COST BENEFIT OF TRANSMISSION LOSSES PROPOSAL P75

A Report for the P75/P85 TLFMG

Prepared by NERA

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1. INTRODUCTION

1.1. Background

On 2nd October 2002, the Transmission Loss Factor Modification Group (TFLMG) issued a consultation document, prepared by Elexon Ltd, regarding modification proposals P75 and P82. Modification proposals P75 and P82 seek the introduction of zonal differentiation of transmission losses into the Balancing and Settlement Code (BSC). The two modification proposals can be characterised as follows:

- P75 seeks the introduction of ***ex-post half-hourly*** marginal loss signals; and
- P82 seeks the introduction of ***ex-ante annual*** scaled marginal loss signals.

In the consultation document, TLFMG agree to undertake "some form of cost-benefit analysis" to assess the two proposals. In this report, we analyse the costs and benefits of the modification proposal P75 to the current losses charging scheme.

1.2. Methodology of a Cost-Benefit Analysis

Cost benefit analysis assesses the additional costs and benefits that arise from implementing a change compared with an alternative "status quo" situation. The method requires the estimation of these costs and benefits for all future years. The costs and benefits are then "discounted", according to how far they lie in the future, to reflect the time value of money. The sum of discounted benefits ***less*** the sum of discounted costs gives the "net present value" of the proposed change, a measure of the potential gain in economic efficiency.

This economic efficiency gain measures the net welfare benefit to society ***as a whole***. This welfare gain includes potential cost savings and potential benefits experienced by consumers and other persons (such as companies, investors and other people). However, this kind of analysis ignores transfers ***between*** companies and people within society.

In order to justify any reform on efficiency grounds, it would be necessary to show overall a positive net benefit. A focus on consumers' interests might suggest that the appraisal should only include factors that affect consumers, including any change in prices paid by consumers. However, such factors are difficult to isolate. For instance, consumers exposure to price increases depends upon how much electricity they consume, whether they have contracts, and whether they own shares in generating companies. Such relationships are practically impossible to disentangle. Instead, we have adopted the view that consumers' best interests are served by the pursuit of economic efficiency, which leads to the lowest cost provision of service.

The BSC objectives identified by the TLFMG as applicable to the two proposals are BSC Objectives C3.3 (b), (c) and (d). These objectives are concerned, either directly or indirectly, with promoting efficiency. As noted above, an economic efficiency gain can be measured as the net welfare benefit to society. Cost benefit analysis provides a positive means of investigating whether implementing a change will provide net benefits to society and, therefore, whether the change promotes economic efficiency. Cost-benefit analysis, therefore, is consistent with the applicable BSC objectives. The TLFMG comment that a cost-benefit analysis "***could then allow consideration of the** … **applicable BSC objectives***".

1.2.1. Discount Rate

For discounting costs and benefits we have used the Government's current estimate of society's time preference rate. We use this rate because we are assessing the benefits to society as a whole rather than the impact on any one company. The time preference rate is 6 per cent.[1]

1.3. Conclusion

We have had to use a number of hypothesis about the ***additional*** relocation of generation that P75 is likely to cause, and we have only two sources of information about the costs that market participants would incur to incorporate the new scheme into their IT systems. However, combining these hypotheses in a way we believe to be reasonable, we found that P75 has a negative net benefit, even before allowing for its effect on risk.

[1] Para 4.52, pg 24, ***Green Book: Appraisal and Evaluation in Central Government, Treasury Guidance***, 1997.

2. SHORT-TERM NET BENEFITS - DESPATCH

Short-term benefits will result from improvements in the efficiency of despatch. NCG estimated that the reduction in losses would be approximately £3 million per annum. NGC's methodology was based on the following assumptions:

- NGC used the marginal zonal TLFs for ***peak demand***; and
- Loss savings were priced at £20/MWh.
- NGC's calculation reflected yearly losses of 5 TWh.

