OFFICE OF ELECTRICITY REGULATION

# REVIEW OF ENERGY SOURCES FOR POWER STATIONS

## SUBMISSION BY THE DIRECTOR GENERAL OF ELECTRICITY SUPPLY

**April 1998**

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## SUMMARY

### 1 Introduction

This is the submission by the Director General of Electricity Supply (DGES) to the Government's Review of Energy Sources for Power Stations

### 2 Developments in England and Wales since Vesting

Since Vesting, the shares of coal and oil in power station output in England and Wales have fallen significantly, while the shares of gas, nuclear and interconnectors have risen. In 1997, coal-fired stations accounted for 34 per cent of output, gas-tired stations for 3 1 per cent. There have been similar but less marked changes in the shares of capacity. The construction of 18,000 MW new, mainly gas-fired, capacity has been matched by closure of older, mainly coal and oil, plant.

Combined cycle gas turbine (CCGT) plant has been constructed both by independent power producers (IPPs) and by the major coal-fired generators, National Power and PowerGen, in about equal amounts. In addition, nearly 800 gas-fired combined heat and power (CHP) schemes have been commissioned. Early CCGTs typically run at baseload, reflecting the nature of the gas purchase contracts. Financial arrangements for some more recent CCGTs are designed with a view to mid-merit running.

### 3 Explanations for Changes in Fuel Sources

The growth of gas-fired generation reflects several factors, notably policy changes to allow such use of gas; increasingly tight environmental restrictions on emissions; and the economic advantages of new gas-fired stations versus older coal-fired ones.

It has been argued that the generation market since Vesting has been artificially distorted to benefit gas. There is limited substance to these arguments. Rather, contractual arrangements to protect coal at the expense of customers were put in place at Vesting and renewed in 1993. The prospect of tighter environmental constraints has increasingly dictated the replacement of coal-fired stations by gas-fired ones. The limited extent of initial competition in generation, the level of Pool and contract prices, and the economics of gas versus coal have also made new entry attractive through the construction of CCGTs

### 4 Possible Future Developments

At present some 13,600 MW of gas-fired generation schemes have Section 36 consent, of which about 5,500 MW is commissioning or under construction. Additional schemes totalling about 13,000 MW have applied for consent, of which 6,000 MW are for conversion of existing stations to dual-firing. The rate at which new gas-fired stations will be built depends upon several factors including the extent to which coal-fired output is constrained by sulphur emission limits; strategies of competitors including coal, gas and electricity prices; and possible actions by Government (including decisions on closing Magnox stations).

Assuming that coal-fired stations fitted with flue-gas desulphurisation (FGD) continue to run at mid-merit, the present sulphur emission limits would broadly require a reduction in coal burn from 39 million tonnes in 1997/98 to 28 million tonnes by 2001 and 23 million tonnes by 2005. The further tightening of the emission limits proposed by the Environment Agency would require achieving these reductions by 1999 and 200 1 respectively.

Since Vesting, the planned reductions in emission limits have limited the incentives on coal-fired generators to increase output and challenge new entry by CCGTs by competing on price. The absence of any explicit mechanism for transferring emission limits has also increased the difficulty of an entrant wishing to purchase existing coal-fired plant in order to compete.

Avoidable costs of existing coal-fired plants have hitherto been higher than for gas-fired plants, but henceforth may be broadly comparable if coal prices and generator margins are sufficiently competitive. There is, therefore, some scope for coal-fired generators to slow the rate of new entry by more competitive prices which discourage the less economic CCGT schemes. Competition ought to be expected to bid prices down to about new entry levels if entry is not constrained.

Scenario modelling explores two cases: the first assumes that all projects with Section 36 consents are commissioned; the second assumes that all schemes with Section 36 consent are commissioned, plus all schemes that have applied for consent except requests for conversion to dual-firing at existing stations and except 2,000 MW of schemes considered less likely to proceed. With such additional entry, prices and load factors would be lower. In both cases, the share of gas as a fuel would be about 50 per cent by 2003, and the share of coal about 15 per cent.

Gas is likely to account for a significantly lower proportion of the market in 2003 than the 72 per cent accounted for by coal as recently as 1989/90. Unlike the situation then with coal, gas will be sold by a large number of different producers, under a variety of contract terms, and in a competitive market.

The first scenario implies annual coal burn of between 35 and 27 million tonnes in 1999, then stabilising thereafter at around 20 million tonnes. The second scenario implies a similar profile at about 2 million tonnes less. The implications for UK deep-mined coal will depend on the competitiveness of UK coal producers and coal-fired generators, including the purchasing decisions of the generators with respect to imports.

## 5 Security of Supply

There are no reasons to expect significant risks of catastrophic failures of gas supplies which could jeopardise security of electricity supplies; or that economically recoverable reserves of gas are likely to run out significantly more quickly than economically recoverable reserves of coal; or that there would be undue exposure to risks of gas price increases; or that gas-fired stations cannot operate sufficiently flexibly; or that the gas transmission network could not be economically reinforced to accommodate the demands of gas-fired stations; or that gas-fired stations could not offer frequency response services.

There have been concerns about interruptible gas supplies. Significant back-up supplies are available and there are likely to be strong incentives to use them. The Pool put in place a short term measure in 1997/98 which it needs to replace by longer term arrangements. Incentives and penalties on generators will be considered in the Review of Electricity Trading Arrangements.

More should be done to improve information flows, particularly to ensure that NGC has better information about the likelihood of interruptions.

The Secretary of State has statutory powers with respect to back-up fuels, and further powers could be considered with respect to endurance during interruptions.

## 6 Relationships between Gas and Electricity Markets

Trading between the gas and electricity markets has advantages in terms of efficient fuel use and reducing extremes of prices. It is likely to continue to be attractive to burn gas in power stations at times of high electricity demand. It will be important to ensure that there are no artificial incentives in the interactions of the gas and electricity markets which might undermine the security of electricity supply. The Review of Electricity Trading Arrangements is considering this.

