at which maintenance tasks are delivered and any associated planned or forced outage arrangements to allow work to be executed on the system. The TAO then carries out the repair and maintenance tasks on the ground and set asset management policy with the objective of minimizing overall system cost.

SKM have concluded that the underspend is due to under achievement of the planned maintenance programme. The underspend does not reflect efficiency savings but reflects the shortfall in the achievement of the planned maintenance programme, particularly on substation maintenance, where only 67% of maintenance tasks required by TSO policies were completed in the period 2006 to 2008. Due to restrictions on outage availability and other constraints not all maintenance required by the policies could be programmed. Over 80% of scheduled maintenance was achieved.

---

69 Please see CER/06/199, CER/07/184, CER/08/178 and CER/09/140
Please refer to the accompanying SKM report for a more detailed examination of this cost item.

9.4.3 Professional Services (Allowed €25.75m; Outturn €25.03m)

Professional Services are almost wholly ESBI costs associated with provision of technical services such as maintaining records, provision of advice on technical matters, managing overhead line infringements. ESBI also provide support during routine planned maintenance by inspecting equipment before it is returned to service.

SKM believe that these activities are core services that could be provided more effectively and with better control of costs from within ESB Networks and this is reflected in their recommendation for PR3.

9.4.4 Telecom Fees (Allowed €8.12m; Outturn €6.44m)

This item cover fees from ESB Telecoms for support of operational IT and telecoms services. SKM have concluded that the underspend of €1.7 million in this category is due to the over-provision of allowed costs in PR2 and not due to efficiency savings.

9.4.5 Asset Management (Allowed €5m; Outturn €3.73m)

The majority of the asset management costs are associated mast interference payments and are increasing due to pressure from landowners. However, SKM have concluded that the underspend of €1.27 million in this category is due to the over-provision of allowed costs in PR2 and not due to efficiency savings.

9.4.6 Corp. Charges & Company Wide costs (Net allowed €14.1m; Outturn €15.27m)

Corporate charges and company-wide costs are allocated according to a basket of measures and are overspent by €1.17 million. This overspend reflects the uncertainty in 2005 of the split of responsibilities and costs between the TAO and TSO, which were later clarified under the Infrastructure Agreement.

9.4.7 Legal, Pension, Insurance & Other (Net allowed €14.42m; Outturn €2.03m)

SKM note that the allowed ‘Other’ costs is understood to include Telecom costs. It is understood that SCADA costs were allowed in the TAO costs but the TSO was allocated these assets under the Infrastructure Agreement. Operational telecom facilities (Optel) were retained by the TAO and not transferred to the TSO, which lead to an underspend. Due to annual ex-post adjustments made to allowed Insurance costs, adjusted allowed costs mirror outturn. Please refer to
the accompanying SKM report for a more detailed examination of the underspend in this cost item.

Table 30: TAO Internal (Controllable) Opex PR2 (€m’s 2009 prices)

<table>
<thead>
<tr>
<th></th>
<th>CER Allowed</th>
<th>PR2 Actual</th>
<th>Variance</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operations</td>
<td>16.10</td>
<td>10.95</td>
<td>-5.15</td>
</tr>
<tr>
<td>Planned maintenance</td>
<td>62.30</td>
<td>52.66</td>
<td>-9.64</td>
</tr>
<tr>
<td>Fault maintenance</td>
<td>8.33</td>
<td>8.28</td>
<td>-0.05</td>
</tr>
<tr>
<td>Professional Services</td>
<td>25.75</td>
<td>25.03</td>
<td>-0.73</td>
</tr>
<tr>
<td>Telecom Fees</td>
<td>8.12</td>
<td>6.44</td>
<td>-1.68</td>
</tr>
<tr>
<td>Asset Management</td>
<td>5.00</td>
<td>3.73</td>
<td>-1.27</td>
</tr>
<tr>
<td>Legal</td>
<td>1.11</td>
<td>0.42</td>
<td>-0.69</td>
</tr>
<tr>
<td>Insurance</td>
<td>0.00</td>
<td>0.47</td>
<td>0.47</td>
</tr>
<tr>
<td>Pension</td>
<td>1.55</td>
<td>1.55</td>
<td>0.00</td>
</tr>
<tr>
<td>Company Wide Costs</td>
<td>2.44</td>
<td>2.38</td>
<td>-0.07</td>
</tr>
<tr>
<td>Corporate Charges &amp; Corp Affairs</td>
<td>11.66</td>
<td>12.89</td>
<td>1.23</td>
</tr>
<tr>
<td>Other</td>
<td>11.76</td>
<td>-0.42</td>
<td>-12.18</td>
</tr>
<tr>
<td><strong>Total Internal (Controllable) Opex</strong></td>
<td><strong>154.13</strong></td>
<td><strong>124.39</strong></td>
<td><strong>-29.74</strong></td>
</tr>
</tbody>
</table>

9.5 TAO Opex - External

Table 31 below provides a high level summary of:

- the external (non-controllable) TAO operational costs approved by the CER for 2006 to 2010, which incorporates the subsequent external Opex approved by the CER reflecting market and industry structure changes⁷⁰;
- the external Opex incurred by the TAO during 2006 to 2010; and
- the variance between the two.

The two sections below provide a short narrative of the items included within the table. It should be noted that a negative number in the variance categories indicate an underspend, while a positive number indicate an overspend. Please also note that the 2010 figures provided are current best projected.

9.5.1 Network Rates (Adj. allowed €82.61m; Outturn €82.61m)

Local Authority Network rates are levied annually by county, city, borough and certain town councils around the country on the TAO. Due to annual ex-post adjustments made to allowed Network Rates costs⁷¹, adjusted allowed costs mirror outturn.

---

⁷⁰ Please see CER/06/199, CER/07/184, CER/08/178 and CER/09/140
⁷¹ Please see CER/09/140
9.5.2 CER Levy (Allowed €5.37m; Outturn €5.37m)

The CER allowed approximately €0.9 million per annum for the Regulatory Levy.

Table 31: TAO External (Non-Controllable) Opex PR2 (€m’s 2009 prices)

<table>
<thead>
<tr>
<th></th>
<th>CER Allowed</th>
<th>PR2 Actual</th>
<th>Variance</th>
</tr>
</thead>
<tbody>
<tr>
<td>Network Rates</td>
<td>82.61</td>
<td>82.61</td>
<td>0.00</td>
</tr>
<tr>
<td>CER Levy</td>
<td>5.37</td>
<td>5.37</td>
<td>0.00</td>
</tr>
<tr>
<td>Non Controllable Costs</td>
<td>87.98</td>
<td>87.98</td>
<td>0.00</td>
</tr>
</tbody>
</table>

9.6 TSO Opex – Internal

Table 32 below provides a high level summary of:

- the internal (controllable) TSO Opex approved by the CER for 2006 to 2010;
- the subsequent internal Opex approved by the CER reflecting market and industry structure changes\(^{72}\);
- the internal Opex incurred by the TSO during 2006 to 2010; and
- the variance between the two.

Table 32 excludes the depreciation associated with the TSO.

Sections 9.6.1 to 9.6.11 provide a narrative of the items included within the table. It should be noted that a negative number in the variance categories indicate an underspend, while a positive number indicate an overspend. Please also note that the 2010 figures provided are current best projected.

9.6.1 Staff and Related Costs (Adj. allowed €105.6m; Outturn €112.2m)

The introduction of the SEM resulted in a reduction or elimination of some existing functions undertaken by the TSO, the introduction of some new TSO functions and the extension of the scope of some existing TSO functions. A revenue adjustment for the TSOs allowed payroll was required in 2007\(^{73}\) to reflect these changes. It was acknowledged by the CER in the October 2007 revenue paper that there was some uncertainty in estimating those costs for 2008 on account of the new nature of the market. In CER/07/184 the CER decided on a net reduction for the TSOs staffing in 2008 of 4.5 FTEs (full time equivalents), equivalent to a reduction of circa €0.5 million on an annual basis in EirGrid’s allowed payroll costs, on account of the introduction of the SEM.

\(^{72}\) Please see 2010 transmission revenue determination CER/09/140.
\(^{73}\) Please see 2008 transmission revenue determination CER/07/184.
The apparent overspend on Staff and Related costs of €6.6 million is misleading and should be considered in conjunction with the underspend on allowed costs for Business Overheads (€12.2 million). In the PR2 determination Business Overheads were originally allowed as ESB Corporate costs but with the vesting of EirGrid they were subsequently expended mainly as TSO payroll costs. Also, part of the Other additional allowed costs of €14 million is also reflected in the outturn as Staff and Related Costs or Contractors costs.

9.6.2 Contractor Costs (Adj. allowed €0m; Outturn €8.1m)

The vesting of EirGrid gave rise to additional once-off or start-up costs. The once-off costs which the TSO requested included costs associated with the hiring of short-term contractors. This was justified on the basis of the TSO needing to meet operational shortfalls, which were expected to arise from certain existing staff not transferring from ESB to EirGrid.

As with Staff and Related costs, the apparent overspend on Contractors is misleading and should be considered in conjunction with the underspend on allowed costs for Business Overheads (€12.2 million) and also that of the category Other, which takes account of some of the additional once-off or start-up costs.

9.6.3 Telecommunications (Adj. allowed €17.8m; Outturn €13.7m)

Telecoms costs during PR2 were largely driven by the PR2 Network Capex plan. At the time the CER expected steadily increasing costs in line with the envisaged large transmission Capex program.

During PR2 these services were provided by ESB ITS and contracts have been renegotiated in the intervening period. In its PR3 submission the TSO has provided details of a consultant’s report which found that the services provided by ESB ITS represent value for money for a specialist service, although not necessarily the lowest cost. There is no evidence to indicate that the savings on Telecoms services have not been efficiently made. However, the underspend on the PR2 transmission non-network Capex program (please see section 7.5) is also a contributing factor to the Telecoms underspend.

9.6.4 Premises (Adj. allowed €18.4m; Outturn €22.6m)

CER/08/178 indicated that there were a number of TSO costs for 2009 and 2010 which could not reasonably have been foreseen or quantified at the time of PR2, which included costs associated with full premises separation of EirGrid from ESB. EirGrid began the move to new, separate office premises, the Oval, in 2008. This move was considered appropriate given EirGrid’s position as an

74 Please see 2007 transmission revenue determination CER/06/199.
75 ibid
independent TSO. EirGrid had previously submitted for costs in relation to the full premises separation of EirGrid from ESB, which were subsequently reviewed by the CER. These costs fell into three categories; Operating costs, Capital costs and Transitional costs and the agreed amounts for each category are detailed in CER 08/178.

The PR2 determination also allowed for Inter Business Unit costs for the TSO. At the time ESB National Grid (ESB NG), a business unit of the ESB Group, was designated as the TSO. Inter Business Unit costs included charges levied by ESB Corporate Centre for the TSO’s use of its head office building, such as light and heat, cleaning, facilities, security, mailing, switchboard and catering. In CER/06/199, the CER agreed to re-examine these Inter-Business costs in the context of the establishment of EirGrid on 1st July 2006 and the full “arms-length” relationship with ESB which then existed.

The overspend in this cost category is largely a cost allocation issue at the time of the PR2 review, where the TSO was still a business unit of the ESB Group and not an independent body. As with Staff and Related costs/Contractor costs the apparent overspend is slightly misleading and should be considered in conjunction with the underspend on allowed costs for Business Overheads (€12.2 million).

9.6.5 IT costs (Adj. allowed €13.2; Outturn €8.9m)

IT operating costs are associated with IT systems being satisfactorily maintained and operated and fixed costs such as IT licences.

The under spend of €4.4m on IT operating costs is considered to be due partly to the TSO non-network Capex (IT Systems) underspend which led to an underspend on associated operating costs.

9.6.6 Insurance & Comps / Selling and Advertising (Net adj. allowed €0m; Outturn €1.5m)

Insurance and Compensations covers costs associated with payments to landowners for work being carried out on their property. In 2006 the TSO has requested costs associated with its plans to run a small commercial supplement and associated press advertising to mark the launch of EirGrid and its role, bringing the company’s full separation and independence to the attention of the wider public. These costs were included in EirGrid ‘once-off’ costs, which is reflected in the “Others” cost category below in Table 32.

EirGrid, in their PR3 submission, also stated that Business Overheads might be defined to include Insurance and Compensations / Selling and Advertising. Therefore, the combined overspend in these two cost categories should be considered in conjunction with the underspend on allowed costs for Business Overheads.
9.6.7 Maintenance and Professional Services (Adj. allowed €35m; Outturn €27.3m)

The TSO is responsible for ensuring the maintenance of the transmission network and incurs costs for tasks such as identifying and specifying maintenance requirements, developing maintenance policies, arranging outages and monitoring maintenance work.

The TSO uses specialist consultancy services from bodies such as ESBI to assist it in developing the policy, determining maintenance requirements, carrying out plant condition assessments, managing and updating the plant database and providing specialist services in relation to safety and the environment.

The actual maintenance activities are carried out by the TAO and to a lesser extent by ESB Power Generation staff for those transmission assets associated with its generation stations.

Overall maintenance and professional services are under spent by €8 million, which is believed to have resulted from efficiency gains, less than anticipated duplication of activities with the TAO and the restructuring of maintenance support upon vesting of EirGrid in July 2006. Again, it should be noted that the ex-ante costs allowed at the start of the PR2 price control could not have been predicted perfectly to account for market and industry structure changes that took place during PR2.

9.6.8 Other (Adj. allowed €14.4m; Outturn €4.4m)

The category of Other within EirGrid internal costs covers a number of categories, including those not foreseen when setting the PR2 control. The establishment of EirGrid as a stand-alone entity on 1st July 2006 gave rise to additional once-off and ongoing costs associated with the continued operation of EirGrid as a fully independent, stand-alone transmission system operator business. The ongoing costs allowed by the CER were associated with the new roles being taken on by EirGrid – in particular the costs of the Client Engineer, managing the Infrastructure Agreement, managing the relationship with the TAO, managing media relations and additional corporate reporting and financial requirements appropriate to a stand-alone company.

Also included in the Other internal costs category are charges associated with working capital arrangements and TSO business readiness projects to support the introduction and establishment of the all-island SEM. Again, this is a category for which no provision was made for in PR2. In addition, wind related expenditure which includes additional supports required to process the Gate 1 applications in a timely fashion, continued development of improved wind modelling and short term wind forecasting techniques are also covered by internal Other.
As with the underspend in Professional and Maintenance charges the underspend in this cost category is considered partly to be due to efficiency savings but also partly due to windfall gains resulting from forecasting errors. There was considerable uncertainty on operating costs at the start up of EirGrid and the exact activities carried out by the TSO and TAO post signing of the Infrastructure Agreement.

9.6.9 Promotion of Research (Adj. allowed €1.3m; outturn €0.3m)

In CER/06/199 the TSO stated that it has been approached by a number of research institutions to investigate possible research avenues which it could support, such as new engineering developments including advances in transmission equipment and its maintenance. For 2007 to 2010, the CER allowed approximately €0.33 million on an annual basis for this cost category. However, the TSO only utilised €0.3 million and in its PR3 submission has proposed to return the remainder to the customer in the PR3 period.

9.6.10 Inter Business Unit – Corp Centre & Other (Net adj. allowed €0m; Outturn €0.85m)

The establishment of EirGrid as a stand-alone entity on 1st July 2006 meant that the TSO was no longer a business unit within the ESB Group. It was anticipated that these costs associated with ESB NG would change upon vesting of EirGrid as TSO. The outturn figure accounts for the period within PR2 before 1st July 2006. The issue of Shared Corporate Centre costs is discussed in section 8.6.4 above.