We adjust this figure to reflect that in the short term changes in despatch save only fuel costs, losses are lower in 2001/02, and the spread of TLFs is wider at peak times and therefore not representative of TLFs over a year. Table 2.1 reports our calculation of the avoidable short-term (ST) cost of generation, £15.01/MWh. In the long-term (LT) all costs are avoidable so losses are priced at a new entrant cost of £23.50/MWh.[2]

Table 2.1: Short term avoidable cost of generation

Gas price	kWh/therm conversion	Gas price	Efficiency	Fuel cost	10% Mark-up for O*M	Avoidable cost
p/therm		p/kWh	%	p/kWh	P/kWh	£/MWh
20	29.31	0.68	50%	1.36	0.14	15.01

We adjusted NGC's peak TLFs to a more representative number using PTI's results. We attributed time weights to each of the six periods analysed by PTI and estimated the average fall in losses from moving generation from the North (zones with average TLM of less that 1) to the South (zones with average TLM of more than 1) over a whole year. Table 2.2 shows our calculations to obtain a 2002/03 figure for annual savings.[3]

Table 2.2: Short Term Savings per Annum

	Year	Price	Generation (2001/02)	Loss Rate (2001/02)	Losses	Diff TLM Over a Year	Diff TLM at Peak	TLM Adjustment	Annual saving
		£/MWh	TWh	%	TWh	%	%		£m
NGC	2001/02	20.00			5.00			1.00	3.00
NERA (ST)	2002/03	15.01	306.00	1.4%	4.28	3.7%	7.9%	0.46	0.89
NERA (LT)	2002/03	23.50	306.00	1.4%	4.28	3.7%	7.9%	0.46	1.40

<u>Timing of benefit:</u> We assume the short-term benefits would occur the same year P75 is introduced and would be applicable for the first 10 years, with the long-run benefits applying from then on.

2 NERA estimate based on 60% operating thermal efficiency, capital costs of £350/kW, 20p/therm gas price, 90% initial load factor (declining at 1%), £25/kW operating costs per year, 12% cost of capital and 15 year lifetime.

3 We update our 2002/03 estimate of losses using NGC's 2002 SYS forecasts of "energy requirements" and assume an annual growth of 1.6% after 2007/08. Cost of energy is decreased for efficiency growth at 1% per annum.

3. NET BENEFITS OF DEMAND RELOCATION

Any reduction in southern demand matched exactly by an increase in northern demand reduces losses due to ***relocation of demand***. The remaining reduction in southern demand is a net ***reduction in consumption*** (which also reduces losses).

The loss reduction due to ***relocation of demand*** as the difference between northern zonal TLMs (0.99-1.01) and the average of southern TLMs (1.04), which we take from PTI's results weighted as in section 2. Table 3.1 shows the change in losses for each northern zone, using a demand elasticity of 0.25 (from Green paper cited by OFGEM in 2001) and assuming that the cost of generation is half of the final price of electricity. The ***relocation*** saves 5.39 GWh - about £81,000 at £15.01/MWh, or £126,731 at the long-term new entrant cost of£23.50/MWh.

Table 3.1: Short Term Savings from Losses Relocation and Reduction

GSP zone	P75 TLM	Current TLM	% change in price	% change in demand	Demand 2000/01 (GWh)	Change in demand (GWh)	% reduction in losses	Loss reduction (GWh)
1	0.99	1.01	-1.2%	0.31%	16,696	51	4%	1.89
2	0.99	1.01	-0.8%	0.19%	24,476	46	3%	1.27
3	0.99	1.01	-0.8%	0.20%	23,703	47	3%	1.31
4	1.00	1.01	-0.6%	0.16%	17,286	27	2%	0.68
5	1.01	1.01	-0.2%	0.05%	27,724	15	2%	0.25
6	1.02	1.01	0.4%	-0.11%	26,887	-28	-	-
7	1.01	1.01	0.1%	-0.01%	34,093	-5	-	-
8	1.02	1.01	0.7%	-0.18%	12,457	-22	-	-
9	1.01	1.01	0.2%	-0.04%	20,608	-9	-	-
10	1.02	1.01	0.5%	-0.13%	24,412	-31	-	-
11	1.03	1.01	0.9%	-0.21%	31,731	-67	-	-
12	1.04	1.01	1.3%	-0.31%	14,967	-47	-	-
Totals					275,040	-24		5.39

The remaining ***reduction in consumption*** reduces net welfare ***in the short term*** by £517,720, ie, the fall in consumption of 24 GWh times £25.34/MWh - the difference between the price consumers pay (£40.95/MWh)[4] and the avoidable cost of producing electricity adjusted for Southern losses. ***In the long term,*** we assume prices reflect all avoidable costs except losses (depending on the loss allocation scheme); the value of the losses saved due to reducing demand is negligible. We update our 2002/03 figures as described in footnote 3 (section 2).