## 7 Competition, Prices and Investment

If new entry is restricted in order to protect a particular fuel, this would have serious disadvantages.

New entry is crucial for the continued growth of competition in generation, and to drive down prices to customers. The MMC conditions for a broadly satisfactory environment for competition in generation have not yet been met. The extent of market power in generation is a continued major concern to customers. Further divestment by existing major generators might be considered, but this would not provide the continuing protection to customers that the threat of new entry does

Restricting entry would be likely to lead to higher prices than otherwise, including by enabling existing generators to raise or maintain prices. If prices in the Pool and contracts market would otherwise have fallen by, say, 10 per cent towards new entry levels, then the additional costs to customers would be about £2 billion in total over a five year period. There would be corresponding windfall gains to incumbent generators.

Less capacity would be available to meet demand, with possible implications for security of supply. It might not be straightforward to stop new investment now, and change policy to encourage it later on. The risks of continued Government intervention would increase the return required on investment.

Satisfactory measures to control generator prices, to counter these problems, are difficult to identify. There is no power to impose restrictions on prices. A voluntary restriction would be unlikely on terms consistent with increasing competition and competitive prices.

Price caps on generation or the Pool would distort the structure of prices. Some market participants would suffer financial damage. There would be a loss of confidence. There would be reduced incentives to identify and implement improved trading arrangements. There would be less scope for competition in supply. The benefits of opening the market from 1998 would be reduced.

It would be difficult to reconcile such a reversal of policy with the lead that Britain has given around the world, and with encouraging other EU countries to open their energy markets to competition.

## 8 Fuel Sources in Scotland

New entry in generation in Scotland has been constrained by the dominant position and vertical integration of ScottishPower and Hydro-Electric, the long term contract for the sale of nuclear output to them, and the absence of an equivalent to the Pool. A few competitors are now trying to enter.

As in England and Wales, further Section 36 consents to entrants would have a detrimental impact on competition, prices and investment in Scotland. Price regulation of the Scottish generation market would need to continue for the long term. If new entry is prevented in England and Wales, leading to higher prices there than would otherwise obtain, these will be reflected in Scotland also.

## 9 Conclusions

Promoting increased competitiveness in the UK coal and electricity generation industries, including by granting consents to independents for new gas-fired power stations, is consistent with maintaining pressure to reduce electricity prices to customers, a diverse mix of fuel supplies, and a stable level of coal burn. It is also consistent with proposed environmental limits, and does not pose problems of security of supply. Such a policy seems consistent with the Government's aim of diverse and sustainable energy supplies at competitive prices. In contrast, government restrictions on new entry and controls on market prices would have serious consequences for competition in generation and supply, for customers and for the long term development of the UK electricity industry.

# 1 INTRODUCTION

1.1 On 22 December 1997, the President of the Board of Trade, Mrs Margaret Beckett, published the terms of reference for the Government's Review of Energy Sources for Power Stations. The Review is intended to look at medium and longer-term scenarios for the development of generating capacity and sources of fuel supply for generation, and to consider the implications of high levels of dependence on any particular fuel, source of supply, transport route or technology. It will take account of the objective of secure, diverse and sustainable supplies of energy at competitive prices and, in particular, the role of coal; and of the objective of sustainable development (including the meeting of environmental targets); and of European and other international obligations. It will address a number of technical factors relating to the growing use of gas in generation. It will make recommendations to Ministers about energy policy considerations relevant to applications for the Secretary of State's consent, under Section 36 of the Electricity Act, for the construction of new power stations, and relevant to notifications under Section 14 of the Energy Act, relating to the burning of gas in power stations.

1.2 This submission examines first the development of the generation market in England and Wales since 1990. It examines the growth of gas-fired generation, and the arguments that have been made that the market has been distorted to the disadvantage of coal. It considers possible future developments in the fuel mix for generation. It discusses the possible need for further measures to enhance security of supply, and issues relating to the interaction of the gas and electricity markets, in the light of the possibility of gas becoming the dominant fuel for generation. It then considers the consequences for competition, prices and investment of a policy of influencing this fuel mix by refusing further consents for gas-fired power stations and introducing controls on prices. A further section looks at the position in the generation market in Scotland. The conclusions consider whether the Government's broad energy policy objectives require, or would be well served by, a decision to prevent new entry by gas-fired generators. The DGES has considered these matters against the background of his statutory duties, particularly his duties to protect customers, as to price, and as to continuity of supply, to promote competition in electricity generation and supply, and to secure that all reasonable demands for electricity are satisfied.

1.3 There are relationships between the Government's Review of Energy Sources for Power Stations and the review which the DGES is at present undertaking into Electricity Trading Arrangements in England and Wales. The latter will consider what incentives on generators might be appropriate to ensure that there is a sufficient margin of generating capacity at all times; and the relationship between the trading arrangements and arrangements for the scheduling and despatch of power plant. One of the objectives for any revised trading arrangements is that they should not discriminate against any particular fuel for generation.

## 2 DEVELOPMENTS SINCE VESTING IN FUEL SOURCES AND MARKET SHARES IN ENGLAND AND WALES

**2.1** Table 1 shows the output of centrally despatched generating stations in England and Wales of different types, and imports over interconnectors, for the period 1989/90 (the year immediately before Vesting) to 1996/97, and also for calendar year 1997, being the latest full year for which figures are available. Table 2 shows power station and interconnector capacity connected to the Grid (that is, excluding mothballed stations), at Vesting (1 April 1990) and annually thereafter. The term "other generators" includes output from renewable energy sources which is sold through the Pool.