9.6.11 Business Overheads (Adj. allowed €12.2m; Outturn €0m)

Business Overheads cover cost items such as travel and training expenses. As discussed above in sections 8.6.1 and 8.6.2 the apparent overspend on Staff and Related costs and Contractors is misleading and should be considered in conjunction with the underspend for Business Overheads. Therefore, the combined overspends in a number of cost categories should be considered in conjunction with this underspend. The CER does not view this underspend as high efficiency gains but rather an issue of cross allocation of costs by EirGrid over a number of different categories.
Table 32: TSO Internal Opex PR2 (€m’s 2009 prices)

<table>
<thead>
<tr>
<th>Service Type</th>
<th>CER PR2 Allowed</th>
<th>Adjusted CER PR2 Allowed</th>
<th>PR2 Actual</th>
<th>Variance PR2 Outturn CER Allowed</th>
</tr>
</thead>
<tbody>
<tr>
<td>Staff and related costs</td>
<td>107.4</td>
<td>105.6</td>
<td>112.2</td>
<td>6.6</td>
</tr>
<tr>
<td>Contractors</td>
<td>0</td>
<td>8.1</td>
<td>8.1</td>
<td></td>
</tr>
<tr>
<td>Telecommunications</td>
<td>17.8</td>
<td>17.8</td>
<td>13.7</td>
<td>-4.1</td>
</tr>
<tr>
<td>Premises</td>
<td>18.4</td>
<td>22.6</td>
<td>4.1</td>
<td></td>
</tr>
<tr>
<td>IT Costs</td>
<td>10.0</td>
<td>8.9</td>
<td>-4.4</td>
<td></td>
</tr>
<tr>
<td>Insurance and Compensations</td>
<td>0</td>
<td>0.8</td>
<td>0.8</td>
<td></td>
</tr>
<tr>
<td>Selling and Advertising</td>
<td>0</td>
<td>0.7</td>
<td>0.7</td>
<td></td>
</tr>
<tr>
<td>Maintenance &amp; Prof. Services</td>
<td>35.0</td>
<td>27.3</td>
<td>-7.8</td>
<td></td>
</tr>
<tr>
<td>Other</td>
<td>14.4</td>
<td>4.4</td>
<td>-10.0</td>
<td></td>
</tr>
<tr>
<td>Promotion of Research</td>
<td>1.3</td>
<td>0.3</td>
<td>-1.0</td>
<td></td>
</tr>
<tr>
<td>Inter Business Unit – Corp. Cent.</td>
<td>0</td>
<td>0.05</td>
<td>0.05</td>
<td></td>
</tr>
<tr>
<td>Inter Business Unit - Other</td>
<td>11.7</td>
<td>0.8</td>
<td>0.8</td>
<td></td>
</tr>
<tr>
<td>Business Overheads</td>
<td>12.2</td>
<td>0.0</td>
<td>-12.2</td>
<td></td>
</tr>
<tr>
<td>Total Internal Opex</td>
<td>194.1</td>
<td>218.1</td>
<td>199.7</td>
<td>-18.3</td>
</tr>
</tbody>
</table>

9.7 TSO Opex – External

Table 33 below provides a high level summary of:

- the external (or non-controllable) TSO Opex approved by the CER for 2006 to 2010;
- the subsequent external Opex approved by the CER reflecting market and industry structure changes;
- the external Opex incurred by the TSO during 2006 to 2010; and
- the variance between the two.

Sections 9.7.1 to 9.7.7 provide a narrative of the items included within the table. It should be noted that a negative number in the variance categories indicate an underspend, while a positive number indicate an overspend. Please also note that the 2010 figures provided are current best projected.

9.7.1 CER Levy (Adj. allowed €5.0m; Outturn €4.9m)

In the PR2 determination the CER allowed projected costs of circa €0.8 million per annum throughout the review period to cover the CER Regulatory Levy.

As outlined in CER/06/199 due to anticipated increases in the regulatory levy for 2007, largely associated with CER resources required for the SEM project, an

---

76 Actual minus Outturn.
77 Please see CER/06/199, CER/07/184, CER/08/178 and CER/09/140.
adjusted amount of circa €1.5 million was provided for in 2007. However an amount of approximately €0.8 million per annum was assumed to continue to apply for 2008, 2009 and 2010.

The outturn mirrors this adjusted allowed amount.

### 9.7.2 DUoS Costs (Adj. allowed €2.4m; Outturn €2.1m)

Distribution Use of System (DUoS) Costs, relate to the cost paid by the TSO to the DSO associated with the solitary 110kV connected customer that is classified as distribution rather than transmission due its location in the Dublin area. This is to prevent discrimination against this single customer. In the PR2 determination the CER allowed projected costs of circa €0.35 million per annum throughout the review period to cover this cost.

In CER/08/178 the CER expected that further DSO wires costs would arise in 2009 on account of the connection of an additional customer to the 110kV distribution system in the Dublin area. Accordingly, the CER increased the allowed revenue to €0.9 million for 2009 to account for this additional cost.

The outturn mirrors this adjusted allowed amount.

### 9.7.3 Interconnector Services (Adj. allowed €0.6m; Projected outturn €0.6m)

This was a new line item included for 2010\(^{78}\) to account for costs associated with System Operator to System Operator trades on the Moyle Interconnector. These costs are to be shared between EirGrid and SONI, as TSOs, on a 75:25 basis. This is consistent with the previous SEMO revenue determination (SEM/08/093)\(^{79}\) and was made on the basis that the Moyle Interconnector currently provides an all island benefit and that the costs be based on a MWh basis across the island. The costs incurred can be ascribed to three main groupings; Interconnector error, administration and capacity costs associated with System Operator trading.

According to the most recent TSO submission the projected outturn mirrors the adjusted allowed amount for this cost.

---

\(^{78}\) Please refer to CER/09/140

9.7.4 Inter TSO Compensation (Adj. allowed €4.6m; Outturn €4.1m)

European Regulation 1228/2003, which took effect from 1st July 2004, requires that TSOs are compensated for hosting cross-jurisdictional flows of electricity from those TSOs where the flows arise and where they end. A voluntary European ITC scheme\(^{80}\), of which Ireland is a member, was introduced. The PR2 determination allowed for approximately €1 million per annum for this cost category.

According to the most recent TSO submission the projected 2010 outturn closely mirrors the adjusted allowed amount for this cost.

9.7.5 Ancillary Services (Adj. allowed €181.9m; Outturn €183.3m)

As can be seen from Table 33 below the TSO’s external costs consist predominantly of Ancillary Services. Ancillary services comprise of Operating Reserve, Reactive Power and Black Start Facilities\(^{81}\). In January 2009 the CER’s determination on Secondary Fuel Obligations (CER/09/001)\(^{82}\) stated that the costs of EirGrid performing tests of Generators on their secondary fuel will be remunerated through the Ancillary Services mechanism with recovery allowed for outturn costs on a pass-through basis. The TSO, in its 2010 revenue submission to the CER, estimated that the costs associated with testing the units on secondary fuelling to be circa €1 million, which the CER allowed on a pass through basis, but to be reviewed ex-post in 2011.

According to the most recent TSO submission the projected outturn closely mirrors the adjusted allowed amount for this cost.

9.7.6 Constraints Banking Fees (Adj. allowed €0.6m; Outturn €0.5m)

The constraints banking fee line item is separate to the general working capital arrangements contained in the allowed TSO revenue and it covers funding arrangements associated with the Imperfections charge\(^{83}\).

According to the most recent TSO submission the projected outturn closely mirrors the adjusted allowed amount for this cost.

---

\(^{80}\) From March 2011 it is envisaged that a compulsory European wide TSO scheme will be in place.

\(^{81}\) Please see the following link:

\(^{82}\) Please see the following link:

\(^{83}\) Please refer to current Imperfections Charge decision paper for description.
9.7.7 Constraints (Adj. allowed €86.8m; Outturn €86.8m)

The PR2 determination paper allowed for Constraint costs, associated with the balancing of the transmission systems in ROI, to be recovered through TUoS. With the introduction of the SEM in November 2007 these costs are now recovered by the SEMO and are no longer recovered through ROI TUoS.

The adjusted allowed and outturn figures reflects those amounts pre-introduction of the SEM.

Table 33: TSO External Opex PR2 (€m’s 2009 prices)

<table>
<thead>
<tr>
<th></th>
<th>CER Allowed</th>
<th>Adjusted CER PR2 Allowed</th>
<th>PR2 Actual</th>
<th>Variance PR2 Outturn CER Allowed</th>
</tr>
</thead>
<tbody>
<tr>
<td>CER Levy</td>
<td>3.9</td>
<td>5.0</td>
<td>4.9</td>
<td>-0.1</td>
</tr>
<tr>
<td>DUoS costs</td>
<td></td>
<td>2.4</td>
<td>2.1</td>
<td>-0.3</td>
</tr>
<tr>
<td>Interconnector services</td>
<td></td>
<td>0.6</td>
<td>0.6</td>
<td>0.0</td>
</tr>
<tr>
<td>Inter TSO Compensation</td>
<td></td>
<td>4.6</td>
<td>4.1</td>
<td>-0.4</td>
</tr>
<tr>
<td>Ancillary Services</td>
<td>205.4</td>
<td>181.9</td>
<td>183.3</td>
<td>1.4</td>
</tr>
<tr>
<td>Constraints Banking Fees</td>
<td></td>
<td>0.6</td>
<td>0.5</td>
<td>-0.1</td>
</tr>
<tr>
<td>Constraints</td>
<td>223.8</td>
<td>86.8</td>
<td>86.8</td>
<td>0.0</td>
</tr>
<tr>
<td><strong>Total External Costs</strong></td>
<td><strong>433.2</strong></td>
<td><strong>281.9</strong></td>
<td><strong>282.3</strong></td>
<td><strong>0.4</strong></td>
</tr>
</tbody>
</table>

9.8 Conclusion

The above sections of this paper cover the TSO’s and TAO’s Opex over the 2006 to 2010 period at a high level. Parties that are interested in more detail should also read the consultant’s report on this expenditure which has been published alongside this paper.

As per the PR2 transmission determination the CER employed a five-year rolling retention mechanism for the TSO and TAO since this will deliver the most even distribution of efficiency savings across the duration of the price control. The determination allowed for the TAO and TSO to retain Opex related savings for a period of five years, provided such savings have not been made at the expense of performance and quality of service.

It should be noted that the costs described here as ‘2010 outturns’ are estimates of what the 2010 outturn cost will be. It is intended that the final 2010 figures will be reviewed when these are available to ensure that they are consistent with this review.

**TAO**

The TAO’s PR2 total Opex of €212.4 million are €29.7 million lower than the allowed costs of €242.1 million. The TUoS tariffs over PR2 are based on the
allowed expenditures and SKM have recommended that allowed Opex for PR3 be reduced by €25.04 million\textsuperscript{84}, as these savings have not been efficiently incurred.

The net underspend is due to an under spend on transmission maintenance of €9.7 million which arises due to under achievement of the planned maintenance programme and associated under spend on field operations of €3.2 million. The remainder of the under spend is due to the over-provision of allowed costs in PR2, partly due to the uncertainty at that time of the split of responsibilities and costs between the TAO and TSO, which were later clarified under the IA.

The TAO accepted that there were some windfall gains in PR2 for the reasons stated above. SKM have concluded that much of the underspend is not due to efficiency savings. The CER agrees with the findings of SKM and have decided that the TAO should not receive a windfall benefit from that uncertainty and that €25.04 million of the underspend be deducted from PR3 allowed costs. This figure will be clawed back from the TAO in the PR3 period as detailed in section 13.4 below.

**TSO**

The underspend on internal Opex of circa €18.3 million is considered to have arisen due to a combination of forecasting errors and efficiency savings. There has been a considerable amount of change to market and industry structures since the time of setting the PR2 determination. These changes include the vesting of EirGrid in July 2006, the signing of the IA also in 2006 and the implementation of the SEM in November 2007. Reflecting these various changes the CER allowed a number costs to be included in the allowed TSO revenue subject to an ex-post review. However, the CER stated in the 2007 to 2010 revenue determinations, that it expected these new and “start-up” costs to be incurred in an efficient manner by the TSO.

Furthermore, the specific activities that need to be undertaken and costs incurred cannot be perfectly forecast at the beginning of a 5 year control and, indeed, the level and scope of EirGrid’s activities has, as detailed in section 2.5, increased significantly over the PR2 2006-2010 period.

With respect to TSO external costs, although these costs were allowed as pass through in PR2, as they are (in the most part) outside the control of the TSO, the CER undertook an annual ex-post adjustment to take account of actual outturn costs. This ex-post adjustment was subsequently reflected in the following year’s allowed revenue. Hence the reason why outturn external costs for PR2 closely mirrors that of outturn figures provided by the TSO.

\textsuperscript{84} This underspend takes account of €3.68 million spent efficiently in accordance with the CPI-X model and €1.95 million due to the flexing of the Field Operations expenditure.
In conclusion, although there was considerable uncertainty on the TSO internal operating costs required to facilitate the start up of EirGrid as TSO, the CER has decided that the TSO should not receive a windfall benefit from that uncertainty and that €8.48 million\(^{85}\) of the underspend be deducted from allowed PR3 costs, i.e. just under 50% of the underspend in each year in which it occurred. This figure will be clawed back from the TSO in the PR3 period as detailed in section 13.4 below.

\(^{85}\) SKM in their report recommends a clawback of €9.15 million. The CER clawback figure of €8.48 million takes account of €672k for the TSO 2009 system performance incentives (SPIs). The 2009 SPIs outturn figures were provided by the TSO subsequent to the CER undertaking the review of the PR2 TSO costs.
10.0 Review of forecast operational expenditure

10.1 Introduction

The revenue requested by the TSO and TAO to cover their respective Opex over the PR3 period is outlined within the TSO and TAO documents, which have been published alongside the consultation paper CER/10/102. The recommendations provided by the CER’s consultancy support (SKM) have also been published alongside that paper.

This section provides the CER’s position on the various items. For a level of detail greater than that provided below, readers should refer to the SKM TSO/TAO reports.

Separate information on benchmarking the TAO and TSO against international comparators is covered in section 11.0 of this paper. The conclusions regarding benchmarking are consistent with the recommendations and allowances outlined below.

10.2 Objectives for the Opex review

The CER has carefully reviewed the TSO’s and TAO’s submissions on Opex for the PR3 period 2011 to 2015. In reaching a view on the appropriateness of the TSO’s and TAO’s proposals, the CER has taken into account, inter alia:

- The TSO’s / TAO’s historic performance and the accuracy of previous forecasts;
- The information gained from the accompanying benchmarking analysis carried out by SKM; and
- The TSO’s/ TAO’s submissions on projected Opex.

As mentioned in section 2.4 above one of overarching principles guiding the CER in its decision is to ensure that the activities being completed by the TSO and TAO and accompanying allowed revenues represent value for money for consumers.

10.3 Efficiencies built into allowances

There are three main factors that have led to the recommendation put forward by SKM on the appropriate revenue for TAO and TSO Opex for the PR3 period being lower than the values put forward by the TAO and TSO. These are summarised below and covered in more detail within the accompanying SKM reports.
The factors outlined below have led to reductions in internal TSO Opex, however due to the forecasted rise in external (non-controllable) costs there is an increase from a forecasted total (internal and external) TSO Opex value of €89 million for 2010 to an allowed value of €95.6 million for 2011.

Furthermore, the allowed CER amount of €100.4 million for 2015 reflects the assumption that external (non-controllable) costs, which are a considerable level of TSO opex (e.g. Ancillary Services) will rise through the PR3 period. The total TSO opex allowed by the CER for PR3 amounts is €487.39 million to which is €151.6 million less than the total ex-ante allowed for the PR2 period of €639 million.

It should be noted that the amounts proposed by SKM based on their analysis, do not reflect the East-West Interconnector charge that EirGrid is expected to be subject to from the 2012-2013 tariff period onwards. This matter is discussed in section 10.8 below.

As with the TSO, with respect to the TAO, the factors outlined below have led to reductions in internal TAO Opex. However due to the forecasted rise in external (non-controllable) costs there is a small increase from a forecasted outturn value of €46 million for 2010 to an allowed value of €47 million for 2011. The TAO had requested to the CER a cost of €51.5 million for 2011. The total TAO opex allowed by the CER for PR3 amounts to €232 million, which is €31 million less than that allowed for the PR2 period of €263 million.

It should be noted that the above allowed amounts do not take into account the further reduction in TAO approved costs. The reduction for the TAO has been included in Table 2 of the Executive Summary, but has not been broken down by line item within this paper; rather it is a reduction in overall revenue for Opex (and Capex). The TAO is to determine how these reductions will be achieved across Opex and Capex. With respect to the TSO this has fed through in a reduction in allowed “Other” costs as detailed below in section 10.6.10.

The analysis below is not intended as a direction to the TSO or TAO on how to run their respective businesses; it is an explanation of the factors that underpin SKM’s recommendations and the CER’s allowances.

In general, the below factors also extend to SKM’s recommendations on the appropriate level of revenue that should be approved for capital expenditure. Those recommendations are discussed in section 8.0 of this paper.

10.3.1 The appropriate base year

For each cost item an appropriate base level has been recommended by SKM for 2011 taking into account the following:

- TAO’s and TSO’s PR2 costs (particularly those for 2009 and 2010);
• TAO’s and TSO’s forecasts for PR3;
• TAO’s and TSO’s historic accuracy of forecasting of line items;
• a review of the TAO’s and TSO’s submission; and
• responses provided separately by the TAO and TSO to queries posed by SKM and the CER.

10.3.2 Wages

SKM TAO recommendation

SKM consider that the TAO’s assumption that internal labour costs will be maintained at CPI is too conservative in the present economic climate and when compared with pay reductions elsewhere in the Irish economy. Its recommendations are based on a reduction in TAO and ESB Group payroll costs of 5% in 2011, equivalent to a 1.7% reduction in controllable Opex.

This reduction notes, and is in addition to, the reductions in payroll costs (the majority of these reductions have related to reducing staff numbers, bonuses, expenses, overtime, etc) that have been implemented by the TAO under the PR2 regulatory model. These reductions have fed into SKM’s recommendations on the appropriate base allowed revenue for the first year of PR3, as described above. More details on these reductions are provided below within this section.

In addition, SKM notes that ESB Networks (as TAO and DSO) is operating a voluntary selective severance scheme in 2009 and 2010 and will lose a net 287 staff, over the whole of PR2. This will reduce staffing levels in ESBN at the outset of PR3 by about €25 million of which approximately 43% are operating costs during PR3. SKM note that these savings are not reflected in a step decrease in costs over the period 2009 to 2011; in fact forecast costs from 2009 to 2011 are rising. SKM has therefore included a step change in its recommendations on 2011 costs for some line items.