Table 3.2: Net Benefit per Annum from Long-term Demand Relocation (2002/03)

	Units GWh	Loss reduction GWh	Saving per unit £/MWh	ST-Savings £	LT-Savings £
Relocation S-N (1-10 years)	187	5.4	15.01	80,956	
Relocation S-N (10+ years)	187	5.4	23.50		126,731
Demand reduction	24		-25.34	-598,677	
Total				-517,720	126,731

Timing of benefit: We assume the short-term benefits accrue gradually over the first 5 years, staying at this level for another 5 years, with the long-term benefits applying from then on.

4 Average final price of electricity for 2001 was £45.85/MWh (DTI, 2002, Digest of United Kingdom Energy Statistics. Table 1.7). Electricity contracts agreed in April 2002 for industry and commerce fell by 9% (OFGEM, 1992, Electricity Wholesale Market –facts and figures); assuming that domestic prices fell by the same rate we obtain a figure of £40.95/MWh=£45.85/MWh*(1-9%).

4. GENERATION RELOCATION HYPOTHESIS 1

Under relocation hypothesis 1, we assume that P75 results in 1000MW ***fewer*** plant closures in the South and 1000MW ***more*** plant closures in the North – over and above any closures that would have happened anyway.

In the short run, a reduction in losses only saves the energy costs of generation. In the long run, capacity costs are also avoidable.

- To estimate the energy savings, we calculate the reduction in losses as the difference between average TLMs in Northern zones and Southern zones ***over a year*** (estimated by a weighting of PTI's results - see section 2 above) and valuing losses saved at the energy unit cost of £15.01/MWh – see calculation in section 2 above.
- To estimate capacity savings, we calculate the reduction in losses as the difference between average TLMs in Northern zones and Southern zones ***at peak*** (PTI's results for 02 Jan 2002) and value losses at the capacity unit cost of £8.49/MWh – the difference between the entry cost (£23.50/MWh) and the energy cost (£15.01/MWh) of generation.[5]

Given that this hypothesis concerns plants already built, for which gas and electricity transmission assets will remain in place, the change in non-loss related costs is zero.

Table 4.1 reports our net benefit calculation under hypothesis 1 for 2002/03. The value of losses (ie the cost of energy) is updated assuming a 1% per annum reduction due to efficiency growth.

Table 4.1: Hypothesis 1 - Net benefits for different time horizons (2002/03)

	Capacity MW	Load Factor %	Output GWh	Diff in TLMs %	Losses saved GWh	Value of losses £/MWh	Saving £ million
Short-term saving	1,000	40%	3504	3.7%	128	15.01	1.9
Long-term energy cost saving	1000	0.4	3504	3.7%	128	15.01	1.9
Long-term capacity cost saving	1000	0.4	3504	7.9%	276	8.49	2.3
Total							4.3

<u>Timing of benefit:</u> We assume the short-term benefits would occur gradually spread over the first 5 years, staying at this level for another 5 years, with the long-term benefits applying from then on.

5 New entrant price is NERA estimate based on 60% operating thermal efficiency, capital costs of £350/kW, 16p/therm gas price, 90% initial load factor (declining at 1%), £25/kW operating costs per year, 12% cost of capital and 15 year lifetime

5. GENERATION RELOCATION HYPOTHESIS 2

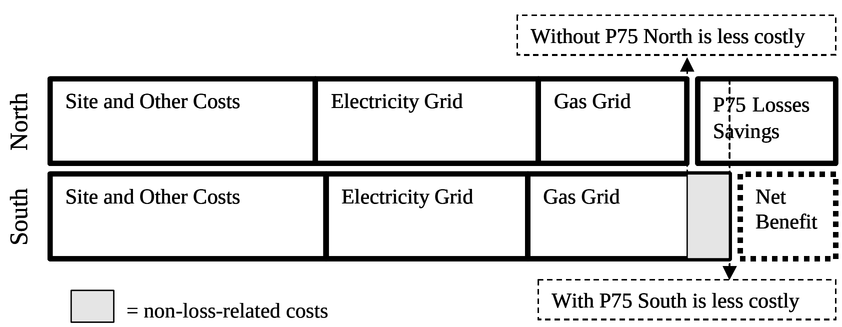
Under this hypothesis, P75 causes an extra 1000MW of new plant to be built in the South, instead of the North. We calculate 2002/03 savings in energy costs and capacity costs separately and update them assuming 1% per annum efficiency as described in section 3.

