Appendix 10 Gas headroom analysis

1.1 Table A10.1 illustrates the underlying costs and incumbent prices used in the gas headroom analysis discussed in Chapter 5.

Table A10.1: Possible new entrant costs in the domestic gas markets by payment type

	Standard Credit	Direct Debit	Prepayment
Annual Medium Consumption	19,050 kWh	19,050 kWh	12,300 kWh
Revenue per customer per annum (£)			
BGT Gas Prices (excluding VAT)	£359.29	£320.87	£251.75
Cost per customer per annum (£)			
Gas Costs	£146.89	£146.89	£94.84
Transportation	£87.10	£87.10	£56.24
Supply Business Costs	£59.03	£22.83	£60.41
Acquisition Costs	£19.58	£19.58	£19.58
Meter Provision and Maintenance	£13.50	£13.50	£29.98
Storage & Balancing	£4.00	£4.00	£4.00
Energy Efficiency Commitment	£3.60	£3.60	£3.60
Total Costs	£333.70	£297.51	£268.65
Headroom (£)	£25.58	£23.36	-£16.90
Headroom (per cent)	8	8	-6

Source: Ofgem research

1.2 In calculating the underlying costs and incumbent prices presented in table A10.1 it was necessary to make a number of assumptions. BGT's gas prices were based on a medium annual consumption of 19,050 kWh for standard credit and direct debit, and an annual medium consumption level of 12,300 kWh for prepayment. As a proxy for forward gas prices, Ofgem has used BGT's latest price increases (effective from January 2004 for those customers paying by standard credit and direct debit and March 2004 for those customers paying by prepayment). Gas wholesale costs were based on future spot market gas prices for quarter 1, 2004 to quarter 4, 2004 over the period January 2003 to December 2003, weighted for a domestic consumption profile.

1.3 The analysis assumes an acquisition cost of £53 for gas customers and discounted this cost over a three year period using a long-term risk free rate of five per cent. The acquisition cost is based on the average marketing and

advertising costs of the incumbent gas and electricity suppliers, which are given in the Datamonitor report '2002 UK Residential Review', plus the cost of acquiring a customer given in the Datamonitor report 'Reducing the cost to acquire'. It has been assumed that acquisition costs are the same for all suppliers, including new entrants.

1.4 Supply business costs have been estimated using data previously available to Ofgem and represent the supply costs associated with approximately 1 million customers. It has been assumed that supply costs differ depending on the method of payment.

1.5 Transportation and metering costs were obtained from published charging statements for 2003/04 and are assumed to be the same for all suppliers. Storage costs were based on Ofgem's supply cost model of 2001/02 and inflated by approximately 100 per cent given the rise in the cost of storage at Rough.

Appendix 11 Electricity headroom analysis

1.1 Table A11.1 illustrates the underlying costs and incumbents' prices used in the electricity standard credit headroom analysis discussed in Chapter 5.

Table A11.1: Possible new entrant costs in the domestic electricity markets assuming payment by standard credit

	Standard Rate	Economy 7
Annual Medium Consumption	3,300 kWh	6,600 kWh
Revenue per customer per annum (£)		
Range of Incumbent Electricity Prices (excluding VAT)[1]	£232.66 to £281.07	£337.95 to £398.86
Cost per customer per annum (£)		
Range of Electricity Costs	£76.11 to £80.11	£152.22 to £160.23
Range of DUoS costs	£40.53 to £75.20	£44.65 to £96.69
Supply Business Costs	£60.00	£62.30
Acquisition Costs	£19.58	£19.58
Meter Provision and Maintenance	£2.59 to £4.65	£4.00 to £11.08
Range of TNUoS costs	£0.53 to £13.29	£0.66 to £16.61
Renewables Obligation	£4.50	£9.01
Energy Efficiency Commitment	£3.60	£3.60
Total Costs	£216.22 to £253.72	£310.13 to £365.62
Headroom Range (£)	£10.23 to £29.82	£17.16 to £52.65
Headroom Range (per cent)	4 to 13	5 to 17
Average Headroom (per cent)[2]	8	10

Source: Ofgem research

1.2 Table A11.2 illustrates the underlying costs and incumbents' prices used in the electricity direct debit headroom analysis discussed in Chapter 5.

[1] Where a range is given this refers to variations across the 14 ex-PES regions.

[2] The average headroom figure is the average across the 14 ex-PES regions.

Table A11.2: Possible new entrant costs in the domestic electricity markets assuming payment by direct debit

	Standard Rate	Economy 7
Annual Medium Consumption	3,300 kWh	6,600 kWh
Revenue per customer per annum (£) Range of Ex-PES Electricity Bills (excluding VAT)	£224.65 to £266.84	£327.95 to £388.12
Cost per customer per annum (£)		
Range of Electricity Costs	£76.11 to £80.11	£152.22 to £160.23
Range of DUoS costs	£40.53 to £75.20	£44.65 to £96.69
Supply Business Costs	£36.65	£37.62
Acquisition Costs	£19.58	£19.58
Meter Provision and Maintenance	£2.59 to £4.65	£4.00 to £11.08
Range of TNUoS costs	£0.53 to £13.29	£0.66 to £16.61
Renewables Obligation	£4.50	£9.01
Energy Efficiency Commitment	£3.60	£3.60
Total Costs	£192.86 to £230.37	£285.47 to £340.96
Headroom Range (£)	£25.58 to £40.95	£31.81 to £67.30
Headroom Range (per cent)	12 to 19	11 to 23
Average Headroom (per cent)	16	15

Source: Ofgem research

1.3 Table A11.3 illustrates the underlying costs and incumbents' prices used in the electricity prepayment headroom analysis discussed in Chapter 5.

Table A11.3: Possible new entrant costs in the domestic electricity markets assuming payment by prepayment

	Standard Rate	Economy 7
Annual Medium Consumption	3,300 kWh	6,600 kWh
Revenue per customer per annum (£)		
Range of Ex-PES Electricity Bills (excluding VAT)	£231.43 to £296.07	£324.80 to £418.09
Cost per customer per annum (£)		
Range of Electricity Costs	£76.11 to £80.11	£152.22 to £160.23
Range of DUoS costs	£40.53 to £75.20	£44.65 to £96.69
Supply Business Costs	£56.88	£57.00
Acquisition Costs	£19.58	£19.58
Meter Provision and Maintenance	£4.15 to £14.40	£9.00 to £18.09
Range of TNUoS costs	£0.53 to £13.29	£0.66 to £16.61
Renewables Obligation	£4.50	£9.01
Energy Efficiency Commitment	£3.60	£3.60
Total Costs	£233.42 to £269.57	£328.99 to £378.36
Headroom Range (£)	-£5.71 to £36.09	-£15.63 to £42.20
Headroom Range (per cent)	-2 to 15	-5 to 13
Average Headroom (per cent)	5	5

Source: Ofgem research

1.4 As with the gas headroom analysis, in calculating the underlying costs and incumbent prices presented in tables A11.1 – 11.3 it was necessary to make a number of assumptions.

1.5 Revenue per customer per annum was calculated for each of the 14 ex-PES regions by taking the in-area incumbents' electricity tariff. The tariffs used were also split by standard credit, direct debit and prepayment payment methods. The final electricity bills were based on a medium annual consumption of 3,300 kWh for customers on a standard rate tariff and a medium annual consumption level of 6,600 kWh for customers on an Economy 7 tariff. Where incumbent suppliers increased their prices prior to 1 March 2004, these were given as the incumbent in-area price.

1.6 Electricity wholesale costs were based on annual April 2004 baseload and peak prices over the period 9 June 2003 to 30 January 2004. It was assumed that peak prices represented ten per cent of the total electricity wholesale cost.

1.7 As with the gas headroom analysis, Ofgem assumed that the acquisition cost was £53.33 and that it was discounted over three years using a long-term risk free rate of five per cent. The analysis also assumed that acquisition costs are the same for all suppliers, including new entrants.

1.8 Supply business costs were estimated using data previously available to Ofgem and represent the supply costs of associated with approximately 1 million customers. It was assumed that supply costs differ depending on the method of payment.

1.9 Distribution Use of System (DUoS) charges and meter provision and maintenance costs for each of the 14 ex-PES regions were obtained from published charging statements for 2003/04 and were assumed to be the same for all suppliers. Transmission Network Use of System (TNUoS) charges were calculated for each of the 14 ex-PES regions using published charging statements for 2003/04, a loss adjustment factor for each of the 14 regions, which varied between standard rate and economy seven, and a peak share of 18.6 per cent for standard rate and 11.6 per cent for economy seven.

1.10 The estimate of the cost of the Renewables Obligation was made assuming that a new entrant would purchase Renewable Obligation Certificates (ROCs) and pay the buy-out price in the same proportions as the average for the Renewable Obligation period of 2002-2003. The Renewables Obligation assumed was 4.9 per cent, that is, the obligation for April 2004 – March 2005 and the buy-out price assumed was £31.39.

1.11 The Energy Efficiency Commitment (EEC) cost was assumed to be £3.60. This was based on an estimate made by the Department for the Environment, Food and Rural Affairs (DEFRA) of how much it would cost per customer per fuel for suppliers to meet their EEC. However, it should be noted that only suppliers with more than 15,000 domestic customers will be required to meet an EEC.

Appendix 12 Price parallelism methodology

Background

1.1 Price parallelism analysis looks at whether or not competitive conditions are uniform across different products and across different geographical regions. It is useful in evaluating the extent to which competitive conditions are uniform between domestic electricity and gas supply. The analysis is based on the belief that market conditions are reasonably comparable between sectors in those instances when these conditions impact similarly on prices. In other words, if two products form part of the same relevant product or geographic market, then one might expect to see their prices move together over time.

1.2 This can be tested using historical pricing data. The matrix below sets out cuts of the analysis presented in this review.

Payment method	Gas			Electricity			Dual Fuel		
	DD	SC	PPM	DD	SC	PPM	DD	SC	PPM
Regional (ex PES)	√	√	√	√	√	√	√	√	√
National	√	√	√	√	√	√			

DD: direct debit, SC: standard credit and PPM: prepayment

Notes on data

Prices

1.3 The price parallelism analysis uses time series pricing data for gas, electricity and dual fuel. The source of the data is Ofgem's Domestic Prices Database (DPD).

1.4 One of the limitations of the DPD is that the pricing data currently only goes back as far as June 2000 for electricity and gas and April 2002 for dual fuel. The analysis extracted pricing data for each payment type using the median bill as an indicator of price competition plotted over time.

1.5 The median price is the middle value of a list of figures organised in order of magnitude. The median is used in preference to an average since it is not as likely to be distorted by very high or very low outlying values in the range.

1.6 The prices are inclusive of VAT. They are expressed in real terms using the latest (December 2003) monthly CHAW Retail Price Index (RPI) from the Office of National Statistics website[3]. Real prices are used because inflation may give a false impression of co-movement.

Common costs

1.7 Common costs are costs that are experienced by all suppliers. The price parallelism analysis is enhanced by stripping out these costs to leave us with the part of the price that is directly affected by competitive pressures. However, because Ofgem only has access to accurate information on the regulated parts of the bill, for the regional and national analysis these are taken away from prices.

1.8 Transco's charges for transporting gas across Great Britain are excluded from gas and dual fuel prices. Transco is subject to a price control so their charges are not directly determined by competitive pressures.

1.9 Electricity and dual fuel prices have been stripped off Transmission Network Use of System (TNUoS) charges and Distribution Use of System (DUoS) charges. As with Transco charges these costs of transporting electricity are subject to price controls and therefore not directly subject to competitive pressures.

