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Technical Appendix to

MARKET POWER IN THE ENGLAND AND WALES WHOLESALE ELECTRICITY MARKET 1995–2000

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Supplementary Appendix for 'Market Power in the England and Wales Wholesale Electricity Market 1995–2000'

This Appendix describes some additional empirical evidence that supports the results in the main article.

Robustness Checks on Market Power Estimates

Section 2 of the article shows that generators exercised considerable market power from the beginning of 1997, by estimating competitive benchmark prices using data on generator marginal costs. Here I report two robustness checks that show that using different assumptions on fuel and operating and maintenance costs does not change the qualitative results.

Actual Fuel Costs: column (1) of Table A1 presents estimates of the market power index when I use the average fuel prices paid by generators for coal, heavy fuel oil and natural gas to measure input prices. These series are reported in the Department of Trade and Industry's *Quarterly Energy Prices* publication. The average coal price reflects generators' purchases of significant amounts of relatively expensive British coal. The base case assumes that generators used cheaper imported coal on the margin. The market power index falls in every quarter but the conclusion that generators were exercising considerable market power from the beginning of 1997 does not change, with the index varying between 0.25 and 0.58.

Alternative Estimates of O&M Costs: the base case assumed, based on MMC (1996*a*), p. 101, that the variable non-fuel operating and maintenance costs of coal and oil units were £1/MWh in 1995 prices. A *Power UK* article in 1994 also estimated that the variable non-fuel operating costs of coal plants were £1/MWh.[1] However, OFFER (1998*b*, Section 3.2), estimates that variable O&M costs at plants NP and PG were planning to close were £3/MWh in 1998 prices. Column (2) of Table A1 shows that when I use these higher O&M costs for all coal and oil units, the market power

[1] *Power UK*, 'Are low merit coal plants profitable?', December 21, 1994.

index falls, but only by between 3 and 8 percentage points in each quarter from the base case.[2]

Availability of Inframarginal Generating Units

The results in the article suggest that generators did not exercise market power in the late 1990s by declaring inframarginal capacity unavailable (so that units with higher marginal costs would set the SMP). This is a potentially controversial conclusion as Wolak and Patrick (1997) suggest that generators would prefer to exercise market power in this way rather than by increasing their price bids. To provide further evidence on this question I look directly at how much inframarginal capacity NP and PG declared unavailable.

For each half-hour period I create an aggregate marginal cost function using the expected availability (based on NERC forced outage rates) of units not owned by NP and PG and the full capacity of NP and PG's units. I then use this marginal cost function and the Pool's demand forecast to identify the highest cost unit required to meet demand and define all units with lower costs to be inframarginal. Table A2 compares the average available capacity of NP and PG's inframarginal units with their expected available capacity given

(*i*) NERC forced outage rates and
(*ii*) NERC Availability Factors.

Availability Factors reflect scheduled maintenance as well as forced outages. Units are excluded from the comparison for the first six months following commissioning as they have unusual availability patterns because of testing requirements.

NP and PG's inframarginal capacity falls over time reflecting the changes in market structure. The availability of NP and PG's units was generally below what would be expected given NERC forced outage rates but it was, on average for both generators, more than 95% of what would be expected given NERC Availability Factors. This provides further evidence that NP and PG were not distorting their availability by much.[3] It is also noticeable that NP and PG declared more of their inframarginal capacity to be unavailable in the low demand summer months when electricity demand, prices and market power were lower. We would expect competitive generators to have behaved in the same way, scheduling maintenance when prices were relatively low.

[2] I continue to use MMC's estimate of £1.80/MWh at 1995 prices for the O&M costs of CCGT units. This seems reasonable as CCGT units were perceived to have low operating costs because they employed minimal labour and had highly automated operations (*Power UK*, 'Are low merit coal plants profitable?', December 21, 1994 and Competition Commission, 2001). Increasing CCGT operating costs as well has only a small effect on the results.

[3] NP and PG declared a higher proportion of their inframarginal capacity available if inframarginal capacity is identified using the actual availability and bids of other generators rather than their expected availability and estimates of their marginal costs. Availability performance was poor in the last quarter of the sample. This may be explained by generators performing additional maintenance in advance of NETA, as under NETA it was potentially much more costly for a unit to have an unplanned outage.

Robustness Checks on Generator Best Response Behaviour

Section 3 of the article tests the Nash equilibrium assumption of static oligopoly models that each generator's bids should be profit-maximising best responses to the bids of other generators. I find that both NP and PG (the two largest generators) could have increased their short-run profits by reducing their bids and increasing their output. Here I report two additional robustness checks on these results.