Table 5.1: Hypothesis 2 - Net benefits from losses savings (2002/03)

	Capacity MW	Load Factor %	Output GWh	Diff in TLMs %	Losses saved GWh	Value of losses £/MWh	Saving £ million
Long-term energy cost saving	1000	80%	7008	3.7%	256	15.02	3.8
Long-term capacity cost saving	1000	80%	7008	7.9%	553	8.48	4.7
Total						23.50	8.5

We could also calculate some ***non-loss-related net benefits***, the difference between increases in non-loss-related avoidable costs (such as gas grid reinforcement and extra land costs) and other savings in avoidable costs (in the electricity grid). Revealed preference shows that these net benefits are negative – although in our calculation we set them to zero. If charges faced by a new plant reflect economic costs (in particular, usage charges for the gas and electric grid),[6] and the change in costs due to P75 (alone) causes a new plant to change location, then (before P75) non-loss related costs must have been higher in the South than the North, but by less than the saving in losses. As a result, the net benefit must be less than the savings in losses identified above. The following figure illustrates why this condition holds.

Figure 5.1: Cost Difference of Building and Operating New Plant



<u>Timing of benefit:</u> New build would only occur after year 5 and the net benefit from P75 would accrue gradually the following 5 years (year 5 to year 10) with the full impact applying from then on.

6 Both NGC's use of system charges and Transco's exit charges have a locational component to reflect the long run incremental cost of expanding their respective transmission systems; however it is not clear to what extent final charges reflect the difference in expansion costs due to extra injections (or withdrawals) in different areas. (see NGC (2002) "The Statement of the Use of System Charging Methodology" and Transco (2001) "Pricing Consultation Paper PC71").

6. ADDITIONAL SYSTEMS AND ADMINISTRATION COSTS

The BSC Central Services Agent estimates the one-off costs of introducing the functionality required to support variation is TLFs for P75 to be in the region of £230,000. Elexon expects operational costs for TLFA to be below £1 million per annum, excluding the cost of interfaces between new and existing systems. We assume that central operational costs will be £1 million per annum.

NGC has provided estimates which suggest that provision of half-hourly network data would involve a set-up cost of £500,000-£600,000 with annual operating costs ranging from £50,000-£60,000. We take the middle range of both estimates.

In its response to Ofgem's consultation on access and losses, London Electricity suggested that changes to its own system ***to incorporate varying loss factors*** would cost between £3 million and £7 million. We have considered two possibilities: all systems cost are fixed and LE's estimate is therefore a cost per supplier or all systems costs are variable and LE's estimate is a cost per costumer. With these two assumptions we calculate two ranges for participants' IT system costs. The centre point of the range is £45 million.

Table 6.1: Participants' Investment Costs for New IT Systems

	Number of customers millions	Number of suppliers	Lower Bound £m	Upper Bound £m
London Electricity estimate	3.3	1	3	7
All participants (assuming fixed cost)	N/A	10	30	70
All participants (assuming variable cost)	22	N/A	20	47
Range	-	-	20	70

In the responses to the TLFMG consultation Teesside Power estimate that P75 will require it to incur in new systems and legal costs of £500,000. Teesside is a relatively small market participant while LE is a relatively large participant. Taking the average of LE's lower bound figure of £3 million and Teesside's £0.5 million suggests an average cost per participant of about £1.75 million; if this is the average cost for the 23 participants that replied to the TLFMG consultation, total costs would be £40.25 million. We use this figure in our calculations. We assume annual operating costs are 10% of investment costs.

Table 6.2: IT and Operating Costs Associated with Marginal Losses Scheme (£m)

		Range	Value Used	Annualised	Source
Capital Investment (one-off)	Central systems		0.23	0.02	TLFMG
	NGC	0.5-0.6	0.55	0.04	NGC
	Participants	20-70	40.25	3.15	LE/Teesside/NERA
Operating costs (per annum)	Central systems		1	1	TLFMG
	NGC	0.05-0.10	0.075	0.075	NGC
	Participants	2-7	4.03	4.03	NERA
Total				8.31	

7. ADDITIONAL RISK FROM WINDFALL GAINS/LOSSES

In addition to the cost-benefits identified above, P75 would increase the perceived market risk by

- causing windfall gains and losses from the reallocation of transmission losses; and
- creating additional uncertainty in the daily operation of the market by exposing participants to ex-post signals which may change significantly depending on unforeseen conditions on the grid (outages) leaving participants exposed to imbalance prices.