1.10 Metering charges are also common to all suppliers and Ofgem has accurate data on these charges. These charges are therefore excluded from the all prices.

1.11 Ofgem was able to extract these regulated parts of the bill but other common costs that have not been extracted are discussed below.

Energy costs

1.12 The price parallelism analysis has not taken out the energy component of the bill, ie gas costs and electricity costs. This was not done because of the difficulties in estimating the appropriate wholesale costs as illustrated in the discussion on the responsiveness of domestic retail prices to wholesale price changes in Chapter 4 and Appendix 6.

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[3] http://www.statistics.gov.uk/STATBASE/tsdataset.asp?vlnk=229&More=Y

Entry Capacity Charges

1.13 Transco charges used in this analysis do not include National Transmission System (NTS) entry capacity charges. These charges are difficult to estimate because they are determined by auctions and if Transco over-recovers on auctions there may be a refund for shippers.

1.14 Entry capacity charges are payable when a right to flow gas is purchased, with payment due irrespective of whether or not the right is exercised. Transco's terminals can only flow a certain amount of gas on to the NTS system at any one time, this is known as entry capacity. Transco has to ensure that the NTS is always balanced with enough gas being brought onshore to meet demand. If shippers want to put more gas onto the system than is physically possible, Transco may manage this constraint by buying back entry capacity from shippers at market prices. These buy-back costs are spread across shippers, based on their holdings of capacity. The exact monthly amount of over-recoveries in NTS entry capacity auctions is therefore very difficult to estimate.

Price parallelism charts

1.15 The product analysis chart shows national median gas and electricity prices over time minus regulated parts of the bill. The regional analysis chart shows the median price for each ex-PES region over time minus regulated parts of the bill.

1.16 Appendix 13 sets out charts for payment methods not covered in the Review document - standard credit and prepayment. In the Review document the analysis uses the direct debit payment method because Ofgem believes it is subject to more competitive pressures for several reasons: this was the first payment method to have price controls lifted (in gas), most companies use direct debit as their spearhead for gaining customers and it is the fastest growing payment method.

Correlation coefficients

1.17 In order to further test the co-movement between gas and electricity prices, between prices in different regions and to evaluate its strength correlation coefficients are calculated.

1.18 The correlation coefficient is a number ranging between -1 and 1 that indicates how much a change in one variable may explain a change in another. The correlation coefficient is a statistical measure of interdependence of two or more random variables. It indicates the degree of association between two variables but does not imply that a change in one variable causes a change in the other. A coefficient of -1 implies that as one variable increases the other decreases at the same rate (perfect negative correlation), a coefficient of 1 implies that as one variable increases the other also increases at the same rate (perfect positive correlation), and a coefficient of zero implies no correlation (although it does not necessarily imply that variables are independent). A correlation of price movements is consistent with, although not proof of, two goods being in the same market[4].

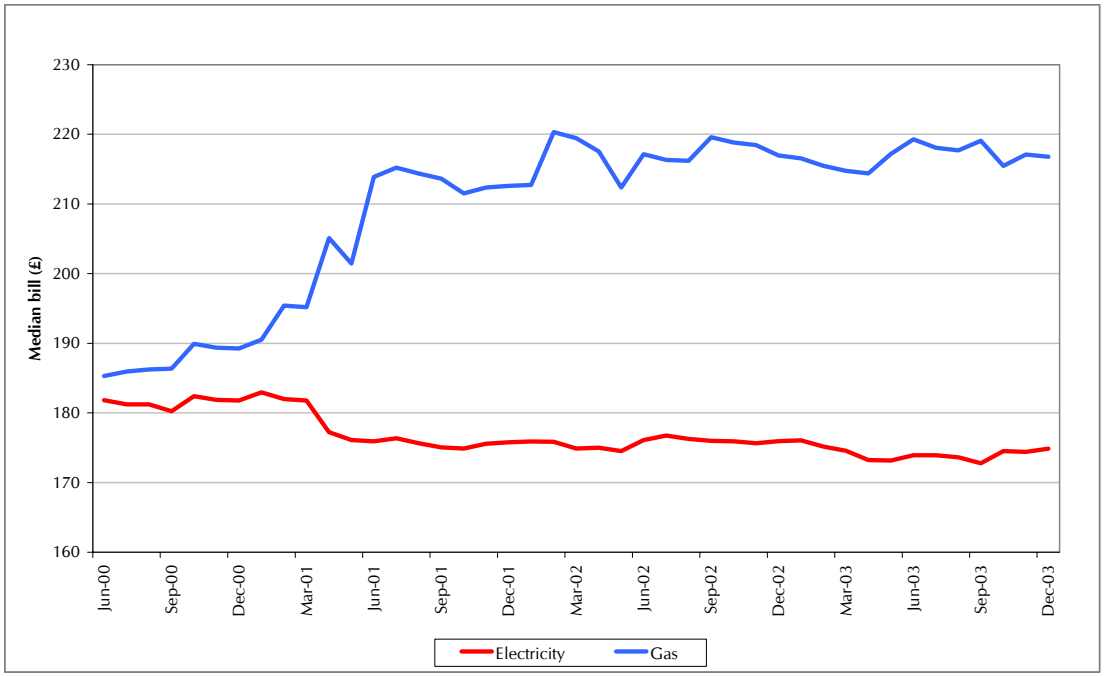
1.19 For the regional analysis the correlation coefficients are presented in matrices in Appendix 14 with the rows and columns labelled with the relevant regions. For the national analysis the correlation coefficients are presented in the text of the Review document.

[4] "The role of market definition in monopoly and dominance inquiries," OFT Research Paper, July 2001, p 11

Appendix 13 Price parallelism charts

Standard credit price parallelism charts

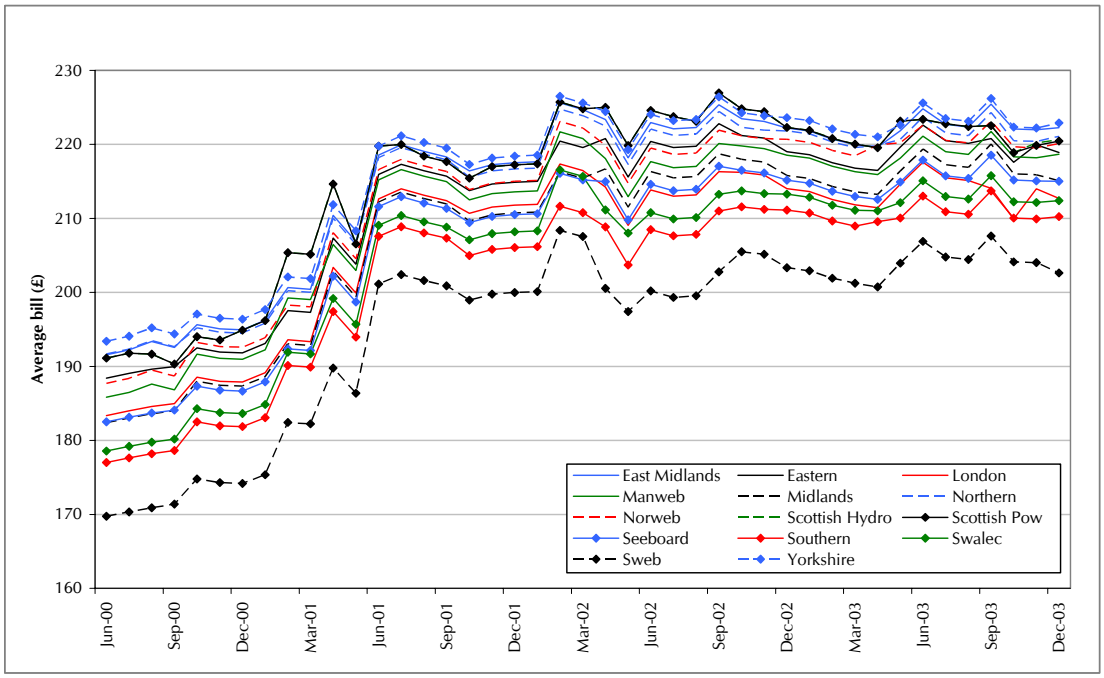
Figure A13.1: Price parallelism analysis - electricity and gas standard credit median bills excluding DUoS, TNUoS for electricity and transportation charges for gas (medium consumption bills[5], inc. VAT, Dec 03 = 100)



Source: Ofgem, Transco, distribution companies

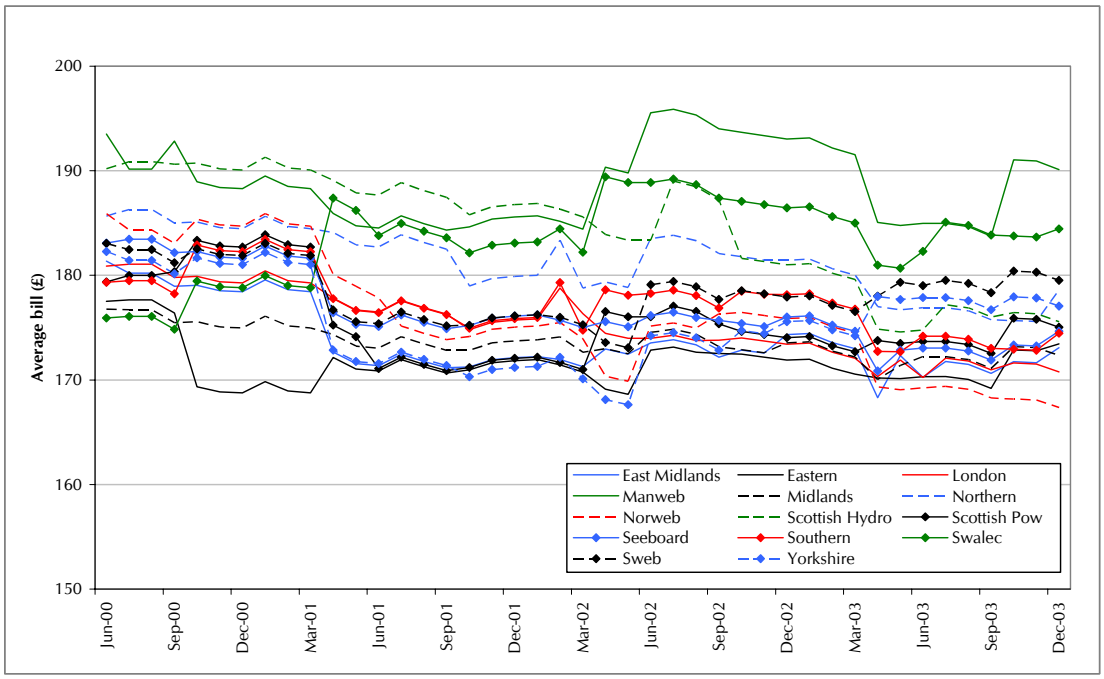
[5] Medium consumption for gas is 19,050kWh and for electricity 3,300kWh per annum.