Contract Cover: The contemporaneous evidence suggests that the vast majority of generators' output was covered by financial hedging contracts. My base case assumption is that 80% of their output was covered in each half-hour period. However, it is possible that generators' contract cover varied with the time of day and, in particular, if generators had lower contract cover in high demand periods then they might find it profitable to submit high bids in order to raise prices in these more profitable periods. To test whether this could explain my results I assume that the generators had the same *absolute* amount of output covered by contracts in every half-hour period of the day, equal to 80% of its average output. This is an extreme assumption because the evidence suggests that the output covered by contracts did vary with demand at least to some extent.[4] Table A3 shows that the profit-maximising outputs under this assumption are very similar to those in the base case. This is not surprising because margins were quite high in medium and low demand periods, as well as high demand periods, in most months in the late 1990s (see Figure 3 in the article).

Alternative Algorithm: My approach assumes that I can estimate prices and generator outputs accurately using the algorithm described in Appendix B of the article. As a robustness check, I use an alternative algorithm, similar to the ones used by Hortacsu and Puller (2005) and Wolak (2000; 2003), to estimate profit-maximising bids. For each half hour period and each generator in turn the algorithm works as follows:

1. I construct a supply function for other generators using the Table A prices (described in Appendix B of the article) of their available units;
2. I calculate the generator's residual demand function, which is a step function, by subtracting this supply function for other generators from the Pool's price inelastic demand forecast (TGSD).
3. I construct a bid function for the generator using the Table A prices of its units. I calculate the price and output when the generator uses its actual bids from the intersection of this bid function and the residual demand function;
4. I construct a marginal cost function for the generator's available units by estimating unit marginal costs as described in Section 2 of the article;

[4] NP and PG's contracts with the RECs were shaped to match the RECs' demand profile (*Power UK*, 'The Market for CFDs', July 22, 1997). In 2000 there was increasing trade in Electricity Forward Agreements (EFAs), which were standardised contracts traded through brokers (OFGEM, 2000). The most popular EFA was called 'Load Shape 44' which covered 20 MW of output throughout the day and an additional 20 MW between 7am and 7pm on weekdays.

5. I find the generator's profit-maximising output using its residual demand function and marginal cost function.[5]

This alternative algorithm has the advantage of not limiting me to consider a limited set of alternative bids. However, unlike GOAL, it treats periods independently and takes no account of unit start-up costs or technical constraints on unit operation. This leads to Pool prices being consistently underestimated.[6] Using generators' actual bids it predicts an average SMP of £15.56/MWh (standard deviation £6.52/MWh) compared to an actual average SMP of £21.15/MWh (£13.30/MWh). My preferred algorithm gives a better fit with an average SMP of £20.47/MWh (£11.88/MWh). As the alternative algorithm predicts prices which are consistently too low, this should make me less likely to find that a generator could profitably increase its output.

Table A4 presents the results of using this alternative algorithm assuming that 80% of a generator's actual output in each half-hour period was covered by contracts. I present the results both including and ignoring the Eastern earn-out and, as before, including the earn-out does not change the qualitative results. The alternative algorithm tends to give lower values for both actual and profit-maximising outputs than my preferred algorithm. The general pattern, as before, is that NP and PG would have maximised their profits by increasing their outputs from the beginning of 1997. When I include the effect of the earn-out I estimate that NP would have maximised its profits by reducing its output in the third quarter of 1998. This reflects the alternative algorithm's underestimation of prices as on Wednesdays during this quarter, the alternative algorithm predicts an average SMP using generators' actual bids of only £12.93/MWh, compared with an actual average SMP of £18.11/MWh, so that the margin a generator could earn on additional output is incorrectly estimated to be very small.

Joint Profit-Maximising Bids

One explanation for why a generator might have submitted bids which were too high to have maximised its short-run profits is that it was colluding with other generators. If NP and PG were the only colluding generators then we would expect their joint output to have been no less than the output which would maximise their joint short-run profits. I examine whether this is the case by repeating my analysis to find joint profit-maximising bids. Table A5 reports the results, including the effects of the earn-out on NP and PG's profits, for two different levels of contract cover. In all quarters before the last quarter of 1999 I find that NP and PG would have maximised their joint profits by reducing their joint output. This is consistent with tacit collusion between these generators. In 2000 I find that the generators could have increased their profits by

[5] I use a grid search to find the profit-maximising output because the residual demand function is a step function. Hortacsu and Puller (2005) and Wolak (2003*b*) suggest smoothing the residual demand function using a normal kernel. It is harder to apply this approach when I include the effects of the Eastern earn-out on a generator's profits, but if I ignore the effects of the earn-out then the results from using step-function and smoothed residual demand functions are almost identical.

