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Cost Benefit Analysis for Zonal Transmission Loss Factors: A Review

For Teesside Power Ltd

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1. Introduction

On 26 June 2007 Ofgem published the "minded-to" decision[1] on zonal transmission loss factors (the "Minded-to Decision"). This decision is described as the "Authority's" (i.e. as a decision of the Gas and Electricity Markets Authority, GEMA), but the document is listed formally as a consultation document. I refer to it below as a document issued by Ofgem.

1.1. Outline of this Report

The Minded-to Decision refers extensively to the cost benefit analysis (CBA) carried out by Oxera for the P198 Modification Group during 2006.[2] This cost benefit analysis forms the basis of the discussion of short-term gains in efficiency and environmental benefits. In section 2, therefore, I review Oxera's CBA. Sections 2.1 to 2.3 review the input assumptions used by Oxera, whilst sections 2.4 to 2.10 review Oxera's approach to modelling and the associated results.

The Minded-to Decision also discusses regulatory risk at a number of points. In section 3, I respond to Ofgem's comments on regulatory risk and the implications for the cost-benefit analysis of P198, P200, P203, P204 and the associated Alternatives (altogether, the "Proposed Losses Modifications").

Finally, in section 4, I consider the related issues of discrimination, competition and distributional impacts.

My conclusions are to be found at the end of each chapter.

1.2. Terminology

Throughout this report, I use a number of abbreviations taken from documents published by Oxera, Elexon and Ofgem. The following are the most important terms, which I describe following the conventions in the Balancing and Settlement Code (BSC), but omitting subscripts:

TLF	= Transmission Loss Factor
ZLF	= zonal loss factor, i.e. TLFs that vary by zone, taking values around 0% to –10% for northern zones and 0% to +10% for southern zones
TLM	= Transmission Loss Multiplier = 1+ ZLF + [TLMO+]
TLMO+	= flat-rate adjustment to generator TLMs that ensures generators as a group cover 45% of total transmission losses
AAZ (TLM)	= Annual Average Zonal (Transmission Loss Multiplier)

[1] Ofgem (2007), "Zonal transmission losses – the Authority's 'minded-to' decisions", Ref: 153/07, 26 June 2007.

[2] Oxera (2006), "What are the costs and benefits of zonal loss charging? - Prepared for Elexon", July 2006.

2. Short-Term Efficiency

Changing the allocation of transmission losses from “flat-rate” to “half-marginal” will have implications for short-term efficiency in despatch. Ofgem’s “Minded-to Decision” refers repeatedly to the Oxera analysis carried out for the P198 Modification Group. In this section, I list my concerns about the approach used by Oxera and the areas where some clarification or updating would be desirable.

2.1. Fuel Price Assumptions

The source of the Oxera fuel price assumptions is somewhat shrouded in mystery. Oxera claims to have used the DTI document "UK Energy and CO2 Emissions Projections - Updated Projections to 2020", published in February 2006.[3] It seems that, at least in parts, Oxera used another DTI document, "UK Energy and CO2 Emissions Projections", published in July 2006 as a source, at least for some of the data.[4] I compare the fuel prices used by Oxera,[5] the aforementioned DTI documents, and the latest DTI forecasts in Table 2.1 and Table 2.2. The DTI (July 2006) projections are closest to the Oxera projections and probably served as the source from 2010 onwards (with Oxera’s “central” scenario corresponding to the DTI’s “favouring coal” scenario, and Oxera’s “gas” scenario corresponding to the DTI’s “favouring gas” scenario). However, the exact source of Oxera data for the period between 2006 and 2010 remains unclear.

Irrespective of the source, comparing the Oxera figures and the DTI 2007 predictions shows that Oxera’s figures for 2010 are towards the lower end of the current forecast range:

§ In the “central” scenario for gas, the DTI is currently predicting a gas price of 42p/therm, whilst Oxera’s “central” gas price forecast is 35p/therm, 17% lower. The current price at the National Balancing Point (NBP, the onshore point of delivery for many gas contracts in Britain) for an annual contract for 2008 is already around 39p/therm.

§ In the central scenario for “coal”, the DTI is currently predicting a coal price of £30/tonne, whilst Oxera’s “central” coal price forecast is £28/tonne, 7% lower. However, forward prices of 2010 indicate prices of £40/tonne, implying that Oxera is underestimating the coal price by 30%.

Relative to up-to-date DTI forecasts, therefore, Oxera’s forecasts are an underestimate, which is more severe for gas than for coal. For 2015, Oxera’s forecasts are more in line with the latest DTI forecasts (36 vs 38p/therm for gas, £27 vs £31 per tonne for coal), though the coal price forecast still lies below current forward prices for coal up to 2013 (£40 per tonne). The analysis should be updated using more up to date fuel prices, since the relative fuel prices of gas and coal were distorted in 2006 by temporary supply problems in the gas sector.

3 Oxera (2006), p. 11.

4 Besides inconsistencies in early years, the DTI data is published quinquennially and we assume that Oxera must have extrapolated the data in between years.

5 Presented in Table 2.5 of Oxera (2006), p.14.

Table 2.1
Gas Price Predictions (2006 Prices)

(p/therm)	2005	2006	2010	2015	2020
DTI 2007 (High)			50	53	55
DTI 2007 (Central)			42	38	40
DTI 2007 (Low)			32	18	21
DTI July 2006 (Fav Gas)	42		26	28	29
DTI July 2006 (Fav Coal)	42		34	36	37
DTI February 2006 (Fav Gas)	37		24	24	24
DTI February 2006 (Fav Coal)	37		29	29	29
Oxera 2006 (Gas)		37	18	20	
Oxera 2006 (Central)		47	35	36	

Source: DTI,[6] Oxera,[7] Eurostat.[8] Notes: (1) All prices were updated to 2006 prices where appropriate using the inflation rates published by Eurostat and assuming that prices in the Oxera report are 2005 prices. (2) The year 2006 corresponds to 2006/07 in the Oxera report. The year 2010 corresponds to 2010/11, etc.

Table 2.2
Coal Price Predictions (2006 Prices)

(£/tonne)	2005	2006	2010	2015	2020
DTI 2007 (High)			38	41	45
DTI 2007 (Central)			30	31	32
DTI 2007 (Low)			28	20	20
DTI July 2006 (Fav Gas)	34		28	27	26
DTI July 2006 (Fav Coal)	34		28	27	26
DTI February 2006 (Fav Gas)	37		22	21	20
DTI February 2006 (Fav Coal)	37		22	21	20
Oxera 2006 (Gas)		34	28	27	
Oxera 2006 (Central)		34	28	27	

Source: DTI,[9] Oxera,[10] IMF,[11] Eurostat.[12] Notes: (1) All prices were updated to 2006 prices where appropriate, assuming that prices in the Oxera report are 2005 prices. (2) The year 2006 corresponds to 2006/07 in the Oxera report. The year 2010 corresponds to 2010/11, etc. (3) The table uses a conversion rate of 26.1 GJ/tonne.[13]

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6 DTI, "UK Energy and CO2 Emissions Projections - Updated Projections to 2020", February 2006, p. 15; DTI, "UK Energy and CO2 Emissions Projections", July 2006, p. 19; DTI, "Updated Energy and Carbon Emissions Projections - The Energy White Paper", May 2007, p. 29.

7 Oxera (2006), p.14, Table 2.5.

8 Eurostat, "Harmonised Indices of Consumer Prices - May 2007", Statistics in Focus, no. 84/2007.

9 DTI, "UK Energy and CO2 Emissions Projections - Updated Projections to 2020", February 2006, p. 15; DTI, "UK Energy and CO2 Emissions Projections", July 2006, p. 19; DTI, "Updated Energy and Carbon Emissions Projections - The Energy White Paper", May 2007, p. 29.

10 Oxera (2006), p. 14, Table 2.5.

11 IMF, "International Financial Statistics", May 2007.

12 Eurostat, "Harmonised Indices of Consumer Prices - May 2007", Statistics in Focus, no. 84/2007.

13 See also http://www.dti.gov.uk/files/file26372.pdf.

The effect of changing *relative* gas and coal prices is to increase or decrease the potential for zonal loss factors to achieve efficiencies in the cost of despatch and environmental benefits through fuel switching. Ofgem's decision refers directly to the benefits mentioned in the Oxera CBA, but these benefits may have depended upon the temporary distortion of gas markets in 2005/06. Assessment of these benefits should be based on a range of scenarios that are clearly not affected by this distortion.

2.2. Demand Assumptions

The Oxera report uses two demand scenarios, based on the National Grid's 2005 Seven Year Statement (referred to here as NG (2005)):

- The "central" scenario is based on the "base" scenario of the NG (2005);[14] and
- The "demand" scenario is based on the "high" scenario of the NG (2005).[15]

Table 2.3 shows the data used by Oxera, as well as the data published by National Grid in 2005 and 2007. It seems that Oxera's figures do not match those in NG (2005), but the source of this difference is not clear.

Table 2.3
Peak Demand Scenarios

(GW)	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16
NG(2005) "Base"	63.0	63.5	64.1	64.5	64.7	65.0				
NG(2005) "High"	64.4	65.8	67.3	68.7	70.0	71.2				
NG(2007) "Base"	61.3	61.3	61.4	62.0	62.7	63.0	63.5	63.9		
NG(2007) "High"		62.0	63.2	64.2	65.4	66.2	67.2	68.1		
Oxera "Central"	62.4	62.9	63.5	64.0	64.1	64.4	64.7	65.0	65.3	65.6
Oxera "Demand"	63.8	65.2	66.7	68.1	69.4	70.6	71.8	73.0	74.2	75.4

Source: National Grid,[16] Oxera.[17] Note: National Grid's forecasts include transmission and distribution losses.[18]

NG (2007) is the most recent forecast by National Grid. Comparing NG (2007) with NG (2005) and Oxera's figures implies that National Grid has revised its demand forecast downwards since 2005. For example, for the year 2008/09, the NG (2005) base forecast was 64.1 GW and Oxera's central forecast was 63.5 GW. However, the 2008/09 base forecast in

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14 Oxera (2006), p. 11.