Figure A13.2: Price parallelism analysis - gas standard credit median regional bill excluding transportation charges (medium consumption bills, inc. VAT, Dec 03 = 100)



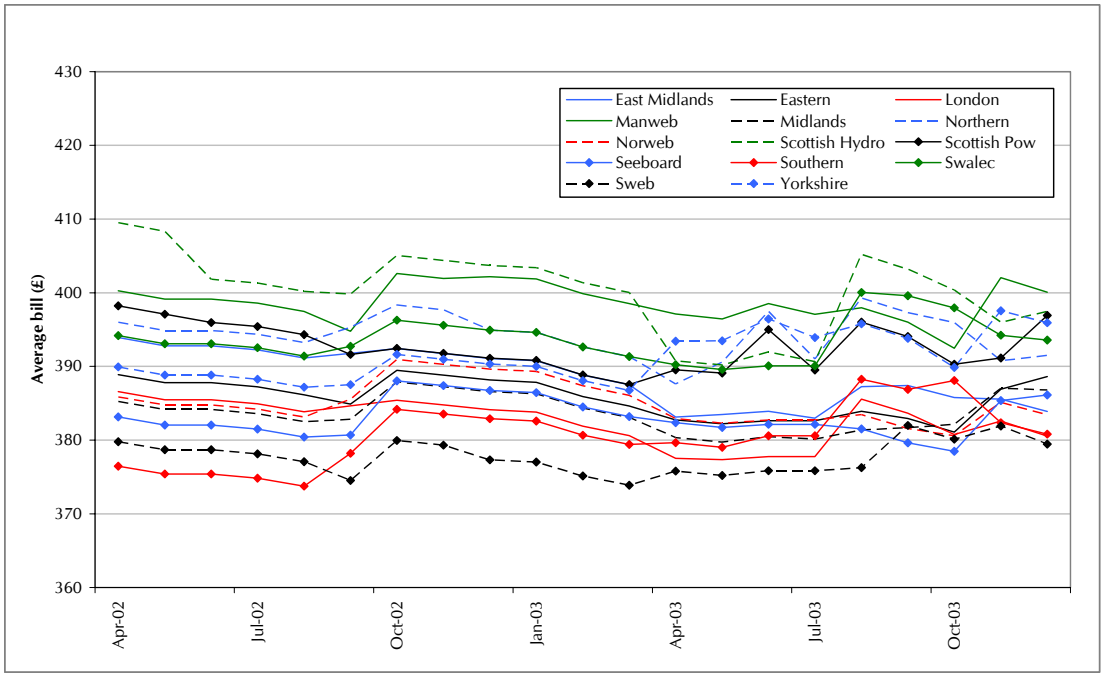
Source: Ofgem, Transco

Figure A13.3: Price parallelism analysis - electricity standard credit median regional bill excluding DUoS and TNUoS charges (medium consumption bills, inc. VAT, Dec 03 = 100)



Source: Ofgem, distribution companies

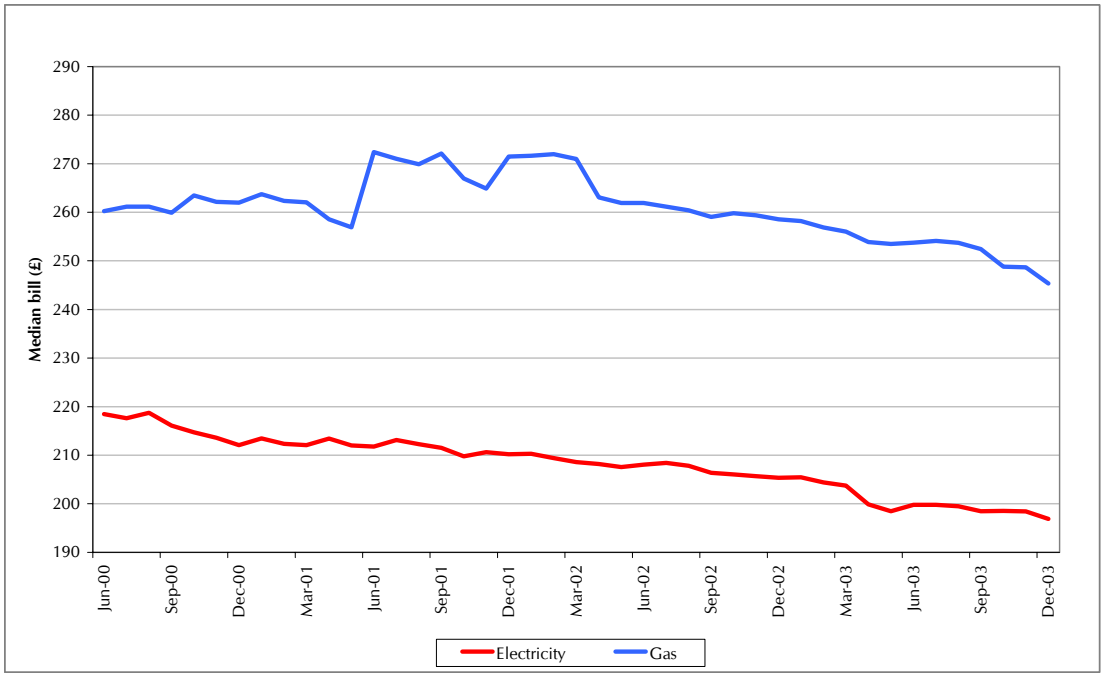
Figure A13.4: Price parallelism analysis - dual fuel standard credit median regional bill excluding DUoS, TNUoS and transportation charges (medium consumption bills, inc. VAT, Dec 03 = 100)



Source: Ofgem, Transco, distribution companies

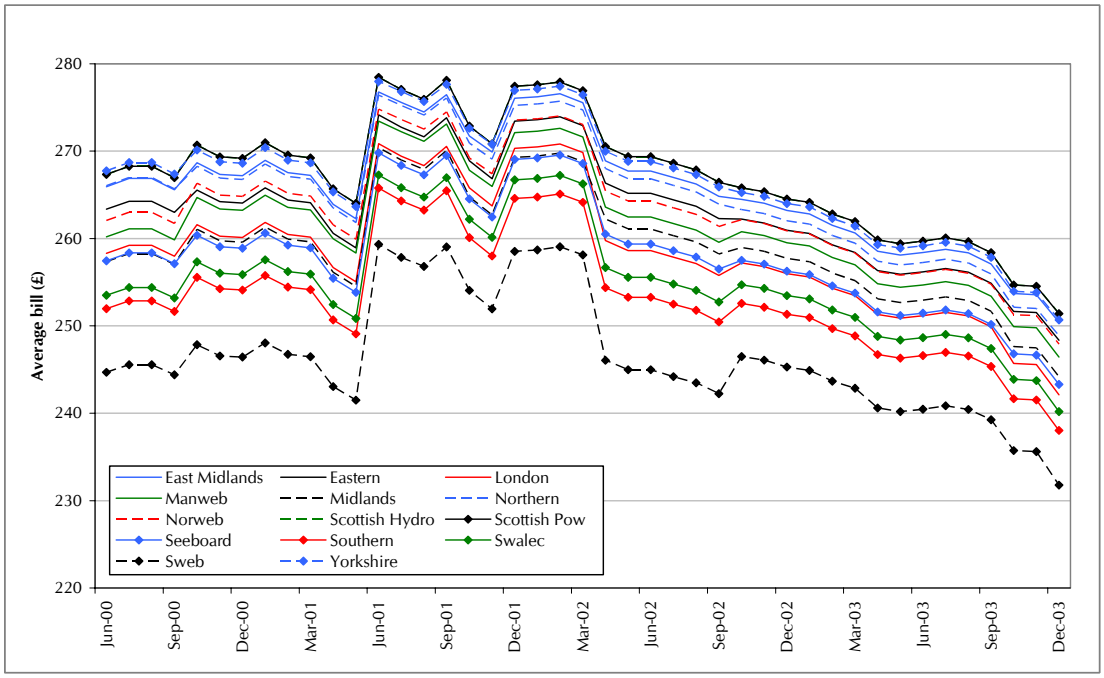
Prepayment price parallelism charts

Figure A13.5: Price parallelism analysis - electricity and gas prepayment median bills excluding DUoS, TNUoS for electricity and transportation charges for gas (medium consumption bills6, inc. VAT, Dec 03 = 100)



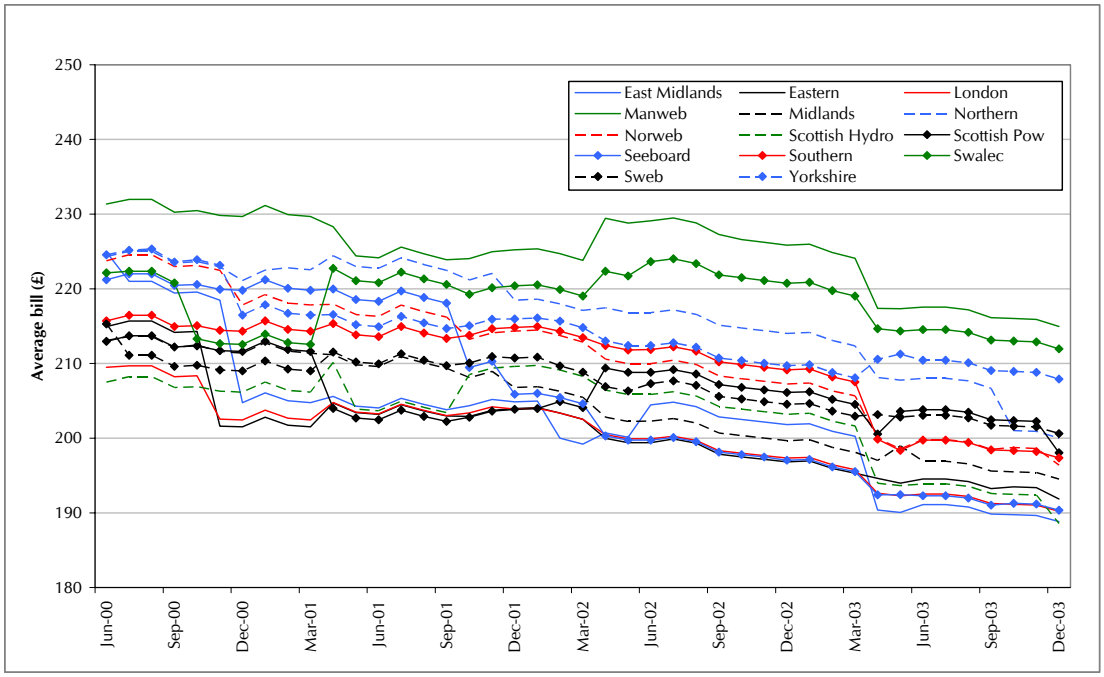
Source: Ofgem, Transco, distribution companies

Figure A13.6: Price parallelism analysis - gas prepayment median regional bill excluding transportation charges (medium consumption bills, inc. VAT, Dec 03 = 100)



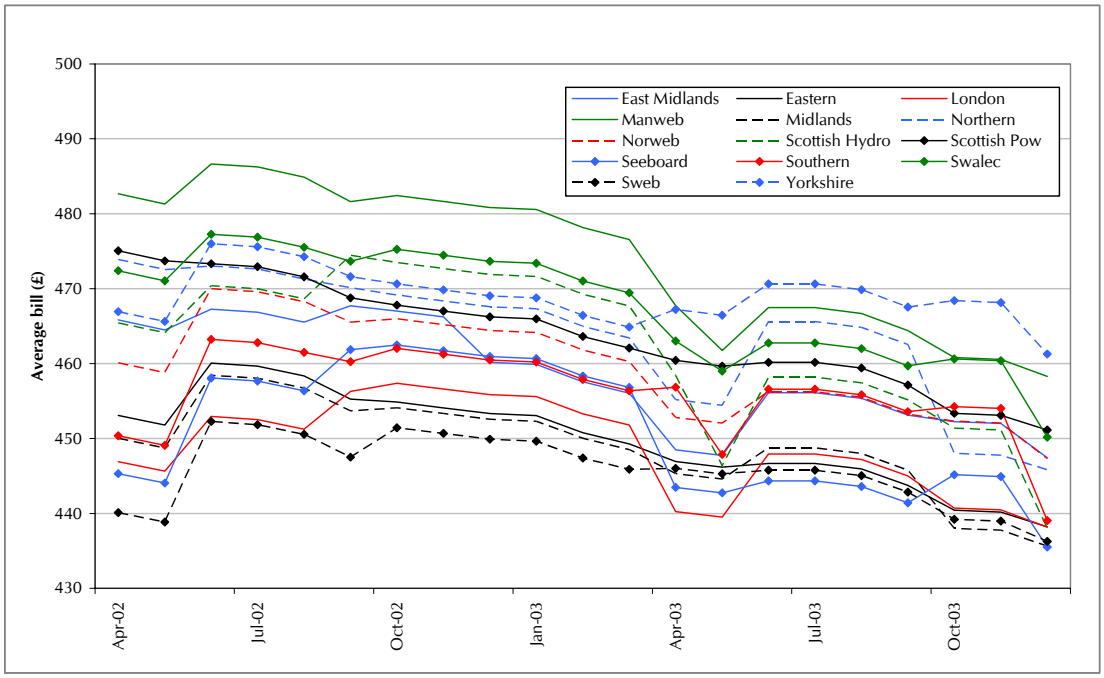
Source: Ofgem, Transco

Figure A13.7: Price parallelism analysis - electricity prepayment median regional bill excluding DUoS and TNUoS charges (medium consumption bills, inc. VAT, Dec 03 = 100)



Source: Ofgem, distribution companies

Figure A13.8: Price parallelism analysis - dual fuel prepayment median regional bill excluding DUoS, TNUoS and transportation charges (medium consumption bills, inc. VAT, Dec 03 = 100)



Source: Ofgem, Transco, distribution companies

[6] Medium consumption for gas is 19,050kWh and for electricity 3,300kWh per annum.