[6] If one uses the alternative algorithm to schedule output but uses the Pool's formulae, including start-up prices, to calculate prices then one consistently overestimates Pool prices in peak demand periods because the alternative algorithm schedules many units to run for only one or two periods. This makes increases in output appear to be even more profitable than in my base case.

increasing their output if 80% of their output was covered by contracts. This could be explained by tacit collusion between a larger group of generators as by 2000 several other generators were approximately the same size as NP and PG (see Table 1 in the article).

Table A1

Estimates of Market Power – Robustness Checks on Marginal Costs

Quarter	Number of half hour periods	Average demand (MW)	Average SMP (£/MWh)	Estimates of market power index: Base case (from Table 3)	(1) Average fuel costs	(2) Higher O&M costs
Q1 1995	4,318	35,905	16.94	0.23	0.15	0.14
Q2 1995	4,368	29,267	18.77	0.34	0.22	0.28
Q3 1995	4,416	28,349	16.71	0.27	0.18	0.20
Q4 1995	4,416	34,192	22.40	0.36	0.31	0.30
Q1 1996	4,366	37,809	19.70	0.27	0.23	0.19
Q2 1996	4,368	30,319	19.90	0.35	0.29	0.27
Q3 1996	4,416	28,779	16.74	0.27	0.18	0.20
Q4 1996	4,416	35,188	19.60	0.35	0.27	0.30
Q1 1997	4,126	36,721	25.65	0.50	0.44	0.47
Q2 1997	4,368	30,318	21.00	0.43	0.37	0.37
Q3 1997	4,416	29,548	17.83	0.30	0.25	0.23
Q4 1997	4,416	35,264	28.67	0.56	0.51	0.52
Q1 1998	4,318	36,529	30.48	0.59	0.54	0.55
Q2 1998	4,368	31,050	21.13	0.45	0.41	0.39
Q3 1998	4,416	29,885	17.31	0.34	0.31	0.26
Q4 1998	4,416	35,810	25.53	0.55	0.49	0.51
Q1 1999	4,318	37,275	30.56	0.63	0.58	0.59
Q2 1999	4,368	30,923	16.48	0.32	0.27	0.24
Q3 1999	4,416	30,119	21.73	0.52	0.46	0.47
Q4 1999	4,416	35,869	20.86	0.50	0.39	0.43
Q1 2000	4,366	37,485	21.34	0.50	0.40	0.43
Q2 2000	4,272	31,929	18.15	0.40	0.36	0.33
Q3 2000	4,406	30,581	18.56	0.40	0.37	0.34

Notes: Excludes periods with missing SMP or TGSD data and 4 days where unit codes in availability and bid data do not match.

Table A2

Availability of Inframarginal Units

		National Power				PowerGen			
Quarter	Market power Index	Average inframarginal capacity	Average inframarginal capacity available	Expected available inframarginal capacity based on NERC forced outage factors	Expected available inframarginal capacity based on NERC availability factors	Average inframarginal capacity	Average inframarginal capacity available	Expected available inframarginal capacity based on NERC forced outage factors	Expected available inframarginal capacity based on NERC availability factors
Q1 1995	0.23	11,341	10,649	10,589	9,701	8,413	7,824	7,846	7,079
Q2 1995	0.34	9,851	8,451	9,227	8,401	6,936	5,801	6,497	5,786
Q3 1995	0.27	9,244	7,322	8,659	7,894	6,412	5,109	6,007	5,350
Q4 1995	0.36	11,248	9,758	10,499	9,628	7,200	6,733	6,737	6,022
Q1 1996	0.27	11,333	10,672	10,753	9,952	8,299	7,786	7,966	7,288
Q2 1996	0.35	8,006	6,859	7,552	7,066	4,377	3,658	4,190	3,868
Q3 1996	0.27	5,817	4,447	5,476	5,070	6,547	4,883	6,317	5,680
Q4 1996	0.35	8,727	7,585	8,265	7,576	9,218	7,253	8,887	8,015
Q1 1997	0.50	9,494	8,437	8,803	8,139	9,719	8,602	9,012	8,184
Q2 1997	0.43	6,299	4,830	5,849	5,496	7,044	5,556	6,556	6,016
Q3 1997	0.30	6,321	4,208	5,905	5,636	4,848	3,831	4,528	4,195
Q4 1997	0.56	9,044	8,158	8,402	7,831	8,866	6,759	8,227	7,487
Q1 1998	0.59	9,268	8,433	8,532	8,003	9,559	7,639	8,835	8,103
Q2 1998	0.45	7,104	5,316	6,530	6,164	7,503	5,071	6,935	6,351
Q3 1998	0.34	6,771	5,402	6,229	6,008	5,044	4,115	4,667	4,362
Q4 1998	0.55	9,180	8,341	8,450	7,926	9,025	6,813	8,342	7,646
Q1 1999	0.63	8,726	8,032	8,028	7,393	8,073	6,322	7,406	6,620
Q2 1999	0.32	4,738	3,488	4,361	4,159	3,388	2,899	3,112	2,946
Q3 1999	0.52	4,680	3,617	4,308	4,107	2,801	2,203	2,573	2,443
Q4 1999	0.50	6,101	5,268	5,613	5,201	5,123	4,200	4,702	4,262
Q1 2000	0.50	4,286	3,793	3,987	3,623	5,323	4,101	4,957	4,386
Q2 2000	0.40	2,538	2,233	2,351	2,331	3,023	2,465	2,807	2,637
Q3 2000	0.40	2,100	1,256	1,945	1,928	2,615	1,943	2,427	2,327