**TABLE 1: POWER STATION OUTPUT AND MARKET INTERCONNECTOR TRADING, ENGLAND AND WALES, BY FUEL TYPE (TWH)**

| | 1989/90 | 1990/91 | 1991/92 | 1992/93 | 1993/94 | 1994/95 | 1995/96 | 1996/97 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| **coal** | **184.7** | **185.5** | **187.6** | **168.9** | **144.3** | **140.8** | **129.5** | **111.7** | **95.7** |
| **Nuclear** | **42.5** | **47.6** | **51.9** | **57.8** | **63.7** | **61.9** | **65.0** | **71.8** | **70.1** |
| **Gas** | **0.0** | **0.3** | **0.8** | **6.2** | **29.6** | **38.9** | **56.1** | **74.4** | **85.4** |
| **Oil** | **14.4** | **11.4** | **7.7** | **7.7** | **7.4** | **5.1** | **3.9** | **3.6** | **0.9** |
| **Interconnectors** | **12.6** | **20.3** | **23.1** | **23.1** | **23.1** | **25.2** | **26.2** | **27.2** | **25.6** |
| **Others** | **1.8** | **1.8** | **1.3** | **1.6** | **1.4** | **2.0** | **2.3** | **2.6** | **2.9** |
| TOTAL, | 256.0 | 266.9 | 272.4 | 265.3 | 269.5 | 273.9 | 283.0 | 291.3 | 280.6 |

2.2 Table 3 looks at the output of power stations (including interconnectors) in England and Wales, in terms of the percentage share accounted for by different fuels, as estimated for 1989/90 (the last year before Vesting) and for calendar year 1997 (the latest full year for which figures are available); and for capacity at 1 April 1990 (Vesting) and 1 April 1997.

2.3 It will be seen that the share of coal in power station output in England and Wales has declined from 72 per cent in 1989/90 to 34 per cent in 1997, while the share of gas has increased from a negligible level to 31 per cent over the same period. There has also been an increase in the share of nuclear, from 16 per cent to 25 per cent, and of interconnectors and other generators from 6 per cent to 10 per cent, while the share of oil has fallen from 6 per cent to a negligible level.

**TABLE 2: POWER STATION AND INTERCONNECTOR CAPACITY, ENGLAND AND WALES, BY FUEL TYPE (MW GROSS REGISTERED CAPACITY) AS AT 1 APRIL, 1990 TO 1997**

| | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|
| **Coal** | **36,655** | **35,734** | **34,517** | **31,721** | **29,393** | **27,358** | **27,432** | **27,087** |
| Nuclear | 8,463 | 8,884 | 9,480 | 10,808 | 10,735 | 10,013 | 10,467 | 10,529 |
| Gas | 1,427 | 1,709 | 4,912 | 6,477 | 9,759 | 11,282 | 13,320 | 14,826 |
| Oil | 10,352 | 10,412 | 8,926 | 8,932 | 7,573 | 4,536 | 3,888 | 3,388 |
| Interconnectors | 2,822 | 2,822 | 2,822 | 2,822 | 3,452 | 3,188 | 3,188 | 3,588 |
| Others | 2,220 | 2,220 | 2,264 | 2,455 | 2,461 | 2,449 | 2,449 | 2,280 |
| TOTAL | 61,939 | 61,781 | 62,921 | 63,215 | 63,378 | 58,826 | 61,144 | 61,698 |

**TABLE 3: PERCENTAGE SHARES OF OUTPUT AND CAPACITY OF POWER STATIONS BY FUEL TYPE, ENGLAND AND WALES**

| | Output % | | Capacity % | |
|---|---|---|---|---|
| | **1989/90** | **1997** | **1 April 1990** | **1 April 1997** |
| Coal | 72 | 34 | 59 | 44 |
| Nuclear | 16 | 25 | 14 | 17 |
| Gas | 0 | 31 | 2 | 24 |
| Oil | 6 | 0 | 17 | 5 |
| Interconnectors | 5 | 9 | 5 | 6 |
| Others | 1 | 1 | 3 | 4 |
| TOTAL | 100 | 100 | 100 | 100 |

2.4 For the most part, the changes in shares of capacity have been less marked than in output. The lower reduction from 59 per cent to 44 per cent for coal is primarily because the reduction in coal output has been met by reductions in load factors at some plants as well as by plant closure. The smaller rise from 2 per cent to 24 per cent for gas capacity reflects the entry of new gas plants, to date operating at above average system load factor. The relatively small increases in capacity of nuclear (from 14 to 17 per cent) and interconnectors (5 to 6 per cent) reflect the significant increase in output from existing plant.

**2.5** Demand has fluctuated somewhat from year to year, reflecting weather and economic conditions, but average electricity demand growth since Vesting has been around 1.5 per cent a year. In contrast, the total capacity available has declined slightly.

**2.6** Table 4 shows gross increases and reductions in power station and interconnector capacity between 1 April 1990 and 1 April 1997, and reconciles these to the net changes shown in Table 2. Over the period, gross increases in capacity totalled around 18,000 MW, of which about 14,300 MW was gas-fired capacity and 2,400 MW was nuclear capacity. This was more than offset by gross capacity reductions of about 18,200 MW, of which coal accounted for 10,000 MW, oil for nearly 7,000 MW and gas (mainly older open cycle gas stations) for almost 900 MW.

**TABLE4: CHANGES IN POWER STATION AND INTERCONNECTOR CAPACITY, ENGLAND AND WALES, BETWEEN 1 APRIL 1990 AND 1 APRIL 1997 (MW)**

| | Gross increases | Gross reductions | Net |
|---|---|---|---|
| Coal | 476 | -10,044 | -9,568 |
| Nuclear | 2,431 | -365 | 2,066 |
| Gas | 14,270 | -871 | 13,399 |
| Oil | 0 | -6,964 | -6,964 |
| Interconnectors | 766 | 0 | 766 |
| Others | 60 | 0 | 60 |
| TOTAL | 18,003 | - 18,244 | -241 |

## Further Details of Gas-Fired Capacity

**2.7** It may be helpful to give some further details of the gas-fired capacity built to date (see Annex 1). At present in England and Wales there are 30 operating gas-fired stations which are centrally despatched by NGC. Of these, 20 are combined cycle gas turbine (CCGT) stations, 9 are open cycle gas turbine (OCGT) stations, and one is a partial conversion of a coal station to dual coal and gas firing. In addition, four large combined heat and power (CHP) stations are also centrally despatched. There are several hundred gas-fired stations which are not subject to central despatch, chiefly smaller CHP and OCGT schemes. Of the 20 CCGT stations, nine are owned by generators with substantial interests in coal-fired plant (National Power, PowerGen and Eastern) and 11 by independent power producers (IPPs).