Appendix 14 Correlation coefficients

1.1 Gas regional correlation coefficients to go with Figure 6.2 in the Review document.

Table A14.1: Price parallelism analysis - gas direct debit median regional bill excluding transportation charges (medium consumption bills, inc VAT, December 2003 = 100)

Gas DD MC Dec 2003 Prices	*East Midlands*	*Eastern*	*London*	*Manweb*	*Midlands*	*Northern*	*Norweb*	*Scottish Hydro*	*Scottish Power*	*Seeboard*	*Southern*	*Swalec*	*Sweb*	*Yorkshire*
East Midlands	1.00													
Eastern	1.00	1.00												
London	0.99	0.99	1.00											
Manweb	1.00	1.00	1.00	1.00										
Midlands	1.00	1.00	1.00	1.00	1.00									
Northern	1.00	1.00	0.99	1.00	1.00	1.00								
Norweb	1.00	1.00	0.99	1.00	1.00	1.00	1.00							
Scottish Hydro	1.00	0.99	0.99	0.99	0.99	1.00	0.99	1.00						
Scottish Power	1.00	0.99	0.99	0.99	0.99	1.00	0.99	1.00	1.00					
Seeboard	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.99	0.99	1.00				
Southern	1.00	1.00	1.00	1.00	1.00	0.99	1.00	0.99	0.99	1.00	1.00			
Swalec	0.99	0.99	1.00	1.00	1.00	1.00	1.00	0.99	0.99	1.00	1.00	1.00		
Sweb	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	1.00	1.00	1.00	
Yorkshire	1.00	1.00	0.99	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.99	1.00	0.99	1.00

Source: Ofgem, Transco

1.2 Electricity regional correlation coefficients to go with Figure 6.3 in Review document.

Table A14.2: Price parallelism analysis - electricity direct debit median regional bill excluding DUoS and TNUoS charges (medium consumption bills, inc VAT, December 2003 = 100)

Electricity DD MC Dec 2003 Prices	*East Midlands*	*Eastern*	*London*	*Manweb*	*Midlands*	*Northern*	*Norweb*	*Scottish Hydro*	*Scottish Power*	*Seeboard*	*Southern*	*Swalec*	*Sweb*	*Yorkshire*
East Midlands	1.00													
Eastern	0.53	1.00												
London	0.74	0.48	1.00											
Manweb	0.67	0.50	0.31	1.00										
Midlands	0.63	0.56	0.92	0.29	1.00									
Northern	0.67	0.56	0.86	0.44	0.88	1.00								
Norweb	0.70	0.41	0.90	0.42	0.79	0.88	1.00							
Scottish Hydro	0.57	0.37	0.90	0.30	0.90	0.88	0.93	1.00						
Scottish Power	0.79	0.40	0.64	0.70	0.60	0.61	0.55	0.53	1.00					
Seeboard	0.71	0.53	0.90	0.53	0.87	0.89	0.93	0.92	0.62	1.00				
Southern	0.72	0.38	0.85	0.60	0.75	0.83	0.94	0.89	0.61	0.93	1.00			
Swalec	-0.67	-0.33	-0.72	-0.13	-0.71	-0.58	-0.51	-0.54	-0.65	-0.56	-0.37	1.00		
Sweb	0.38	0.63	0.58	0.01	0.75	0.54	0.29	0.45	0.41	0.45	0.22	-0.66	1.00	
Yorkshire	0.60	0.63	0.36	0.34	0.44	0.42	0.20	0.16	0.56	0.34	0.11	-0.71	0.65	1.00

Source: Ofgem, distribution companies

1.3 Dual fuel regional correlation coefficients to go with Figure 6.4 in the Review document.

Table A14.3: Price parallelism analysis - dual fuel direct debit median regional bill excluding DUoS, TNUoS and transportation charges (medium consumption bills, inc VAT, December 2003 = 100)

Dual Fuel DD MC Dec 2003 Prices	*East Midlands*	*Eastern*	*London*	*Manweb*	*Midlands*	*Northern*	*Norweb*	*Scottish Hydro*	*Scottish Power*	*Seeboard*	*Southern*	*Swalec*	*Sweb*	*Yorkshire*
East Midlands	1.00													
Eastern	0.88	1.00												
London	0.92	0.81	1.00											
Manweb	0.72	0.56	0.71	1.00										
Midlands	0.60	0.75	0.63	0.32	1.00									
Northern	0.32	0.55	0.31	0.06	0.62	1.00								
Norweb	0.78	0.88	0.79	0.65	0.83	0.54	1.00							
Scottish Hydro	0.94	0.88	0.88	0.77	0.64	0.42	0.87	1.00						
Scottish Power	0.39	0.74	0.40	0.29	0.73	0.67	0.73	0.50	1.00					
Seeboard	0.65	0.77	0.67	0.53	0.82	0.45	0.90	0.78	0.69	1.00				
Southern	0.55	0.70	0.54	0.49	0.60	0.62	0.78	0.73	0.67	0.85	1.00			
Swalec	0.64	0.77	0.67	0.63	0.66	0.39	0.86	0.78	0.73	0.93	0.90	1.00		
Sweb	-0.22	-0.10	0.06	-0.20	0.24	0.42	0.11	-0.17	0.24	0.07	0.15	0.06	1.00	
Yorkshire	-0.12	0.28	-0.07	-0.30	0.55	0.75	0.27	-0.04	0.75	0.28	0.31	0.21	0.53	1.00

Source: Ofgem, Transco, distribution companies

Appendix 15 Dual fuel customer shares

1.1 There appears to be a slight weakness in the underlying data that Ofgem has used to analyse dual fuel customer shares. In order to calculate the dual fuel customer share Ofgem looked at the same question in the gas and electricity surveys. The question asked whether it was correct that the customer took both fuels from the same supplier. Table A15.1 illustrates the results for each survey. In 2001 and 2003 the results were similar whether the analysis looked at the gas or the electricity surveys, however, in 2002 there was more variation between the two fuels, and for all years the gas survey reported BGT's dual fuel customer share higher than the electricity survey did. For Table 6.7 in the Review document Ofgem used an average of the two surveys for each year.

Table A15.1: Dual fuel customer share - gas and electricity surveys compared

Supplier	Summer 2001	Summer 2001	Summer 2002	Summer 2002	Summer 2003	Summer 2003
	Gas	*Electricity*	*Gas*	*Electricity*	*Gas*	*Electricity*
British Gas	54	36	56	34	50	38
EDF Energy					7	10
London Electricity	2	3	3	3		
Seeboard	3	2	2	5		
npower	9	13	11	17	12	13
Northern Electric	4	4				
Powergen	6	12	7	10	16	19
TXU Energi	8	13	8	13		
SSE	8	10	6	10	8	11
Scottish Power	6	7	6	8	7	9

Source: J.D. Power and Associates Gas and Electricity Surveys 2001, 2002 and 2003

1.2 Ofgem requested a booster of BGT customers in the 2003 gas survey. The J.D. Power and Associates 2003 electricity survey samples about 400 BGT, Powergen and npower electricity customers and about 300 electricity customers each from the other principal suppliers[7]. The gas survey also takes a set number of customers per supplier but, at Ofgem's request, has a booster of an extra 400 BGT customers for 2003. This booster in gas highlights BGT's large number of gas customers.

[7] London Electricity, SWEB, SEEBOARD, Scottish Hydro, Southern Electric, SWALEC, Manweb and Scottish Power.

Appendix 16 Mergers and acquisitions

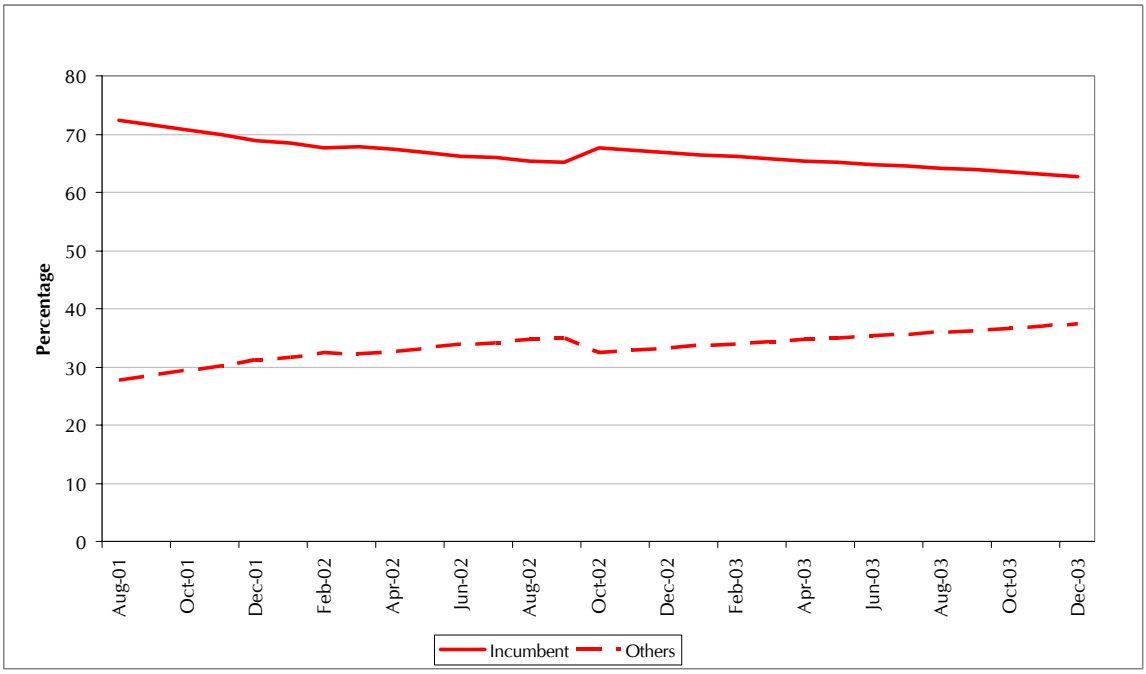
Table A15.1: Recent mergers and acquisitions in gas and electricity