Enron, in its 5 July 2001 submission for Ofgem's consultation on transmission access and losses, estimated that the introduction of the proposal on losses would increase the cost of capital for new entrants by one per cent, which Enron translated into an increase of £0.50 per MWh on the new entry price. On further enquiry, Enron explained to us that their figure represented their risk management department's estimate of the cost associated with a 3 per cent variation in output (ie in the allocation of losses) over a 15-year period.

We cross-checked Enron's estimate, against our own model of new entrant prices. Consistent with Enron's estimate, we found that a one per cent increase in the cost of capital would raise the cost of a new entrant by £0.60 per MWh.

Table 7.1: The Effect of a Change in Rates of Return on New Entrant Costs

	12 % Rate of Return	13% Rate of Return
(Initial) new entrant price (£/MWh)	23.5	24.1

Source: NERA calculation assuming 60% operating thermal efficiency, capital costs of £350/kW, 20p/therm gas price, 80% load factor, £25/kW operating costs per year and 15 year lifetime

An increase in the new entrant price will affect the average price of electricity in the market since, over the long term, prices will tend towards the new entrant level. Adding £0.60 per MWh to all purchases in a 300TWh annual market amounts to £180 million per annum. However, part of this figure is a transfer from customers to existing generators, rather than a net cost. To offer a conservative estimate of the costs due to increased risk under P75, we only consider the extra cost for new entrants. The following table reports the extra risk-related cost for 1000MW of new capacity.

Table 7.2: Extra cost from risk

Capacity	Load Factor	Output	Extra cost per MWh	Extra cost per annum
MW	%	GWh	£/MWh	£m
1000	80%	7008	0.6	4.2

8. P75 COST-BENEFIT RESULTS

The tables in Appendix A summarise our analysis of P75 under different scenarios for generation relocation and the period of analysis. For different hypotheses, we estimate different net costs and benefits of P75.

Our results show in each case a substantial negative net benefit, ie, they suggest that the proposed modification does not promote greater efficiency and is therefore inconsistent with BSC objectives overall, even before allowing for the extra costs imposed by risk. However, this result hinges upon the estimates of administrative costs incurred by market participants, as well as by the central systems. We would therefore be very interested in seeing any other information about these costs provided by users via the TLFMG's consultation.

APPENDIX A. EFFECTS OF RELOCATION, BY DIFFERENT HYPOTHESES

Table A.1: P75 CBA – Generation Relocation Hypothesis 1 (excluding cost of risk, 10 years)

Year endng March	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	N
BENEFITS												
Savings from dispatch		0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.4
Benefits of shifting ***demand*** from South to North		-0.1	-0.2	-0.3	-0.4	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	0.1
Benefit of reallocating generation (hypothesis 1)		0.4	0.8	1.1	1.5	1.8	1.8	1.8	1.8	1.8	1.7	4.3
Total Benefits		1.2	1.5	1.7	2.0	2.2	2.2	2.2	2.2	2.2	2.1	5.8
NPV of the Benefits (6% discount rate, over 10 years)	13.9											
COSTS												
Capital Investment in IT - central systems	0.2											
Capital Investment in IT - participants	40.3											
BSC agent operational costs		1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Participant's transaction costs		4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Increased cost of capital due to market risks		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Benefits		5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
NPV of the Costs (6% discount rate, over 10 years)	77.5											
NET BENEFIT	-63.6											

Table A.2: P75 CBA - Generation Relocation Hypothesis 1 (excluding cost of risk, 20 years)

Year endng March	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	N
BENEFITS												
Savings from dispatch		0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.4
Benefits of shifting ***demand*** from South to North		-0.1	-0.2	-0.3	-0.4	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	0.1
Benefit of reallocating generation (hypothesis 1)		0.4	0.8	1.1	1.5	1.8	1.8	1.8	1.8	1.8	1.7	4.3
Total Benefits		1.2	1.5	1.7	2.0	2.2	2.2	2.2	2.2	2.2	2.1	5.8
NPV of the Benefits (6% discount rate, over 20 years)	36.4											
COSTS												
Capital Investment in IT - central systems	0.2											
Capital Investment in IT - participants	40.3											
BSC agent operational costs		1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Participant's transaction costs		4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Increased cost of capital due to market risks		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Benefits		5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
NPV of the Costs (6% discount rate, over 20 years)	98.1											
NET BENEFIT	-61.7											

Table A.3: P75 CBA - Generation Relocation Hypothesis 2 (excluding cost of risk, 10 years)