2.8 Those promoting and financing the earliest IPP stations in England and Wales faced significant uncertainties, in particular, about how the newly created electricity market would operate in practice, how incumbents would react to new entry, and what the future level of prices would be. British Gas Long Term Interruptible (LTI) gas contracts were, in the early 1990s, the only significant contracts available with low enough prices to be attractive to power stations. New entrants needed to find off-take contract arrangements which would offset the risks in the take-or-pay conditions in the LTI contracts. They sold their output to RECs under 15 year contracts, since RECs were at that time the only market participants in a position to accept long-term supply commitments. The take-or-pay terms on which gas was contracted, and the available prices in the electricity Pool, made it economic for the early independent CCGT stations to operate at baseload. However, LTI contracts are only part of the picture. These stations have also bought significant quantities of gas additional to their LTI contracts, because it is economical at present gas and Pool prices for them to do so and to run their stations at high output levels. In 1996/97 LTI contracts accounted for only about 60 per cent of the gas taken by stations with such contracts.

2.9 National Power and PowerGen also invested in CCGT stations. Their risk profile was different from that of the new independent generators since they benefited from the advantages of incumbency, and of owning a portfolio of plant operating in a range of different load factors. The financing arrangements for their projects did not require them to sell the output of their new gas stations for many years ahead. However, in common with the independents, where National Power and PowerGen have take-or-pay conditions in their gas contracts, they operate their gas-fired plant at baseload. In addition, National Power has converted part of Didcot “A” to dual coal and gas firing, and National Power and PowerGen have applied for Section 36 consents for further such conversions.

2.10 Over the last few years, as competition to run baseload has increased, Pool prices have become less flat. For example, the differential between average demand-weighted and time-weighted prices has increased from about £0.63 per MWh in 1993 to £1.52 per MWh in 1997. Later CCGT schemes have more flexible gas purchase contracts which do not constrain them to run at baseload, though they have incentives to run at baseload where possible.

2.11 A number of RECs have built or recently announced the intention to build smaller open cycle gas turbines (OCGTs), typically 50 MW plant, based on the Rolls Royce “Trent” engine. Some of these will be embedded in REC distribution systems. These stations will be able to operate at a variety of load factors including at peak.

**2.12** In parallel with the development of gas-fired plant for electricity generation alone, there have been significant developments in combined heat and power (CHP) schemes using gas as a fuel. Such stations provide electricity and heat at a much higher fuel conversion efficiency (over 80 per cent) than electricity-only stations, with associated environmental benefits. The Government has actively promoted CHP and continues to do so. Since 1990, nearly 800 gas-fired CHP stations with a capacity of about 1,300 MW have been commissioned.

**Changing Market Shares of Generators**

**2.13** The growth of gas-fired generation by IPPs, and other changes in the generation fuel mix including increasing output from nuclear generators and interconnectors, have been reflected in significant changes in market shares of different generators, and the development of competition in the generation market.

**2.14 Table 5 shows the changing market** shares of output of different generators between 1989/90 (the last full year before Vesting) and 1997; and of capacity between Vesting and 1 April 1997.

**TABLE 5: MARKET SHARES OF OUTPUT AND CAPACITY IN ENGLAND AND WALES**

| | **output %** | | **Capacity %** | |
|---|---|---|---|---|
| | **1989/90** | **1997** | **1 April 1990** | **1 April 1997** |
| **National** Power | 48 | 21 | 48 | 27 |
| PowerGen | 30 | 20 | 30 | 24 |
| Eastern | 0 | 9 | 0 | 11 |
| Nuclear Electric | 16 | 17 | 13 | 12 |
| Magnox Electric | 0 | 7 | 0 | 5 |
| New Entrants | 0 | 16 | 0 | **12** |
| **Interconnectors** | **5** | **9** | **5** | **6** |
| **Others** | 1 | 1 | **4** | **4** |
| **TOTAL** | **100** | **100** | **100** | **100** |

2.15 In 1989190, power stations which were transferred at Vesting to National Power and PowerGen together accounted for an estimated 78 per cent of output in England and Wales. By 1997, this had declined to 41 per cent. Of this 37 percentage point decline, about 16 percentage points were accounted for by the output from new entrants who had constructed CCGT plant, the growth in nuclear output for 8 percentage points, the disposal of 6 GW of capacity to Eastern and the construction of new CCGTs by that company for 9 percentage points, and increased output through interconnectors and by other generators for 4 percentage points.

2.16 The decline in the combined capacity share of National Power and PowerGen has been less marked, from an estimated 78 per cent at Vesting to 5 1 per cent at 1 April 1997. New entrants (excluding Eastern) accounted for 11 percentage points of this 27 percentage point decline, the disposal of plant to Eastern and the construction of new CCGTs by that company for 11 percentage points, and increased nuclear capacity (at Sizewell B) for the remaining 4 percentage points.

## 3 EXPLANATIONS FOR CHANGES IN FUEL SOURCES IN ENGLAND AND WALES

**3.1** The change in fuel shares since Vesting described in the previous Section reflect a number of factors. The most important were the arrangements put in place at Vesting (particularly those intended to protect the coal industry); certain policy changes in the UK and the EU, which made investment in new gas-fired stations possible; environmental factors and emissions policy; the economics of investment in CCGT stations; and developments in competition in generation and decisions of incumbent generators and new entrants since Vesting.

3.2 Immediately before Vesting, the Government put in place three-year contracts between British Coal and National Power and PowerGen for the supply of an average of 70 million tonnes of coal per year at prices above international coal prices. The higher costs of these contracts were reflected in three-year contracts for differences (CfDs) between the generators and the RECs, who passed higher costs through to franchise electricity customers. In 1993, the Vesting coal and coal-backed contracts were replaced by new five-year arrangements, also intended to protect the position of coal.