Date	Acquirer	Acquired
Dec-01	BGT	Enron
Mar-02	TXU	Amerada
Jul-02	EDF	Seeboard
Aug-02	BGT	Electricity Direct
Oct-02	Powergen	TXU
Dec-02	SSE	Cambridge Electric & Gas

Source: Ofgem

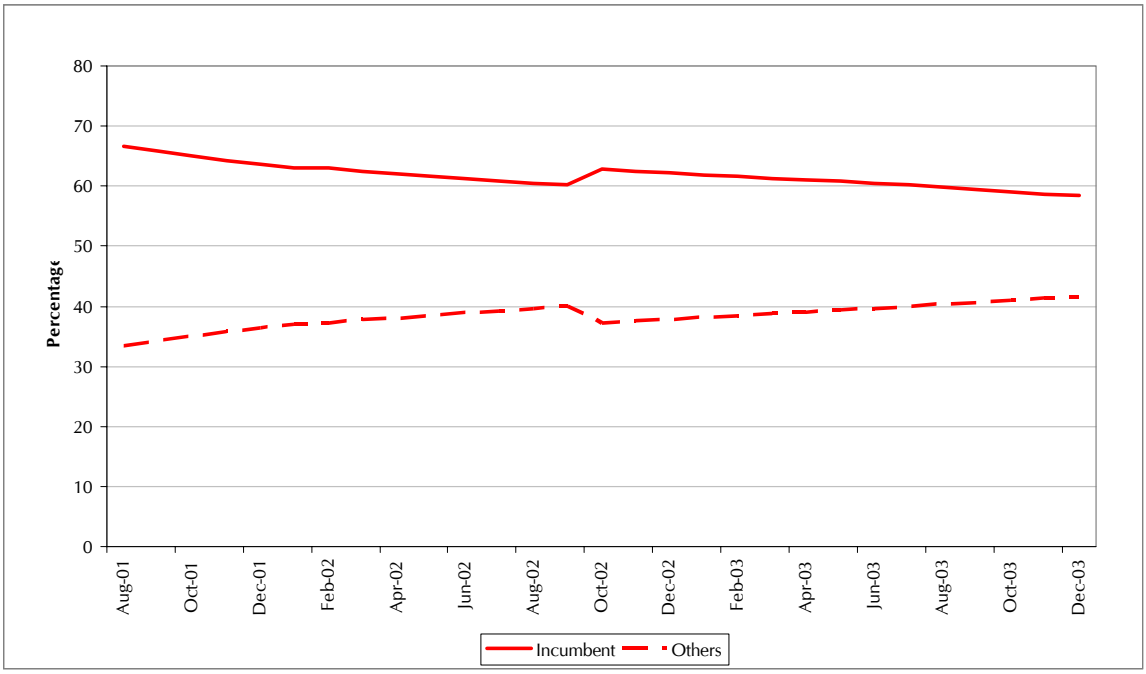
Appendix 17 Electricity regional customer shares

Figure A17.1: Electricity regional customer shares over time in Eastern area



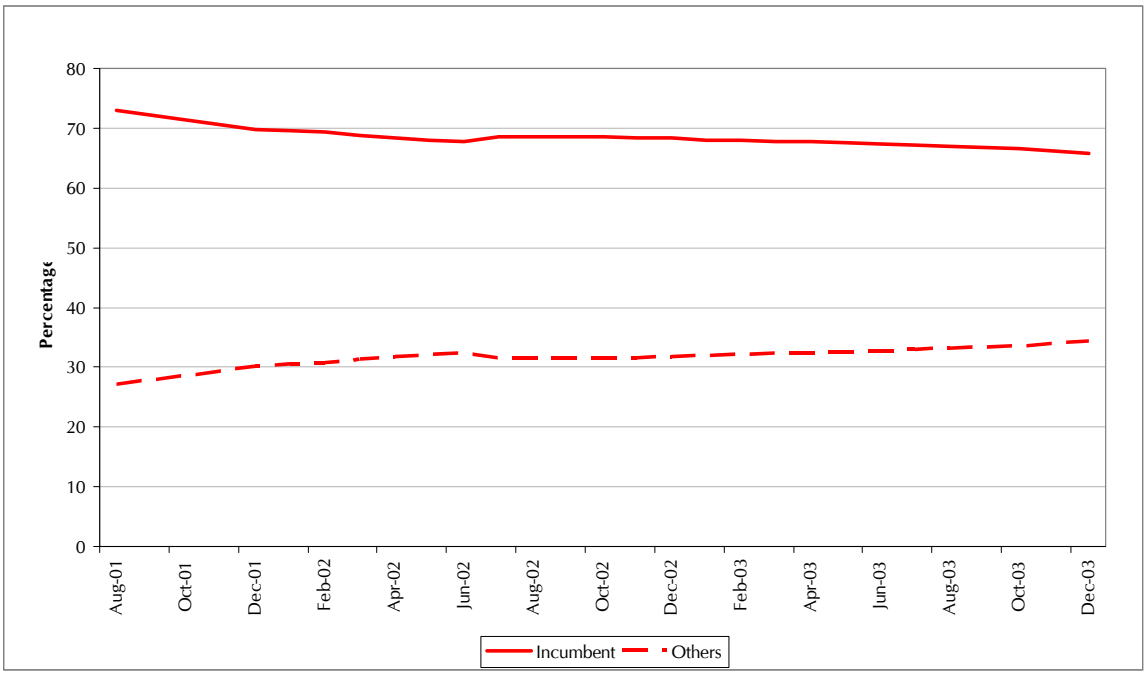
Source: Distribution Companies

Figure A17.2: Electricity regional customer shares over time in East Midlands area