15 Oxera (2006), p. 14.

16 National Grid, "Seven Year Statement", 2005, Table 2.5 (downloaded from the NG website: http://www.nationalgrid.com/uk/library/documents/sys05/dddownloaddisplay.asp?sp=sys_Table2_5; http://www.nationalgrid.com/uk/library/documents/sys05/default.asp?action=mnch2_7.htm&Node=SYS&Snode=2_7&Exp=Y#National_Grid_Forecasts); and National Grid, "Seven Year Statement", 2007, Table 2.3 (downloaded from the internet: http://www.nationalgrid.com/uk/sys%5F07/dddownloaddisplay.asp?sp=sys_Table2_3; http://www.nationalgrid.com/uk/sys%5F07/default.asp?action=mnch2_7.htm&Node=SYS&Snode=2_7&Exp=Y#National_Grid_Forecasts).

17 Oxera (2006), p. 14, Table 2.5.

18 See: http://www.nationalgrid.com/uk/sys%5F07/default.asp?action=mnch2_16.htm&Node=SYS&Snode=2_16&Exp=Y#demand_Terminology.

NG (2007) is now only 61.4 GW, 4.2% lower than the NG (2005) forecast and 3.3% lower than the Oxera forecast.

This data comparison suggests that it would be useful to update the data used in Oxera's cost benefit analysis. Even if the locational pattern of demand is unchanged in NG (2007), changes in total demand can affect power flows over the national grid – and hence the level of transmission losses – because higher total demand may be met by increasing output from either northern or southern generators, depending on which is at the margin.

2.3. EU Emission Trading Scheme

Oxera makes some assumptions about prices of European Union CO2 Emissions Allowances (EUAs) issued under the EU Emission Trading Scheme (EU ETS). For the first phase (2005-2007) and the second phase (2008-2012), Oxera assumes a price of €20/tCO2. For the third phase Oxera assumes a price of €30/tCO2 (in prices of 2005)[19] or about €38-39/tCO2 in prices of 2013-2016. To evaluate the accuracy of these price assumptions I compared them with the latest available forward prices, as in Table 2.4.

Table 2.4
EU ETS Forward Prices

(€/tCO2)	Bloomberg	Pointcarbon	LEBA
2007	0.12	0.14	0.13
2008	20.50	20.95	19.81
2009	20.85		20.15
2010	21.75		
2011	22.15		
2012	22.60		

Source: Bloomberg, Pointcarbon and LEBA. Notes: (1) All prices refer to products traded between 10/7/2007 and 12/7/2007; (2) Bloomberg quoted rates are daily "Mid Price" exchange rates; Ticker is GBPEUR Curncy; (3) Pointcarbon daily data have been collected from PointCarbon's website, specifically https://pointcarbon.com/Home/Market+prices/Historic+prices/category390.html (requires subscription); (4) Prices are weighted averages; Data taken from http://www.leba.org.uk/carbon_indices.xls.

Table 2.4 reveals, of course, that Oxera's forecast of prices no longer accurately reflects the prices of 2007. Actual prices are close to zero, rather than Oxera's forecast of €20/tCO2. However, 2007 is no longer relevant to the appraisal, since implementation will not take place before 2008. The price assumption for the second phase appears reasonable, given current forward prices.

No forward prices are available for Phase III. Oxera's forecast price of €30/tCO2 in prices of 2005 (equivalent to €35-40/tCO2 in prices of 2014), lies within the bounds of conventional forecasts for Phase III, although it is a relatively high estimate.

[19] Oxera (2006), p. 12.

Hence, my review of prices for CO2 emissions allowances does not indicate any major changes, but does call into question the validity of any net benefits attributed to 2007 and the use of benefits calculated for a period beginning in 2006/07.

2.4. The Presentation of Oxera's Results

Oxera's modelling results are presented in Tables 3.17 to 3.20 of the Oxera report. Table 2.5 below shows a selection of these results. The lines "Annual saving in losses" and "Price of electricity" are outputs from the Oxera model. Multiplying one by the other gives the "Gross benefit" from the total reduction in losses (not shown in the Oxera report of July 2006). This reduction in losses was achieved by re-despatching generators after the introduction of zonal loss factors, so that generation is shifted, in some periods at least, from northern zones to southern zones. Oxera's draft reports dated June 2006 focus on this element of the short-term efficiency savings due to the introduction of zonal loss factors.

However, the re-despatch due to these zonal loss factors also means that more expensive generators in the South operate more often, displacing cheaper northern generators. Oxera therefore adjusts the gross benefit of the reduction in losses to take account of the additional cost of using more expensive generators. The resulting "Net benefits" are therefore lower, as reported by Oxera and as shown in the table below.[20]

Table 2.5
Gross and Net Benefit in the Oxera Analysis

	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	Average
Central Scenario							
Annual saving in losses (GWh)	90	235	107	420	73	165	182
Price of electricity (£/MWh)	44.4	42.5	35.8	33.9	32.5	35.2	37
Gross benefit (£m)	4.0	10.0	3.8	14.2	2.4	5.8	6.7
Net benefit (£m)	3.4	9.0	1.6	12.0	1.9	4.5	5.4
Seasonal Scenario							
Annual saving in losses (GWh)	491	373	497	545	538	252	449
Price of electricity (£/MWh)	44.4	42.5	35.8	33.9	32.5	35.2	37.4
Gross benefit (£m)	21.8	15.9	17.8	18.5	17.5	8.9	16.7
Net benefit (£m)	17.8	13.1	13.5	13.8	15.7	7.1	13.5

Source: Oxera[21] and NERA calculations.

The results reported in Tables 3.17 to Tables 3.20 of the Oxera report only extend as far as 2011/12. The reported net benefits of re-despatch of generation over the period 2006/07–2011/12 average £5.4 million for the central scenario and £13.5 million for the seasonal scenario.

[20] I assume that the last rows in Tables 3.17 to 3.20 do indeed report net benefits, as stated on page 39 of Oxera's report. In principle the figures in the last row (entitled "Value of savings in losses (£m)") could also be a weighted sum of gross benefits, i.e. loss savings in GWh multiplied by a variety of market prices which are not stated. However, that amount would not constitute a "net" benefit in any meaningful sense.

[21] Oxera (2006), pp. 39-40, Table 3.17 and Table 3.20.

For the overall cost-benefit analysis (see Table 8.1 and Table 8.2 of the Oxera report), Oxera calculated all costs and benefits from 2006/07 to 2015/16, but provides only a summary of the data over the period as a whole. According to Table 8.1, the annual (net) benefits from re-despatch of generation over these 10 years average £2.9 million for the central scenario and £8.9 million for the seasonal scenario.

This combination of results for the central scenario is curious. Total benefits are £32.4 million over the period 2006/07 to 2011/12 (Oxera Table 3.17), but only £29 million over the longer period 2006/07 to 2015/16 (Oxera Table 8.1: £2.9 million times 10 years). That would imply that net benefits in years 2012/13 to 2015/16 were ***negative*** (-£0.85 million per annum on average). Such a result is unlikely (unless introducing zonal loss factors leads to a less efficient pattern of despatch). In practice, it calls into question the consistency and accuracy of the results reported in Oxera's report.

Even for the seasonal scenario, this combination of results indicates that net benefits after 2011/12 are only £2 million per annum. (That amount on average over four years gives the £8 million difference between £81 million shown in Table 3.20 for 2006/07 to 2011/12, and £89 million implied by Table 8.1 for 2006/07 to 2015/16.) Such a small amount is likely to be within the margin of error and indicates that the net benefits are no longer significant by 2012. Oxera indicated that benefits were being eroded by decisions to put new plant in the south of the country, for reasons unrelated to transmission losses. Delays in implementation of zonal loss factors, that push back the benefits, may therefore also lower total net benefits substantially.

2.5. Gross Benefits Versus Net Benefits

As indicated above, Oxera identified a number of short-term costs and benefits, under the following categories:[22]

§ **Reduction in losses:** zonal charging is expected to reduce losses by forcing market participants to take into account the effect of their decisions on losses. Thus, zonal charging must affect generator despatch.

§ **Offsetting costs**, which include:

 – **Generation re-despatch:** zonal loss charging might imply that generators are despatched that are less cost-efficient ***before*** zonal charging is taken into account (but more cost-efficient ***after*** zonal charging). This will partly offset the (gross) benefits from the reduction in losses.

 – **Location of new entry:** if plant location under zonal charging is different than under uniform charging, it might indicate that some cost elements of the new location are higher ***before*** zonal charging is taken into account (but lower ***after*** zonal charging).

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[22] Oxera (2006), pp. 2-3

- **Demand-side response:** as a consequence of price changes due to the introduction of zonal charging, if consumers, for example, reduce their consumption they will experience a loss in welfare associated with the reduction in consumption.

There is a great uncertainty over how Oxera assembled its estimate of total net benefits from these elements.

2.5.1. Indications in Oxera's draft and final reports

The picture painted in Oxera's June 2006 *draft reports* suggests that Oxera first estimated and valued the reduction in losses (at a price of around £42.5/MWh) and then calculated an offsetting cost of re-despatch (equal to approximately 25% of the value of the reduction in losses).[23]

The final report of July 2006 seems to imply that Oxera revised its method in order to calculate the total net change in the costs of generation. On estimating the balance of cost and benefits, Oxera wrote:

> "The existence of these offsetting costs was discussed in Oxera (2003) and estimated at the time. In this report **the net benefits from the generation sector from loss reductions have been estimated directly** by comparing the total cost of generation under uniform loss charging with that under zonal loss charging, thereby accounting for the reduction in overall generation required due to avoided losses, and the offsetting increases in output from more expensive plant."[24]

As if to confirm this approach to estimating the offsetting costs of "generation re-despatch", Oxera also wrote:

> "This impact is captured in the wholesale market modelling by comparing the total costs of generation under zonal loss charging and those under a uniform loss charging regime"[25]

Thus, in July 2006, Oxera claimed to be computing the actual cost saving by comparing total generation costs under uniform and zonal loss charging in the final report. This approach yields the net benefits by accounting for both the gross benefit from the reduction in losses and the offsetting cost of a more expensive pattern of generation despatch.

However, the process involves some iterative transfer of information between models, not the simultaneous solution of an overall equilibrium. On pages 6 and 7 of the July report, Oxera explains the interaction between its load-flow model and its wholesale market model. The wholesale model (under uniform and zonal TLMs) is run to determine the pattern of generation, while the load-flow model is used to estimate losses and the associated TLMs (for

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23 This description is found on page 2 of the Oxera report of the same name as the final report, but dated 14 June 2006. The 25% figure appears on page 61.