Discussion: payroll costs during the PR2 period

Both the private and public sectors have had to meet the challenges over the past two to three years presented by the current recession. One significant response has been to cut payroll cost; wages have been cut in the public sector and there is evidence that there has been significant wage restraint/wage falls in the private sector of the Irish economy. This represents a requirement to readjust wage levels in order to help regain economic competitiveness. While definitive economy-wide statistics are not available at this time, a recent ESRI

---

86 Please see the following link: http://www.budget.gov.ie/Budgets/2010/Summary.aspx#Reductions
87 Please see the following link: http://www.mercer.ie/summary.htm?idContent=1366355
document expects a nominal wage decrease in the region of 6% over the 2009 to 2011 period.\textsuperscript{88}

The CER notes that there has not been widespread wage reductions in the TAO and TSO over the past two years and that there is an impression that these organisations are insulated from the economic difficulties experienced in the Irish economy in recent years. There is also a debate with regard to the appropriate classification of staff in these monopoly semi-state companies. While TAO and TSO staff are not public sector workers, they do enjoy equivalent job security benefits to public sector workers.

The regulatory model which was in place during the PR2 period has led to these challenges faced by the wider economy being reflected in the allowed revenue which can be collected from the TUoS customer. In practice, this meant that total transmission revenue for 2009 was reduced by 4.5\%\textsuperscript{89} in line with level of deflation in the Irish economy. On top of this, the expected 0.25\% CPI in 2010 is also applied to the allowed revenue in 2010.

One implication of this downward pressure on income was that the TAO reduced its payroll costs in the later years of PR2. When viewed on a per employee basis, there was a 1\% reduction in 2009 and a further 5\% reduction in 2010.\textsuperscript{90} These reduced payroll costs have fed through into allowances on allowed revenue for 2011 (the first year of the PR3 control) as detailed in Section 10.4.

One point worth highlighting is that the majority of these reductions are related to reductions in staff numbers and cuts in expenses, overtime and bonuses. Apart from certain management groups the TAO has not introduced wage reductions throughout the recent recession. Indeed the TAO continued to pay National Wage Agreement pay increases during 2009.

With respect to the TSO, its evolution of staffing numbers and costs through the PR2 period differs to that of the TAO. EirGrid’s organisation and workforce has evolved to meet changing circumstances such as vesting in July 2006, the signing of the IA also in 2006 and the implementation of the SEM in November 2007. In addition, the TSO elected not to pay the increases under the National Wage Agreement in 2009 and 2010.

\textsuperscript{88} The ESRI document ‘Recovery Scenarios for Ireland’ is available [here](#).
\textsuperscript{89} The CPI for 2009 is -4.5\% (actual); the forecast CPI for 2010 is 0.25\%. The statistics for 2009 are available [here](#) on the CSO website. The forecast CPI for 2010 is based on the Spring 2010 ESRI report -Quarterly Economic Commentary, Spring 2010.
\textsuperscript{90} These payroll costs include basic salaries & wage expenses, overtime & shift allowance, any other allowances, and bonuses & profit related pay. If social security, defined benefit and defined contribution pension costs and other costs are included these figures change to 0\% and -4\% for 2009 and 2010 respectively.
Table 34 above shows the evolution of EirGrid staffing and staff costs over period 2006 to 2010. The figures exclude ESB seconded staff, averaging around €2 million in the first three years and approximately 22 staff. The total staff increase of 57 from 2006 to 2009 is therefore partly due to replacement of seconded ESB staff and contractors.

The CER is aware of the relatively high wage levels in both the TSO and TAO compared to the wider economy. Much of this high wage level can be justified through the skilled nature of the job and the need for TAO and TSO to attract and retain skilled staff. However, the CER is also aware though that the TAO and TSO have not in general experienced the same economic re-adjustment as others in the economy including other highly skilled or highly qualified staff in the competitive sectors of the economy.

As TAO and TSO payroll costs are ultimately paid for by electricity customers, it is appropriate to expect wage adjustments in TAO and TSO to reflect the economic realities of the past two years. The TUoS customers cannot be expected to fund wage increases in TAO and TSO during the PR3 period at a time when wages in the economy are falling.

**Discussion: payroll costs during PR3 period**

For the PR3 period, the TAO proposals reflect an assumption that its internal labour costs will rise at a level consistent with CPI. The TSO proposals reflect a different approach consistent with their argument that their cost base rises higher than CPI. EirGrid have argued in their PR3 submission to the CER that their workforce consists primarily of highly skilled labour, outside resources, high tech IT and telecoms professional where inflation is normally higher than CPI. The TSO’s justification for the application of a higher ‘wage’ indexation factor over CPI is discussed in more detail in the accompanying SKM report.
For the TAO the SKM recommendations build an expectation that wage levels will fall by 5% in 2011, on top of:

- the reductions in other payroll costs which have been implemented during PR2 and which also feed into the PR3 recommendations; and
- a step change reduction in its recommendations on 2011 costs for some line items due to savings related to a voluntary selective severance scheme that is being completed in 2009 and 2010.

For the TSO, the assumption that internal salary costs will rise by 4% above CPI with a 1% increase in productivity (net 3% rise in staff costs) is considered to be too conservative by SKM in the present economic climate.

The ESRI Medium Term Review 2008\(^{91}\) forecasts that the average productivity of the Irish economy to be 2.5% per annum over the period 2011 to 2015. SKM expects the TSO to achieve at least 2.5% productivity improvement over PR3 as the EirGrid organisation becomes more settled.

Therefore, SKM expect wage levels and other internal TSO costs to fall by at least 5% in 2011 compared to 2010 and remain at that level relative to inflation throughout PR3. SKM have provided recommendations to the CER consistent with that approach.

In its report SKM also note a comparison of the hourly payroll costs for the utilities sector in Ireland compared with manufacturing for a number of European countries and EU area average\(^{92}\). 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. SKM note that 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.

However, a separate comparison based on 2006 data which does not include manufacturing is provided in the below figure. While this figure shows that Ireland’s utility costs are slightly above the EU average, they are more in line than the previous comparison would suggest.

It could be argued that both of these comparisons do not reflect wage costs paid by TAO’s or TSO’s in the relevant countries. Both are based on the average labour costs paid by utilities over a range of sectors; they are not limited to electricity transmission or even the electricity sector. In addition, the first comparison includes the variable of the manufacturing wage that is paid in each

---


\(^{92}\) Eurostat statistics
country. This factor could lead to misleading comparisons as higher/lower relative manufacturing wages influence the results.

Another factor that is worth noting is the benchmarking work completed by SKM, which indicated the availability of further efficiencies over the transmission utilities as a whole. SKM have also reviewed the Engineers Ireland Salary Survey 200893 and the Brightwater Salary Survey 201094 and are of the opinion that overall the salaries and benefits of the TSO and TAO appear to be aligned with others in similar sectors and with similar skills, after the 5% reduction in PR3. However the results of this comparison should be treated with caution as the Engineer Ireland data is a small sample of self reported data and may not be wholly representative. But it should be made clear that the labour costs underpinning SKM’s recommendations are consistent with the findings of its benchmarking and comparison work.

Finally, there is a widespread expectation of wage restraint and reductions over the coming years. Recent CSO data shows a decrease in various earnings categories across the economy. “Earnings and Labour Costs Q1 2010 - Q2 2010 (Preliminary Estimates)”, published on 21st October 2010, shows average hourly earnings fell in the period Q2 2009 to Q2 2010 by 1.0%95.

The recent Government – Draft Public Service Agreement 2010-201496 indicated a commitment that following public sector wage reductions in 2009 that wage levels would remain unchanged up to 2014. This proposal indicates no further decrease but also no increase in that period. Indeed even since the publication of this agreement and the publication of the CER’s consultation paper in July, there has been a further deterioration of the Irish economic situation. A severe four–five year austerity programme is now planned by the Government with the expectation that all sectors of the economy will continue to show wage constraint.

In addition to this, cuts to the provision of services are expected in order to regain competitiveness. It is reasonable to expect that the services provided by TSO and TAO are also subject to the required efficiency and competitiveness gains over the next four to five years, in line with all other sectors of the economy.

93 Please see the following link:
94 Please see the following link:
95 Please see the following link for various CSO papers:
http://www.cso.ie/releasespublications/pr_earns.htm
96 Please see the following link:
Discussion: CER position

The CER is comfortable that the reductions in costs recommended by SKM for both TAO and TSO activities could be achieved through reducing labour costs as outlined by SKM. While international comparisons vary, the data does indicate that potential cost savings are available in this area. This is backed up by SKM’s benchmarking work and the ESRI’s expectations on labour costs as well as the fact that the vast majority of TSO and TAO employees have not suffered wage reductions in the past two years, meaning that wages in these organisations entering the PR3 period are considered to be out of line with the wider economy, both public and private sector.

The CER intends to approve the level of TAO and TSO revenue recommended by SKM for PR3, which is underpinned by, among other things, the above reductions in labour costs. The CER believes that the available evidence regarding labour costs (as discussed above) justifies that element of the reduction in TAO and TSO costs.

Table 35: Utilities hourly rates (data from 2006)
10.3.3 Efficiency improvements

Both the TSO and TAO have reflected a 1% per annum productivity improvement within its submission. SKM, however, has built a productivity improvement of 2.5% per annum into its recommendations for the PR3 period.

It is noted that the ESRI Medium Term Review 2008 to 2015 indicates a productivity increase measured by GNP per worker of 2.5% per year over the period 2010 to 2015\textsuperscript{97} which broadly lines up with the above recommendations.

10.3.4 Services provided by ESB Group

A portion (22%) of the TAO’s costs derives from work completed by other parts of the ESB Group for the TAO. These include costs associated with work completed by:

- ESB Corporate - Examples include the work completed by HR, directors and management, etc;
- the ESB Group’s IT Services business unit;
- the ESB Group’s telecoms service; and,

\textsuperscript{97} Economic and Social Research Institute Ireland Medium Term Review 2008 to 2015.
• ESB International - This includes asset management services, design activities, project management and other specialist services.

SKM note that limited details have been provided on any margin between the cost the TAO pays for these services, and the actual cost incurred by the other ESB Group business units when providing these services. Some of the services (for example, HR) are provided at cost and others are provided at benchmarked rates.

In making recommendations for efficiency savings of 2.5% per annum in allowed costs, SKM has taken into account the margin, payroll costs and general productivity improvements when assessing those costs which have a component of costs from other parts of ESB Group.

Even with the vesting of EirGrid as TSO in July 2006 and therefore becoming an independent body to the ESB Group, these are still a number services that continue to be provided by ESB, including ESB ITS and ESBI. However as outlined above in section 9.4 contracts, such as those with ESB ITS, have been renegotiated during PR2.

In its PR3 submission to the CER, the TSO has also provided details of a framework for the hiring of external contractors. The submission to the CER indicated that there were 27 companies on EirGrid framework, with ESBI being the recipient to 16% of the contracts awarded.

10.4 TAO Opex – Internal

10.4.1 Introduction

This section outlines the allowances by the CER for the TAO internal (controllable) Opex over the PR3 period. Table 36 below outlines the allowed PR3 amounts.

As noted in the executive summary the CER accepts the recommendations of our advisors and has allowed expenditure for Opex as detailed below, but notes that this allowance is subject to further efficiency savings (to be determined by the TAO) as detailed in section 8.3 of this paper.

10.4.2 Operations (PR2: €11m, TAO: €14.4m, Allowed: €10.5m)

This cost item includes operational switching, station attendance, fault location, and a range of other services. The TAO proposed €14.4 million to cover these costs over the PR3 period. The CER’s consultants have recommended that a value of €10.5 million be approved.
The CER has accepted this recommendation, the details of which are contained within the consultant’s report which has been published alongside the consultation paper (CER/10/102). The CER will also consider the possibility of volumetric flexing during PR3 if this situation arises where revenue adjustments are required.

10.4.3 Planned & Fault Maintenance (PR2: €60.9m, TAO: €93.5m, Allowed: €73.7m)

As set out in the IA, the TSO is responsible for setting the maintenance policy, which includes the frequency at which maintenance tasks are delivered and any associated planned or forced outage arrangements to allow work be executed on the system. The TAO carries out the repair and maintenance tasks on the ground and set asset management policy with the objective of minimizing overall system cost.

SKM have recommended that the PR3 costs for these two categories should be adjusted on an annual basis for changes in volumes of maintenance work completed, either due to shortfall in the maintenance programme or due to changes in volumes of maintenance required. In this way the TAO will be able to retain savings associated with achieving lower than allowed unit costs, but not due to changes in volumes.

The CER will consider this proposal during PR3, keeping in mind the price control policy of the TSO and TAO being permitted to retain annual savings made for a period of five years, provided such savings have not been made at the expense of performance and quality of service. This issue is further discussed in section 13.1.2 below.

The TAO proposed €93.5 million to cover these costs over the PR3 period. The CER’s consultants have recommended that a value of €73.7 million be approved. The CER has accepted this recommendation, the details of which are contained within the consultant’s report which has been published alongside the consultation paper.

10.4.4 Professional Services (PR2: €25m, TAO: €24.3m, Allowed: €19.4m)

Professional services are those services provided to the TAO by ESBI which relate to the transmission maintenance work programme. The TAO proposed €24.3 million to cover these costs over the PR3 period. The CER’s consultants have recommended that a value of €19.4 million be approved. The CER has accepted this recommendation, the details of which are contained within the consultant’s report which has been published alongside the consultation paper.
10.4.5 Telecom Fees (PR2: €6.4m, TAO: €9m, Allowed: €7.6m)

This item covers fees from ESB Telecoms for support of operational IT and telecoms services.

The TAO proposed €9 million to cover these costs over the PR3 period. The CER’s consultants have recommended that a value of €7.6 million be approved. The CER has accepted this recommendation, the details of which are contained within the consultant’s report which has been published alongside the consultation paper.

10.4.6 Asset Management (PR2: €3.7m, TAO: €8.1m, Allowed: €5.1m)

This cost relates to mast interference and foreshore payments, which is expected to increase significantly in PR3 with the development of the transmission network.

The TAO proposed €8.1 million to cover these costs over the PR3 period. The CER’s consultants have recommended that a value of €5.1 million be approved. The CER has accepted this recommendation, the details of which are contained within the consultant’s report which has been published alongside the consultation paper.

10.4.7 Other Internal (Controllable) Costs (PR2: €17.3m, TAO: €22.0m, Allowed: €18.72m)

Other controllable costs include legal, pension administration, insurance, company-wide costs and corporate charges.

The TAO proposed €22 million to cover these costs over the PR3 period. The CER’s consultants have recommended that a value of €18.72 million be approved. The CER has accepted this recommendation, the details of which are contained within the consultant’s report which has been published alongside the consultation paper.
Table 36: TAO Internal (Controllable) Opex PR3 (€m's 2009 prices) – Allowed

<table>
<thead>
<tr>
<th></th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>Total PR3 Allowed</th>
<th>TAO PR3 Forecast</th>
<th>Variance Allowed. vs TAO Forecast</th>
<th>Variance %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operations</td>
<td>2.19</td>
<td>2.15</td>
<td>2.10</td>
<td>2.06</td>
<td>2.02</td>
<td>10.52</td>
<td>14.4</td>
<td>-3.9</td>
<td>-27.2%</td>
</tr>
<tr>
<td>Planned maintenance</td>
<td>14.17</td>
<td>13.89</td>
<td>13.61</td>
<td>13.34</td>
<td>13.07</td>
<td>68.09</td>
<td>87.3</td>
<td>-19.2</td>
<td>-22.0%</td>
</tr>
<tr>
<td>Fault maintenance</td>
<td>1.17</td>
<td>1.15</td>
<td>1.12</td>
<td>1.10</td>
<td>1.08</td>
<td>5.62</td>
<td>6.2</td>
<td>-0.6</td>
<td>-9.1%</td>
</tr>
<tr>
<td>Professional Services</td>
<td>4.04</td>
<td>3.96</td>
<td>3.88</td>
<td>3.81</td>
<td>3.73</td>
<td>19.43</td>
<td>24.3</td>
<td>-4.9</td>
<td>-20.1%</td>
</tr>
<tr>
<td>Telecom Fees</td>
<td>1.58</td>
<td>1.55</td>
<td>1.52</td>
<td>1.49</td>
<td>1.46</td>
<td>7.60</td>
<td>9.0</td>
<td>-1.4</td>
<td>-15.6%</td>
</tr>
<tr>
<td>Asset Management</td>
<td>1.01</td>
<td>1.01</td>
<td>1.01</td>
<td>1.01</td>
<td>1.01</td>
<td>5.05</td>
<td>8.1</td>
<td>-3.0</td>
<td>-37.4%</td>
</tr>
<tr>
<td>Legal</td>
<td>0.20</td>
<td>0.20</td>
<td>0.20</td>
<td>0.20</td>
<td>0.20</td>
<td>1.00</td>
<td>2.0</td>
<td>-1.0</td>
<td>-50.1%</td>
</tr>
<tr>
<td>Insurance</td>
<td>0.28</td>
<td>0.28</td>
<td>0.28</td>
<td>0.27</td>
<td>0.27</td>
<td>1.38</td>
<td>1.38</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>Pension</td>
<td>0.14</td>
<td>0.14</td>
<td>0.14</td>
<td>0.14</td>
<td>0.14</td>
<td>0.69</td>
<td>1.7</td>
<td>1.0</td>
<td>-60%</td>
</tr>
<tr>
<td>Company Wide Costs</td>
<td>0.45</td>
<td>0.44</td>
<td>0.43</td>
<td>0.42</td>
<td>0.41</td>
<td>2.15</td>
<td>2.5</td>
<td>-0.4</td>
<td>-15.2%</td>
</tr>
<tr>
<td>Corporate Charges &amp; Corp Affairs</td>
<td>2.29</td>
<td>2.25</td>
<td>2.20</td>
<td>2.16</td>
<td>2.11</td>
<td>11.01</td>
<td>11.8</td>
<td>-0.8</td>
<td>-6.6%</td>
</tr>
<tr>
<td>Other</td>
<td>0.50</td>
<td>0.50</td>
<td>0.50</td>
<td>0.50</td>
<td>0.50</td>
<td>2.50</td>
<td>2.5</td>
<td>0.0</td>
<td>-1.2%</td>
</tr>
<tr>
<td><strong>TAO Internal (Controllable) Costs</strong></td>
<td><strong>28.02</strong></td>
<td><strong>27.50</strong></td>
<td><strong>27.00</strong></td>
<td><strong>26.50</strong></td>
<td><strong>26.01</strong></td>
<td><strong>135.03</strong></td>
<td><strong>171.2</strong></td>
<td><strong>-36.2</strong></td>
<td><strong>-21.1%</strong></td>
</tr>
</tbody>
</table>

10.5 TAO Opex – External

10.5.1 Introduction

This section outlines the allowances by the CER for the TAO external (non-controllable) Opex over the PR3 period. Table 37 below outlines the allowed CER PR3 amounts.