3.3 Despite this extensive protection for coal, there was a significant shift to gas. Two policy changes enabled this. First, in 1990 the EU removed its prohibition on the use of gas for electricity generation. Second, at Vesting, the CEGB policy of favouring coal and nuclear plants ceased. In the absence of these EU and CEGB policies, it seems likely that gas-fired stations would have been built on an increasing scale before 1990.

3.4 Two main factors explain why gas-fired plant, particularly CCGTs, have increasingly been the preferred choice of new technology. First, Government sulphur emissions limits (discussed in the section below) meant that existing fossil plant would increasingly need to be replaced or retrofitted with sulphur-reduction equipment. Gas-fired generation in general poses fewer environmental and planning problems than coal-fired generation; in particular carbon dioxide emissions are lower, and sulphur emissions much lower, and there is no requirement to construct large cooling towers or to use large quantities of water for cooling purposes.

3.5 Second, the costs of new CCGT stations are lower than those of new stations using other fuels, and have fallen since 1990. This reflects reductions in capital costs; the further development of CCGT technology, including improved energy conversion efficiencies; falling gas prices over most of this period (after some initial increase); and reductions in planning lead times.

3.6 As discussed in the previous Section, the extent of competition in generation at Vesting was limited. National Power and PowerGen between them accounted for over three-quarters of both output and capacity. With the exception of the disposal at the instigation of the DGES of 6,000 MW of coal-fired plant to Eastern in 1996, it did not prove possible for potential competitors to purchase existing plant from the incumbents. Nuclear generators were able to increase output from existing plant, and from Sizewell B which came on stream in 1995. Interconnector traders were able to increase the volumes sold into the England and Wales Pool within existing capacity, Other potential new entrants, however, had no choice but to build new plant. For the environmental and cost reasons explained above, CCGT plant was their preferred choice. Existing and prospective prices in the Pool and in the contracts market were high enough to make such investment attractive. For the incumbents, National Power and PowerGen, the prospect of environmental constraints requiring the closure or expensive cleaning up of coal-fired plant made CCGTs attractive to them also; indeed, their total investment in new CCGT capacity has been to date about the same as that of the independents in aggregate.

**Concerns about Market Distortions**

3.7 A number of arguments have been advanced to the effect that the growth of gas-fired generation since 1990, and the decline of coal-fired generation, has occurred because the market has in one way or another been distorted to the advantage of gas and the disadvantage of coal. In fact, as noted above, the prospect of tightening emissions constraints has increasingly dictated the replacement of much coal-fired plant by about the turn of the century, and the electricity market has also been constrained to favour coal in the meantime. The market distortion allegations have been dealt with previously, but it may be helpful to summarise the arguments again.

3.8 It has been argued, for example, that the costs per kWh of generating electricity from new gas-fired stations exceeded the avoidable costs of generating that electricity from existing coal-fired generation, hence the RECs were acting uneconomically in investing in and purchasing from gas-fired stations developed by independent power producers (IPPs). To some extent, the point turns on what is meant by “avoidable”, which in turn depends upon the time period being considered. Over a time period which spans the need for investment to meet emissions constraints, coal-fired generation is more costly than CCGT investment rather than less.

3.9 In a shorter time horizon, future investment needs may not be relevant to profitable operations. However, from the point of view of a supplier purchasing electricity contracts, the relevant consideration is the price at which electricity is offered over the contract period, rather than the costs of the generator in producing it. It might have been possible for the coal generators to bid into the Pool or offer contracts for differences at prices which sought to maintain output of coal stations and made new entry by the first gas generators unprofitable or at least significantly less attractive. They did not do so. They may have considered that it was more profitable for them to maintain prices than to compete more aggressively for market share; they also faced the prospect of tightening environmental constraints on coal-fired output (such as sulphur emission limits); they had to estimate the long-term price of coal; and such a strategy might have undermined their own investments (in coal importing plant and in gas-fired generation) aimed in part at reducing their dependence upon British produced coal. It is possible that, had the generation market been more competitive at Vesting, and had British produced coal been more competitively priced and available from several producers rather than just one, the incentives on the incumbent coal-fired generators would have been different. But this was not the case.

3.10 Against this background the DGES examined in 1992 and 1993 whether the RECs had complied with the "economic purchasing" condition in their licences as regards their purchases of long-term contracts from new gas-fired stations. He concluded that the RECs' IPP contracts compared well with other contracts available at that time, and noted that they had given the RECs a greater diversity of fuel source and supply, and were less vulnerable should environmental factors lead to greater restrictions on power station emissions. He also concluded that RECs would not breach the economic purchasing condition in their licences if they were to sign the five-year coal backed contracts with National Power and PowerGen.

3.11 It has been argued that the RECs' IPP contracts have turned out to be more expensive over the past few years than other possible contracts which subsequently became available, and that the DGES should revisit the economic purchasing review. However, the only reasonable basis for assessing compliance with the economic purchasing condition in REC licences is against other possibilities open at the time. Alternative contracts were not on offer at the time the IPP contracts were signed. The fact that National Power and PowerGen themselves invested heavily in early CCGT stations suggests that the judgements and decisions of RECs and IPPs were not without foundation at the time.

3.12 In the competitive supply market from 1998 onwards, RECs will not be able to rely on recovering from customers the costs of expensive electricity purchase contracts, whether from gas-fired or coal-fired generators. In setting restraints on the RECs' prices to domestic and small business customers in the competitive market, the DGES has not made provision for the RECs to continue to be able to recover the full costs of IPP contracts from these customers. Some RECs have already made accounting provisions relating to their IPP contracts.