24 Oxera (2006), p. 3. Emphasis in the original.

25 Oxera (2006), pp. 2-3.

the next year). The July report still states that, after the wholesale model has been run for 2006/07:

> "The generator outputs for 2006/07 under both uniform and zonal loss charging were fed back into the load–flow modelling to give an estimate of the *potential change in transmission losses* for three snapshot periods for 2006/07 data, with *losses calculated using generation conditions and nodal TLFs.* AAZ TLMs for 2007/08 were then calculated."[26] (***emphasis added***)
>
> "This year-by-year process continued, with the wholesale market model despatched one year at a time, and the results fed into the load–flow model to give estimated TLFs for the following year."[27]

Chapter 2 of the Oxera report therefore describes the modelling process in some detail, but there is no similar explanation of how Oxera calculated the net benefits from the model. The report does not explain what is meant by the "potential change in transmission losses" or the purpose of calculated losses "using generation conditions and nodal TLFs".

Tables 3.17 to 3.20 show a number of model results, but provide no explanation as to how the "value of savings in losses" is derived from them. For example, for 2006/07, Table 3.17 shows an "Annual saving in losses" of 90 GWh and a "Price of electricity" of £44.4/MWh: together they would imply a gross benefit of £3.996 million, but the table shows the "Value of savings in losses" as £3.4 million, only 85.1% of the implied figure. There is no explanation of the difference.

The Oxera report therefore lacks the transparency that one might expect of a regulatory document and does not provide enough information to allow a new reader to appraise the methodology fully.[28]

2.5.2. Discussion of the methodology

Although I cannot reconstruct Oxera's methodology from the July report, certain phrases are sufficient to trigger concern. The following section explains possible errors that Oxera may have made.

To balance supply and demand, it is necessary to adopt a consistent definition of costs, capacities and outputs for a certain point of delivery. Oxera is likely to have set up the model to minimise the total costs of output, with costs (c_i) and output (Q_{ij}) for each generator i in each half-hour j being defined as at the station gate. In formal terms, that means that the optimisation problem is specified as follows:

Minimise the Total Cost of Generation = $C_j = \Sigma\, Q_{ij} * c_i$

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26 Oxera (2006), p. 7.

27 Oxera (2006), p. 7.

28 I attended some of the meetings of the P198 modification group. After seeing the June draft reports, the group asked for the methodology to be changed, as explained above. However, the group had few or no opportunities to question Oxera on the July report and even my attendance at the P198 modification group does not enable me to reconstruct the methodology from that report.

This optimisation must be constrained by the need to match output to demand. The model would need to match the sum of delivered outputs, D_{ij}, from each generator i in each half-hour j to some measure of total demand, D, implying a constraint on the model as follows:[29]

Demand = D = Σ D_{ij} = sum of delivered outputs

Total generation output is equal to total offtake from the national grid plus total losses within the transmission network. Conventional models of electricity markets therefore define demand, D, as equal to total offtake plus total transmission losses:

Demand = total generation output = total offtake plus total transmission losses

However, it is likely that Oxera modelled the volume of "delivered output" for each generator i as net of transmission losses (calculated using the generator's own zonal transmission loss multiplier), in order to allow for the cost disadvantage associated with high loss factors:

Delivered output = D_{ij} = Q_{ij} * TLM_{ij}

That is, Oxera is likely to have assumed that a fraction of each generator's output is lost before being delivered to "the market".

However, the definition of TLMs for generators takes into account the need to assign 45% of total transmission losses to generators (or rather, to Balancing Mechanism Units running a surplus in half-hour j). Generators' total output is reduced by 45% of total transmission losses, both currently and under the proposed rules. The other 55% of losses is charged to suppliers (or rather, to Balancing Mechanism Units running a deficit in half-hour j) and is recovered through the TLMs applying to offtake. After deducting zonal losses, therefore, the sum of delivered output from all generators is total generation less 45% of losses. The total level of demand D in the equation above should therefore be defined on a consistent basis as total offtake plus the 55% of losses assigned to suppliers (but excluding the 45% of losses already assigned to generators):

Demand = [total generation output] *less* 45% of total transmission losses

= [total offtake *plus* total transmission losses]
less 45% of total transmission losses

= total offtake *plus* 55% of total transmission losses

However, Oxera stated in the July 2006 report that:

> "The total level of demand to be met was reduced by the estimated level of losses, allowing the total net benefit of zonal loss charging to be calculated." [30]

This statement is rather hard to interpret. It might mean that the level of demand used in Oxera's wholesale market model was total generation less *total* transmission losses:

[29] In the model, such a constraint would be specified as an inequality, but I use equations here for clarity.

[30] Oxera (2006), p. 7.

Demand = [total generation output] *less* total transmission losses

= total offtake

This measure of demand is not consistent with the conventional approach or with the assumption that generators cover 45% of transmission losses through their TLMs. It is then difficult to see how the level and cost of total generation output would reflect the level of transmission losses.

Alternatively, it may mean that the figure for total demand, D, is adjusted after the introduction of zonal loss factors for the total change in losses. That too would be incorrect, if the consistent level of demand should include 55% of losses, since only the adjustment should only equal that proportion of any change in losses.

It is therefore possible that the approach used inconsistent definitions of demand and output. However, Oxera's explanations of the interaction between load-flow and wholesale market model are not entirely clear. With the level of explanation offered in the report, it is impossible to know whether Oxera's approach causes any potential problem or not.

2.6. Generation Costs

Chapter 2 of the Oxera report provides the following description of the wholesale market model:[31]

> "The price at which generators are willing to despatch was modelled as short-run avoidable costs adjusted by the generator AAZ TLM. Intuitively, this reflects the fact that the more output is scaled back, the higher the market price will need to be to allow a generating unit to cover its overall avoidable costs."

The first sentence says that the price is equal to the short-run avoidable cost adjusted by the generator's "AAZ TLM" (Annual Average Zonal Transmission Loss Multiplier). Avoidable cost are costs incurred only when the generator produces output, meaning all the costs that are not fixed. Such costs would be defined in £ per MWh and would vary in line with output. That is a conventional way to model electricity markets and is confirmed by the description of the wholesale market model in Appendix 1 of the Oxera report.[32] However, the second sentence seems to imply that there is some kind of target for covering average or annual avoidable costs defined in £ per annum, so that lower output leads to higher market prices. That would be an unusual way to model despatch. No other section of the report confirms this approach, but it would be an odd comment to make about a conventional model and calls into question precisely how it works.

2.7. Demand Response

The potential response of demand from consumers to the introduction of zonal charging is estimated separately from the despatch modelling. Presumably for the purpose of facilitating the supply side modelling, Oxera assumed that demand was ***perfectly*** price inelastic, that is,

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31 Oxera (2006), p. 7.

32 Oxera (2006), p. 78.

that demand does not respond to price changes. Electricity demand is price inelastic, typical assumptions about elasticities being only -0.1 to -0.25, whereas a "price elastic" demand has an elasticity below -1.0 (i.e. with a negative sign and an absolute size greater than 1.0). However, demand for electricity does respond to price signals to a small extent. Oxera estimated these effects separately in Chapter 6.

To model the change in consumption due to changes in electricity prices, Oxera assumed a range of price elasticities of demand for (1) domestic, and (2) industrial and commercial (I&C) consumers. The low price elasticities are -0.15 for domestic customers and –0.25 for I&C customers. These elasticities are described as the "low scenario", but are in line with central or even relatively high estimates. The "high scenario" uses elasticities of –0.35 for domestic customers and –0.45 for I&C customers, which are higher than values I have seen used before.

Oxera did not have a precise breakdown of demand between domestic and I&C consumers, but assumed that domestic consumers make up a fixed proportion of 33%. I cannot improve on this assumption (not having any better information by zone) but Ofgem may have access to a more detailed breakdown of demand by zone that would improve the analysis.

Zonal loss charging affects (1) the overall price level through the workings of the wholesale market,[33] and (2) the local prices directly through the zonal loss charging. The size and direction of the change in electricity prices due to zonal loss charging is described in Oxera's report as "marginal and uncertain".[34] Demand effects therefore come from interzonal price changes caused by changing loss factors. The typical effect of introducing zonal loss factors is to reduce prices for consumers in the north (which increases consumption in the north) and to increase prices for consumers in the south (which reduces consumption in the south). Oxera records the estimated changes in consumption in Tables 6.2 to 6.5 of the July 2006 report. Table 2.6 on page 13 summarises the results for the "low elasticity" scenario.

2.7.1. Effects of integrating demand response and despatch

Some increases in demand in the north lead to reductions in total losses. This effect derives from the assumption that northern demand has a positive TLF, i.e. just as a reduction in northern generation saves losses, so an increase in northern consumption has the same effect. The rationale for this effect is that an increase in northern consumption will lead to a reduction in north-south flows over the network.

In fact, as with all such marginal changes, the precise effect on network losses depends on how the system is balanced. For example, Oxera's analysis forecasts that the relocation of consumption from south to north caused by price response will lead to an increase in total consumption, but a fall in total losses (due to the reduction in north-south flows). Overall, there is a net increase in demand to be met by additional generation, thus raising the total cost of generation. Furthermore, if this net increase in demand is met by northern generators (because they are at the margin), some north-south flow will be restored and the overall reduction in losses will be smaller than Oxera predicts.

[33] See Table 3.21 of Oxera (2006).

[34] Oxera (2006), p. 42.

Table 2.6
Potential Annual Benefit from the Demand-Side Response to Zonal Loss Charging (Low Scenario)

	Consumption (GWh)	Change in Consumption (MWh)		Estimated Change in losses (MWh)	Estimated value of loss reduction (£)
		Domestic	I&C		
North Scotland	12,000	4,517	28,958	-2,421	89,000
South Scotland	25,000	5,808	37,232	-2,924	107,000
Northern	19,000	3,944	25,279	-1,312	48,000
North Western	27,000	3,111	19,944	-848	31,000
Yorkshire	29,000	7,603	48,736	-2,629	96,000
Merseyside&North Wales	19,000	1,008	6,459	-235	9,000
East Midlands	32,000	2,289	14,675	-362	13,000
Midlands	36,000	-4,482	-28,728	239	-9,000
Eastern	42,000	410	2,629	-19	1,000
South Wales	14,000	-1,135	-7,275	62	-2,000
South Eastern	26,000	-1,149	-7,366	-4	0
London	35,000	-6,045	-38,749	-602	22,000
Southern	39,000	-6,552	-41,999	-394	14,000
South Western	15,000	-3,587	-22,991	-323	12,000
Total	370,000	5,741	36,804	-11,773	431,000

Source: Oxera.[35] *Note: this table only includes the results of the low scenario.*

Oxera's description of the various feedback loops by which its models are integrated is not very clear. It is therefore impossible to say whether Oxera's estimate of the benefits of demand relocation have been fully taken into account. However, Oxera reports the benefit of the reduction in losses without mentioning any offsetting costs for meeting additional demand. Integrating models to achieve a simultaneous equilibrium is always difficult, but this aspect would merit some investigation, if only to see if the effect of changing total demand is significant.