10.5.2 Network Rates (PR2: €82.6m, Allowed: €92.9m)

SKM suggest that Transmission rates are allowed as forecast by the TAO. The CER has accepted this recommendation. However, the TAO shall be required to justify the level of this cost and demonstrate that it has minimised this during and at the end of the PR3 period.

10.5.3 CER Levy (PR2: €5.4m, Allowed: €4m)

The CER will allow €0.8million per annum for the regulatory levy for the period 2011 to 2015.
Table 37: TAO External (Non-Controllable) Opex PR3 (€m’s 2009 prices) - Allowed

<table>
<thead>
<tr>
<th></th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>Total PR3 allowed</th>
<th>PR2 Outturn</th>
<th>Var. Allowed PR3-PR2</th>
<th>Var. %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Network Rates</td>
<td>18.21</td>
<td>18.21</td>
<td>18.21</td>
<td>18.21</td>
<td>20.03</td>
<td>92.9</td>
<td>82.6</td>
<td>10.3</td>
<td>12.4%</td>
</tr>
<tr>
<td>CER Levy</td>
<td>0.80</td>
<td>0.80</td>
<td>0.80</td>
<td>0.80</td>
<td>0.80</td>
<td>4.0</td>
<td>5.4</td>
<td>-1.4</td>
<td>-25.6%</td>
</tr>
<tr>
<td>TAO External (Non – Controllable) Costs</td>
<td>19.01</td>
<td>19.01</td>
<td>19.01</td>
<td>19.01</td>
<td>20.83</td>
<td>96.9</td>
<td>88.0</td>
<td>8.9</td>
<td>9.2%</td>
</tr>
</tbody>
</table>

10.6 TSO Opex – Internal

10.6.1 Introduction

This section outlines the allowances by the CER for the TSO internal (controllable) Opex over the PR3 period.

10.6.2 Staff and Related Costs (PR2:€112.2m, TSO:€148.4m, Proposed: €112.9m, Allowed: €118.6m)

The reasons put forward by the TSO for the PR3 forecast increase in staff numbers are provided in Section 4 and the SKM recommendations for staff numbers in Section 5 of the accompanying SKM report. In their submission to the CER the TSO outlined its intent to increase staff by 87 from 253 in 2009 to 339 by the end of PR3 in 2015. This proposal involved the following:

- Increasing Grid Development network capex staff by 63 from 22 to 85 to meet the forecast ‘Network Needs’ scenario capital programme.
- Increasing Client engineering staff by 11 from 9 to 20.
- Increase Network Control staff by 5, i.e. a 24/7 additional shift in the Control Centre to accommodate the variability of wind dispatch, and
- An additional 8 staff across the organisation in support functions.

However, the SKM forecast indicates an increase in Opex staffing numbers (which does not include staff related to Capex) from 230 in 2010 to 239 by 2013 and then to remain at that level for the remainder of the price control.

There has been an amendment made to the allowed TSO Salaries and Related Costs from that proposed in the consultation paper. The CER acknowledges that within the 2009 baseline Payroll costs the IAS 19 numbers for the TSO pension contribution were anomalously low relative to other years (below 10% of pensionable pay and below cash contributions actually made by the TSO in 2009). Therefore, the CER, on the basis of advice from SKM, has decided to apply the same percentage employer contribution into PR3 TSO Salaries and Payroll costs as that applied to the TAO in PR3 – 13.5%.
The CER’s consultants have now recommended that a value of €118.6 million be approved, which is still over 20% less than that proposed by the TSO. This figure is still reflective of a Po cut of 5% to average TSO staff costs in 2009. The only change from that proposed in CER/10/102 is the amended percentage employer contribution.

It should be noted that this recommendation does not include the TSO request for additional costs associated with the TSO client engineering role. SKM have recommended that the TSO should review and streamline the client engineering activity in order to avoid the need for an increase in client engineering staff from 9 to 20 in PR3. Therefore, SKM have recommended that TSO client engineering staff remains at 9. Please refer to the transmission response to comments paper published alongside this paper for further details on these matters.

The CER will also consider, in consultation with stakeholders, allowing costs for TSO requested additional control centre shift staff if and when requirements become clearer during the PR3 period.

10.6.3 Contractors (PR2:€8.08m, TSO:€6.23, Allowed: €5.95m)

As outlined in section 9.6.2 above, in PR2 the CER allowed a number of start-up costs for EirGrid upon vesting, which included costs associated with the hiring of contractors to meet any short-term operational shortfalls. With the bedding down of the EirGrid organisation and the increase in internal staff numbers highlighted for PR3 the CER will reduce the allowed amount for external contractors.

In its submission to the CER, EirGrid also indicated a reduction in contractors for the PR3 period. This position by the CER must be balanced with the work (internal and external provided) that will be required from the TSO for the effective development of the transmission network in PR3.

The CER’s consultants have recommended that a value of €5.95 million be approved. The CER has accepted this recommendation, the details of which are contained within the consultant’s report which has been published alongside the consultation paper.

10.6.4 Telecommunication (PR2:€13.7m, TSO:€19.86m, Allowed: €19.24m)

Telecoms costs during PR3 are expected to be largely driven by PR3 network Capex development.

The CER’s consultants have recommended that a value of €19.24 million be approved. The CER has accepted this recommendation, the details of which are contained within the consultant’s report which has been published alongside the consultation paper.
10.6.5 Premises (PR2:€22.55m, TSO:€22.68m, Allowed: €22.68m)

SKM have proposed that allowed Premises costs, associated with the Oval in Ballsbridge, are those forecast by the TSO of €4.54 million per annum. The increase over the PR2 period relates to buildings rates on the EirGrid buildings (Oval) but also Global rates, whereby both the NCC and the Emergency Control Centre (ECC) in Deansgrange were rated as being part of the transmission system. The CER has accepted this recommendation, the details of which are contained within the consultant’s report which has been published alongside the consultation paper.

<table>
<thead>
<tr>
<th>Description</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rent (lease)</td>
<td>€2.9m</td>
</tr>
<tr>
<td>Building Rates (Oval + Deansgrange)</td>
<td>€0.4m</td>
</tr>
<tr>
<td>Global Rates (Oval + Deansgrange)</td>
<td>€0.3m</td>
</tr>
<tr>
<td>Facilities and Other Services</td>
<td>€1.9m</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>€5.5m</strong></td>
</tr>
<tr>
<td>Less contribution from SEMO</td>
<td>(€1.0m)</td>
</tr>
<tr>
<td><strong>Chargeable to TSO</strong></td>
<td><strong>€4.5m</strong></td>
</tr>
</tbody>
</table>

10.6.6 Insurance & Comp. (PR2:€0.77m, TSO:€1.34m, Allowed: €1.34m)

SKM have proposed that allowed Insurance and Compensations costs are held at the forecast 2010 levels of €0.27 million, as submitted by the TSO, throughout the PR3 period. The CER accepts this recommendation.

The CER’s consultants have recommended that a value of €1.34 million be approved. The CER has accepted this recommendation, the details of which are contained within the consultant’s report which has been published alongside the consultation paper.

10.6.7 Selling and Advertising (PR2:€0.71m, TSO: €1.76m, Allowed: €1.71m)

Selling and Advertising costs during PR3 are expected to increase and be largely driven by PR3 Network Capex development and the need for EirGrid, as the TSO in Ireland, to communicate the transmission network development program to the Irish public.

The CER’s consultants have recommended that a value of €1.71 million be approved. The CER has accepted this recommendation, the details of which are contained within the consultant’s report which has been published alongside the consultation paper.
10.6.8 Maintenance and Professional Fees (PR2: €27.26m, TSO: €26.61m, Allowed: €26.10)

The similar level forecast of maintenance and professional fees is due to the increase in resources required for increases in volumes of commissioning generators and client engineering. However, the underlying level of professional fees is reducing due to the TSO becoming self sufficient in network planning. This cost category will match the PR3 capex workload.

SKM have suggested allowed costs of €26.1 million (€5.22 million per annum). The CER has accepted this recommendation, the details of which are contained within the consultant’s report which has been published alongside the consultation paper.

10.6.9 Promotion of Research (PR2: €0.33m, TSO: €2m, Allowed: €2m)

SKM have proposed allowed Promotion of Research annual costs as submitted by EirGrid, throughout the PR3 period. The CER has accepted this recommendation, the details of which are contained within the consultant’s report which has been published alongside the consultation paper. The CER notes the PR2 underspend in this area, as detailed in section 9.6.9 above, and will look for EirGrid to be more active in the PR3 period in using the allowed amount to promote the objectives advanced in section 9 of the Electricity Regulation Act 199998 and solving existing or anticipated transmission-related problems.

10.6.10 Other (PR2: €5.24m, TSO: €3.22m, Proposed: €3.22m, Allowed: €2.9m)

This allowance refers to those costs such as TSO management of the Infrastructure Agreement, directors’ fees and other general business overhead (stationery, printing, postage etc). SKM have suggested allowed costs of €3.22 million. The CER has accepted this recommendation further to an additional efficiency factor of approximately 10% (or €320k over the PR3 period).

---

98 Please see the following link:
Table 38: TSO Internal (Controllable) Opex PR3 (€m’s 2009 prices) - Allowed

<table>
<thead>
<tr>
<th></th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>Total PR3 allowed</th>
<th>TSO PR3 Forecast</th>
<th>Var. Allowed vs. TSO Forecast</th>
<th>Var. %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Staff and related costs</td>
<td>23.51</td>
<td>23.70</td>
<td>23.80</td>
<td>23.80</td>
<td>23.80</td>
<td>118.62</td>
<td>148.43</td>
<td>-29.8</td>
<td>-20.1%</td>
</tr>
<tr>
<td>Contractors</td>
<td>1.19</td>
<td>1.19</td>
<td>1.19</td>
<td>1.19</td>
<td>1.19</td>
<td>5.95</td>
<td>6.23</td>
<td>-0.28</td>
<td>-4.5%</td>
</tr>
<tr>
<td>Telecommunications</td>
<td>3.38</td>
<td>3.60</td>
<td>3.83</td>
<td>4.08</td>
<td>4.34</td>
<td>19.24</td>
<td>19.86</td>
<td>-0.62</td>
<td>-3.1%</td>
</tr>
<tr>
<td>Premises</td>
<td>4.54</td>
<td>4.54</td>
<td>4.54</td>
<td>4.54</td>
<td>4.54</td>
<td>22.68</td>
<td>22.68</td>
<td>0.00</td>
<td>0.0%</td>
</tr>
<tr>
<td>IT Costs</td>
<td>2.24</td>
<td>2.35</td>
<td>2.47</td>
<td>2.47</td>
<td>2.47</td>
<td>11.99</td>
<td>12.37</td>
<td>-0.38</td>
<td>-3.0%</td>
</tr>
<tr>
<td>Insurance and Compensations</td>
<td>0.27</td>
<td>0.27</td>
<td>0.27</td>
<td>0.27</td>
<td>0.27</td>
<td>1.34</td>
<td>1.34</td>
<td>0.00</td>
<td>0.0%</td>
</tr>
<tr>
<td>Selling and Advertising</td>
<td>0.38</td>
<td>0.32</td>
<td>0.31</td>
<td>0.29</td>
<td>0.42</td>
<td>1.71</td>
<td>1.76</td>
<td>-0.05</td>
<td>-3.0%</td>
</tr>
<tr>
<td>Maintenance and Professional Services</td>
<td>5.22</td>
<td>5.22</td>
<td>5.22</td>
<td>5.22</td>
<td>5.22</td>
<td>26.10</td>
<td>26.61</td>
<td>-0.51</td>
<td>-1.9%</td>
</tr>
<tr>
<td>Promotion of Research</td>
<td>0.40</td>
<td>0.40</td>
<td>0.40</td>
<td>0.40</td>
<td>0.40</td>
<td>2.00</td>
<td>2.00</td>
<td>0.00</td>
<td>0.0%</td>
</tr>
<tr>
<td>Other</td>
<td>0.58</td>
<td>0.58</td>
<td>0.58</td>
<td>0.58</td>
<td>0.58</td>
<td>2.90</td>
<td>3.22</td>
<td>-0.32</td>
<td>-9.9%</td>
</tr>
<tr>
<td>TSO Internal (Controllable) Costs</td>
<td>41.70</td>
<td>42.16</td>
<td>42.61</td>
<td>42.84</td>
<td>43.23</td>
<td>212.53</td>
<td>244.49</td>
<td>-31.96</td>
<td>-13.1%</td>
</tr>
</tbody>
</table>

10.7 TSO Opex – External

10.7.1 Introduction

This section outlines the allowances by the CER for the TSO external (non-controllable) operational costs over the PR3 period.

Although these external costs will be allowed as pass through in PR3, as they are (in the most part) outside the control of the TSO, the CER will undertake an annual ex-post adjustment to take account of actual outturn costs. This ex-post adjustment will subsequently be reflected in the following year’s allowed revenue.

10.7.2 CER Levy (PR2: €4.89m, Allowed: €4.79m)

The CER allows €4.79 million for the regulatory levy for the period 2011 to 2015.

10.7.3 DUoS Costs (PR2: €2.05m, Allowed: €2m)

DUoS Costs, relate to the cost paid by the TSO to the DSO associated with the 110kV connected customers that are classified as distribution rather than transmission due to their location in the Dublin area.

SKM suggest that DUoS Costs are allowed as forecast by the TSO of €2 million over the PR3 period. The CER accepts this recommendation.
10.7.4 Interconnector Services (PR2: €0.63m, Allowed: €3m)

This line item accounts for costs associated with SO-SO trades on the Moyle Interconnector. These costs are to be shared between EirGrid and SONI, as TSOs, on a 75:25 basis. This is consistent with the previous SEMO revenue determination (SEM/08/093) and was made on the basis that the Moyle Interconnector currently provides an all-island benefit and that the costs be based on a MWh basis across the island.

This line item was included as part of the 2010 transmission revenue (CER/09/140) and the expected outturn figure is €0.63 million. SKM suggest that a cost of €0.6 million be allowed on an annual basis. The CER accepts this recommendation.

10.7.5 Inter-TSO Compensation (PR2: €1.13m, Allowed: €5.6m)

European Regulation 1228/2003\(^{99}\), which took effect from 1\(^{st}\) July 2004, requires that TSOs are compensated for hosting cross-jurisdictional flows of electricity from those TSOs where the flows arise and where they end. A voluntary European ITC scheme, of which Ireland is a member, has been introduced and the outturn net contribution for the scheme for EirGrid for 2010 is expected to be €1.13 million.

SKM suggest that the expected 2010 cost of €1.13 million be allowed on an annual basis. The CER accepts this recommendation.

10.7.6 Ancillary Services (PR2: €183.3m, Allowed: €244.2m)

During PR2 the largest item of TSO external expenditure was that of Ancillary Services\(^{100}\), as is the case for the PR3 period. Ancillary services costs are forecast to rise to €244.2 million, €60.9 million (33.2\%) higher than the PR2 outturn figure of €183.3 million.

The arrangements for Ancillary Services have been harmonised between ROI and Northern Ireland\(^{101}\). This RA initiative has been taken into account by the TSO in its forecast of PR3 Ancillary Services costs. The reasons advanced by EirGrid for the forecast increase in this line item are as follows:

---

\(^99\) Please see the following link:

\(^100\) The PR2 determination allowed for Constraints costs to be recovered through TUoS. Upon implementation of the SEM in November 2007 Constraints costs were recovered by the Imperfections Charge through the SEMO.