Notes. Capacities measured in MWs and reported capacities are averages across half-hour periods in each quarter, excluding periods with missing SMP or TGSD data and 4 days where unit codes in availability and bid data do not match. Units within 6 months of commissioning are excluded from all of the reported numbers. The set of half-hour periods used for each quarter in the same as in Table 3 of the article.

Table A3

Testing Best Response Bidding Behaviour for NP and PG Robustness Check on Proportion of Output Covered by Contracts

		National Power			PowerGen		
		Contract cover	80%	80% Average daily output	Contract cover	80%	80% Average daily output
Quarter	Market power Index	Eastern earn-out Estimated actual output	Yes	Yes	Eastern earn-out Estimated actual output	Yes	Yes
Q1 1995	0.23	13,609	12,320***	12,256***	11,303	10,113*	10,113*
Q2 1995	0.34	10,380	10,237	9,774*	7,496	7,590	7,289
Q3 1995	0.27	8,930	9,099	8,591	6,559	6,585	5,631***
Q4 1995	0.36	11,445	11,740	10,571**	8,745	9,546**	9,381*
Q1 1996	0.27	13,145	12,777	12,521	10,114	10,004	9,853
Q2 1996	0.35	8,942	8,709	7,761***	7,446	7,777*	7,489
Q3 1996	0.27	7,404	6,444***	6,134***	6,851	6,319*	5,892***
Q4 1996	0.35	7,802	8,653**	8,796**	8,052	9,058***	8,949**
Q1 1997	0.50	8,340	9,762***	9,590***	7,728	9,839***	9,755***
Q2 1997	0.43	5,987	7,867***	7,867***	5,633	7,397***	7,397***
Q3 1997	0.30	6,636	7,848***	7,382***	5,985	6,689***	6,699***
Q4 1997	0.56	6,997	9,386***	9,274***	6,785	8,940***	8,940***
Q1 1998	0.59	8,040	10,162***	10,162***	7,076	9,953***	9,953***
Q2 1998	0.45	7,565	9,320***	8,963***	5,965	7,489***	7,378***
Q3 1998	0.34	7,352	8,003***	7,960***	5,827	6,736***	6,499*
Q4 1998	0.55	7,189	8,501***	8,432***	6,176	7,587***	7,629***
Q1 1999	0.63	6,951	8,197***	8,098***	6,117	7,395***	7,301***
Q2 1999	0.32	5,389	6,632***	6,564***	5,614	6,815***	6,668***
Q3 1999	0.52	5,487	6,584***	6,729***	4,288	5,765***	5,764***
Q4 1999	0.50	6,259	8,272***	8,337***	5,009	6,722***	6,782***
Q1 2000	0.50	5,128	6,542***	6,542***	4,962	6,795***	6,764***
Q2 2000	0.40	4,154	4,584***	4,540***	4,074	5,888***	5,682***
Q3 2000	0.40	3,210	3,542**	3,544**	2,960	4,109***	3,841***

Notes. Outputs measured in average MWs of capacity operating per half-hour period. Days with missing demand data are excluded. Market Power Index from column (1) of Table 3. ***,**,* denote statistical significance of the difference between actual and profit-maximising outputs at the 1, 5 and 10% levels respectively. Statistical significance is assessed by regressing the difference in outputs in each half-hour period on a constant, allowing for heteroscedasticity and correlation between the regression residuals from different half-hour periods on the same day.