3.13 It has been argued that the RECs' IPP contracts have in some sense foreclosed the baseload part of the market, and made it impossible for coal-fired generation to compete in this market sector. The nature and extent of the baseload part of the market depend on the definition used; definitions vary widely and measurement is not straightforward. It is broadly true that gas has been displacing coal in the baseload part of the market, but nuclear, interconnectors and coal still have a significant share. Gas meets only part of the baseload demand, and cannot reasonably be said to dominate it.

3.14 Nor have REC IPP contracts foreclosed this part of the market, or predetermined future market shares. The latter depend crucially on present and prospective prices of gas and coal, and the bidding behaviour of generators.

3.15 It has been argued that aspects of the Pool price-setting arrangements work to the disadvantage of coal. For example, IPPs, nuclear generators and generators selling through the interconnectors can secure baseload running by bidding low or at zero in the Pool, then receiving system marginal price. The possibility of bidding at zero to secure baseload running is equally open to all generators. However, to the extent that future changes to Pool price-setting arrangements might make this practice unprofitable, it is possible that such changes could induce coal-fired generators to increase output. The Review of Electricity Trading Arrangements in England and Wales, which is presently underway, will consider all aspects of the present Pool, including the bidding and price-setting arrangements. One of the aims is to identify revised arrangements which do not discriminate against any particular fuel.

3.16 It has been argued that coal is disadvantaged by provisions of the Grid Code which give an apparent preference to nuclear stations. Under conditions of very low system demand (typically during warm summer nights) NGC has to ensure that sufficient flexible plant remains on the system for control purposes. Most CCGT plant chooses to be inflexible for commercial reasons and all nuclear plant has technical limitations on flexibility imposed by its nuclear safety case. Where a choice has to be made as to which inflexible plant to remove from the system, the Grid Code provides an order which requires NGC to keep nuclear plant on till last. However, this stage of the procedure is only relevant in extreme circumstances and, since Vesting, it has never needed to be applied to the extent that brings the apparent nuclear preference into play. These Grid Code provisions have therefore not in practice worked to the disadvantage of coal.

3.17 There is limited substance therefore in the arguments that the market has been distorted to the disadvantage of coal. Rather, the Vesting coal contracts and the restriction on competition in electricity supply have explicitly favoured coal, and these arrangements have been at the expense of franchise customers. The prospect of tighter environment constraints has increasingly dictated the replacement of coal-fired stations by gas-fired ones. The limited extent of initial competition in generation, the level of Pool and contract prices, and the economics of gas versus coal, have also made new entry attractive through the construction of CCGTs.

3.18 The situation today is significantly different from that at Vesting. UK coal production has been privatised, is more efficient, and is significantly exposed to competition, both from imports and from other domestic production. The competitive supply market and the maximum price restraints on public electricity suppliers (PESs) tariffs for smaller customers place strong incentives on suppliers to purchase the best available supply contracts. New entry is already coming from independents without REC ownership. Competition in generation has increased, though there is an urgent need for it to increase further. The review of trading arrangements will seek to make improvements which benefit customers and increase efficiency and competition, and avoid any discrimination between fuel sources that might be implicit in present Pool procedures.

## 4 FUEL SOURCES FOR POWER STATIONS: POSSIBLE FUTURE DEVELOPMENTS

4.1 Under Section 36 of the Electricity Act, the consent of the Secretary of State is required for the construction of any generating stations over 50 MW. Some 13,600 MW of new gas-fired capacity has Section 36 consent; of this 1,700 MW is commissioning and a further 3,800 MW is understood to be under construction (see Annex 2). Schemes with a total capacity of about 13,000 MW have applied for but not yet obtained Section 36 consent. About 6,000 MW of this represents applications by National Power, PowerGen and Eastern to convert existing capacity to dual-firing. It is not to be expected that all of the schemes obtaining Section 36 consent will in fact proceed. In the past, several have had consent for many years but have not been taken forward. For example, the MMC[1] listed 5 GW of CCGT plant with transmission contracts for commissioning dates between 1994 and 1999 that had been terminated by the end of 1995. Annex 3 lists the main schemes which have applied for but not yet received Section 36 consent, and what types of stations these are (CCGT, CHP and conversions from other fuels).

4.2 How many new gas projects will go ahead, and more generally how future fuel sources will develop, will depend upon a number of factors, including the extent to which coal-fired output is constrained by tighter limits on sulphur emissions; the strategies pursued by competitors and the levels of gas, coal and electricity prices; and any actions which might be taken by Government (for example, with respect to Section 36 consents and closure of Magnox stations).

### Environmental Constraints

**4.3** As regards environmental constraints on coal burn in power stations, the key factor is the present and future policy of the Environment Agency. The Agency's consultation document "Proposals for Reducing Emissions of Polluting Substances from Existing Coal and Oil-Fired Power Stations" published in January 1998 proposes to bring forward the reductions in sulphur limits applying to coal and oil-fired stations and companies. These proposals reflect a lower forecast of likely coal-burn in power stations than that used by its predecessor body (HM Inspectorate of Pollution). Specifically, the forecast assumes that all new gas stations which presently have Section 36 consent will be built and come into operation.

4.4 Table 6 below sets out estimates of the maximum coal burn implied by the Environment Agency's present sulphur emission limits and also its proposals for tighter limits. For each sulphur emission limit, the table shows two possibilities. Under the first, the coal stations presently equipped with flue gas de-sulphurisation (FGD) are assumed to operate at baseload. In the second, these stations are

[1] Reports on the proposed mergers of National Power and Southern Electric, and PowerGen and Midlands Electricity, Cm 3230 and 3231, London: HMSO, April 1996.

assumed to run at mid-merit. The recent operating pattern of these stations is more consistent with the second, rather than the first, of these possibilities.

**TABLE 6: ESTIMATED MAXIMUM COAL BURN (IN MILLION TONNES) CONSTRAINED BY PRESENT AND PROPOSED SULPHUR EMISSION LIMITS**

| | 1999 | 2001 | 2005 |
|---|---|---|---|
| Present limits: | | | |
| a) FGD plant at baseload | **53** | **34** | **30** |
| b) FGD plant at mid-merit | **46** | **28** | **23** |
| Proposed tighter limits: | | | |
| a) FGD plant at baseload | **34** | **30** | |
| b) FGD plant at mid-merit | **28** | **23** | |

Note: Estimated coal burn in 1997/98 is 39 million tonnes.