\(^101\) Please see the following link:
• Operating reserve is forecast to increase from €96 million in PR2 to €130.6 million in PR3 mainly due to the need to support the loss of the largest infeed. This increases from 403 MW to 445 MW in 2010 when the Whitegate power station in Cork is commissioned and to 500 MW in 2012 when the East-West Interconnector is expected to come into service.

• Further STAR interruptible load services are expected and costs will rise from €13.8 million in PR2 to €28.5 million in PR3.

• Reactive Power charges will remain reasonably constant, increasing from €57 million in PR2 to €58.4 million in PR3.

SKM suggest that a cost of €244.2 million be allowed over the PR3 period. The CER accepts this recommendation. However, as stated above, Ancillary Services costs will be allowed as pass through in PR3, the CER will undertake an annual ex-post adjustment to take account of actual outturn costs. This ex-post adjustment will subsequently be reflected in the following year’s allowed revenue.

10.7.7 Stage 1 Working Capital (Proposed €12.8m; Proposed: €15.2m, Allowed €15.24m)

A feature of the IA is that EirGrid must carry project costs until Project Agreement, at which point all costs incurred are transferred to the TAO, i.e. moving from Stage 1 into Stage 2. EirGrid have argued, due to their size and relatively small asset base, for the provision of working capital arrangements to cover the expenditure on Stage 1 costs until they can be transferred to the TAO. This matter is discussed further in section 10.9 below.

The CER is keen to ensure that the TSO works with the TAO to actively progress projects from Stage 1 to Stage 2 and project delays do not result from the provision of working capital. However, the CER understands the position of the TSO in relation to the funding of projects within Stage 1. Based on a revised WACC the CER now allows €15.24 million for this line item over the PR3 period. Please see table 39 below for the year by year breakdown of this cost. As with all external costs, the CER will review this working capital costs on an ex-post basis. This is discussed further in section 10.9 below.
Table 39: TSO External (Non-Controllable) Opex PR3 (€m’s 2009 prices) - Allowed

<table>
<thead>
<tr>
<th></th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>Total PR3 Allowed</th>
<th>TSO PR3 Forecast</th>
</tr>
</thead>
<tbody>
<tr>
<td>CER Levy</td>
<td>0.86</td>
<td>0.91</td>
<td>0.96</td>
<td>1.01</td>
<td>1.06</td>
<td>4.79</td>
<td>4.79</td>
</tr>
<tr>
<td>DUoS costs</td>
<td>0.40</td>
<td>0.40</td>
<td>0.40</td>
<td>0.40</td>
<td>0.40</td>
<td>2.00</td>
<td>2.00</td>
</tr>
<tr>
<td>Interconnector services</td>
<td>0.60</td>
<td>0.60</td>
<td>0.60</td>
<td>0.60</td>
<td>0.60</td>
<td>2.99</td>
<td>2.99</td>
</tr>
<tr>
<td>Inter-TSO Compensation</td>
<td>1.13</td>
<td>1.13</td>
<td>1.13</td>
<td>1.13</td>
<td>1.13</td>
<td>5.64</td>
<td>5.64</td>
</tr>
<tr>
<td>Ancillary Services</td>
<td>45.10</td>
<td>46.30</td>
<td>49.40</td>
<td>50.90</td>
<td>52.50</td>
<td>244.20</td>
<td>244.2</td>
</tr>
<tr>
<td>Stage 1 Working Capital</td>
<td>4.15</td>
<td>4.71</td>
<td>3.30</td>
<td>1.66</td>
<td>1.42</td>
<td>15.24</td>
<td>0.0</td>
</tr>
<tr>
<td>TSO External (Non-Controllable) Costs</td>
<td>52.23</td>
<td>54.05</td>
<td>55.78</td>
<td>55.69</td>
<td>57.11</td>
<td>274.86</td>
<td>259.62</td>
</tr>
</tbody>
</table>

10.8 East-West Interconnector Charge

This is a new cost item applicable in the PR3 period. The East West Interconnector (EWIC) charge is not a TSO related cost but recoverable under TUoS in accordance with the interconnector licence\(^{102}\). However, the EWIC charge will be treated in the exact same fashion as all the external TSO cost items listed above, i.e. this charge will be allowed as pass through in PR3. However the CER will undertake an annual ex-post adjustment to take account of actual outturn costs and revenues earned by the EWIC. This ex-post adjustment will subsequently be reflected in the following year’s allowed revenue.

With the 500MW EWIC expected to become operational in Q4 2012\(^{103}\), for the purposes of PR3 modelling the CER included the EWIC charge that is likely to be recovered through TUoS from the 2012/2013 tariff period onwards.

The CER based the forecast annual cost of circa €50 million on the estimated cost for the infrastructure and the financing arrangements. Therefore, with the commissioning of the EWIC expected in Q4 2012, a quarter of €50 million (€12.5 million) has been profiled for the calendar revenue year 2012 (please see Table 40 below). The total allowed charge for the EWIC to the TSO in the PR3 period is €162.5 million.

Prior to setting the 2012/2013 TUoS tariff the CER will have reviewed in detail the costs and projected revenues received from usage of the EWIC and will determine the ex-ante charge incurred. To repeat, this cost will be allowed as pass through in PR3. However the CER will undertake an annual ex-post adjustment to take account of actual outturn costs and revenues earned by the

\(^{102}\) Only EWIC costs which are not recovered through the EWIC operational regime will be recovered through TUoS. The full level of costs have been profiled for the purposes of transmission PR3.

\(^{103}\) Please see the following link: [http://www.cer.ie/en/electricity-transmission-network-interconnection.aspx?article=ebbb5e27-29b5-4fb8-82ea-694b22da972c](http://www.cer.ie/en/electricity-transmission-network-interconnection.aspx?article=ebbb5e27-29b5-4fb8-82ea-694b22da972c)
EWIC. This ex-post adjustment will subsequently be reflected in the following year’s allowed revenue.

Table 40: EWIC Charge (€m's 2009 prices) - allowed

<table>
<thead>
<tr>
<th></th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>Total PR3 Allowed</th>
</tr>
</thead>
<tbody>
<tr>
<td>EWIC Charge</td>
<td>0.00</td>
<td>12.50</td>
<td>50.00</td>
<td>50.00</td>
<td>50.00</td>
<td>162.50</td>
</tr>
</tbody>
</table>

10.9 TSO Working Capital Arrangements in PR3

In their PR3 submission to the CER the TSO has stressed that the cost of working capital was becoming a serious material issue, impacting on the day to day running of the TSO business. EirGrid has argued that vesting in July 2006 and with the implementation of the IA have fundamentally changed EirGrid’s working capital requirements. These changes relate both to the carrying costs of network development to Project Agreement (Stage 1 costs) and the underlying exposure to energy volume risk relative\(^\text{104}\) to EirGrid’s underlying equity base. EirGrid believe that the cumulative cost of working capital shortfall is of the order of €2 to €2.5 million per year.

For the first price control PR1, the CER introduced an allowance that granted the TSO the cost of capital on what was effectively a ‘notional’ working capital requirement, with adjustments to the actual level in the following year. While this arrangement was appropriate at the time, the TSO argued that it is now insufficient to meet requirements with the changing industry arrangements in 2006 and the vesting of EirGrid.

Current Provision

The current working capital for external cost variation is remunerated according to the following formula:

\[
WCP_{\text{ext}} = 0.2 \times (REXT_t + (0.75 \times FIMP_t)) \times WACC_t
\]

Where:

- \(WCP_{\text{ext}}\) is the Working Capital Provision in year \(t\), in €’s;
- \(REXT_t\) is the is the forecast external part of the TSO’s regulatory revenue in year \(t\), in €’s;
- \(FIMP_t\) is the forecast Imperfections Charge for tariff year \(t\), in €’s; and

\(^{104}\) The exposure to energy volume risk relates to the provision of the IA which essentially leaves EirGrid covering any shortfalls in energy throughput (and therefore loss of TUoS revenue), while keeping ESBN as TAO whole in the tariff period, as was the case in 2009 and could be in 2010.
$WACC_t$ is the allowed real opportunity cost of capital in year $t$.

The TSO state that the nominal cost of acquiring funds must be recognised directly in their underlying remuneration. For that reason a nominal WACC should be applied in the case of $WACC_t$ in the formula above, as opposed to a real rate.

The CER does not agree with this assertion. The return on the existing working capital allowance constitutes part of the TUoS tariff, and since the TUoS tariff is indexed to inflation this does provide the TSO with compensation for inflation. Further, in determining the working capital allowance at the next review the effects of inflation will be taken into account by the fact that the working capital is expressed as a percentage of TUoS revenue, and TUoS revenue will have grown in line with inflation due to indexation.

The CER will continue applying a real WACC to the existing TSO working capital arrangement and not a nominal WACC for the PR3 period.

**TSO Requested Provision**

The TSO has argued that it is not currently compensated for working capital required to manage ‘Income Variation’ and ‘Timing Variation’. As a result of the IA EirGrid takes all of the TUoS volume risk and in relation to the ‘timing variation’ is vulnerable to shortfalls (but also indeed the opposite) due to the TUoS billing cycle.

EirGrid have requested the equivalent to 0.5% of TUoS to remunerate it for potential timing and income variation, as per the following formula:

$$WCP_{TSO,REV_t} = 0.005 \times TUoS\ REV_t$$

**CER position**

Currently any over-recovery / under-recovery resulting from income variations will be returned to / recovered from consumers through adjustments to the TUoS tariff in subsequent tariff periods. When this adjustment is made interest is included based at the Euribor rate\textsuperscript{105}.

The interest rate adjustment already provides partial compensation for the cost of financing working capital required due to income variations. For instance, consider the case where the TSO under-reco vers. In this case, it would need to obtain working capital to cover the period until the under-recovery is recovered through a TUoS tariff adjustment. There will be a financing cost associated with obtaining this working capital and the TSO will need to be remunerated for this. However, this financing cost is already partially compensated through the interest

\textsuperscript{105} Please refer to section 5.1.7 of CER/05/143.
added to the under-recovered amount when the tariff adjustment is made. This partial compensation has been taken into account with the CERs provision below.

The CER is aware of the variances to which the TSO business is exposed to as a result of both energy volumetric risk and the timing of TUoS billing. It is a feature of the IA that the TSO takes all of the TUoS volume risk. It is acknowledged that the TSO was exposed to volumetric risk in the final two years of the PR2 period (as well as volumetric growth above estimations from 2006 to 2008).

When reviewing this proposal by the TSO the CER has taken the following into account. ESRI, in its most recent medium term publication, *Recovery Scenarios for Ireland*\(^\text{106}\)*, is predicting that if the world economy recovers significant momentum by 2011, which is widely anticipated, then the Irish economy can be expected to grow quite rapidly in the 2011-2015 period, averaging over 5% per year to 2015. The TSO in its PR3 submission to the CER is predicting steady energy demand growth in the second half of the PR3 period, with an average annual growth rate of 2.3% over the period. For the purposes of PR3 tariff profiling the CER is profiling a growth rate of 2.0% in 2011, with an average annual growth rate of 2.5% over the period.

With regards to energy forecasts, it is extremely difficult in the current economic climate with significant uncertainty around the timing of the return to economic growth and by extension growth in electricity consumption. Also models that were used to predict consumption growth in the previous decade may no longer be applicable. However it is too early to tell this.

Volumetric adjustments will only affect the TSO where actual energy demand in any one year is less than that forecast by the CER at this point for the PR3 period. Taking the estimate of 2.5% for the average annual PR3 growth rate with the ESRI prediction of Irish economic growth over the PR3 period, volumetric risk may not be a serious an issue as portrayed by the TSO in its PR3 submission.

In principle, timing differentials between when costs are incurred and when payment is received give rise to requirements for working capital. The TSO does not have to pay the TAO element of TUoS revenues to the TAO until it receives this revenue from the TUoS customer. Hence, there is no timing differential in relation to the TAO element of TUoS.

In relation to the TSO element of TUoS revenues, there is a lag of up to 35 working days between when EirGrid delivers services to consumers and when EirGrid receives payment for these services, with the TSO element accounting for approximately 40% of TUoS revenues. In the absence of any other factors, this would imply a significant requirement for working capital.

\(^{106}\) Please see the following link: [http://www.esri.ie/publications/latest_publications/view/index.xml?id=2774](http://www.esri.ie/publications/latest_publications/view/index.xml?id=2774)
Indeed, *in the absence of other factors*, the appropriate compensation would be given approximately by the amount of revenue which is subject to the timing differential (40% of TUoS) multiplied by the time difference as a proportion of a year (= 45 working days / 250 working days) multiplied by the WACC.

Clearly, the amount of additional working capital implied by the above is an order of magnitude higher than the amount which the TSO is requesting, demonstrating that there are other offsetting factors which significantly reduce working capital requirements compared with the amount implied by the above calculation. These factors are likely to include:

- The working capital benefits which the TSO receives due to the time delay in paying its own creditors. For instance, if the TSO also has a period of 35 working days in which to pay its creditors, then for cost items procured from third parties the timing differential between payment of costs and receipt of revenues would disappear;
- The working capital benefits the TSO receives due to the seasonal profile of tariff revenues; and
- The fact that some customers may make payment in advance of the deadline of 35 working days.

The TSO has not provided sufficient information on these factors to allow its actual working capital requirements due to timing differentials to be assessed.

With regard to potential default risk of TUoS payments, the CER understands that the TSO has robust and up-to-date systems in place to monitor invoicing and receipt of TUoS payments and instances of default or even late payments are minimal.

The CER notes that in asking for a 0.5% allowance of TUoS revenues the TSO appears not to have taken into account the fact that the financing cost of working capital for income variations is already partly compensated through the interest added when TUoS tariffs are adjusted. However, the CER does acknowledge that the risk associated with volumetric adjustments does still exist and that the risk associated with income variation will increase in PR3, as the scale of TUoS increases, relative to the TSO’s underlying operating margin. We also acknowledge that SKM in their accompanying report believe that 0.5% of total TUoS revenue would be a reasonable basis for an additional provision of working capital.

The CER therefore deems that in addition to the current working capital provision, the TSO be allowed an additional financial provision (taking account of the factors outlined above). However, in acknowledging that partial compensation of income variation is accounted for through application of the Euribor rate, the
decision for EirGrid is to be remunerated to 0.25% of TUoS (as opposed to the requested 0.5% of TUoS), as per the following formula:

\[ WCP_{t} = 0.0025 \times TUoS \times REV_t \]

Where REV\(_t\) is the allowed transmission revenue in year \( t \).

**Treatment of Pre Project Agreement Costs**

As outlined in section 2.5 EirGrid is responsible for planning and design work up to approval from authorities at which point responsibility is passed to ESB Networks as TAO. A feature of these arrangements is that the TSO must carry costs until Project Agreement, at which point all costs incurred are transferred to the TAO, i.e. moving from Stage 1 into Stage 2. The TSO may have to carry costs on many projects for three years or more before transferring them to the TAO.

This process is managed through the IA between EirGrid and ESB Networks. However, EirGrid have argued that when this agreement was put into place, the length of time to Project Agreement and size of capex programmes – and by extension the funding requirements for EirGrid – were not anticipated.

The treatment of these Pre Project-Agreement costs is somewhat anomalous compared to the more general regulatory treatment for the capitalisation of network assets. All network assets constructed by the TAO, and indeed costs associated with the same Stage 1 activities incurred by DSO, are all capitalised onto the Distribution RAB in the year in which the expenditure is incurred and regulatory return (and depreciation) applied from that time.

Therefore, the current treatment of the TSO Capex on network assets is unique in the regulatory model in that they must currently be carried and Interest During Construction added over that carrying period, which must ultimately be remunerated by the TUoS customer through a further rate of return. Furthermore, as the TSO argues, given the scale of activity relative to the TSO RAB, this weakens EirGrid’s underlying financial ratios and its ability to source funds consistent with the assumed opportunity cost of capital.

**TSO Requested Provision**

In their PR3 submission to the CER, EirGrid proposed three alternatives to deal with the issue associated with Stage 1 costs:

- **‘formalise as normal asset in RAB’**

Costs are included in the RAB, earning the WACC until disposed of at Project Agreement. The existing approach is crystallised, but funding costs are brought
upfront as per the treatment in other asset based businesses. As the WACC is expressed in real terms EirGrid would have to inflate the costs incurred for the time value of money (actual inflation) over the period and book the difference between the real value (at time of disposal) and actual costs incurred to its profit and loss account.

- ‘formalise in side RAB’

Costs are included in a ‘side RAB,’ earning the WACC until disposed of at project Agreement. The WACC, however, would be on a nominal basis, consistent with the working capital arrangements described above and recognising the nominal opportunity of acquiring funds.

- ‘expense’

Provision could be made to expense the full Stage 1 cost as it is incurred as Opex. This removes pre-project agreement costs from Capex and provides an improved cash profile to the TSO but would also have a direct but significant upfront tariff impact.

**CER position**

The CER is aware then when the TSO invoices Stage 1 costs to the TAO it applies indexation to take account of inflation in the time that has elapsed since costs were incurred. This mechanism fully compensates EirGrid for inflation effects. Furthermore, we note that the WACC is also applied at the point in time when costs are invoiced to the TAO, thus providing EirGrid with a return on the capital it has invested.