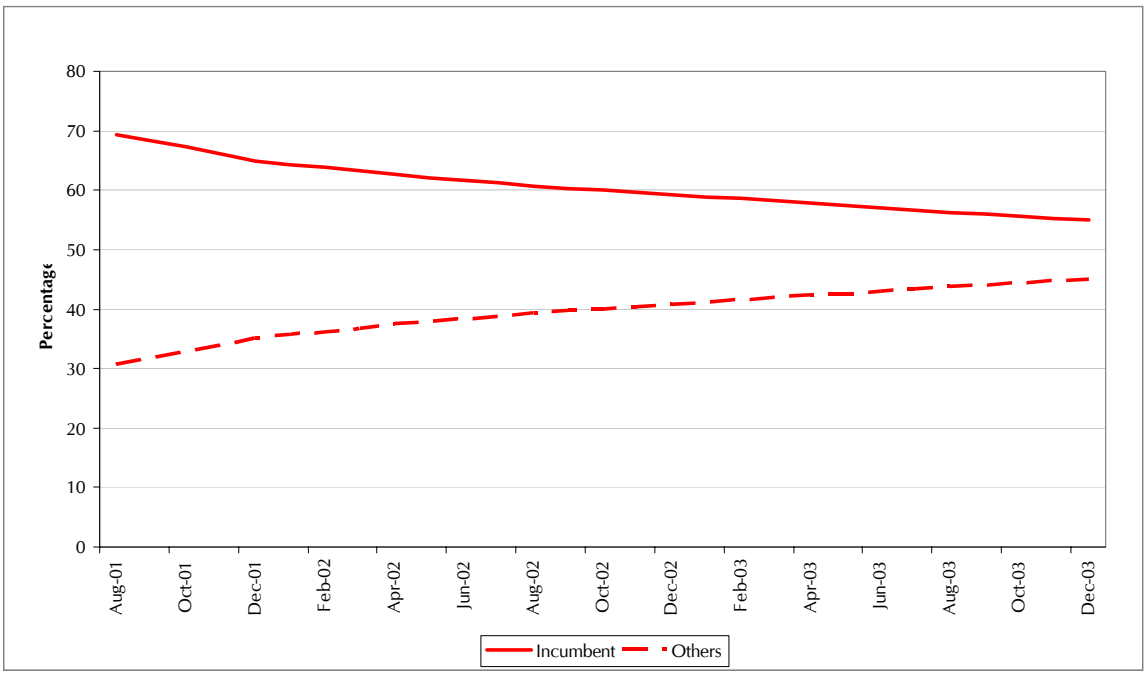
Source: Distribution Companies

Figure A17.3: Electricity regional customer shares over time in London area



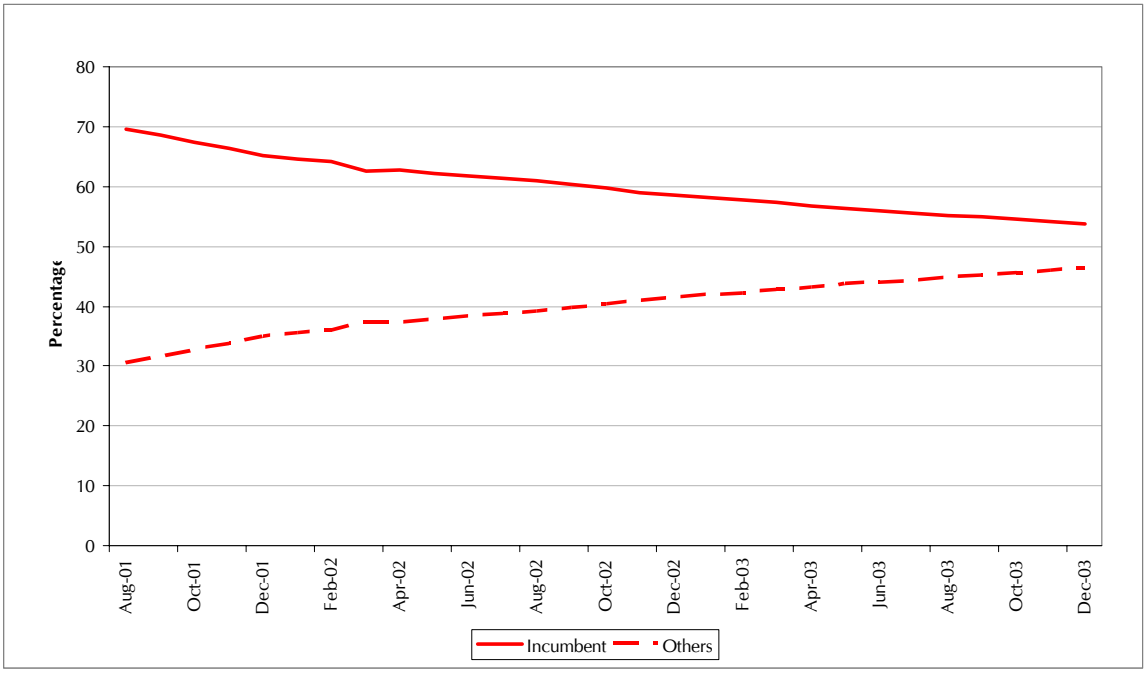
Source: Distribution Companies

Figure A17.4: Electricity regional customer shares over time in Manweb area



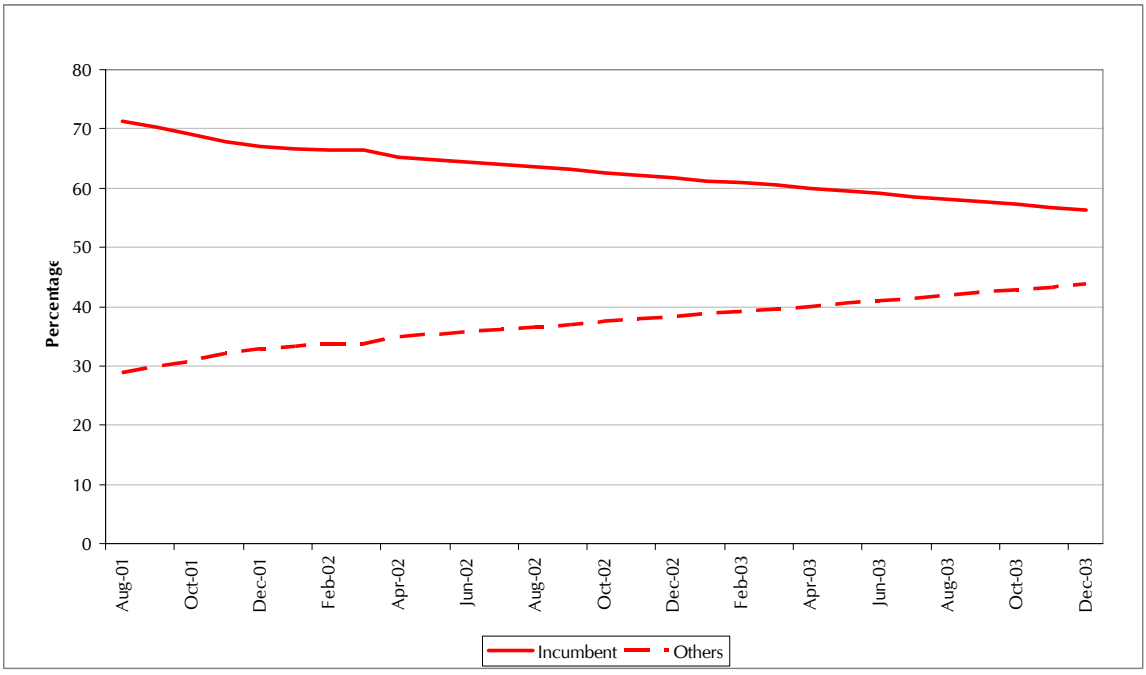
Source: Distribution Companies

Figure A17.5: Electricity regional customer shares over time in Midlands area



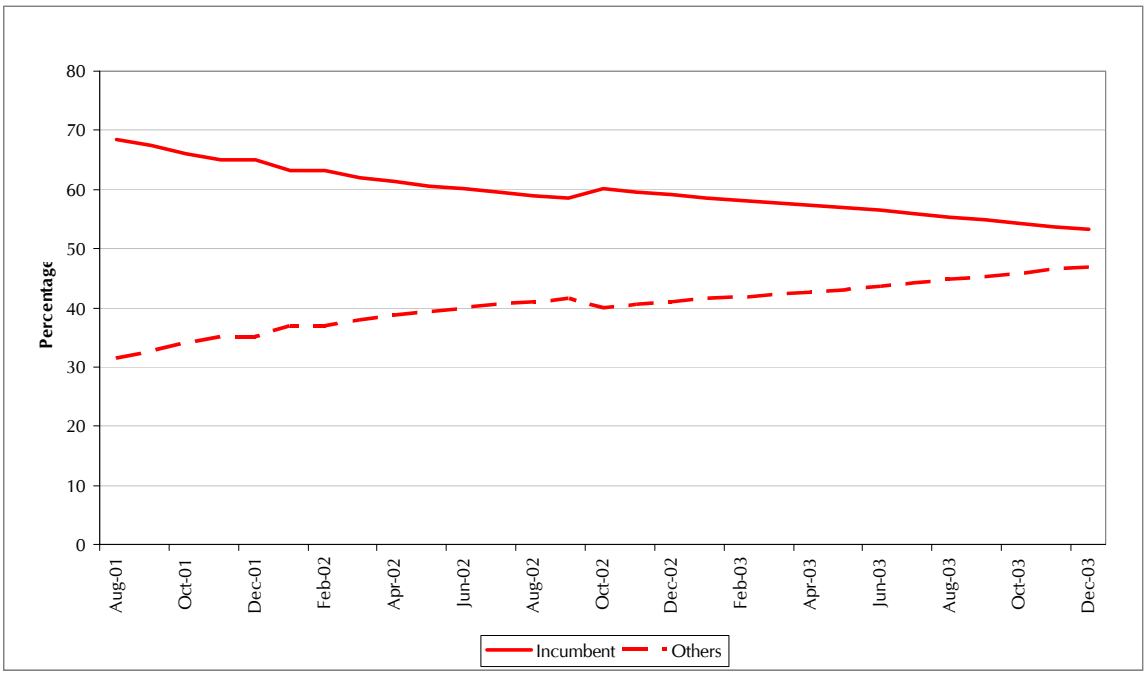
Source: Distribution Companies

Figure A17.6: Electricity regional customer shares over time in Northern area



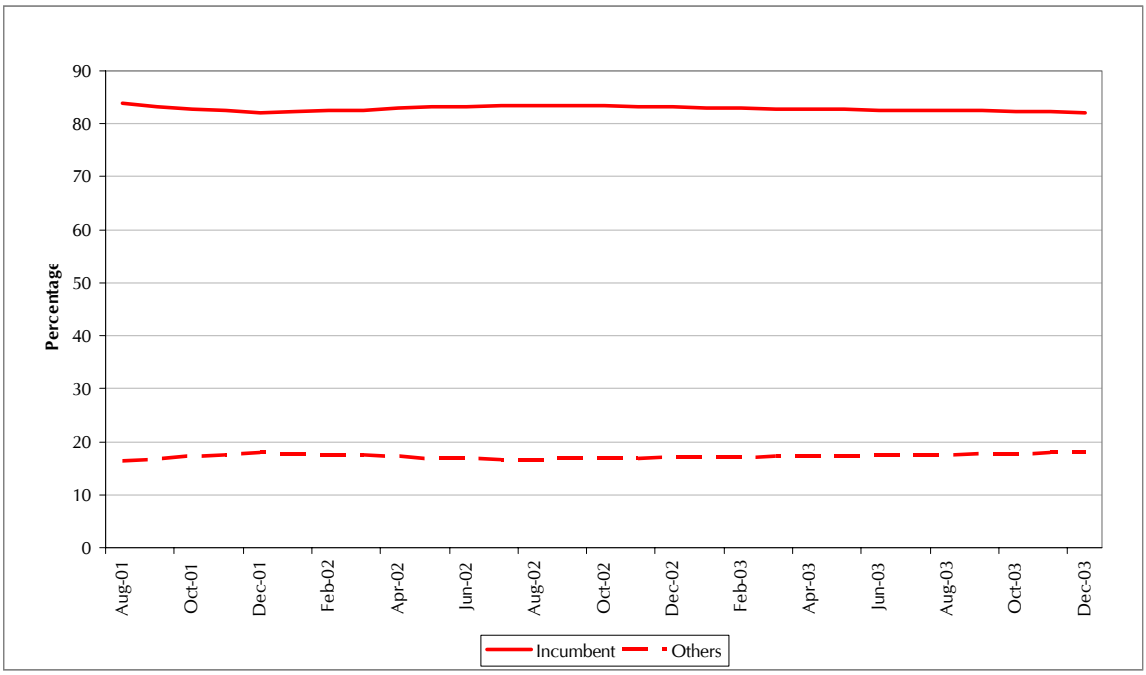
Source: Distribution Companies

Figure A17.7: Electricity regional customer shares over time in Norweb area



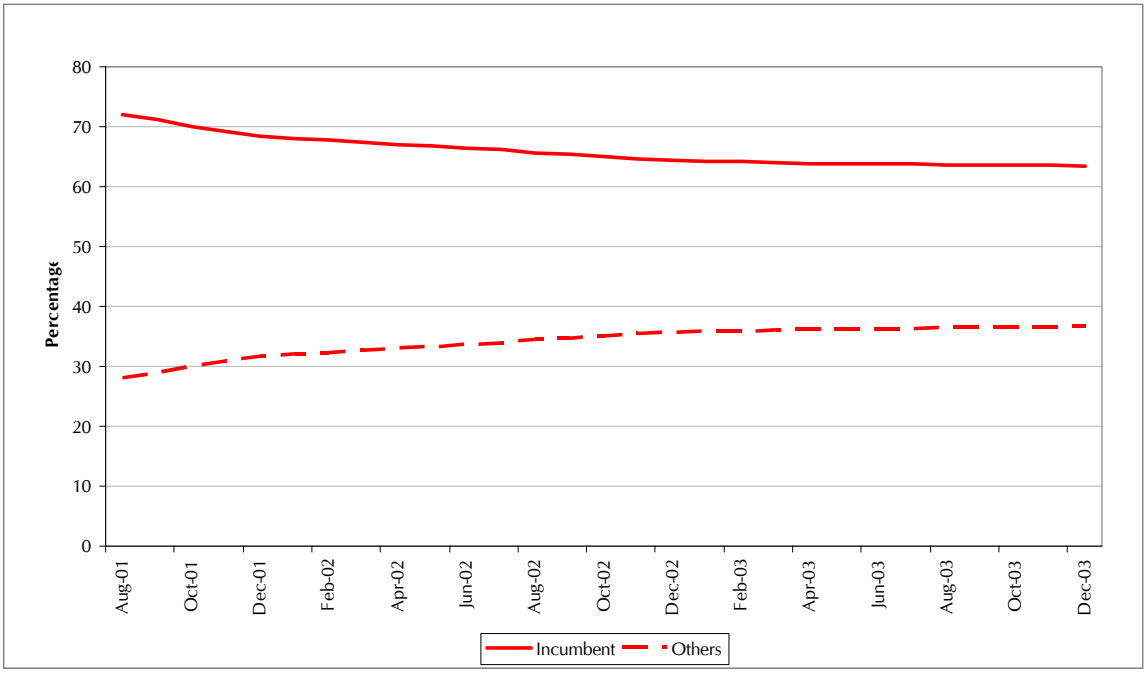
Source: Distribution Companies

Figure A17.8: Electricity regional customer shares over time in Scottish Hydro area



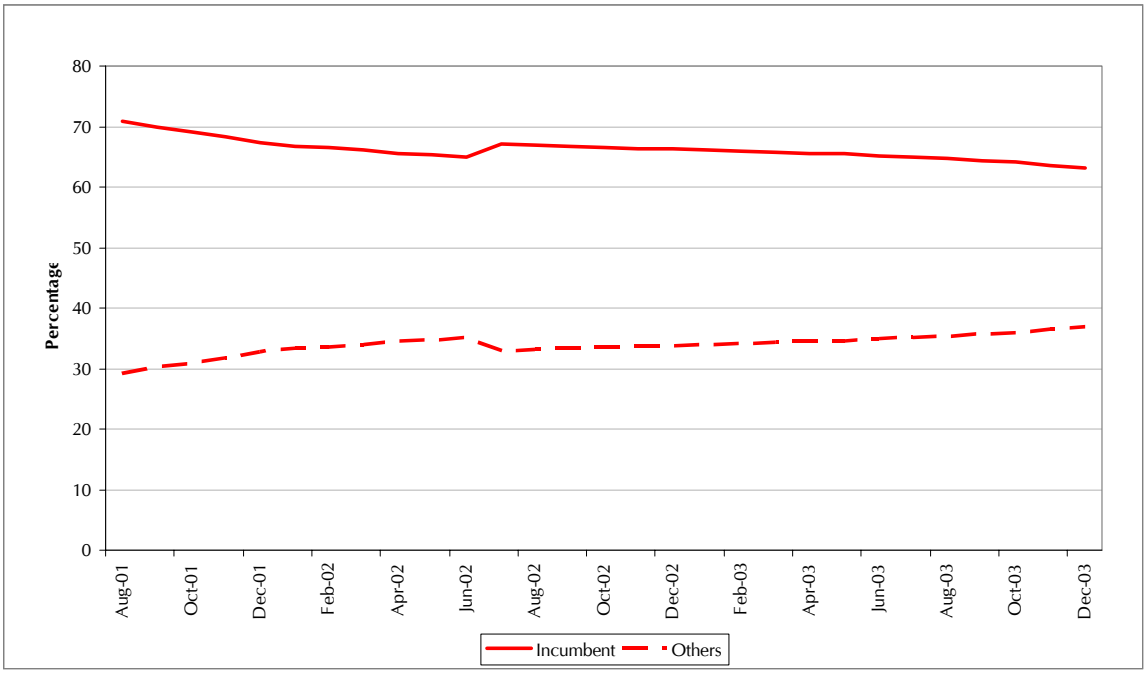
Source: Distribution Companies

Figure A17.9: Electricity regional customer shares over time in ScottishPower area