**4.5** It will be seen that, regardless of the level of running by FGD-equipped stations, the Environment Agency's present limits might be expected to limit coal burn to below the present level of 3 9 million tonnes by the year 2001 On the more realistic assumption about running FGD plant, coal burn is constrained to about 23 million tonnes by 2005. If the limits are tightened as proposed by the Agency, then coal burn would be constrained below that level by 2001,

**4.6** It is unlikely to be economic for the coal-fired generators to meet emissions limits by retrofitting additional FGD equipment to existing coal plant. The costs of FGD equipment are broadly comparable with those of investment in an equivalent gas-fired station. However, the continuing costs of operation and investment including refurbishment are likely to be significantly lower for a new gas plant than for an older coal plant with retrofitted FGD. The generators will have some scope for other strategies to reduce the impact of tighter sulphur emission limits, including burning more low sulphur coal, though this would imply a greater reliance on low sulphur coal imports.

**4.7** Against this background it seems probable that since Vesting the emissions limits, in particular their planned reduction over time, have had an important impact on the commercial policies of the coal-fired generators and of entrants and that they will continue to have such an impact. The present limits have already implied a substantial reduction over time in coal burn in power stations and the closure of much coal-fired plant. The owners of coal-fired generation have had little incentive to attempt to protect the output of coal-fired plant, or to limit the construction of CCGTs. Rather, they have sought to construct new CCGTs themselves as replacement for their coal-fired plant. They seem to have seen their interests as lying in obtaining high prices for output from coal-fired plant over the remaining life allowed to it.

4.8 An aspect of the policy of the Environmental Agency has a possible adverse consequence for competition and for coal burn. At present all sulphur emission quotas are allocated to National Power, PowerGen and Eastern. There is no transparent mechanism independent of these incumbent generators for transferring quotas to others. There is a particular problem in respect of the sites presently occupied by stations earmarked by National Power or PowerGen for closure. The Agency's practice is not to allocate emission quotas to these stations beyond their projected closure date. This creates difficulties for potential competitors who might wish to purchase coal-fired plant from the incumbents or to re-open plant which has been closed.

**Strategies of Competitors and Prices**

**4.9** The baseload part of the market is becoming increasingly competitive. Many existing gas stations have long-term baseload contracts, but are topping these up with purchases in the market. Nuclear generators and interconnectors are also keen to run at baseload. As a result, later entrant CCGTs tend to assess the economics of their projects against lower load factors than earlier CCGTs. The timing of entry will depend upon their assessments of the commercial strategies of coal-fired generators, particularly how aggressively the latter seek to hold on to market share in each section of the market in the period before emission constraints limit further the level of coal burn.

**4.10** It is relevant to consider whether more competitive pricing by coal-fired generators could displace output from existing gas-fired stations, and how it could affect further entry by new CCGTs. These questions rest mainly on the avoidable costs of coal stations as against the avoidable costs of gas stations. The relevant avoidable costs depend upon the period under consideration and upon the price of input fuels

4.11 As regards competition between existing stations, the relevant period may be a few years, where the future costs to be covered include fuel inputs and station operation and maintenance including connection charges. The delivered price of coal under existing contracts is about £1 .60/GJ, which might translate into an avoidable cost to coal stations of the order of 1.6p/kWh - 1.7p/kWh. This is higher than the comparable avoidable cost of existing CCGT stations, which might be mainly in the range 1.4p/kWh to 1.5p/kWh. If coal could be secured in future at internationally traded prices of around £0.90/GJ, or about £l.lO/GJ delivered, this would imply avoidable costs for coal stations of around 1.2p/kWh - 1.3p/kWh, which is lower than the above calculation for CCGT stations. However, if the gas take or pay contracts are assumed to be "sunk", then the cost at the margin of additional CCGT output, using gas purchased on the spot market, could be in the same range as for the coal stations or lower.

4.12 Costs at individual stations will vary from these figures. But these indicative calculations suggest that the competitive position as between avoidable costs of existing coal-fired and gas-fired stations is quite finely balanced. It should not be assumed that coal-fired stations would automatically lose out to gas-fired stations. Much depends on the efficiency of operation, and fuel costs and on the location of the stations concerned. There seems to be more scope for coal-fired stations to challenge existing gas-fired stations than has hitherto occurred.

4.13 Whether it is plausible to expect bidding down to the level of avoidable costs is another matter. These avoidable cost figures imply no return to past investment, nor any provision for future refurbishment. They are also considerably lower than present Pool prices. Average Pool purchase prices were about 2.45p/kWh time-weighted and 2.6p/kWh demand-weighted in 1997.

4.14 As regards the possible impact of more competitive pricing of coal-fired plant on investment in new CCGT plant, avoidable costs of around 1.2p/kWh - 1.3p/kWh are below new entry costs of CCGTs, which might be of the order of 2.Op/kWh for baseload operations, 2.2p/kWh for operation at about 60 per cent load factor. Prices below new entry costs would presumably deter or delay investment in CCGTs. However, the avoidable costs just quoted for coal-fired plant are valid only for a few years, and do not include the costs of retrofitting FGD or other measures to meet tighter environmental standards. Whether prices below CCGT new entry levels are credible for a period lasting beyond, say, 2001 is therefore questionable. Nevertheless, competition ought to be expected to bid prices down to about new entry levels if entry is not constrained. Under such circumstances all new gas-fired plant that has applied for consent, and indeed plant that has already obtained consent, would need to consider carefully whether to proceed and, if so, when.

**Fuel Source Scenarios**

**4.15** The broad implications for fuel sources of various scenarios for future new entry of gas-fired generation may be examined using a simple model, based on assumptions about new capacity, average load factors of each type of plant and average demand growth. A scenario of interest is the Environment Agency assumption that all those stations with Section 36 consent (about 13,600 MW) will proceed. This implies about as much new CCGT construction over the next six years as over the last six years. The timing of this new entry reflects what is known of the companies' intentions.