With respect to options one and three above, the CER currently believes that they may be overly complex, and burdensome on TUoS (in the case of option three). Therefore, the CER is focusing on the second option, the creation of a ‘side’ RAB.

In principle, the use of a side RAB with a return provided each year would provide an alternative mechanism for providing the TSO with a return on its capital. As stated by the TSO, this would change the timing of cashflows and could help to address any financeability problems that might otherwise arise. The TSO will no longer be allowed to apply the WACC when it invoices the TAO. Doing so would mean that the TSO would be provided with a return twice over.

The implications of a side RAB for the treatment of inflation also need to be considered. Within a standard price control employing a RAB and a real WACC, the regulated company is compensated for the effects of inflation in two ways:

- Price limits are indexed to inflation within each regulatory period;
• The regulatory asset base is indexed to inflation, such that the opening regulatory asset base at the next price review will take account of inflation during the price control period.

If the CER were to adopt a nominal WACC for the side RAB, then the company would be fully compensated for expected inflation within the WACC. For consistency, therefore, the price control would need to be changed to remove the inflation adjustments identified above, application of Euribor. In particular:

• Indexation would need to be removed from that element of the tariff which comprises the return on the side RAB;

• The side RAB should not be indexed for inflation. Further, the rules would need to be changed such that, when the RAB is invoiced to the TAO, no adjustment is made to the amount originally spent for inflation.

Hence, either a real or a nominal WACC could in theory be used. An advantage of using a nominal WACC for the side RAB is that it would help to address any financeability problems resulting the mismatch between receive a real return within a price control and paying interest on nominal debt. A disadvantage of using a nominal WACC is that tariffs would become more complex, since part of the tariff (i.e. the return on the side RAB) would not be indexed to inflation while the rest of the tariff would continue to be indexed to the inflation rate.

For PR3 the CER will create a Stage 1 ‘side’ RAB to take account of pre Project-Agreement working capital costs, with a real WACC applied to the side RAB. Although a real or nominal WACC could be employed, the CER believes that using a nominal WACC would be quite complex, for the reasons outlined above. With a real WACC applied to the side RAB the TSO will still be compensated for the effects of inflation in two ways, i.e. price limits are indexed to inflation within each regulatory period and the RAB is indexed to inflation over the course of a price control.

The effective roll-out of Gate 3 requires that projects move from Stage 1 into Stage 2 (construction and energisation etc) as quickly as possible. The CER wishes to avoid a situation where the TSO, in the knowledge that it has been provided with a working capital arrangement, is given a perverse incentive to slowly move through Stage 1 or even hold on to Stage 1 costs107.

Therefore the CER will treat the provision of Stage 1 working capital costs as an external TSO cost, which will be subject to an annual ex-post review throughout the PR3 period (see table 39). Actual Stage 1 spend in every year of the PR3 period will be reviewed against that provisionally assumed in this paper. Any over

107 Taking into account TSO non-controllable factors such as delays associated with receipt of planning permission etc.
or under-requirements of Stage 1 working capital will be reflected in the following years’ allowed revenue.

To repeat, the TSO will no longer be allowed to apply the WACC when it invoices the TAO for Stage 1 costs as doing so would mean that the TSO would be provided with a return twice over.

The CER will also request on an annual basis a report from the TSO on what projects have successfully moved from Stage 1 into Stage 2 as per projections and those that have not, although were expected to do so. Explanations and justifications behind requirements for annual Stage 1 working capital levels above what has been provisionally provided by the CER in table 41 will also be detailed in this report. It is expected that this report will be part of the updated Capex Monitoring report, as outlined in section 8.5.

The annual Stage 1 working capital provision will be calculated as per the following formulas:

\[
\text{Stage 1CAV}_t = \text{OAV}_t + \text{SIS}_t - \text{INVTAO}_t
\]

\[
\text{WCT}_{st} = \text{Stage 1CAV}_t \times \text{WACC}_t
\]

Where:

OAV\(_t\) is the opening asset value of the Stage 1 side RAB in year \(t\).

SIS\(_t\) is the Stage 1 spend in year \(t\).

INVTAO\(_t\) is the Stage 1 costs invoiced in year \(t\) (i.e. upon projects moving from Stage 1 into Stage 2).

WACC\(_t\) is the allowed real opportunity cost of capital in year \(t\).
Table 41: Stage 1 RAB and Working Capital provision (€m’s 2009 prices)\textsuperscript{108}

<table>
<thead>
<tr>
<th></th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>CER allowed (based on</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Stretched NN)</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Stage 1 OAV</td>
<td>61.8</td>
<td>69.7</td>
<td>79.2</td>
<td>55.4</td>
<td>27.9</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Stage 1 Spend</td>
<td>18.0</td>
<td>21.6</td>
<td>22.2</td>
<td>22.5</td>
<td>26.1</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Invoked to TAO</td>
<td>10.1</td>
<td>12.1</td>
<td>45.9</td>
<td>50.1</td>
<td>30.1</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Stage 1 CAV</td>
<td>61.8</td>
<td>69.7</td>
<td>79.2</td>
<td>55.4</td>
<td>27.9</td>
<td>23.9</td>
<td>15.24</td>
</tr>
<tr>
<td>Stage 1 Working Capital</td>
<td>4.1</td>
<td>4.7</td>
<td>3.3</td>
<td>1.7</td>
<td>1.4</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

10.10 Conclusion

**TAO**

The above section covered the allowed TAO Opex over the PR3 2011 to 2015 period at a high level. Parties that are interested in more detail should also read the consultant’s report on these allowances which has been published alongside the consultation paper CER/10/102. The figures requested by the TAO are outlined in more detail within an overview of its submission, which has been published alongside this document.

The CER allows the TAO Opex of €232 million over the PR3 period. This is €36 million lower than the €268 million requested by the TAO for this period.

In addition, following the publication of the CER’s proposals on this matter the CER is requiring that the TAO deliver additional efficiency savings in operating and capital expenditure, the benefits of which will be given to customers within the 2011 to 2015 period. This reduction has been included in Table 2 in the Executive Summary and the TAO revenue table in section 13, but has not been broken down by line item within this paper; rather it is a reduction in overall revenue for Opex and Capex. The CER believes that given the current economic conditions that there are additional efficiencies to be realised by the TAO. The CER has not specified how these efficiency savings are to be delivered across the various line items. Rather the TAO is to determine how these reductions will be achieved across Opex and Capex.

**TSO**

The above section also covered the allowed TSO Opex over the PR3 2011 to 2015 period at a high level. Parties that are interested in more detail should also

\textsuperscript{108} The figures included in this table are based on the ‘Stretched Network Needs’ scenario of €1.45 billion capex spend over the PR3 period.
read the consultant’s report on these allowances which has been published alongside the consultation paper CER/10/102. The figures requested by the TSO are outlined in more detail within an overview of its submission, which has been published alongside the consultation document.

The CER allows the TSO Opex of approximately €487.39 million over the PR3 period. Even taking into account the additional TSO working capital arrangement this is €16.72 million lower than the €504.11 million requested by the TSO for the PR3 period.
11.0 Benchmarking

11.1 Introduction

When reviewing the TAO’s and TSO’s costs for the PR2 and PR3 periods, the CER’s consultants examined each cost item and made specific recommendations on those items. In addition to this, the TAO’s and TSO’s costs were benchmarked against international comparators. This section provides a summary of the main points from that benchmarking. Further information is available within the SKM reports, which have been published alongside this consultation paper.

Top down benchmarking covers ESB Networks DSO costs and TAO 110 kV costs against Great Britain’s Distribution Network Operators (DNOs) costs, excluding Scottish DNOs, which are not responsible for 132 kV assets.

Bottom up benchmarking of tree cutting costs on a per km basis has also been completed and some of the apparent differences in performance explained.

Some general points on the TAO’s and TSO’s performance are also provided.

DSO and 110 kV TAO opex and non network capex

Benchmarking of ESB Networks DSO and 110 kV TAO opex and non-network capex for indicates that the TAO costs are 7.5% above the Upper Quartile of the GB DNO costs and 16 % above the efficiency frontier. This is consistent with SKMs recommendations for allowed PR3 costs.

Tree cutting

SKM also benchmarked tree cutting costs and the TAO’s costs of €107 per km are lower than the GB DNO costs of €251 per km. This may be partly due to the relative tree cover and the temporary increase in tree cutting in GB due to new safety regulations.

Transmission Activities

The combined TSO and TAO activities in Ireland is comparable to the TSO Transpower in New Zealand who both own and operate down to the 110 kV level and serve a population of 4.4 million. Neither TSO is involved in market operations. Operating costs are similar but not necessarily comparable due to different capitalisation polices and overheads. For example, 30% of the TAO costs are for local authority rates.
Transpower has 520 staff which is similar to current TSO and TAO staff in Ireland of 495. However due to the large capital programme the combined TSO/TAO staff is forecast to peak at 685 in 2013 before dropping back to 554 in 2015.

However, these companies are likely to have different outsourcing policies which impacts staff levels. For example, the TAO depends heavily on ESBI and in 2009 charged €25.9 million to the TAO, which was made up of €7.1 million in operating costs and €18.8 million in capital projects. This amounts to the equivalent of around 300 staff.

11.2 Conclusion

The CER considers that the benchmarking work completed by SKM, provides a useful gauge to measure the TAO’s and TSO’s performance against international best practice and is a useful complementary measure to the detailed analysis of PR3 costs. It is accepted that it is difficult to find useful comparator companies and even more difficult to obtain useful information from such companies.

SKM’s comments within its report on the difficulties associated with ensuring that similar costs are compared and the challenges related to effectively benchmarking as efficiency gaps narrow are noted.

While these difficulties do arise, this work still provides a useful sanity check to ensure that the recommendations put forward by SKM and the values allowed by the CER within this paper are sensible, consistent with international best practice and will require the TAO and TSO to further narrow the gap between them and international comparators.
12.0 Tariff rebalancing

12.1 Introduction

The CER allows TUoS revenues based on the calendar year 1st January to 31st December. As per AIP/SEM/07/93, annual TUoS Demand tariffs were set on a 1st October to 30th September period. A demand weighted approach is currently adopted by the CER to take account of these two different calculation periods.

The TSO collects revenue to cover its costs through Transmission Use of System (TUoS) charges to electricity suppliers. Suppliers are charged for each of the end-users to whom they supply electricity. TUoS tariffs are designed to recover the total costs associated with the transmission utilities, i.e. the TSO and TAO. There are demand tariff schedules provided by the TSO:

- Tariff Schedule DTS-T: applies to suppliers serving customers connected directly to the transmission system.
- Tariff Schedule DTS-D1: applies to suppliers serving customers connected to the distribution system and having a Maximum Import Capacity of 0.5MW or above (before adjusting for the appropriate distribution loss factor).
- Tariff Schedule DTS-D2: applies to suppliers serving all other customers connected to the distribution system who are not served under the other tariff schedules noted above.

In a similar manner, the Distribution System Operator (DSO) recovers its costs through Distribution Use of System (DUoS) charges.

The following section covers the effects this will have on TUoS.

12.2 Details regarding tariff rebalancing

On 15th July 2009 the Minister for Communications, Energy and Natural Resources wrote to the CER to convey a Government decision that savings of some €50 million should be passed on to large energy users (LEUs), funded by a rebalancing of domestic network tariffs. While it was up to the CER to determine the detail of how this should be implemented in terms of network tariff structures,
the amount (€50 million) and timeframe (it is to apply from 1st October 2010) were determined by the Government.

In this context the CER worked with the TSO and DSO to determine a workable solution to allow the above to be implemented by 1st October 2010. The decision from the DCENR included the following main points regarding implementation of the Government’s decision:

- Networks tariffs were to be rebalanced in favour of large energy users (LEUs) from 1st October 2010;
- The savings for large energy users were to be funded by a rebalancing of domestic network tariffs;
- The amount of the savings was to be €50 million per annum; and
- It was for the CER to determine the details of how this would be implemented in terms of tariff structures.

The decision for implementation of the Government’s decision are provided below. The CER has worked closely with the TSO and DSO when arriving at this decision:

- Network tariffs are made up of TUoS and DUoS. The most clear-cut method of implementing the above would involve transfers of revenue between different TUoS categories and different DUoS categories, with no transfers between TUoS and DUoS. However, the TUoS billing system is not currently designed to bill domestic customers separately; therefore an interim process is required. This means that domestic customers will be billed the full amount (of the rebalancing, €50 million) through DUoS tariffs (as opposed of through DUoS and TUoS). There is no net difference to domestic customers arising from the use of this approach. This approach would be used (that is, the DSO to collect the revenue in lieu of domestic TUoS) until the TSO’s systems are changed, a process which involves:
  - Changes to messaging regime would be carried out in conjunction with Global Aggregation working group.
  - Changes would be made to the TSO’s systems to accept new market messages regarding domestic TUoS tariffs.
- The TSO and the CER will advise DSO each year of the revenue to be collected in lieu of domestic TUoS until the long term solution is implemented.
- For LEUs the decrease will be implemented on the network charges only.
• Importantly TUoS and DUoS rates for LEUs will reduce by the same percentage.

The implementation of the above results in a **45% decrease** on the transmission network charges applied to LEUs.

The above has been implemented within the Demand TUoS tariffs for the 1st October 2010 to 30th September 2011 period, which have been published in of this paper\(^{112}\).

**12.3 Conclusion**

The tariffs for the 1st October 2010 to 30 September 2011 period which have been published in this paper and the PR3 Distribution consultation paper (CER/10/103) include two underlying changes\(^{113}\) relative to the previous tariff period. These allow for:

• A rebalancing of network (TUoS and DUoS) tariffs to change the relative amounts of total revenue which will be recovered from domestic customers and LEUs.

• A smoothing of the DUoS standing charge to domestic customers to ensure that they pay the same standing charge regardless of whether they have a standard or a day/night meter.

\(^{112}\) It is also recommended that interested parties review the published tariffs in the Distribution PR3 proposed decision paper CER/10/103.

\(^{113}\) This excludes the normal change to total revenue to be recovered through all TUoS tariffs.
13.0 Form of the Control

This section describes the overall form of the price control, specifying the approach taken by the CER and the incentives that it intends to create and how the base and subsequent year revenues have been determined.

During the PR3 period it is intended that, consistent with the previous controls, yearly updates would be completed as detailed below. During the previous controls the CER consulted on these yearly updates. For the forthcoming control the CER will, rather than holding a formal consultation, publish an information note outlining the effect of implementing the yearly updates detailed below.

13.1 Structure of the Price Control

The CER believes that the price control for both the TSO and TAO businesses should be set consistent with previous price controls. Applying different principles or models for each price control would risk creating an inconsistent set of incentives and uncertainty. Therefore, the CER has taken into account some new issues, but has substantially retained the model used in PR2.

The PR3 model will contain:

- Incentive regulation based broadly on the CPI-X model.

- A rolling retention of benefits achieved through costs lower than target levels. As in the current price control, the TSO and TAO will be able to retain these benefits for five years so that they remain neutral as to when in the regulatory cycle those efficiencies are gained. It is up to both the TSO and TAO to prove the creation of additional benefits and request their inclusion in the rolling retention. Where the CER deems that benefits gained have been as a result of forecasting error rather than efficiency gains, these benefits will be clawed back.

- Incentives linked to system performance and network development.

- Uncertain costs, such as those relating to changes in legislation or other aspects of regulation, will be reviewed on a case by case basis by the CER.

- Pass-through such as TSO Ancillary Services costs and TAO Local Authority Rates should be kept to a minimum. Incentives to minimise pass-through will be applied where practical.
• Incentive mechanisms to improve quality of service, continuity in supply and transmission network performance and connection of renewable generator.

• The inter-year adjustments broadly as in PR2 will be applied to the TAO and TSO.

The CER’s position on each of the above is set out below in turn.

13.1.1 CPI-X

Since publication of CER/09/047 in April 2009 the CER has further examined the application of a strict CPI-X approach to the TSO and TAO and has decided to discontinue it for the PR3 period.

In the PR2 transmission decision CPI-X, was used as the basis for the price control. A core issue in setting the trajectory of prices was the relative values of X and the starting price level in 2006. In CER/05/143 the CER noted that in the calculation of the allowed Opex and Capex, efficiency improvements had already been incorporated. Therefore, the purpose of the X factor was not to set the level of efficiency improvements but rather to profile them over time, in conjunction with the base year revenue\textsuperscript{114}.

The Commission has decided to continue the application of an incentive based approach. Efficiencies are built into the Opex and Capex allowances and the resulting revenue is profiled over the period.

13.1.2 Benefit retention

The CER will continue the use of a five-year rolling retention mechanism since this will deliver the most even distribution of efficiency savings across the duration of the price control. For Opex, both the TSO and TAO will be permitted to retain the annual savings made for a period of five years, provided such savings have not been made at the expense of performance and quality of service or as a result of poor forecasting. Therefore, the CER has included a set of additional incentives to be applied in respect of these elements, which are described below.

However, as per a number of PR2 annual transmission determinations\textsuperscript{115} and discussed above in section 10.5 it is the CER’s intention to continue to review certain pass through Opex costs (Ancillary Services, Local Authority Rates etc) on an annual basis.