2.7.2. Welfare losses due to irreversible and fixed costs

There is an additional demand effect, which Oxera's report does not include and which Ofgem does not mention in the Minded-to Decision.

When consumers increase demand for a product or service, they derive welfare from consuming it. Economic efficiency is measured by the difference between consumers' welfare from consumption and the cost of the resources used up in production. At the margin, consumers' welfare from consuming a product is equal to the price they have to pay for it. Hence, (small) changes in consumer welfare due to changes in consumption can be valued at the price of the product concerned.

If prices equal marginal cost, any change in consumption causes a change in costs that offsets the change in consumer welfare. The overall effect on economic efficiency is then zero.

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[35] Oxera (2006), p. 59, Table 6.2.

However, when consumers reduce their demand for electricity, the costs saved are less than the price, due to the existence of irreversible and fixed costs in networks, for example. The reduction in consumer welfare is therefore not fully compensated by a reduction in costs. As a result, there is a decline in economic efficiency (the difference between consumer welfare and costs). Increases in consumption may also experience a mismatch between prices and costs, but that is less likely (since the irreversibility of fixed costs does not apply to increases in output, so prices are more likely to be close to marginal costs).

Table 2.7 shows the valuation of welfare effects due to the changes in consumption in Oxera's own "low" (i.e. low elasticity) and "high" (i.e. high elasticity) scenarios. I summed the changes in consumption across all zones according to whether they experience a positive change in consumption (for which prices are likely to match marginal costs) or a negative change in consumption (for which prices may overstate marginal costs). The sum for "negative excluding London)" recognises the possibility that reducing demand in London causes immediate cost savings, due to the stretched nature of the capital's infrastructure.

These changes in consumption are then evaluated at £40/MWh. This figure is only an assumption, adopted on the basis that the avoidable cost of generating electricity is given by Oxera's market price estimate of around £40/MWh and that the irreversible fixed costs of the network and other costs included in final tariffs are about the same. Changing this assumption would change the estimate of welfare effects proportionately.

On this basis, the table shows that the loss of welfare in one year due to consumers reducing their demand in zones where prices rise has a value of £6.8 million, even if price elasticity is low. If price elasticity is high, the annual loss of welfare is £12.7 million. Leaving out London reduces the loss of welfare to £5.0 million ("low") or £9.4 million "high".

Table 2.7
Welfare Effects of Changes in Consumption

	Low Scenario		**High Scenario**	
Change in Consumption	**Volume (MWh)**	**Valued at £40/MWh**	**Volume (MWh)**	**Valued at £40/MWh**
Positive	212,602	8,504,080	397,988	15,919,520
Negative	-170,058	-6,802,320	-318,341	-12,733,640
Negative (Excl. London)	-125,264	-5,010,560	-234,488	-9,379,520
Total	42,545	1,701,800	79,644	3,185,760

To some extent, this loss of welfare is offset by gains in areas where consumption increases ("positive"). If the gap between price and marginal cost were also £40/MWh on every additional MWh consumed, the gains would outweigh the losses, and the total change in welfare would be positive. However, as explained above, increases in demand are unlikely to exhibit the same gap between prices and marginal costs. Indeed, in many cases, there will be no gap, as the marginal cost of meeting higher demand is close to (or even above) the price that consumers pay.

If the difference between the price for increases in demand and the marginal cost is any less than £32/MWh (i.e. 80% of the gap for demand reductions), the total change in welfare would be negative, and at £20/MWh (i.e. 50% of the gap for demand reductions) the change results in a substantial loss of welfare overall: “low” = £2.6 million; “high” = £4.8 million.

Given the tendency for demand to grow, the reductions in consumption will not cause network assets to be under-utilised forever. Once demand growth replaces the consumption lost because of price rises, the effect falls to zero. However, in the context of the overall estimate of net benefits, the figures given above are significant enough to warrant investigation.

2.8. Electricity Prices

Oxera stated categorically that “[t]he introduction of AAZ TLFs has a marginal and uncertain impact on wholesale electricity prices”. Generally, the wholesale price in this country is defined as including losses allocated to generators. Oxera’s statement implies that the reduction in losses will not affect consumers to the extent that the reduction is passed through to generators in the first instance. Only reductions in the 55% of transmission losses borne by consumers (or rather their suppliers) would feed through to consumers – and then to differing degrees depending on the zone where the consumer is located.

From the point of view of a cost benefit analysis, the incidence of costs and benefits is immaterial. GEMA’s Minded-to Decision adopts the same point of view. However, any attempt to assess more narrowly defined “benefits to consumers” would need to consider (or review) this finding by Oxera.

2.9. Robustness of Results

2.9.1. Volatility of losses

The results are highly volatile from year to year, as can be seen in Table 2.5 above. Between 2006/07 and 2010/11, annual net benefits in the central scenario swing from £3.4 million, up to £9.0 million, down to £1.6 million, up to £12.0 million and then down to £1.9 million, respectively. Such cyclical volatility is unusual for the electricity market, where the norm is a combination of structural shifts separated by stable time trends.

Oxera wrote that

> “the snapshot losses are highly dependent on the exact configuration of the network and its loading. Therefore the estimated loss savings can show significant variations year-on-year and between scenarios”.[36]
>
> and
>
> “Volatility in the level of losses from year to year is the result of using only three snapshots per year.” [37]

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[36] Oxera (2006), p. 37.

[37] Oxera (2006), p. 39.

However, the cyclical nature of the benefits may reflect the time lag involved in transferring TLFs from the load flow model into the next year's despatch model.[38] Such time lags can create cyclical effects by causing overcompensation:

- in year 0, the despatch model predicts large north-south flows, so the load flow model calculates widely dispersed TLFs;
- in year 1, these large TLFs dramatically reduce north-south flows from the despatch model, so when this pattern of generation is fed into the load-flow model, it calculates narrowly dispersed TLFs;
- in year 2, the situation in year 0 is restored, and so on.

This volatility calls into question both the quality of Oxera's results, if they do not mimic reality, or alternatively the potential benefits of the scheme itself, if the pattern of generation is really as sensitive to errors in calculating TLFs as these results suggest.

2.9.2. Merit Order Analysis and Environmental Benefits

Oxera reports some potential environmental benefits in switching production from northern coal-fired plant to southern gas-fired plant. However, the extent of this switching depends, like the overall change in costs, on the form of the merit order. Such switching will only occur if the costs of southern gas-fired plant exceed the costs of northern coal-fired plant by less than the difference between their TLFs, in other words, if the introduction of TLFs varying by +/-5% can shift gas-fired plant from being more expensive to less expensive than coal-fired plant. Such switching may therefore be a function of particular fuel prices. Before making firm statements about the likelihood of this particular type of fuel switching, it would be necessary to investigate a number of updated scenarios.

2.9.3. Snapshot data

For computational reasons, Oxera relies on snapshot data, deriving results for three representative periods in every year (peak, midpoint and trough demand conditions). To aggregate the data to the whole of the year, Oxera used time-weighting coefficients. Since the three snapshots may not be typical of the three demand conditions, it is important to consider how sensitive Oxera's results are to changes in the time-weighting coefficients.

I therefore reviewed the effect of changing the time weights and found that in most cases it required major adjustments to the weights to vary the gross benefits significantly. The only exception is the weighting given to mid and trough results. Even shifting the "peak-mid-trough" weights from "10.4-73.8-15.8" to "10-80-10" caused a 12 % drop in gross benefits, implying that much of the benefit arises in relatively few trough hours. It would therefore be worth investigating other trough hours, to see whether Oxera's results were typical.

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[38] Oxera (2006), p. 7.

2.10. Environmental Implications

Finally, to investigate the possibility of zonal loss charges affecting renewable generation investments, Oxera used its Renewables Obligation model. Results are only reported in the form of a figure.[39] Oxera concludes:

> "When the underlying results of all scenarios are analysed, it is shown that the build decisions of individual renewable sites—either embedded or transmission-connected—are not affected by the introduction of zonal loss charging. Therefore, while there may be some distributional impacts, there are no net welfare losses or benefits to the system as a whole.
>
> In summary, due to the design of the Renewables Obligation (specifically its bluntness as a policy tool) and non-economic difficulties in obtaining significant volumes of onshore wind new build in the early years, the introduction of zonal loss charging will have little, if any, impact on renewable new build across the period to 2015/16." [40]

Given the information provided by Oxera, the analysis of renewables remains a "black box" that I cannot independently verify. If GEMA wishes to place any weight on this finding, it would be desirable to support it with a more transparent analysis.

2.11. Conclusions

My review of the Oxera report identified a number of areas where conditions have clearly changed since 2006 and the results deserve to be updated. I also identified cases where there may have been problems with Oxera's method of modelling, which led to inaccuracies, double-counting or false cyclical lags.

However, from the point of view of a regulatory decision process, the main difficulty I found was that Oxera's analysis lacked the necessary transparency, so that it was impossible to check whether it had been carried out correctly.

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39 Oxera (2006), p. 56, Figure 5.1.

40 Oxera (2006), p. 56.

3. Regulatory Risk

In this section, I respond to comments in the Minded-to Decision on regulatory risk and the implications for the cost-benefit analysis of the Proposed Losses Modifications.

In Section 3.1, I recap discussions of the nature of regulatory risk. In Section 3.2, I relate these concepts to transmission losses and in section 3.3 I comment on Ofgem's discussion of the issue.

In sections 3.4 to 3.6, I respond to the comment in paragraph 3.28 of the Minded-to Decision that no respondent has provided data on the impact of hedging. In these sections, I provide a quantified estimate of the benefits of reducing regulatory risk and show that it far outweighs the costs of implementing a hedging scheme.

3.1. Regulatory Risk

As noted in paragraph 3.19 of the Minded-To Decision, Teesside Power Ltd (TPL) submitted a paper by NERA on regulatory risk,[41] which explained the economic theory as to how regulatory risk affects the cost of capital. Ofgem accepted the potential existence of these effects in the Minded-to Decision (paragraph 3.19-3.20), but suggested that regulatory risk is limited to the period leading up to the final Decision. The following section refers to other recent writings on the subject of regulatory risk, by government and multi-national bodies, and explains why Ofgem is wrong to consider the final Decision as ending regulatory risk in relation to the allocation of transmission losses.