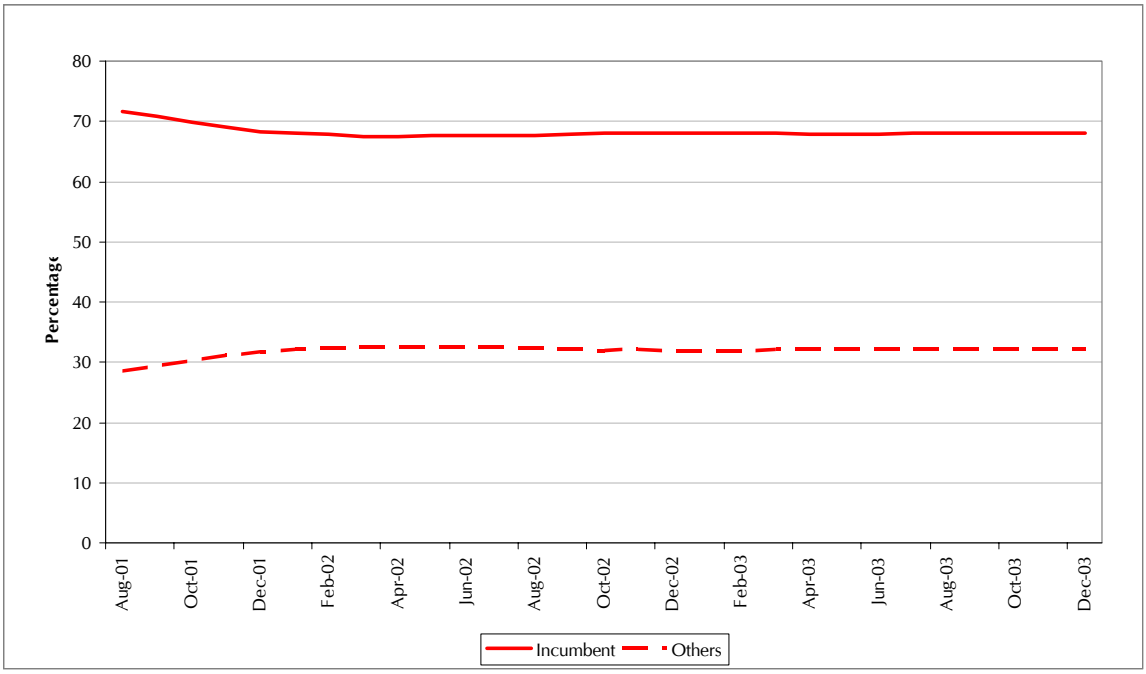
Source: Distribution Companies

Figure A17.10: Electricity regional customer shares over time in Seeboard area



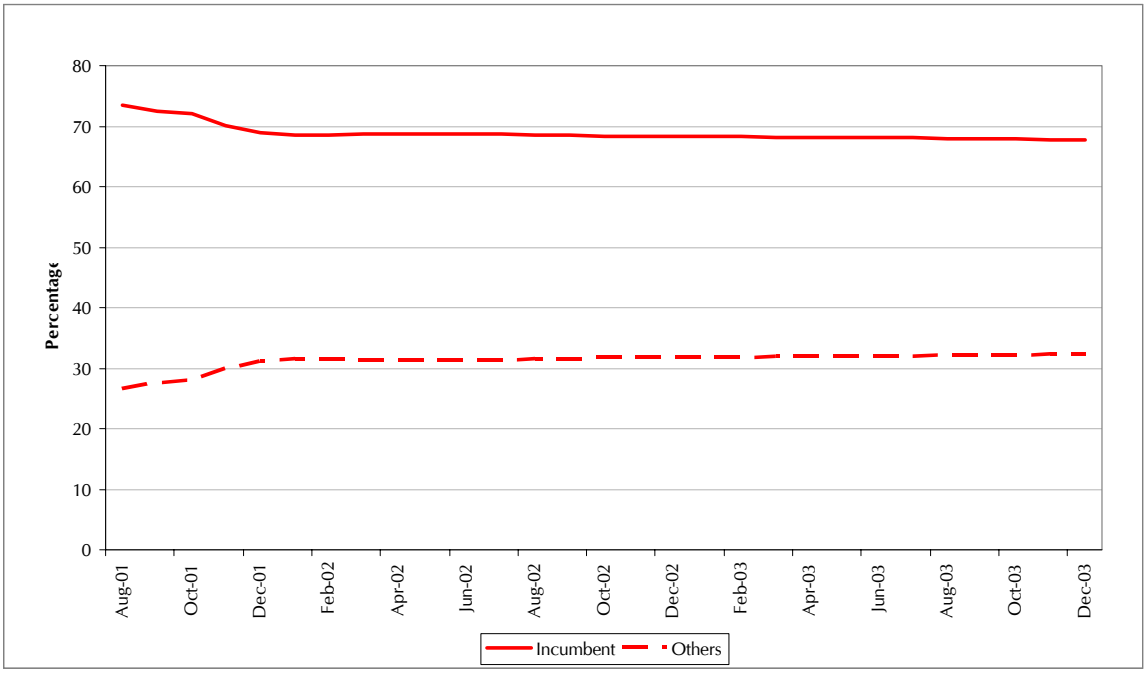
Source: Distribution Companies

Figure A17.11: Electricity regional customer shares over time in Southern area



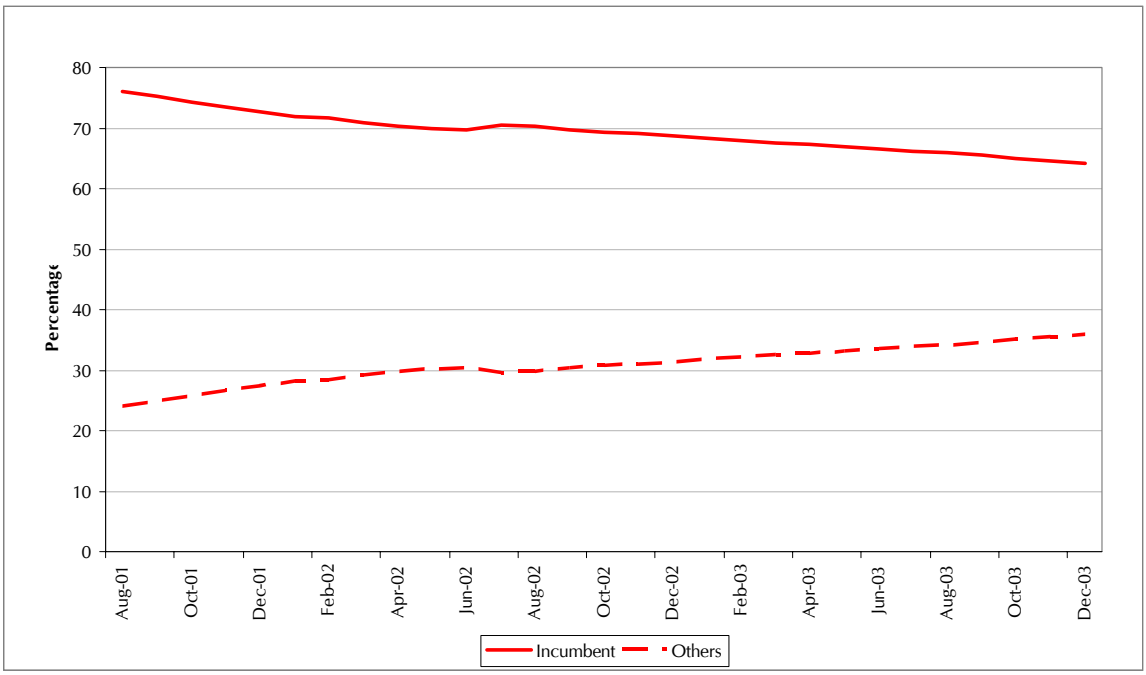
Source: Distribution Companies

Figure A17.12: Electricity regional customer shares over time in Swalec area



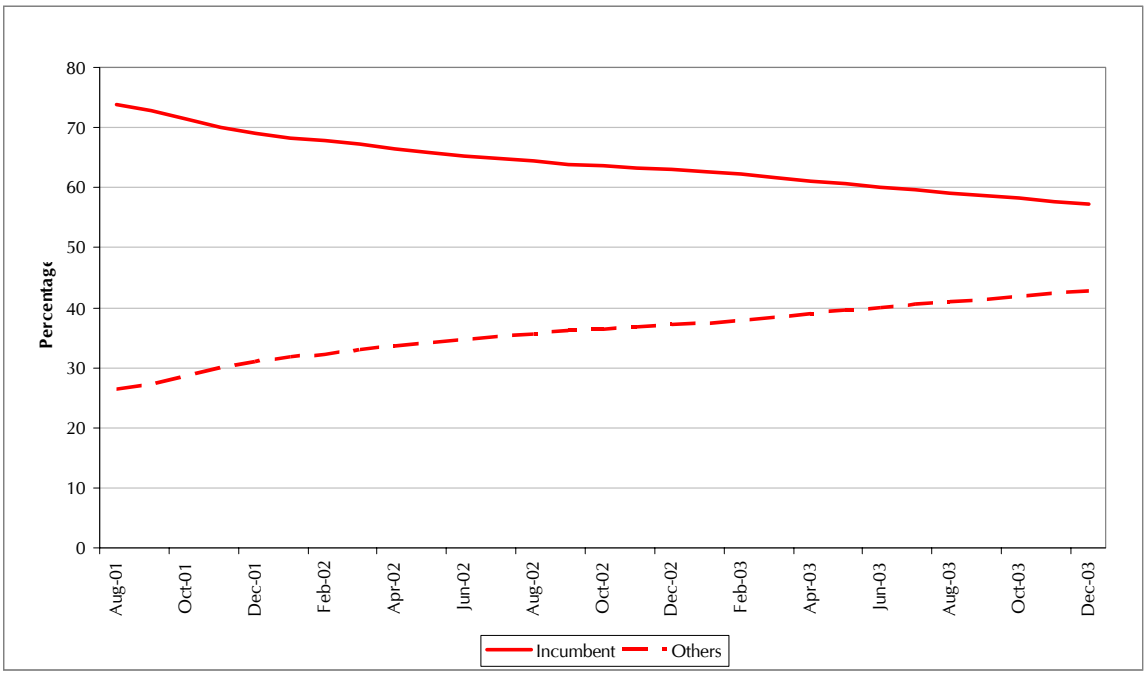
Source: Distribution Companies

Figure A17.13: Electricity regional customer shares over time in Sweb area



Source: Distribution Companies

Figure A17.14: Electricity regional customer shares over time in Yorkshire area



Source: Distribution Companies

Appendix 18 Coordinated effects theory

1.1 The matrix below uses a simple market model with two firms (firm A in grey and firm B in white) to illustrate the game-theoretic ideas behind coordinated effects. The matrix shows each firm's pay-offs, which can be thought of as profits or revenues. These pay-offs depend on each firm's individual pricing decisions to either price high or low.