Table A4

Testing Best Response Bidding Behaviour for NP and PG. Robustness Check Using Alternative Scheduling Algorithm

		National Power Estimated profit-maximising average outputs			PowerGen Estimated profit-maximising average outputs		
			(1)	(2)		(3)	(4)
		Contract cover	80%	80%	Contract cover	80%	80%
		Eastern earn-out	No	Yes	Eastern earn-out	No	Yes
Quarter	Market power Index	Estimated actual output			Estimated actual output		
Q1 1995	0.23	13,336	11,790***	11,790***	11,516	9,242***	9,242***
Q2 1995	0.34	9,889	9,531	9,531	7,242	7,250	7,250
Q3 1995	0.27	8,395	8,122	8,122	6,320	5,799*	5,799*
Q4 1995	0.36	10,863	11,001	11,001	8,751	9,066	9,066
Q1 1996	0.27	12,916	11,878***	11,878***	10,217	9,009**	9,009**
Q2 1996	0.35	8,831	8,314***	8,314***	7,438	7,454	7,454
Q3 1996	0.27	7,223	6,177***	5,906	6,987	6,068***	5,947***
Q4 1996	0.35	7,445	7,886	7,448	7,609	7,993**	7,697
Q1 1997	0.50	7,883	9,015***	8,733***	7,523	8,520***	8,480***
Q2 1997	0.43	5,784	7,003***	6,623***	5,388	6,997***	6,914***
Q3 1997	0.30	6,613	6,707	6,536	5,903	6,310**	6,284**
Q4 1997	0.56	6,763	8,392***	8,071***	6,700	8,329***	8,293***
Q1 1998	0.59	7,741	9,214***	9,090***	7,031	9,867***	9,859***
Q2 1998	0.45	7,346	8,810***	8,659***	5,719	7,638***	7,638***
Q3 1998	0.34	7,232	7,076	6,895**	5,662	5,852	5,767
Q4 1998	0.55	6,787	7,498***	7,424***	5,769	6,466***	6,346***
Q1 1999	0.63	6,653	7,454***	7,056***	5,867	6,902***	6,824***
Q2 1999	0.32	5,110	6,455***	5,582***	5,371	6,834***	6,354***
Q3 1999	0.52	5,321	6,653***	6,381***	4,258	5,669***	5,646***
Q4 1999	0.50	6,121	8,300***	8,043***	4,937	6,573***	6,560***
Q1 2000	0.50	5,048	6,488***	6,241***	4,879	6,543***	6,513***
Q2 2000	0.40	4,123	4,337**	4,297**	3,971	5,200***	5,200***
Q3 2000	0.40	3,044	3,138*	3,098	2,784	3,705***	3,705***

Notes. Same as Table A3.

Table A5

Testing Joint Profit Maximising Bidding by NP and PG

Month	Year	Number of days	Estimated market power index	Estimated actual average joint output of NP and PG	Estimated profit-maximising average joint output assuming 80% contract cover	Estimated profit-maximising average joint output assuming 60% contract cover
Q1	1995	13	0.23	24,912	23,596***	23,596***
Q2	1995	13	0.34	17,875	17,319***	17,319***
Q3	1995	13	0.27	15,489	15,037***	15,037***
Q4	1995	13	0.36	20,189	19,462***	19,462***
Q1	1996	13	0.27	23,259	22,551***	22,551***
Q2	1996	13	0.35	16,388	15,918***	15,918***
Q3	1996	13	0.27	14,255	12,974***	12,858***
Q4	1996	13	0.35	15,854	14,261***	13,853***
Q1	1997	13	0.50	16,068	15,060**	13,901***
Q2	1997	13	0.43	11,620	10,335***	10,061***
Q3	1997	13	0.30	12,620	11,100***	10,903***
Q4	1997	14	0.56	13,782	12,525***	12,396***
Q1	1998	12	0.59	15,117	14,125***	13,953***
Q2	1998	13	0.45	13,530	12,312***	11,788***
Q3	1998	14	0.34	13,180	12,203***	11,209***
Q4	1998	13	0.55	13,365	12,335***	11,798***
Q1	1999	13	0.63	13,067	12,075***	11,444***
Q2	1999	13	0.32	11,003	9,614***	9,527***
Q3	1999	13	0.52	9,775	9,128***	7,843***
Q4	1999	13	0.50	11,268	11,207	8,831***
Q1	2000	13	0.50	10,090	10,672	8,098***
Q2	2000	12	0.40	8,229	9,144***	8,447
Q3	2000	13	0.40	6,170	6,986***	6,325

Notes. Same as Table A3. All estimates include the effects of the earn out on NP and PG's profits.