\textsuperscript{114} The mechanism is such that if X were set equal to zero, the Base year revenue would be set at a lower level than had X been set at a positive value. An X of zero would thus encourage the regulated business to become more efficient earlier in the price control period.

\textsuperscript{115} Please see section 3 of the 2010 transmission revenue determination paper CER/09/140.
In assessing the benefit to be retained on Capex, the CER will pay attention to the cost, volume and quality of the investment made. For example, no benefit will be retained if the transmission utilities were to make savings through reducing the volume of their respective investments, as this is independent of the benefits defined in their capex plans.

The efficiency savings will be reviewed as part of the next price control and as in this review inefficient expenditure will not be allowed into the RAB. Revenue earned on Capex not spent will be clawed back, except where the TSO and TAO can show that the avoided spend is due to efficiencies on their own part.

13.1.3 Cost Drivers

Cost drivers are a common feature of price controls. The objective of their use is to model the impact of factors outside the business’s control on its costs.

In the PR2 transmission determination\textsuperscript{116} the CER considered the use of a number of cost drivers, specifically network length and the volume of energy transmitted, for the TAO and TSO. One TSO cost driver considered by the CER for the PR3 period was customer support services associated with the significant amount of generation connections anticipated. However, the CER considers that the application of such a driver would be complex at this point in time and could be dealt with through an appropriate incentive mechanism (see section 6.3 of this paper). Therefore, PR3 will not contain any transmission related cost drivers.

13.1.4 Uncertain costs

Uncertain costs are defined as those that could not reasonably be foreseen by the transmission utilities and comprise elements such as:

- SEM related costs and others related to the bedding down of the market, most likely to impact on the TSO;
- Changes in legislation or regulation that impose a cost on the company, such as environmental restrictions; and
- restructuring costs driven by changes in legislation.

The CER has decided that such costs should be dealt with on a case-by-case basis. In each case, the TSO or TAO would be expected to ensure that changes in Opex or new Capex would take place in an efficient manner and this would be reflected in the allowance provided – there would not be an automatic pass-through of such costs.

\textsuperscript{116} Please see section 5.1.3 of CER/05/143.
13.1.5 Pass-Through Items

The previous price control contained a provision for the pass-through of certain types of costs, such as Ancillary Services and Local Authority Rates, which are deemed to lie outside the transmission utilities control. The CER will continue to use this approach.

However, as with “uncertain costs”, the CER believes that the TSO and TAO should provide evidence that they have attempted to minimise pass-through item costs through negotiation wherever possible. The transmission utilities, therefore, will be required to provide a detailed justification of this expenditure and to have demonstrated that it has taken reasonable steps to minimise their impact as part of the annual review process.

13.1.6 Additional incentive mechanisms

The TSO’s current price formula contains three key incentives:

- Revenue caps below which the savings may be retained for a period of 5 years;
- To improve the transmission system performance through system minutes lost, system frequency and fault clearance rates being kept within/below a target level; and
- It is also incentivised with regard to the lodgement of planning permission for shallow connections assets for both generators and demand and the roll-out of transmission related Gate 3 offers.

For the latter two items, the PR2 contained target levels for each year and a monetary rate to be applied to the differential between actual and target values. This adjustment was made year on year and provided a continuous incentive to improve performance.

The CER will continue to use this general approach and to broaden the range of factors to be taken into account. Specifically, the CER has decided that the following will be included:

- Incentive mechanism to improve overall transmission system availability; and
- Incentive mechanism for delivery of network capacity/build.

Proposed transmission incentives for the next incentive period will be consulted on with stakeholders in a separate CER paper in the coming weeks.
13.1.7 Inter-year Adjustments for Over- or Under-Recovery

Currently, the mechanisms for inter-year adjustments for the TAO and the TSO operate as follows:

For the TAO and TSO, there will be an annual correction factor that equilibrates actual and forecast revenues for the tariff year. The correction factor will take into account:

- Pass-through items;
- Uncertain cost items, where these relate to costs in the previous year; and
- Other over or under recovery.

Interest at the three-month average Euribor rate would be added to this over/under recovery amount.

The CER will retain this mechanism for the PR3 period.

13.2 Base year revenue and profiling

Subsequent sections of this document set out how the various components of the TSO’s and TAO’s regulatory revenue have been determined and how expected efficiency improvements have been used to determine the future path of regulatory revenue. In this section, the principles that have been applied to that calculation are set out.

In general terms, the CER has sought to strike a balance between:

- Allowing the TSO and TAO to make the investments required to develop the Irish transmission system and associated infrastructure (e.g. IT);
- Ensuring that the TSO and TAO provide Irish consumers with value for money;
- Incentivising efficiency gains on a continuous basis throughout the price control period;
- Providing the businesses with sufficient revenue to operate the transmission system, develop it and provide a reasonable return on their respective assets; and
- Ensuring that the TSO and TAO has sufficient cashflow to finance their operations;
In this section we present the CER’s allowed regulated revenues and price control separately for the TSO and TAO during the PR3 period 2011 to 2015.

13.2.1 Key principles

Ensuring that the TSO and TAO have sufficient revenues throughout the period to maintain effective operations is core to the price control. Specifically, the transmission utilities should be able to finance their planned investment, operating costs, financing costs and taxation liabilities. The CER has therefore developed a cash-flow model each for the TSO and TAO designed to ensure the compatibility of the price control with these objectives. This model is published with the decision paper.

However, as noted in section 2.4 the CER also has the objective of improving the transmission utilities efficiency over time so that it more closely matches the performance of a business at the efficiency frontier. Therefore, the CER still proposes to include a set of incentives linked to key performance indicators within the price control formula to encourage specific desirable behaviours. The penalties associated with these incentives will be capped at a level that does not endanger the TSO’s and TAO secure continued operation.

13.2.2 Indexation

As mentioned above the CER has used and will continue to use incentive regulation to determine the TSO’s and TAO’s allowed revenue. The incentive model uses a base allowable revenue which is indexed to take account of price inflation. The index used should be the best reflection of the increases in prices faced by the transmission utilities, such as wage inflation or materials inflation etc. Also the index needs to be practical to implement, robust and transparent.

In PR1 (2001 to 2005) the CER used the Consumer Price Index (CPI) as the index to inflate revenue. In the first review of allowable revenues for BGE Networks as gas transmission and distribution network operator the CER used CPI and in the second review we used HICP.

In PR2 (2006 to 2010) the CER indicated in the transmission revenue determination that Harmonised Index of Consumer Prices (HICP) would be used however, during the PR2 period we used CPI. The change from using CPI was not explicitly raised in the consultation or determination paper. Also the revenue formula referred to CPI as the index, while the definitions of CPI in the paper referred HICP. Therefore, the CER decided to continue to use CPI as the index for PR2.
However, as part of the PR3 review the CER has decided to re-examine this issue. The following items, which constituting approximately 9.5% of the CPI expenditure weighting, are excluded from the HICP:

- mortgage interest;
- building materials;
- concrete blocks;
- union subscriptions;
- motor car insurance (non-service);
- dwelling insurance (non-service);
- motor car tax; and
- motor cycle tax.

The inclusion of mortgage interest in CPI means that the index is affected by changes in the ECB interest rate. Table 42 describes the movement of the CPI and HICP. The indices generally follow the same path. However significant divergence occurs when there are large changes in the ECB interest rate. Recent changes to the ECB interest rate have introduced significant volatility into the CPI.

It is questionable whether the pressures on the TSO’s and TAO’s costs have followed the rollercoaster ride that the CPI has experienced. As per the table above, from highs of +5% in March 2008 to lows of -6.5% in September 2009 for
CPI; the corresponding HICP was +3.7% in March 2009 and -3% in September 2009. This volatility has significant impacts on the charges paid by the final customer and on the revenue that the transmission utilities have to cover their costs.

Another issue is whether a consumer focused index is relevant for the transmission utilities. The majority of their costs relate to wages, materials and contractor costs. Furthermore, it has been argued by the TSO in its PR3 submission that the forces affecting CPI are not necessarily representative of the cost drivers for its business, with the TSO being a largely labour-based organisation and the presumption that wage inflation in general tends to outpace CPI.

In Great Britain, Ofgem has concluded in its recent price determination (DPCR5117) that 1.4% should be added to the Retail Price Index to reflect expected higher that inflation cost increases for the distribution businesses. Graph 2 below shows the price of copper on the London Metal Exchange as it changes from 2003 to 2010. Copper is an important material used in transformers and cables. As highlighted earlier the CER does accept that input costs can increase more the inflation index used.

Table 43: Price of Copper – London Metal Exchange

![Graph of Copper Price on LME](Image)

Source: LME

However, indexation is not the only way in which the regulatory model takes into account the changes in input prices. Some operational costs are treated as pass-through costs, such as business rates. The TSO and TAO can separately apply for a re-opener to the transmission determination. This occurred in PR2 distribution where the DSO requested the CER to re-examine the allowed costs

117 Please see the following link
http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/DPCR5/Pages/DPCR5.aspx
of connections in light of emerging price increases significantly greater than inflation. It should also be noted that in reviewing the outturn Capex, the CER’s advisors take into account outturn efficient increases in input prices when reviewing the outturn costs of the capital programme.

The majority of the TAO’s (and to a certain extent TSO’s) revenues as determined by the CER come under the headings of depreciation and return on capital. The calculation of both uses the inflation index from real to nominal terms. This application of inflation reflects the changing value of money and can be argued that a consumer index reflects this best.

The CER believes that using a consumer focused inflation index is appropriate and that the HICP is a better index to use as it is likely to be less volatile. Stable transmission revenues will be a benefit for both the final customer and the transmission utilities.

Therefore, the CER will use the Irish Harmonised Index of Consumer Prices (HICP) as the inflation index for PR3 period.

13.3 Allowed Revenue

Tables 44 and 45 set out the allowed revenue calculation for the TSO and TAO respectively and is structured as follows:

- The calculation commences with the opening TSO RAB and TAO RAB, as defined in section 4.0.
- Allowed Capex is then added and depreciation subtracted from the respective RABs for each successive year of the price control period.
- Allowed Opex are added, together with any deferred (clawback) revenue from previous years, i.e. through the operation of a ‘K’ factor. Please refer to section 9.8 for respective TSO and TAO clawback amounts.
- The next stage of the calculation is to determine the NPV of the total cash required by the TSO and TAO separately, using the WACC as the basis for discounting.
- Finally, the NPV of the change in the TSO RAB and TAO RAB over the price control period (i.e. the opening value less the discounted value of the closing RAB, with the discount rate set at the cost of capital derived in Section 6) is added to the total cash required to determine the net present value of the cash required by the TSO and TAO to finance the increase in the RAB over the regulatory period.

A core issue in setting the trajectory of prices would be the relative values of X and the starting price level in 2011. By changing the value of X, the price control
formula would profile the distribution of revenues over time, while maintaining the same NPV of revenue for the TSO and TAO. It should be noted that X in these circumstances is not an efficiency factor. The Commission has set efficient Opex and Capex allowances for each year of the period. The X factor is used to smooth out the allowed revenue over the period so consumers are not faced with volatile tariffs and also to ensure that the TSO and TAO has sufficient cash to meet their requirements over the price control period.

Table 44 below shows the values calculated by the CER for each of the above for the TSO. Table 45 shows the values calculated by the CER for each of the above for the TAO. Interested parties should refer to the published PR3 transmission model for further information on PR3 assumptions made (e.g. energy throughput).
Table 44: TSO Allowed revenues PR3 (€m’s 2009 prices)

<table>
<thead>
<tr>
<th></th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Opex &amp; EWIC Charge</td>
<td>93,927,967</td>
<td>108,710,612</td>
<td>148,388,241</td>
<td>148,527,648</td>
<td>150,331,346</td>
<td>649,885,814</td>
</tr>
<tr>
<td>Capex</td>
<td>7,130,000</td>
<td>4,396,000</td>
<td>3,896,000</td>
<td>4,416,000</td>
<td>3,284,000</td>
<td>23,122,000</td>
</tr>
<tr>
<td>Clawbacks/Deferrals</td>
<td>-8,478,000</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>-8,478,000</td>
</tr>
<tr>
<td>Incentives</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Working Capital</td>
<td>2,208,356</td>
<td>2,275,193</td>
<td>2,423,578</td>
<td>2,522,867</td>
<td>2,632,608</td>
<td>12,062,602</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>578,999,296</td>
</tr>
<tr>
<td>NPV of Costs</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>OAV</td>
<td>36,488,298</td>
<td>36,347,142</td>
<td>33,193,091</td>
<td>30,301,319</td>
<td>28,833,259</td>
<td>23,122,000</td>
</tr>
<tr>
<td>Capex</td>
<td>7,130,000</td>
<td>4,396,000</td>
<td>3,896,000</td>
<td>4,416,000</td>
<td>3,284,000</td>
<td>23,122,000</td>
</tr>
<tr>
<td>Depreciation</td>
<td>-7,271,156</td>
<td>-7,550,051</td>
<td>-6,787,772</td>
<td>-5,884,060</td>
<td>-5,447,506</td>
<td>-32,940,545</td>
</tr>
<tr>
<td>CAV</td>
<td>36,347,142</td>
<td>33,193,091</td>
<td>30,301,319</td>
<td>28,833,259</td>
<td>26,669,753</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>16,512,038</td>
</tr>
<tr>
<td>NPV of Return</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>595,511,333</td>
</tr>
<tr>
<td>NPV of Costs + Return</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>OAV</td>
<td>36,488,298</td>
<td>36,347,142</td>
<td>33,193,091</td>
<td>30,301,319</td>
<td>28,833,259</td>
<td>23,122,000</td>
</tr>
<tr>
<td>Capex</td>
<td>7,130,000</td>
<td>4,396,000</td>
<td>3,896,000</td>
<td>4,416,000</td>
<td>3,284,000</td>
<td>23,122,000</td>
</tr>
<tr>
<td>Depreciation</td>
<td>7,271,156</td>
<td>7,550,051</td>
<td>6,787,772</td>
<td>5,884,060</td>
<td>5,447,506</td>
<td>32,940,545</td>
</tr>
<tr>
<td>Return on Capital +</td>
<td>751,947</td>
<td>1,828,966</td>
<td>1,872,008</td>
<td>2,239,981</td>
<td>2,612,023</td>
<td>9,304,926</td>
</tr>
<tr>
<td>Incentives</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Working Capital</td>
<td>2,208,356</td>
<td>2,275,193</td>
<td>2,423,578</td>
<td>2,522,867</td>
<td>2,632,608</td>
<td>12,062,602</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Annual Revenue</td>
<td>95,681,426</td>
<td>120,364,822</td>
<td>159,471,600</td>
<td>159,174,556</td>
<td>161,023,483</td>
<td>695,715,888</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NPV of Revenue</td>
<td>595,511,333</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>2011</td>
<td>2012</td>
<td>2013</td>
<td>2014</td>
<td>2015</td>
<td>Total</td>
</tr>
<tr>
<td>------------------</td>
<td>-------------</td>
<td>-------------</td>
<td>-------------</td>
<td>-------------</td>
<td>-------------</td>
<td>-------------</td>
</tr>
<tr>
<td>Opex</td>
<td>47,031,322</td>
<td>46,512,017</td>
<td>46,003,009</td>
<td>45,504,153</td>
<td>46,836,025</td>
<td>231,886,526</td>
</tr>
<tr>
<td>Capex</td>
<td>206,400,000</td>
<td>275,000,000</td>
<td>309,200,000</td>
<td>325,700,000</td>
<td>333,800,000</td>
<td>1,450,100,000</td>
</tr>
<tr>
<td>Further Opex and Capex efficiencies</td>
<td>-25,040,000</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>-25,040,000</td>
</tr>
<tr>
<td>Clawbacks/Deferrals</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Incentives</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>NPV of Costs</td>
<td>1,454,056,739</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>OAV</td>
<td>1,208,737,949</td>
<td>1,381,439,551</td>
<td>1,617,964,898</td>
<td>1,882,848,245</td>
<td>2,157,882,592</td>
<td></td>
</tr>
<tr>
<td>Capex</td>
<td>206,400,000</td>
<td>275,000,000</td>
<td>309,200,000</td>
<td>325,700,000</td>
<td>333,800,000</td>
<td>1,450,100,000</td>
</tr>
<tr>
<td>CAV</td>
<td>1,381,439,551</td>
<td>1,617,964,898</td>
<td>1,882,848,245</td>
<td>2,157,882,592</td>
<td>2,434,421,939</td>
<td></td>
</tr>
<tr>
<td>NPV of Return</td>
<td>-614,700,247</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NPV of Costs + Return</td>
<td>791,255,134</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Opex</td>
<td>47,031,322</td>
<td>46,512,017</td>
<td>46,003,009</td>
<td>45,504,153</td>
<td>46,836,025</td>
<td>231,886,526</td>
</tr>
<tr>
<td>Clawbacks/Deferrals</td>
<td>-25,040,000</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>-25,040,000</td>
</tr>
<tr>
<td>Depreciation</td>
<td>33,698,398</td>
<td>38,474,653</td>
<td>44,316,653</td>
<td>50,665,653</td>
<td>57,260,653</td>
<td>224,416,011</td>
</tr>
<tr>
<td>Return on Capital + Incentives</td>
<td>111,978,993</td>
<td>78,746,492</td>
<td>78,630,249</td>
<td>105,378,706</td>
<td>131,316,100</td>
<td>506,050,541</td>
</tr>
<tr>
<td>Annual Revenue</td>
<td>164,293,318</td>
<td>160,395,037</td>
<td>165,648,317</td>
<td>198,282,720</td>
<td>232,476,066</td>
<td>921,095,457</td>
</tr>
<tr>
<td>NPV of Revenue</td>
<td>791,255,134</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### 13.4 TSO Revenue control formula

The CER has reviewed the price control formula used currently and has introduced a number of changes to reflect the additional incentives that it wishes to apply to the TSO. The new incentives were described in Section 6.3.