		Firm B's price strategy	
		High	Low
Firm A's price strategies	High	150 / 150	175 / 100
	Low	100 / 175	125 / 125

1.2 In a one stage game the starting point is both firms pricing high. Either firm could cheat by pricing low and thereby earn higher pay-offs by capturing more customers, whilst the non-cheater loses out.

1.3 However, if there is repeated interaction between firms they will learn over time that if they coordinate their pricing strategies, and both price high, they will both end up with higher pay-offs. This outcome is known as the optimum equilibrium or the mutually advantageous equilibrium. It may be sustained by the threat of increased competition if prices are reduced.

1.4 This simple model has a highly concentrated market structure. The more firms there are in the market the more difficult it is to track competitors' activities and therefore the more difficult coordination will be.

1.5 The capacity to reach a mutually advantageous equilibrium is associated with stable market conditions such as stable demand, low innovation and low demand volatility. If the market is transparent and prices are easily observed then all market players can monitor their competitors' behaviour enabling firms to detect cheating quickly. If cheating can be detected quickly then firms are less likely to cheat, reinforcing the commitment to continue pricing high.

1.6 The capacity for repeated interaction is important in this model because it is only over time that firms may experience their mutual interdependence and learn

through experience. In the simple model presented in the matrix the actions of each firm depend on what they think will be the reactions of the other. Coordinated effects are therefore more likely where firm interactions are easily observed and straightforward.

1.7 A punishment strategy is the ability of firms to retaliate and price low if one firm cheats. Credible punishment strategies result from stable market conditions and a broad symmetry of firms. For example, if each firm has a similar share of the market then a retaliation strategy by one firm will have an equal impact on the other firms' profits[8].

1.8 The speed of the reaction to a cheat may also be important when considering how effective and so how credible punishment strategies are. Customer switching costs may make punishment strategies more difficult because if a customer is reluctant to switch this slows down the process by which punishment strategies take immediate effect.

1.9 It is important to note the limitations to the simple model of competition presented in the matrix above. The greater the difference between pricing high and low, the higher will be the pay-offs from coordination, but the market characteristics conducive to coordination, such as a homogenous product, may also be conducive to fierce price competition.

[8] For further discussion of switching costs see 'Switching costs: Economic Discussion Paper 5', OFT, April 2003.

Appendix 19 Updates on potential barriers to entry and expansion

1.1 This Appendix re-visits certain features of gas and electricity sectors that Ofgem's November 2001 Review[9] identified as potential barriers to entry. This Appendix gives an up-date on any changes relating to features discussed in the November 2001 Review.

BGT's and the ex-PES suppliers' market position and behaviour

1.2 Respondents to the November 2001 Review raised concerns that BGT's and the ex-PESs dominant positions in the energy sector may act as a barrier to entry.

1.3 The November 2001 Review pointed out that the Competition Act prohibits the *abuse* of a dominant position and that Ofgem has powers to investigate possible abuses. Possession of a dominant position is not in itself prohibited. Ofgem also noted that there appeared to be little evidence that the consolidation was, in itself, a strong barrier to entry since new entrants were not precluded from identifying and targeting relevant smaller parts of the sectors or from entering strategic partnerships with established firms.

Update

1.4 Since the November 2001 Review was published:

- Ofgem has considered a number of complaints under the Competition Act. It also carries out regular monitoring of the domestic sectors to ensure that competition is working effectively
- incumbent share of customers continues to erode (see Chapter 6 paragraphs 6.34 to 6.56), and
- new entrants (both small independent suppliers and 'white label' partnerships) have entered the gas and electricity sectors (see Chapter 6 paragraphs 6.61 to 6.66).

[9] Ofgem, *"Review of domestic gas and electricity competition and supply price regulation: Evidence and initial proposals"*, November 2001, 71/01.

Shared Unmetered Supplies (SUS)

1.5 Some customers in the north of Scotland use some electricity from a shared and unmetered source, for example for communal lighting. The additional processes and costs involved in billing customers for this electricity deterred other suppliers from competing for customers in this area.

Update

1.6 In February 2002 Ofgem proposed transferring the recovery of SUS from joint bills to distribution losses where consumption is estimated at or below 350kWh a year[10]. The proposals set out in the February 2002 proposal were implemented in the north of Scotland on 1 April 2002.

Competition on gas transportation networks operated by companies other than Transco

1.7 Concern was raised that suppliers' incentives to compete for customers on these networks was reduced for a number of reasons including a lack of common administrative arrangements, lack of consistency and unpredictability of charges (which are not price controlled by Ofgem) and the relative expense or difficulty of providing prepayments to customers on these networks.

Update

1.8 Following an extensive period of consultation, Ofgem published its final proposals for the regulation of iGT charges in July 2003. The proposals covered a number of important issues associated with the level of iGT charges. In particular, they introduced a system of relative price regulation for charges to new consumers connecting to iGT networks, effectively capping transportation charges at levels that would have been levied if Transco had operated the network. All relevant licensees accepted the licence modifications necessary to introduce these proposals and the policy was implemented on 1 January 2004. Ofgem is currently assessing the appropriate way to monitor and enforce the

[10] 'Supply competition for electricity customers with shared unmetered supplies and dynamic teleswitched heating loads in the north of Scotland: Proposal Document', Ofgem, February 2002.

new licence conditions and is determining the process by which charges to existing iGT customers will migrate to the new arrangements.

1.9 Competition is developing in the provision of metering services and Ofgem considers that an effectively competitive metering market will ensure that suppliers are able to obtain metering services such as prepayment metering on all transportation networks. Ofgem is currently considering the barriers preventing suppliers from sourcing prepayment meters to customer on iGT networks.

1.10 Ofgem's Corporate Plan for 2004 - 2007[11] proposes to review the supply licence conditions with the objective of improving the targeting and effectiveness of regulation and to reduce barriers to entry. It is likely that issues concerning supply on iGTs will form part of this review.

Gas system entry capacity auctions

1.11 In the November 2001 review, Ofgem stated that there would be a number of developments to the national transmission entry capacity regime. It was envisaged that these developments, along with a series of incentive arrangements introduced as part of the 2002 price control review, would reduce distortionary effects which emerged under the short term auction arrangements and would provide appropriate and non-discriminatory price signals.

Update

1.12 The long term auction regime was introduced in 2002 (the first long-term auctions were held in January 2003) with the following objectives:

- provide Transco with long term investment signals, thus promoting the economic and efficient development of the national transmission system (NTS) over the long term, and
- ensure that capacity rights would be sold in an efficient and non-discriminatory manner, such that competition in related markets (such as the supply of gas) would not be distorted.

[11] Ofgem Proposed Corporate Plan 2004-2007. Ofgem 59/04 March 2004

1.13 Transco offers firm NTS system entry capacity rights to shippers in a number of long and short term auctions. The range of products allow shippers to invest up to 15 years ahead and to fine tune their physical positions on a monthly and daily basis. Long Term System Entry Capacity (LTSEC) is quarterly capacity sold in the long term auctions, while Monthly System Entry Capacity (MSEC) is made available in annual and monthly allocations. Daily products are made available both day ahead (where capacity for a whole day is offered) and within day (where capacity up to the end of the gas day is made available) and Daily Interruptible Entry Capacity (DISEC) is available ahead of the gas day.

1.14 Under its Gas Transporter (GT) licence, Transco has a predetermined series of capacity output measures which it must provide at each system entry terminal (known as Transmission Asset Owner (TO) baseline). Transco is obliged to offer 90 per cent of these output measures as System Operation (SO) baseline capacity in the entry capacity auctions. Transco offers 80 per cent of its SO baseline in the long-term auctions and reserves 20 per cent, which is offered for sale in short term auctions. This 20 per cent of held back capacity allows new entrants and existing players to compete to secure entry capacity in the short term, thus reducing barriers to entry.

1.15 The entry capacity regime provides certainty and non discriminatory firm access rights to shippers in the long and short term markets. The auctions also provide appropriate signals and investment incentives to Transco.

1.16 For example, new entrants to the storage market signalled demand for the provision of new incremental entry capacity at Garton through the long term auctions in early 2004.

1.17 There has been a continued high level of participation in the long and short term auctions, including the establishment of a secondary market, which allows shippers to trade their firm rights. The auctions have generated substantial revenues.

1.18 Ofgem is continuing to work with Transco to ensure that under or over recoveries against Transco's allowed TO and SO revenues are addressed in line with Transco's charging methodology objectives (as set out under its Gas Transporter licence) wherever possible.

The effect of new electricity trading arrangements (NETA)

1.19 The November 2001 Review noted concerns about NETA, in particular the impact of imbalance charges. Ofgem stated that during the first six months of NETA only 5 per cent of electricity purchases had been made through the balancing mechanism and that recent modifications to the way imbalance costs were calculated should make them more cost-reflective.

Update

1.20 Currently approximately 3 - 4 per cent of all wholesale electricity is traded through the balancing mechanism, the remainder being traded via bilateral contracts between participants. Since the November 2001 review a number of changes to the methodology for the calculation of imbalance cash-out prices have been implemented. These changes have improved the way that the costs incurred by the system operator in balancing the system are reflected back to the market, ensuring that the market receives the appropriate price signals and creating the right commercial incentives on companies to balance and maintain security of supply.

1.21 Since NETA Go-Live there has been a steady decrease in the spread between the System Buy Price and the System Sell Price. In April 2001 the average monthly difference between the two prices was £69.80. The spread fell to £21.99 in February 2002, £14.40 in February 2003 and £5.52 February 2004.

1.22 Ofgem intends to undertake a review of the gas and electricity cash-out arrangements and their impact on incentives to balance and security of supply shortly. A document on this review will be published in April inviting industry's views on these issues.

Renewables Obligation (RO)

1.23 At the time the November 2001 Review was published the DTI was consulting on the RO. The November 2001 Review noted concerns about the impact of the RO, which obliges suppliers to buy a certain percentage of their electricity from renewable sources and whether this favoured larger suppliers.

Update

1.24 The RO has now been in operation for 2 years and Ofgem has published its first annual report on the RO[12]. Electricity suppliers can fulfil the RO by presenting Renewables Obligation Certificates (ROCs), paying the buy-out price or a combination of both. This flexibility appears to have enabled suppliers to regulate their spending on the RO. Ofgem's first annual report on the RO shows that new entrants have taken a variety of approaches to meeting the RO. For example, Opus Energy and The Renewable Energy Company met their whole obligation through buying ROCs, whilst Atlantic relied completely on the buy out fund, and Utility Link used a combination of both[13].

1.25 For the period April 2004 to March 2005 each supplier will have a RO set at 4.9 per cent of all electricity supplied. This will make up about 2 per cent of a typical customer's bill as illustrated in Figure 4.2 in Chapter 4. The level of the RO is set to increase to 10.4 per cent in 2010/11. DTI has recently announced plans to increase the RO to 15.4 per cent in 2015/16. Ofgem will continue to monitor the effect this is likely to have on new entrants in the supply sector[14].

1.26 Later this year DTI and the Scottish Executive will be consulting on the scope of the 2005/6 RO review. This will be an opportunity for industry to raise areas of concern in their response to the consultation.

[12] The Renewables Obligation, Ofgem's first annual report, February 2004.
[13] The Renewables Obligation, Ofgem's first annual report, February 2004, page 25.
[14] For more details on the renewable obligation see Ofgem's website: http://www.ofgem.gov.uk/ofgem/work/index.jsp?section=/areasofwork/renewableobligation and in particular please see 'Renewables Obligation – Ofgem's procedures' February 2002 and 'Renewables Obligation - Ofgem's first annual report' February 2004.