3.1.1. Attracting Capital

Investment in new generation capacity involves irreversible investment in a long-lived asset – i.e. investors are laying out a sum of money that cannot be recovered except through the revenues that the asset will earn. Before investors and companies will make such an irreversible, long-lived investment, they must be convinced that the project will earn a return (after recovering the costs of the investment and operating expenses) that provides adequate recompense for the time value of money and the risks they are taking on. Otherwise, such projects will not attract capital from the private sector.

As the International Energy Agency (IEA) writes:

> "Access to capital depends on the risk and reward profile of the investment concerned, as well as on the availability of financial resources and mechanisms. For the energy sector to attract adequate funding for investment, it must offer term and rates of return which compare favourably with those offered in other sectors, taking into account the different risk profiles." [42]

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[41] NERA (2006), *Regulatory Risk and the Cost of Capital*, NERA, London, 28 June 2006.

[42] IEA (2003), "World Energy Investment Outlook – 2003 Insights", 2003, p. 65.

Risks can arise from a number of sources. The IEA[43] differentiates between (1) economic risks, (2) political risks, (3) legal risks and (4) force majeure risk. Under the second category, political risk, the IEA defines three sub-categories, (i) regulatory risk, (ii) transfer-of-profit risk and (iii) expropriation/nationalisation risk. In this case, the effect on the profits of different generators represents a regulatory risk, within the general heading of political risk.

The effect of higher regulatory risk is that fewer investment projects offer rates of return that sufficiently compensate investors for the risk, so that fewer investments are carried out. This point is particularly important for investments in the energy sector, because energy projects are usually very capital intensive.[44]

3.1.2. The Value of Waiting[45]

The effect of regulatory risk on required returns comes primarily from the value of waiting for regulatory risk to disperse or reduce (which is not to rule out other sources not considered here). A firm that faces uncertainty about the prospects of an investment project may benefit from waiting before it commits funds to the project, if waiting reduces the uncertainty, e.g. through the disclosure of new information. If the investment is (in large part) irreversible, a firm that invests immediately will face whichever prospect materialises. However, if the firm waits (at the cost of foregoing some early profits), it retains the option of ***not*** investing in the event that prospects actually turn out to be unfavourable. The value associated with this option is called the "option value" of waiting. Dixit and Pindyck point out in their seminal work on investment under uncertainty that

> "[w]hen a firm makes an irreversible investment expenditure, it exercises, or 'kills,' its option to invest. It gives up the possibility of waiting for new information to arrive that might affect the desirability or timing of the expenditure; it cannot disinvest should market conditions change adversely. *This lost option value is an opportunity cost that must be included as part of the investment*." [46]

The UK Energy Research Centre (UKERC), a government funded body carrying out research on the energy sector, has recently issued research papers that take these developments in economic theory and convert them into practical lessons for government policy makers. These papers recognise the implicit value in waiting for regulatory risk to diminish, and how this value affects the net present value (NPV) that investors require of a project:

> "[…] there is a financial benefit to waiting until after T_p [the expected time of some policy change] when information is available on how the new policy will affect the project.…The option value of waiting therefore creates an additional financial threshold that the project must exceed in order to justify immediate

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43 IEA (2003), "World Energy Investment Outlook – 2003 Insights", 2003, p. 67.

44 IEA (2003), "World Energy Investment Outlook – 2003 Insights", 2003, Figure 7.4, p. 345.

45 For a more detailed analysis see UKERC (2006a), "Factoring Risk into Investment Decisions", Working Paper, November 2006.

46 Dixit, Avinash K., and Robert S. Pindyck (1994), "Investment under Uncertainty", Princeton University Press, 1994, p.6. Emphasis added.

> investment. The criteria for investment is (sic) therefore no longer that the project should exhibit a positive expected NPV, but that the expected NPV should exceed some minimum threshold which is essentially a risk premium."[47]

Thus, in conditions of regulatory risk, investors will tend to delay investment decisions when facing regulatory risk, or demand a premium for proceeding with investment before uncertainty about a policy decision has been resolved. This "risk premium" arises because the reward for investing immediately has to compensate the investor both for using scarce capital and for exercising the option (to delay).

Regulatory risk therefore affects welfare negatively:

1. by reducing the total amount of investment, because capital will only be attracted to those investments that offer a return high enough to compensate for regulatory risk; and/or

2. by delaying investments, because of the option value of waiting until regulatory policy is clarified.

Some types of risks can be mitigated by sharing them with other parties, or by transferring them to others, through agreements and contracts. Such risk mitigation methods are less often available for political and regulatory risks. The UKERC observed in relation to policy-related risks that "[u]nlike other more technical risks, these are very difficult to mitigate."[48] The UKERC was writing about risks attached to "policy-created markets" intended to support investment in certain technologies (such as renewable energy sources), but the statement is equally valid for the design of centralised electricity trading institutions intended to support efficiency and competition in the electricity generation sector.

Because regulatory risk discourages investment and/or raises costs, it is in the interests of consumers to minimise regulatory risk.

3.2. Zonal Transmission Losses and Regulatory Risk

In this section I discuss how the case of transmission losses exposes generators to regulatory risk and how Ofgem has defined and discussed this regulatory risk.

3.2.1. Generators' exposure to regulatory risk

The method of allocating (and therefore charging for) transmission losses affects the profit stream of electricity generators. To the extent that the associated rules are not irrevocably determined over their investment horizon, electricity generators face a regulatory risk. Electricity suppliers on the other hand are less exposed, since their commitments only last as long as their current fixed price contracts with customers. Such contracts rarely last longer than a year and few last longer than two years. Given the time it will take to implement any

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47 UKERC (2006a), "Factoring Risk into Investment Decisions", Working Paper, November 2006, pp. 9-10.

48 UKERC (2007), "Investment in electricity generation – the role of costs, incentives and risks", May 2007, p. 55.

new arrangements for allocating transmission losses, the associated regulatory risk is only significant for electricity generators. (This difference in exposure to risk may have implications for the discussion of discrimination.)

In paragraph 3.20 Ofgem acknowledges the existence of regulatory risk and makes a number of claims about the nature and extent of regulatory risk in the context of transmission losses.

First, Ofgem claims that the risk would disappear once a decision has been taken:

> "[…] this type of regulatory risk only applies in the period until the decision is made, whereas making that decision (whether it is to approve or reject) removes the risk by removing the uncertainty." [49]

Second, Ofgem notes that there is a certain amount of underlying regulatory risk, which is best minimised by adopting sound methods of reaching decisions:

> "We note that more generally, regulatory risk is an inherent feature of the current governance arrangements in which industry parties can propose modifications which may have a significant commercial impact on other parties. We consider that this risk is minimised where the Authority's decisions on those proposals are made in accordance with a sound regulatory process and against clear objectives and duties." [50]

Finally, Ofgem claims that the amount of regulatory risk is small even before the decision is made:

> "[…] given the history of this subject, parties should have anticipated the potential for industry proposals to be raised to introduce locational losses." [51]

Ofgem therefore concludes that making a decision to approve any of the zonal losses proposals would not have a significant impact on risk and the cost of capital. However, these statements are not a correct or complete description of the regulatory risk facing investors in generation capacity.

3.2.2. The nature and duration of the regulatory risk

On 18 May 2007, I wrote to David Gray in connection with documents released under the Freedom of Information Act, informing him that it was not correct to regard regulatory risk as existing only until the time of a decision on the Proposed Modifications. I pointed out that some risk would remain, since there would remain scope to introduce at a later date either a wider or a narrower difference between transmission loss factors in different parts of the country. The Decision does not consider that possibility.

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[49] Ofgem (2007), paragraph 3.20.

[50] Ofgem (2007), paragraph 3.20.

[51] Ofgem (2007), paragraph 3.20.

Even if GEMA believes that P203 offers benefits over the current system, there is no guarantee that GEMA's decision will represent the final word on the subject over future investment horizons.

The Government has opted for flat rate losses when given a choice in the past and may do so again, for any number of policy reasons.

§ *A reversion to (or towards) flat rate losses cannot therefore be ruled out entirely.*

On the other hand, all of the Proposed Modifications currently being considered allocate transmission losses on the basis of a scaled version of marginal costs. However, economic theory suggests that efficiency gains would be larger if transmission losses were allocated on the basis of full marginal costs.

Furthermore, Appendix 3 to the Minded-to Decision contains some algebra explaining that the ***under***statement of marginal costs in ***scaled*** transmission losses is offset by an equal ***over***statement of marginal costs in Transmission Network Use of System (TNUOS) charges.[52] The analysis is devoid of time subscripts, meaning that this equality applies only over an equivalent time period – essentially a year (as represented by the time period for calculating TNUOS charges). Over a year as a whole, the balance of losses and TNUOS charges affects baseload plant differently from mid-merit and peaking plant. Mid-merit and peaking plant pay the overstated TNUOS charges but do not receive an equivalent benefit from the reduction in liability for transmission losses in off-peak periods. At some point, Ofgem may wish to unwind this implied cross-subsidy between plant types, in order to promote economic efficiency and to enhance competition.

§ *A further change towards full marginal losses (with or without a shift towards restated marginal costs of transmission) cannot therefore be ruled out entirely either.*

Ofgem maintains that a decision "made in accordance with a sound regulatory process against clear objectives and duties" will serve to minimise regulatory risk, but in this context it does not eliminate it. Ofgem's point is, I believe, that sound regulatory procedures ought to lead to the best possible outcome – and therefore the outcome most likely to persist (= most stable). This statement may be true for unfettered regulatory decisions, but GEMA's final decision in this case is not unfettered. GEMA can only choose from among the Proposed Modifications on offer, a limited sub-set of what is possible. Therefore, no matter how sound the process that Ofgem and GEMA adopt at this point, there is nothing to guarantee that the Proposed Modification finally selected is the best possible outcome. There remains scope for someone to propose another Modification that meets the necessary criteria even better and so leads to a further change in the rules. This process of repeated Modifications need not last forever – since the best possible and most stable outcome may finally emerge – but regulatory risk will remain a feature of the system for as long as this process continues.