The formula is as follows:

$$ R_t = \prod_{t=2010}^{t} \left[ \frac{1 - B_t - N_t}{100} \right] \times B_t + \text{INCENT}_t + \text{KINCENT}_{t-1} \Delta P_t + \Delta U_t $$

$$ + K_{t-1} + K_{t-2} $$
Where:

$R_t$ is the maximum level of revenue allowed in year $t$ and the revenues on which the next year’s tariffs are based.

$\text{Inf}_t$ is the annual average percentage change in the Irish (all-items) Harmonised Index of Consumer Prices (HICP) for the 12-month period January to December. Where $j > t$, $\text{Inf}_j$ is a forecast value. Where $j \leq t$ $\text{Inf}_j$ is the value for Irish (all items) HICP published by Eurostat.

$X$ is the efficiency factor, set at 0. The CER has profiled allowed Opex to reflect increased efficiencies year on year. This in practice will have the same effect as putting a value on $X$ and profiling the allowed revenues over the control period to drive efficiencies.

$B_t$ is the level of allowed revenues in real 2009 prices for the TSO in each year of the price control.

$\text{INCENT}_t$ is the value of incentive penalties in year $t$ in € millions in respect of the penalties or payments which will be subsequently defined by the CER through discussions with the TSO. Proposed transmission incentives for the next incentive period will be consulted on with stakeholders in a separate CER paper in the coming weeks.

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>SYSAVT</td>
<td>TBC</td>
<td>TBC</td>
</tr>
<tr>
<td>SMLT</td>
<td>TBC</td>
<td>TBC</td>
</tr>
<tr>
<td>SYSFREQT</td>
<td>TBC</td>
<td>TBC</td>
</tr>
<tr>
<td>DONT</td>
<td>TBC</td>
<td>TBC</td>
</tr>
<tr>
<td>DENC</td>
<td>TBC</td>
<td>TBC</td>
</tr>
<tr>
<td>ANCCONT</td>
<td>TBC</td>
<td>TBC</td>
</tr>
</tbody>
</table>

$\text{KINCENT}_{t-1}$ is the incentive correction factor, defined as:

$$\text{KINCENT}_{t-1} = \text{FINCENT}_{t-1} - \text{PINCENT}_{t-1}$$

Where:

$\text{FINCENT}_t$ is the final value of $\text{INCENT}_t$, determined when all actual values of its component variables are known. This date shall be deemed to be by the end of year $t+1$.

$\text{PINCENT}_t$ is the provisional value of $\text{INCENT}_t$, yet to be determined in respect of year $t$.

118 Proposed transmission incentives for the next incentive period will be consulted on with stakeholders in a separate CER paper in the coming weeks.
ΔPt is the change in pass-through costs from those included in Bt, as available when setting tariffs in year t. This includes, changes in Ancillary Services etc. which the CER has indicated will be allowed on a pass-through basis. These costs will be expressed in Nominal values in year t.

ΔUt is the change in Uncertain Costs allowed by the CER in year t. This may include costs associated with the regulatory or legislative changes; or environmental requirements.

Kt-1 is the correction factor, which ensures that prices in year t are adjusted by an amount equal to the over or under recovery in the previous year. This amount is to be agreed between the TSO and CER on an annual basis.

Kt-2 is the correction factor, which ensures that prices in year t are adjusted by an amount equal to the over or under recovery in two calendars year previous. This amount is to be agreed between the TSO and CER on an annual basis.

13.4.1 Price control value & Formula

Taking into account the evidence presented by the TSO and the CER’s own extensive analysis, the CER allows that the price control be set at based on an allowed revenue of €95.7 million in 2011 (2009 prices). Total allowed revenue for the TSO for the five year period (2011 – 2015) is forecast to be €695.7 million in 2009 prices.

Based on the approach described above, Table 46 below shows the allowed CER’s allowed profile for the TSO’s allowed revenue for the period 2011 to 2015.

Table 46: TSO PR3 revenue profile (€’s 2009 prices)
13.5 TAO Revenue control formula

The CER has reviewed the price control formula used currently and a number of changes will be made to reflect the additional incentives that it wishes to apply to the TAO. Proposed transmission incentives for the next incentive period will be consulted on with stakeholders in a separate CER paper in the coming weeks.

The formula is as follows:

\[ R_t = \prod_{t=1}^{T} \left[ \frac{1 + \text{Inf}_t}{100} \right] \times \frac{B_t + \text{INCENT}_t + K\text{INCENT}_t-1 \Delta P_t + \Delta U_t + K_{t-1} + K_{t-2}}{1} \]

Where:

- \( R_t \) is the maximum level of revenue allowed in year \( t \) and the revenues on which the next year’s tariffs are based.
- \( \text{Inf}_t \) is the annual average percentage change in the Irish (all-items) Harmonised Index of Consumer Prices (HICP) for the 12-month period January to December. Where \( j > t \), \( \text{Inf}_j \) is a forecast value. Where \( j \leq t \) Inf is the value for Irish (all items) HICP published by Eurostat.
- X is the efficiency factor, set at 0. The CER has profiled allowed opex to reflect increased efficiencies year on year. This in practice will have the same effect as putting a value on X and profiling the allowed revenues over the control period to drive efficiencies.
- \( B_t \) is the level of allowed revenues in real 2009 prices for the TAO in each year of the price control.
- \( \text{INCENT}_t \) is the value of incentive penalties in year \( t \) in € millions in respect of the penalties or payments in respect of the incentives, which are to be finalised. Proposed transmission incentives for the next incentive period will be consulted on with stakeholders in a separate CER paper in the coming weeks.

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>DON(t)</td>
<td>TBC(^{119})</td>
<td>TBC</td>
</tr>
</tbody>
</table>

KINCENT\(t-1\) is the incentive correction factor, defined as:

\(^{119}\) Proposed transmission incentives for the next incentive period will be consulted on with stakeholders in a separate CER paper in the coming weeks.
\[ RINCENT_{t-1} - PINCENT_{t-1} - PINCENT_{t-1} \]

Where:

FINCENT\(t\) is the final value of INCENT\(t\), determined when all actual values of its component variables are known. This date shall be deemed to be by the end of year \(t+1\).

PINCENT\(t\) is the provisional value of INCENT\(t\), yet to be determined by the CER in respect of year \(t\).

\(\Delta P_t\) is the change in pass-through costs from those included in \(B_t\), as available when setting tariffs in year \(t\). This includes, changes in Local Authority Rates etc. which the CER has indicated will be allowed on a pass-through basis. These costs will be expressed in Nominal values in year \(t\).

\(\Delta U_t\) is the change in Uncertain Costs allowed by the CER in year \(t\). This may include costs associated with regulatory or legislative changes; or environmental requirements.

\(K_{t-1}\) is the correction factor, which ensures that prices in year \(t\) are adjusted by an amount equal to the over or under recovery in the previous year. This amount is to be agreed between the TSO and CER on an annual basis.

\(K_{t-2}\) is the correction factor, which ensures that prices in year \(t\) are adjusted by an amount equal to the over or under recovery in two calendars year previous. This amount is to be agreed between the TSO and CER on an annual basis.

13.5.1 Price control value & Formula

Taking into account the evidence presented by the TAO and the CER’s own extensive analysis, the CER allows that the price control be set at based on an allowed revenue of €166.6 million in 2011 (2009 prices). Total allowed revenue for the TAO for the five year period (2011 – 2015) is forecast to be €921.1 million in 2009 prices.

Based on the approach described above, Table 47 below shows the allowed CER’s allowed profile for the TAO’s allowed revenue for the period 2011 to 2015.
13.5.2 Total Transmission Revenue for 2011

The CER has decided to allow the following revenue for the transmission businesses in 2011, which is to be €257.36 million in 2011 nominal prices\(^{120}\), as shown in the table below. This is the same amount as proposed in CER/10/102 – the only change has been the allocation of the €257.36 million between the TSO and TAO as a result of the change in the WACC. This transmission revenue amount of €257.36 million (TSO and TAO) feeds into the Demand transmission tariffs shown in the paper CER/10/102(j) of CER/10/102.

### Table 48: Transmission Revenue for 2011

<table>
<thead>
<tr>
<th></th>
<th>2009 prices</th>
<th>2011 prices</th>
</tr>
</thead>
<tbody>
<tr>
<td>TSO Revenue</td>
<td>95,681,426</td>
<td>94,717,436</td>
</tr>
<tr>
<td>TAO Revenue</td>
<td>164,293,318</td>
<td>162,638,062</td>
</tr>
<tr>
<td><strong>Total 2011 Transmission Revenue</strong></td>
<td><strong>259,974,744</strong></td>
<td><strong>257,355,498</strong></td>
</tr>
</tbody>
</table>

\(^{120}\) 2011 prices are nominal and are based on inflation of the actual 2009 prices by assumed Ireland HICP rates of -1.5% in 2010 and 0.5% in 2011. Please see the following link - latest ESRI Spring 2010 report: [http://www.esri.ie/UserFiles/publications/QEC2010Spr/QEC2010Spr_ES_Summary%20Table.pdf](http://www.esri.ie/UserFiles/publications/QEC2010Spr/QEC2010Spr_ES_Summary%20Table.pdf)
14.0 Tariffs for 1\textsuperscript{st} October 2010 to 30\textsuperscript{th} September 2011

14.1 Introduction & background

In recent years, while allowed revenue has been set on a calendar year basis TUoS tariffs have (in some instances) been set for periods that span two calendar years\textsuperscript{121}. The most recent TUoS tariffs covered the period 1\textsuperscript{st} October 2009 to 30\textsuperscript{th} September 2010. This meant that the relevant portion of 2009 calendar year revenue and the relevant portion of 2010 calendar year revenue\textsuperscript{122} were allocated for recovery through TUoS tariffs during that period.

Similarly, within this paper the relevant portion of 2010 calendar year revenue and the relevant portion of 2011 revenue, have been allocated for recovery through TUoS within the 1\textsuperscript{st} October 2010 to 30\textsuperscript{th} September 2011 tariff period.

Details are provided below.

14.2 Revenue related to the PR2 period

14.2.1 The 2010 calendar year

The 2010 calendar year revenue was originally set as part of the PR2 decision paper and was updated last year to provide for the most recent assumptions for inflation, changes in customer numbers, etc\textsuperscript{123}. Allowed transmission revenue was €237.4 million in actual 2009 monies. 73% of the 2010 calendar year revenue was allocated for recovery during the current tariff period\textsuperscript{122}. It is decided that the remaining 27% will be allocated for recovery through TUoS tariffs during the next tariff period. This 27% equates to €64.1 million.

14.2.2 Adjustments relating to PR2

A number of assumptions/forecasts were made/used when setting the 2009 calendar year revenue. For example, the CPI assumption for 2009 has been revised from -4.6% to an outturn figure of -4.5%.

As discussed above in any given year TUoS tariffs for the next tariff period will include a k-factor to allow for over or under recoveries during the previous tariff period. Therefore the 2010/2011 tariff period should include a k-factor for the

\textsuperscript{121} The decision to move to non-calendar-year TUoS tariffs is detailed here. The change was initiated in 2007. Since 2007 the period covered by TUoS tariffs has varied. A summary of the different periods is provided here within the decision on 2009/2010 TUoS tariffs.

\textsuperscript{122} 26.7% of 2009 calendar year revenue and 73.3% of 2010 calendar year revenue, based on the demand weighted average, as detailed here within the decision paper on TUoS tariffs for the 1\textsuperscript{st} October 2009 to 30th September 2010 period.

\textsuperscript{123} Decision as per link above.
2009 calendar year revenue. This k-factor would reflect the differential in TUoS energy volume recovery (associated with the decline in consumption) against the assumed energy throughput forecast in 2009. To date, the CER has not received a submission from the TSO setting out the level of this 2009 k-factor; however it has indicated it intends to do in the near future. Therefore, the CER will reflect the 2009 outcome in subsequent PR3 tariff periods.

14.2.3 AUP for 2010/2011 Tariff Period

Therefore, based on the above annual revenues (allowed 2010 transmission revenue and allowed 2011 transmission revenue) and the estimated consumption, the transmission average unit price (AUP) for the period from 1st October 2010 to 30th September 2011, is estimated to be approximately 0.95 cent/kWh in 2011 nominal prices. This is an increase of 3% on the 2009/2010 tariff period transmission AUP.
15.0 Conclusions

This paper, together with the supporting documents published alongside it, has outlined the CER’s decision on the revenue that the TSO and TAO will be allowed to collect from the TUoS customer over the 2011 to 2015 period.

The five years from 2011-2015 will require significant new investment in the transmission system. The Government target of ensuring 40% of Ireland’s electricity is generated by renewable sources by 2020 means a major expansion of the transmission network. This will allow these new renewable generators to connect to the system. The transmission network also needs ongoing investment to ensure it operates securely and effectively. This necessary investment will mean that the overall revenues to be recovered by the TSO and TAO over the period of the review will rise from their current levels, and that the TUoS charges levied to consumers will rise somewhat.

While the CER is of the view that this investment is necessary and will deliver benefits to consumers, it is very aware of the need to ensure it is delivered as cost-effectively as possible. To that end, and mindful of the general economic difficulties, it is requiring major efficiencies from the TSO and TAO. This is through implementing significant cuts to the Opex required to run the system, as well as ensuring that Capex is fully scrutinised in terms of it being necessary, as well as being procured in an efficient manner. These efficiencies will ensure that end-users are protected as much as is possible, while still allowing for the required level of investment to take place, and continues the pattern of the CER having implemented significant efficiencies in previous price reviews.

In addition, following the publication of the CER’s proposals on this matter the CER is requiring that the TAO deliver additional efficiency savings in operating and capital expenditure, the benefits of which will be given to customers within the 2011 to 2015 period. This reduction has been included in Table 2 of the Executive Summary and the TAO revenue table in section 13, but has not been broken down by line item within this paper; rather it is a reduction in overall revenue for Opex and Capex. The CER believes that given the current economic conditions that there are additional efficiencies to be realised by the TAO. The CER has not specified how these efficiency savings are to be delivered across the various line items. Rather the TAO is to determine how these reductions will be achieved across Opex and Capex. The TSO will also be required an additional efficiency in allowed PR3 Opex.

The Demand TUoS tariffs for the 1st October 2010 to 30th September 2011 tariff period are detailed in the accompanying paper CER/10/102(j). The Generator TUoS tariffs for the 1st October 2010 to 30th September 2011 tariff period were published during the consultation phase – please see CER/10/102(k).
Next steps

- Publication of the consultation paper on 2011/2012 transmission incentives by end 2010.
- Publication of details of PR3 Capex monitoring and approvals process as part of the transmission incentives workstream.
### Appendix A – Composition of the TAO RAB (1st Jan 09)

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Overhead lines</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>- 400kV lines</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>single circuit</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>double circuit</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>- 275kV lines</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>single circuit</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>double circuit</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>- 220kV lines</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>single circuit</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>double circuit</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Total: -</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Underground cables</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>- 400kV cables</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>- 275kV cables</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>- 220kV cables</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Total: -</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Submarine cables</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>- 110kV lines</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>single circuit</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>double circuit</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Total: -</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Switchgear</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>- 400kV substation bays</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>- 275kV substation bays</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>- 220kV substation bays</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>- 110kV CB (GIS)</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>- 110kV CB - other</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

165
<table>
<thead>
<tr>
<th>110kV Isolators</th>
<th>-</th>
<th>26</th>
<th>279</th>
<th>446</th>
<th>505</th>
<th>343</th>
<th>61</th>
<th>204</th>
<th>180</th>
<th>59</th>
<th>231</th>
<th>125</th>
<th>17</th>
<th>15</th>
<th>58</th>
<th>2,549</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total:</td>
<td>-</td>
<td>37</td>
<td>377</td>
<td>573</td>
<td>650</td>
<td>493</td>
<td>90</td>
<td>257</td>
<td>290</td>
<td>99</td>
<td>289</td>
<td>163</td>
<td>30</td>
<td>22</td>
<td>75</td>
<td>3,445</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Transformers (per unit) - incl. tap changers &amp; reactors</th>
<th>400/220kV transformers</th>
<th>400/275kV transformers</th>
<th>275/220kV transformers</th>
<th>220/110kV transformers</th>
<th>400/110kV transformers</th>
<th>110/38/20/10kV transformers</th>
</tr>
</thead>
<tbody>
<tr>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Total:</td>
<td>-</td>
<td>8</td>
<td>11</td>
<td>7</td>
<td>7</td>
<td>5</td>
</tr>
</tbody>
</table>

166