Year endng March	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	N
BENEFITS												
Savings from dispatch		0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.4
Benefits of shifting ***demand*** from South to North		-0.1	-0.2	-0.3	-0.4	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	0.1
Benefit of reallocating generation (hypothesis 2)							1.6	3.2	4.7	6.2	7.7	8.5
Total Benefits		0.8	0.7	0.6	0.5	0.4	2.0	3.6	5.1	6.6	8.1	10.1
NPV of the Benefits (6% discount rate, over 10 years)	18.0											
COSTS												
Capital Investment in IT - central systems	0.2											
Capital Investment in IT - partcpants	40.3											
BSC agent operational costs		1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Participant's transaction costs		4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Increased cost of capital due to market risks		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Benefits		5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
NPV of the Costs (6% discount rate, over 10 years)	77.5											
NET BENEFIT	-59.5											

Table A.4: P75 CBA - Generation Relocation Hypothesis 2 (excluding cost of risk, 20 years)

Year endng March	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	N
BENEFITS												
Savings from dispatch		0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.4
Benefits of shifting ***demand*** from South to North		-0.1	-0.2	-0.3	-0.4	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	0.1
Benefit of reallocating generation (hypothesis 2)							1.6	3.2	4.7	6.2	7.7	8.5
Total Benefits		0.8	0.7	0.6	0.5	0.4	2.0	3.6	5.1	6.6	8.1	10.1
NPV of the Benefits (6% discount rate, over 20 years)	56.3											
COSTS												
Capital Investment in IT - central systems	0.2											
Capital Investment in IT - partcpants	40.3											
BSC agent operational costs		1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Participant's transaction costs		4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Increased cost of capital due to market risks		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Benefits		5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
NPV of the Costs (6% discount rate, over 20 years)	98.1											
NET BENEFIT	-41.8											

Table A.5: P75 CBA - Generation Relocation Hypothesis 1 and 2 (excluding cost of risk, 10 years)

Year ending March	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	N
BENEFITS												
Savings from dispatch		0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.4
Benefits of shifting *demand* from South to North		-0.1	-0.2	-0.3	-0.4	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	0.1
Benefit of reallocating generation (hypothesis 1)		0.4	0.8	1.1	1.5	1.8	1.8	1.8	1.8	1.8	1.7	4.3
Benefit of reallocating generation (hypothesis 2)		0.0	0.0	0.0	0.0	0.0	1.6	3.2	4.7	6.2	7.7	8.5
Total Benefits		1.2	1.5	1.7	2.0	2.2	3.8	5.4	6.9	8.4	9.9	14.3
NPV of the Benefits (6% discount rate, over 10 years)	28.1											
COSTS												
Capital Investment in IT - central systems	0.2											
Capital Investment in IT - partcpants	40.3											
BSC agent operational costs		1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Participant's transaction costs		4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Increased cost of capital due to market risks		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Benefits		5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
NPV of the Costs (6% discount rate, over 10 years)	77.5											
NET BENEFIT	-49.4											

Table A.6: P75 CBA - Generation Relocation Hypothesis 1 and 2 (including cost of risk, 10 years)

Year endng March	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**N**
BENEFITS												
Savings from dispatch		0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.4
Benefits of shifting *demand* from South to North		-0.1	-0.2	-0.3	-0.4	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	0.1
Benefit of reallocating generation (hypothesis 1)		0.4	0.8	1.1	1.5	1.8	1.8	1.8	1.8	1.8	1.7	4.3
Benefit of reallocating generation (hypothesis 2)		0.0	0.0	0.0	0.0	0.0	1.6	3.2	4.7	6.2	7.7	8.5
Total Benefits		1.2	1.5	1.7	2.0	2.2	3.8	5.4	6.9	8.4	9.9	14.3
NPV of the Benefits (6% discount rate, over 10 years)	**28.1**											
COSTS												
Capital Investment in IT - central systems	0.2											
Capital Investment in IT - partcpants	40.3											
BSC agent operational costs		1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Participant's transaction costs		4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Increased cost of capital due to market risks		0.0	0.0	0.0	0.0	0.0	0.8	1.6	2.3	3.1	3.8	4.2
Total Benefits		5.0	5.0	5.0	5.0	5.0	5.8	6.6	7.4	8.1	8.8	9.2
NPV of the Costs (6% discount rate, over 10 years)	**84.5**											
NET BENEFIT	**-56.4**											