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[52] This condition holds for generation capacity in the northern half of the system. For generation capacity in the southern half of the system, this explanation should be couched in terms of an understatement of the *benefit* from a negative transmission loss factor being offset by an overstatement of the *benefit* from avoided transmission costs. For the sake of clarity, I have omitted such complicated cases, but the effect is the same algebraically and in principle, changing whatever needs to be changed.

Finally, the "history of this subject" does not seem conducive to the reduction of regulatory risk. Ofgem may believe that the outcome is a foregone conclusion, but what matters for investment is what investors think. Given the observed reverses to GEMA's decisions, the potential for future political decisions to override GEMA decisions, and the ability of BSC signatories to raise further modifications, only a very narrow view of the world would indicate that a final Decision by GEMA on the Proposed Losses Modifications that currently stand before it would be the final word on this topic.

3.2.3. Potential to mitigate regulatory risks

The difficulty of mitigating policy/regulatory risks was noted by the UKERC and is particularly important in the context of transmission losses. The estimated benefits of the Proposed Losses Modifications depend on the continuation of efficient investment. However, the difficulty of mitigating future regulatory risks may lead investors to select sites for new generation inefficiently. They may, for example, mitigate those risks by diversifying their investments, or delaying investment until the benefits of "investing now" outweigh the benefits of waiting a little longer to find out where is the best place to invest.

In this case, diversification includes locating new plant (and plant-life extensions) in a variety of locations, in order to spread the risk of any future change in the allocation of transmission losses. Diversification in the face of regulatory risk is not efficient, nor is it an outcome that GEMA would seek, given its statutory duties.

Decisions based on a sound regulatory process and against clear objectives and duties may help to ***reduce*** regulatory risk, but GEMA could lower regulatory risk further on new investment by showing it was willing to limit the exposure of past investments to changing regulatory environments, for example, through the use of hedging schemes.

In the way it takes decisions, GEMA can establish a reputation for, or an observed track record of, limiting the exposure of past investments to changes in the rules – or it can allow regulatory risk to have an undiluted effect. If GEMA takes steps now to mitigate the effects of regulatory risk, investors would perceive a greater chance of their investments being protected against future changes to the regulatory framework. In the current context, P200 and its Alternative and the "phased" Alternative to P198 all offer such possibilities (although they have different consequences for efficiency – see below).

There is no new investment associated with existing power stations and it might therefore seem unnecessary to offer protection for existing investors, or necessary only to offer protection to new generation plant from now on. However, investors in new plant would be vulnerable to the same argument, once they had committed their funds. Investors in new plant will not have much confidence in any protection offered to them, if GEMA showed no concern over the plight of existing investors once they had made their investment.

It might be argued that risk mitigation only needs to start after this decision and that existing generators should (or would) have argued for protection against regulatory risk in advance, if it was important to them. In fact, a generator did propose a modification similar to P200 before, but it was disallowed because it was not dealing with an observable defect in the BSC at that time.[53] Apparently, the mitigation of regulatory risk can only take effect in the BSC when the risk comes to pass and risk mitigation measures cannot be passed through the BSC Modification Process until a relevant modification is proposed.

Given the significance of the Proposed Loss Modifications (and the potential for further changes), the implementation of a risk mitigation measure would have a significant impact on perceptions of risk. It would enable investors to have greater confidence in the current rules, knowing that future changes to the rules will not significantly affect the value of their investments. Importantly, such a policy would imply there were no value in waiting and therefore no option value in not investing. Instead, investors would be able to react immediately to the investment signals given by today's rules.

The inclusion of risk mitigation might therefore actually strengthen the incentive properties of the new zonal loss factors, by removing the need for inefficient diversification.

3.3. Ofgem's Interpretation of the Hedging Scheme in P200

Before discussing the costs and benefits of mitigating regulatory risk, it is necessary to correct an error in the description of P200 (and P200 Alternative) in the Minded-to Decision, which affects the associated benefits. Correcting this error shows that the difference between these modifications and P198 or P203 lies entirely in their mitigation of regulatory risk (which I show below to be a significant impact) and costs of implementation (a minor impact). There is however no difference in their effect on the short-term efficiency of despatch, contrary to certain statements in the Minded-to Decision.

In paragraph 3.34 Ofgem criticises the hedging scheme, because it will lead to "inaccurate signals" over time:

> "[…] with the allocation of losses being determined based on historic volumes from a single historical year, over time the F-factor volumes are likely to become less reflective of parties' positions, and thus to lead to less accurate signals and ultimately to less efficient decision making on the part of industry participants."

This interpretation of P200 and P200 Alternative is incorrect. Ofgem does not define what it means by the "accuracy" of the F-factor, but I presume it means the accuracy with which the F-factor mimics the actual output of the generator in future years. Such concerns are irrelevant to any consideration of the efficiency gains provided by P200 and P200 Alternative.

The efficiency of the signals (or, rather, the efficiency of generators' response to those signals) depends on the values of the TLF "at the margin", i.e. the value of the TLF which applies to generators' decisions to increase or decrease their output. The F-factor is a quantity of losses, allocated to a generator in recognition of past levels of generation. This allocation goes some way to offsetting the change in allocated losses due to the introduction

[53] P109 was a previous attempt to introduce a prospective system of risk mitigation through hedging which was not linked to any particular modification to the way losses were allocated. The BSC Panel rejected the proposal in part because of advice that such "contingent" measures were not possible under the rules. P200 and P200 Alternative are not "contingent" on any other changes.

of TLFs based on scaled marginal losses. (The quantity of the F-factor can be positive or negative, so that it offsets both increases and decreases in TLFs.) However, this fixed quantity does not depend on, and does not affect, generators' decisions about their levels of output.

3.3.1. Legal text

The proposed legal text[54] for P200 defines the hedged quantity ($QHED_{ij}$) as follows:

$$QHED_{ij} = QH_{ij} - QNH_{ij}$$
$$= (ALF_j * F_i) - (ZLF_{ij} * F_i) = (ALF_j - ZLF_{ij}) * F_{i.}$$

Hence, the quantity of hedged losses for each generator i in half-hour j depends on (1) a fixed F-factor (F_i) and (2) the difference between average losses assigned to generators under the current scheme (ALF_j) and the new zonal TLF applicable to the generator (ZLF_{ij}). This quantity of hedged losses does not depend on any current or future actions of the market participants, so it does not offer any incentive for generators to change their output.

The remainder of the settlement formulae assign the zonal loss factor, ZLF_{ij}, to the total output of any generator. According to the proposed legal text,[55]

$$UQCE_{iaj} = (QM_{ij} * TLM_{ij}) - [\varepsilon]$$

Where $TLM_{ij} = 1 + ZLF_{ij} + [\omega]$

Thus, for any MWh of output that a generator chooses to produce (QM_{ij}), it receives the same allocation of losses as all other generation capacity within the same zone, based on the same zonal loss factor.[56] This zonal loss factor determines the incentive of that generator to generate, irrespective of the level (or of any "inaccuracy in the level") of the F-factor. Thus, P200 and P200 Alternative provide the same incentives for efficient despatch as P198 and P203 respectively, but offer the additional advantage that they mitigate regulatory risk. This effect on incentives is quite different from the effect of "phasing" the introduction of zonal loss factors, as in P198 Alternative, which affects the value of zonal loss factor used in different years.

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54 Revisions to BSC section T.2.4, from appendix to Elexon (2006), *Assessment Report for Modification Proposal P200, 'Introduction of a Zonal Transmission Losses Scheme with Transitional Scheme',* document reference P200AR, version 2.0, 18 August 2006.

55 Revisions to BSC section T.2.4, rules 4.5.1(b) and 2.3.1(a). In the reduced form equations given here, ε represents an adjustment for other parties operating within a Balancing Mechanism Unit, whilst ω represents $TLMO+_j$, the flat rate adjustment to ensure generators pay 45% of total transmission losses

56 The formula for zonal loss factors includes a flat-rate mark-up to balance losses allocated this way against the total of the actual volume of losses and the total net volume of hedged losses. This flat-rate mark-up does not affect the incentive to despatch one generator rather than another and so has no implications for the efficiency of despatch.

3.3.2. Implementation Costs

The Assessment Report for P200 produced by Elexon records the views of a minority of Modification Group members that the F-factors might encourage closure of plant in the south of the country.[57] Under P200 and P200 Alternative, investors would remain liable for F-factors even after closing plant (to preserve the incentive properties of the TLFs). This view could not therefore have been based on the ability to avoid F-factors by closing real generation plant, but rather by the concern that southern generators might evade their F-factors by closing down Balancing Mechanism Units (BMUs) associated with existing generators and opening new BMUs for the same plant re-labelled as a "new" generator (which would not attract an F-factor). The Modification Group recognised that such manoeuvres would require extra policing by Elexon, but such policing would only affect Elexon's cost of administering the F-factors, as noted by Ofgem at paragraph 4.57. These manoeuvres would not affect the efficiency of despatch, since they would by definition involve the resumption of normal operations at southern generation plant, even if it was (mistakenly) relabelled as a "new" generator.

Ofgem is therefore wrong to state that the F-factor would lead "ultimately to less efficient decision making on the part of industry participants" in paragraph 3.34 and at points where the error is repeated in paragraphs 4.23, 4.30, 4.49, 5.6, 6.10, 6.17, 6.38 and (by implication) 7.11.

3.4. Numerical Estimate of Costs of Regulatory Risk

In paragraph 3.28, Ofgem argues that it is difficult to model the impact of proposals P200 and P200 Alternative and therefore only assesses these proposals qualitatively. However, it is possible to estimate the benefits associated with the risk hedging aspects of these Proposed Modifications, using information already available to Ofgem.

In the 2006 report for Teesside Power Ltd,[58] NERA estimated the increase in the cost of capital due to regulatory risk for a set of circumstances similar to those relating to the treatment of transmission losses. As already discussed in Section 3.1.2, investments in power stations are like exercising an option – once the investor has committed funds to the project, there is no way back. In some conditions, uncertainty lends additional value to the possibility of waiting, which means that the project must offer a higher rate of return, if investors are going to invest now. The most modern theories of the cost of capital analyse investments using a decision tree to examine the possibility of exercising the option now or waiting till later. NERA's 2006 report used a decision-tree to estimate the premium required to overcome the value of waiting and hence to estimate the effect of regulatory risk on the required rate of return and the cost of investing in generation capacity.

The key points of the model presented in the NERA report were:

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[57] Elexon (2006), ***Assessment Report for Modification Proposal P200, 'Introduction of a Zonal Transmission Losses Scheme with Transitional Scheme'***, document reference P200AR, version 2.0, 18 August 2006, pp 40-41.

[58] NERA (2006), ***Regulatory Risk and the Cost of Capital,*** 28 June 2006.

1. Future returns are uncertain, because of regulatory risk;
2. In the model, the regulatory risk is symmetric (i.e. the upside risk is as big as the downside risk);
3. The uncertainty over future returns caused by the regulatory risk would be resolved (or reduced) within the project's lifetime.

Condition 2 is not necessary for the theory to apply, but indicates that the result does not depend on the existence of asymmetric risks, or regulatory penalties. The rise in the cost of capital is caused by the mere existence of regulatory risk, not by a particular kind of risk.

In the model, a risk affecting the annual returns to a project is resolved in year 4 of a 15-year project. The 4-year gap reflects the time period between P82 and P198 and therefore realistically reflects the time period between proposals to modify the allocation of losses. The base case variation in the project's annual margin is +/-4%, equivalent to +/-2% on annual revenues, if the annual margin is about half of revenues. As noted in the NERA report, changes to TLFs can easily affect revenues to power stations by +/-2%. The effect of this regulatory risk is to raise the required rate of return from 10% p.a. to 10.16% p.a.

The model allows simulation of different risk structures and timing. The table below shows the effect of assuming that regulatory risk would be resolved (and investment would take place) after different numbers of years. Assuming that regulatory risk would be resolved earlier has the effect of increasing the premium due to regulatory risk.[59] Similarly, assuming it will take longer to stabilise or clarify the rules tends to reduce the premium attributable to regulatory risk. However, the premium is still present in the same order of magnitude, for any period of 1 to 7 years.

Table 3.1
Regulatory Risk Premium for Different Delays

Uncertainty Resolved in Year	1	2	3	4	5	6	7
Regulatory Risk Premium	0.21%	0.19%	0.18%	0.16%	0.14%	0.13%	0.12%

A premium of 0.16% (0.16 percentage points or 16 basis points) per annum may not seem like a large increase in the rate, but in a capital intensive industry like electricity generation it translates into a large amount in absolute money terms – particularly relative to the estimated cost of implementing F-factors as a risk mitigation measure. The benefit of avoiding or reversing even this increase in the required rate of return, when applied to forthcoming investments in generation capacity, would be enough to offset the additional costs of implementing F-Factors under P200. Hence, whether or not P198 is desirable on its own, additional benefits of implementing P200, relative to P198, would outweigh the additional costs. Thus, a proper consideration of regulatory risk could tip the balance between different Proposed Losses Modifications.

[59] The effect of shortening the period until the uncertainty is resolved is to *increase* the premium demanded by investors to invest immediately, because it becomes less costly to wait in terms of foregone income. Similarly, pushing back the date when the uncertainty is resolved reduces the premium demanded by investors; they are more likely to invest immediately because waiting would imply foregoing income over a greater number of years.

3.5. Effect on the Cost of Investment

In order to estimate the absolute cost of regulatory risk, I calculated the level of total new investment in generation capacity in the coming years and the effect of increasing the required return on this investment by 0.16%. To estimate new investments, I used the additions to generation capacity contained in Platts Powervision database and currently marked as "under construction" or in a state of "advanced development". Such projects offer the opportunity to delay investment. Some of the costs of the plant under construction may already have been incurred, but on the other hand additional projects will also arise in later years. (National Grid's Seven Year Statement shows much higher figures for generation projects, but some may not enter the construction phase in the period of concern.) Hence, I do not believe this approach will overestimate the cost. The figures from Powervision are summarised in Table 3.2.

Table 3.2
Generation Capacity Additions by Plant Type (MW)

Plant Type	2007	2008	2009	2010	2011	2012	2013
CCGT	0	885	1,370	0	1,200	0	0
OCGT	0	0	0	93	0	0	0
Wind	270	160	1,863	376	0	0	0
Waste	117	72	0	0	0	0	0
Hydro	0	6	100	0	0	0	0
Total	387	1,123	3,333	469	1,200	0	0

Source: Platts Powervision; NERA calculations

I derived estimates of the capital cost of this plant from the DTI's 2006 Energy Review (Table 3.3), to obtain an estimate of new investments over the next seven years (Table 3.4). I used only the cost information for CCGTs (without carbon capture and storage - CCS) and for wind power. I assigned zero cost to waste and hydro plant, because neither the DTI nor the OECD reports any cost for such plant. I also used the cost of onshore wind farms for all wind projects, because Powervision does not distinguish between onshore and offshore wind. Offshore projects are more expensive than onshore projects, so the figures in Table 3.4 understate the total cost of future investment in wind generation capacity.

Table 3.3
Capital Cost Estimates (£/kW, prices of 2007)

Plant Type	
CCGT	450
CCGT with CCS - low	847
CCGT with CCS - high	714
Onshore wind	838
Offshore Wind	1,567

Source: NERA calculations based on DTI[60] and OECD.[61]
Note: The cost estimates in the DTI were updated to 2007 prices using the inflation rate published by the OECD (2.3%).

Table 3.4
Expected Future Investments (£million, prices of 2007)

Plant Type	2007	2008	2009	2010	2011	2012	2013
CCGT	0	398	617	0	540	0	0
Wind	226	134	1,561	315	0	0	0
Total	226	533	2,177	315	540	0	0

Source: NERA calculations based on Platts Powervision database, DTI[62] and OECD.[63]

On the basis of Table 3.4, I calculated the extra cost of raising the cost of capital by 0.16% due to the increased regulatory risk. In a single year this is equivalent to expected investment multiplied by the premium of 0.16%, as shown in the second line of Table 3.5.

Table 3.5
The Effect of Raising the Regulatory Risk (£million, prices of 2007)

	2007	2008	2009	2010	2011	2012	2013
Investments	226	533	2,177	315	540	0	0
0.16% x Investments	0.4	0.9	3.5	0.5	0.9	0.0	0.0
Cumulative Investments Net of Depreciation	226	747	2,887	3,055	3,433	3,243	3,053
0.16% x Cumulative Investments	0.4	1.2	4.6	4.9	5.5	5.2	4.9

Source: NERA calculations based on Platts Powervision, DTI[64] and OECD.[65]

60 DTI, "Energy Review 2006: The Energy Challenge", Annex B, p. 194 (downloaded from the internet: http://www.berr.gov.uk/files/file32014.pdf)

61 OECD, "Economic Outlook", May 2007, Annex Table 18.

62 DTI, "Energy Review 2006: The Energy Challenge", Annex B, p. 194 (downloaded from the internet: http://www.berr.gov.uk/files/file32014.pdf)

63 OECD, "Economic Outlook", May 2007, Annex Table 18.

64 DTI, "Energy Review 2006: The Energy Challenge", Annex B, p. 194 (downloaded from the internet: http://www.berr.gov.uk/files/file32014.pdf)

65 OECD, "Economic Outlook", May 2007, Annex Table 18.

The basis of the 0.16% increase in the required rate of return is an assumption that the regulatory risk is resolved in year 4, meaning 2011 for a calculation as of 2007. The effect on costs is therefore limited to the years 2007-2010. To calculate the additional cost of raising the cost of capital during these years, I calculated the cumulative investment, net of depreciation[66] (line 3 of Table 3.5) and multiplied the result by the 0.16% risk premium (line 4 of Table 3.5). Over a time period of four years (shaded grey in Table 3.5), the total undiscounted increase in costs is £11.1 million in prices of 2007. Discounted to 2007 at a real discount rate of 10% per annum, the net present value of this amount is £8.9 million.[67] Even for the period 2009-2010 only (i.e. the period for which no costs will so far have been committed), the total undiscounted increase in costs is £9.5 million in prices of 2007, corresponding to a net present value discounted at 10% of £7.5 million in 2007.

3.6. Effect on Prices

Another approach to estimating the impact of regulatory risk is to estimate the increase in prices, and hence in the cost of electricity, due to the increase in the required rate of return. Oxera, in its cost-benefit analysis of P198, assumes that new entry will take the form of CCGT plants.[68] From the point of view of price setting, I also believe this is a reasonable approach. Table 3.6 shows the assumptions I used to estimate the new entry price of a CCGT power plant, and their sources.

Table 3.6
Assumptions

CCGT	
Plant Total Capacity (MW)	500
Net Efficiency (HHV) (Average during operation)	0.522
Availability	0.85
Construction Period (years)	3
Plant Life (years)	20
Capital Cost (£/kW)	450
O&M Cost (£/kW)	7.161
O&M Cost (£/MWh)	2.046

Source: DTI[69] and OECD.[70] Note: The cost estimates in the DTI were updated to 2007 prices using the inflation rate published by the OECD (2.3%). The plant life of 20 years is a NERA assumption. The DTI/DBERR website suggests 35 years, but this figures appears to be too long unless one allows for the cost of refurbishment.

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66 Using straight line depreciation, assuming an asset life of 20 years.

67 The Minded-to Decision uses a discount rate of 3.5% per annum, at which the net present value is over £10 million.

68 Oxera (2006), p. 13.

69 DTI, "Energy Review 2006: The Energy Challenge", Annex B, p. 194 (downloaded from the internet: http://www.berr.gov.uk/files/file32014.pdf). See also the financial model contained in the spreadsheet entitled ***http://www.berr.gov.uk/files/file32814.xls*** and available at http://www.dti.gov.uk/energy/review/models/page32771.html

70 OECD, "Economic Outlook", May 2007, Annex Table 18.

Using this data, I estimated the price at which new entry would occur, assuming that these prices would be reached in 2010, which is the year Oxera identified as the year when new entry will occur in its central scenario.[71] (In other scenarios, entry occurs even earlier, which would increase the impact.) Given the need to encourage entry of new generation capacity, expected electricity prices have to increase to a level sufficient to cover total costs. The calculation of this level is set out in Table 3.7.

Using the data in Table 3.6, I estimated that an increase in the required rate of return from 10.00% to 10.16% would increase prices by £0.07 per MWh. Given an expected level of output in 2010/11 of 361.2 TWh, the total value of the price increase would be approximately £24.3 million in 2010/11, or £18.2 million discounted at a real rate of 10% per annum by three years (to 2007/08).

Table 3.7
Price Increase Due To Higher Capital Costs

New entry price @ 10%	£35.776 /MWh
New entry price @ 10.16%	£35.843 /MWh
Increase in new entry price	£0.067 /MWh
British Grid Demand (2010/2011)	361.2 TWh
Total increase in cost of electricity purchases	£24.280 million

Source: NERA calculations based on DTI[72] and National Grid.[73] Note: The demand level corresponds to National Grid's forecast for 2010/11.

3.7. Conclusions

In this section I have calculated the costs associated with regulatory risk, using the method set out in NERA's report of 28 August 2006 and publicly available data.

There is widespread consensus that regulatory risk encourages investors to delay until the risk diminishes and that investors require a higher rate of return to invest in the interim. Ofgem's paper acknowledges this view, but assumes that the regulatory risk will only last until the Decision is made. In this report, I have pointed out why the allocation of transmission losses will continue to be subject to regulatory risk for some years after the Decision is made.

Ofgem notes that the cost of implementing the Proposed Losses Modifications without hedging is around £470,000, whilst the cost of implementing P200 and P200 Alternative would be around £850,000, including an additional £380,000 for the cost of setting up the F-factors.[74] The cost of running P198 is estimated as £160,000 per annum. Even if policing F-

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71 Oxera (2006), pp. 15-17.

72 DTI, "Energy Review 2006: The Energy Challenge", Annex B, p. 194 (downloaded from the internet: http://www.berr.gov.uk/files/file32014.pdf)

73 National Grid, Seven Year Statement 2007, Table 2.3. (Downloaded from the internet on 11/07/07 on: http://www.nationalgrid.com/uk/sys%5F07/dddownloaddisplay.asp?sp=sys_Table2_3#; and http://www.nationalgrid.com/uk/sys%5F07/default.asp?action=mnch2_7.htm&Node=SYS&Snode=2_7&Exp=Y#National_Grid_Forecasts.)

74 Ofgem (2007), paragraph 4.53.

factors doubled this cost in every year of a 10-year appraisal period, the additional cost would have a net present value of less than £1 million.

The calculations above show that the additional implementation costs of F-factors pale into insignificance against the avoided cost of regulatory risk. The net present value of the benefit of reducing future regulatory risk runs into many millions of pounds, whether it is counted by reference to the additional cost of new investment (£7.5-8.9 million) or of higher electricity prices (£18.2 million).

The cost of this regulatory risk, even though defined as a small increase in the rate of return required by investors, is therefore significant in absolute terms. The hedging scheme built into P200 and P200 Alternative both protects existing generators from this regulatory risk and shows that future investment can be protected in the same way. Without such a scheme, future investment will be subject to regulatory risk and will have to offer investors a higher rate of return. This higher rate of return translates into a substantial increase in costs.

In comparison, the estimated cost of implementing F-factors is trivial. Even allowing for the costs of policing attempts to avoid adverse F-factors would not outweigh the net benefits of the hedging scheme. Overall, therefore, the hedging scheme in P200 and P200 Alternative offer a benefit relative to P198 and P203 (respectively), whose approaches to TLFs and benefits for short-term efficiency they mimic.

There are no grounds for Ofgem's suggestion that F-factors will lead to less efficient decision-making by generators in the future, and the final Decision should correct the impression given in the Minded-to Decision that it would. P200 and P200 Alternative therefore have no further impacts on the cost benefit analysis, since they offer the same incentives for short-term despatch as P198 and P203, respectively. With regard to longer term decisions, the potential availability of risk mitigation measures may even encourage investors to respond more efficiently to the new TLFs, rather than diversifying their investments (although the potential for such responses seems to be limited, according to Oxera's analysis).

In summary, the hedging arrangements in P200 and P200 Alternative offer a net benefit, relative to the schemes without hedging arrangements, arising from the proper consideration of regulatory risk.

4. Other Issues

The Oxera report and the Minded-to Decision raise a number of other economic issues which merit reconsideration in GEMA's final decision.

4.1. Discrimination

The Minded-to Decision says that P200 raises concerns over discrimination (paragraphs 5.6-5.7) and that it does not better facilitate the BSC objectives "on balance" (paragraph 5.8) largely because of these concerns about discrimination. The Minded-to Decision also rejects P200 and P200 Alternative by reference to GEMA's statutory duties (paragraph 6.38), owing to concerns over (1) discrimination and (2) "inefficient decision-making". I have already dealt with the error that led to the incorrect conclusion on decision-making in section 3.3.

The Minded-to Decision provides inadequate or conflicting analysis of discrimination, a deficiency that (especially in the light of the Competition Commission's decision on E.ON's appeal on Mod 116) should be addressed in the final decision.

In my experience, discrimination is defined in terms of different treatment of similar cases, or similar treatment of different cases, *without objective justification*. The Minded-to Decision refers to these criteria when considering the reason for implementing zonal loss factors (paragraphs 6.28-6.30) and also says that there is no objective justification for the hedging scheme (paragraph 6.30). However, the Minded-to Decision did not properly consider the benefits of mitigating regulatory risk, as set out in section 3 above.

In many cases, the Minded-to Decision refers to discrimination, but discusses it in other (i.e. irrelevant) terms.

Paragraphs 4.4 and 7.20 (2nd bullet) say that any modification resulting in "more cost reflective charging" would be likely to reduce the scope for discrimination. This approach seems to make non-discrimination synonymous with efficiency. Either discrimination should be considered separate from efficiency, or it should not count as a separate (additional) benefit to those already counted under the benefits to efficiency.

On the other hand, Paragraphs 4.5-4.6 note some differences in treatment under the hedging scheme components of P200 and P200 Alternative, but does not consider whether or not these differences cover similar cases, or whether the differences in treatment can be objectively justified. For instance, paragraph 4.6 mentions the exclusion of suppliers, but does not consider the point, made in section 3.2.1 above and elsewhere, that suppliers are not exposed to regulatory risk in the same way as generators, because the reallocation of transmission losses does not affect the value of long-term irreversible commitments by suppliers. The Modification Group considered the detailed coverage of the hedging schemes, but the Minded-to Decision does not take into account the Group's own reasons for adopting the rules that it did. In some cases, the proposal was adopted on grounds of administrative efficiency (ease or cost of implementation), which is a BSC objective and also an important consideration under GEMA's own statutory duties.

In general, therefore, the Minded-to Decision makes assertions about the potential for discrimination that are not backed up by a proper discussion of the reasons for the proposed treatment or its likely effects.

4.2. Competition

The discussion of competition is summarised in paragraphs 4.49-4.51 of the Minded-to Decision. However, this discussion does not describe any effects on competition that are distinguishable from effects on efficiency (or the implications of "more cost reflective pricing", or the "elimination of cross-subsidies", which are the same thing). As with discrimination, it would be wrong to count such effects twice, once as a benefit for efficiency and once as a benefit for competition.

In principle, any consideration of competition (as distinct from efficiency) would need to take in the effect of the proposals on the degree of rivalry between market players, or on the degree of market power possessed by market players. This would require at least some discussion of the willingness of new players or small companies to enter (or to remain in) the market for wholesale electricity, and hence of barriers to entering the market as a whole.

Barriers to entry are defined as costs that new entrants must incur, but which incumbents do not need to incur.[75] Instead, the Minded-to Decision considers (e.g. at paragraph 4.48) the impact of reallocating transmission losses on individual plants – but transmission losses are a cost that affects all generators, new and existing. The minded-to Decision does not therefore contain a proper consideration of barriers to entry or their effect on competition.

In practice, the reallocation of costs associated with transmission losses may not have a major effect on competition (as distinct from efficiency). The additional administrative costs of managing zonal loss factors might create a small barrier to entry, once incumbents have incurred the additional costs of managing them. However, discussion of the impact of the zonal loss factors themselves, of reallocation of costs, or of elimination of "cross-subsidies", has no part in the discussion of competition and is already covered by the discussion of efficiency.

4.3. Distributional Impact

The Minded-to Decision notes in paragraph 4.49 that P198 and P203 would have the biggest distributional effect, but does not consider whether this distributional effect is necessary to achieve the desired outcomes. This omission likely to be due to (1) GEMA's error in misunderstanding the efficiency consequences of P200 and P200 Alternative, and (2) GEMA's earlier (and unjustified) rejection of P200 and P200 Alternative due to concern over discrimination. However, I have shown above how these aspects of the decision have not yet received adequate consideration. GEMA's final Decision should therefore consider whether the greater distribution impact of P198 and P203 is necessary.

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75 See, for instance, W. Baumol, and R. Willig, "Fixed Costs, Sunk Costs, Entry Barriers and Sustainability of Monopoly", Quarterly Journal of Economics, 1981, p. 408.

The distributional impact of the proposals is significant, relative to the forecast benefits. Oxera's report describes the transfers between generators resulting from the introduction of zonal loss factors in tables 9.3 to 9.10 of the July 2006 report. (Oxera also summarises the impact on "suppliers" but, as explained above, suppliers can pass through this impact to their customers within a year or two, whereas generators must live with the implications for the remaining life of their plant.) A couple of examples will serve to summarise these results.

Table 9.3 shows transfers resulting under Oxera's "central" scenario (which corresponds to P198) for 2006/07. The sum of losses accruing to generator capacity in the north is £89 million and generator capacity in the south receives an equivalent benefit. This annual transfer applies to a scenario in which the total present value of net benefits due to the reduction in losses is only £21.1 million for the whole 10-year period from 2006/07 to 2015/16.[76]

Table 9.6 shows transfers resulting under Oxera's "seasonal" scenario (which corresponds to P203) for 2006/07. The sum of losses accruing to generator capacity in the north is £84 million, whilst generator capacity in the south benefits by £80 million. (Oxera did not explain why these figures are not equal and opposite.) Even against a higher net present value of benefits of £65.7 million over 10 years, these annual transfers are significant.

P200 and P200 Alternative offer means to achieve the same efficiency gains, for much lower transfers between players. The final Decision should consider whether this feature would affect the relative merits of each scheme.

4.4. Conclusions

The Minded-to Decision does not provide an economically coherent discussion of discrimination or competition that is distinguishable from the previous discussions of efficiency. GEMA's final Decision should provide a separate analysis of discrimination and competition, with a full description of the expected effects, or else recognise that the effects are already taken into account as efficiency gains.

The treatment of P200 and P200 Alternative should consider discrimination, in particular, using legally relevant criteria to determine whether discrimination is occurring and taking into account potential objective justifications for any discrimination that is identified.

This consideration should take into account the observation that annual transfers between generators under P198 and P203 are many times larger than the estimated annual benefits, but that P200 and P200 Alternative can drastically reduce these transfers without reducing benefits to efficiency.

[76] Oxera (2006), table 8.1.

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