4.16 As regards other capacity, the Scottish interconnector upgrade is assumed to take effect in 2000/01, renewables capacity to increase consistent with present Government policy, and closure of Magnox stations to begin in 2003/04. The scenarios assume the closure of some older coal and oil-fired plant so as to maintain system load factor at about 54 per cent. It is assumed that most types of plant run at about the average load factor observed in this last year (1997/98). Specifically, CCGT plant is assumed to run at an average 70 per cent load factor, nuclear at 75 per cent, oil at 5 per cent, and other generators (mainly renewables) at 12.5 per cent. Interconnectors are assumed to run at 80 per cent initially, declining to 75 per cent after the upgrade, since part of their operation will reflect similar pressure on load factors as on the coal-fired stations in England and Wales. Electricity demand is assumed to grow at the average rate (1.5 per cent a year) experienced since Vesting, starting from an assumed level in 1997/98 equal to the average of the levels observed in 1996/97 and 1997/98. The total output and average load factor at coal stations are outputs of the model, together with an estimate of the implied coal burn.

4.17 Under this first scenario, with all stations with Section 36 consents proceeding, gas-fired output would account for just over 50 per cent of total output (including interconnector imports) by about 2003, and coal for just over 15 per cent. About 9,000 MW of coal-fired capacity would close, and 1,000 MW of oil-fired plant. The load factor of remaining coal-fired plant would fall from about 40 to about 30 per cent. Gas's share of capacity would be about 40 per cent, lower than its share of output, whereas coal's share of capacity at nearly 30 per cent would be higher than its share of output.

# Scenario 1

**All gas fired** schemes with a Section 36 consent are built

| | 1996/7 | 1997/8 | 1998/9 | 1999/00 | 2000/01 | 2001/02 | 2002/03 | 2003/04 | |
|---|---|---|---|---|---|---|---|---|---|
| **Demand (TWh)** | 291.1 | 279.4 | 289.3 | 293.6 | 298.0 | 302.5 | 307.0 | 311.6 | |
| **% pa growth** | | -4.0 | 3.6 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | |
| | | | | | | | | | |
| **Capacity** Changes(GW) | | | | | | | | | Total |
| Coal | | -1.2 | -2.7 | -3.1 | -1.5 | -0.6 | -0.6 | -0.2 | -9.9 |
| Gas | | 1.7 | 3.1 | 3.7 | 1.6 | 1.3 | 1.1 | 1.0 | 13.6 |
| Nuclear | | 0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -0.2 | -0.2 |
| Others | | -0.4 | 0.0 | 0.2 | 0.1 | 0.2 | 0.2 | 0.3 | 0.6 |
| Oil | | 0 | -0.3 | -0.1 | -0.1 | -0.1 | -0.2 | -0.1 | -0.9 |
| **Interconnector** | | 0.0 | 0.0 | 0.0 | 0.6 | 0.0 | 0.0 | 0.0 | 0.6 |
| | | | | | | | | | |
| **Capacity (GW)** | | | | | | | | | |
| Coal | 27.7 | 26.5 | 23.8 | 20.7 | 19.2 | 18.6 | 18.0 | 17.8 | |
| Gas | 12.6 | 14.3 | 17.4 | 21.1 | 22.7 | 24.0 | 25.2 | 26.2 | |
| Nuclear | 10.5 | 10.5 | 10.5 | 10.5 | 10.5 | 10.5 | 10.5 | 10.3 | |
| Others | 3.1 | 2.70 | 2.72 | 2.9 | 3.1 | 3.2 | 3.4 | 3.7 | |
| Oil | 3.4 | 3.4 | 3.1 | 3.2 | 3.3 | 3.4 | 3.6 | 3.7 | |
| Interconnector | 3.6 | 3.6 | 3.6 | 3.6 | 4.2 | 4.2 | 4.2 | 4.2 | |
| Total | 60.9 | 61.0 | 61.1 | 62.0 | 63.0 | 64.0 | 64.9 | 65.9 | |
| | | | | | | | | | |
| **Output (TWh)** | | | | | | | | | |
| Coal | 111.7 | 94.4 | 83.8 | 66.0 | 57.3 | 53.3 | 50.5 | 50.1 | |
| Gas | 72.9 | 87.1 | 106.7 | 129.3 | 139.2 | 147.4 | 154.4 | 160.7 | |
| Nuclear | 71.8 | 68.8 | 69.2 | 69.2 | 69.2 | 69.2 | 69.2 | 67.6 | |
| Others | 4.0 | 3.0 | 3.0 | 3.2 | 3.3 | 3.5 | 3.8 | 4.1 | |
| Oil | 3.6 | 0.3 | 1.4 | 1.4 | 1.4 | 1.5 | 1.6 | 1.6 | |
| Interconnector | 27.2 | 25.8 | 25.2 | 24.5 | 27.5 | 27.5 | 27.5 | 27.5 | |
| Total | 291.1 | 279.4 | 289.2 | 293.6 | 298.0 | 302.5 | 307.0 | 311.6 | |
| | | | | | | | | | |
| Coal Burn ml | 46 | 39 | 34 | 27 | 24 | 22 | 21 | 21 | |
| | | | | | | | | | |
| **Load Factor(%)** | | | | | | | | | |
| Coal | 46.1 | 40.7 | 40.2 | 36.4 | 34.1 | 32.7 | 32.0 | 32.1 | |
| Gas | 66.1 | 69.6 | 70.0 | 70.0 | 70.0 | 70.0 | 70.0 | 70.0 | |
| Nuclear | 78.2 | 74.6 | 75.0 | 75.0 | 75.0 | 75.0 | 75.0 | 75.0 | |
| Others | 14.7 | 12.5 | 12.5 | 12.5 | 12.5 | 12.5 | 12.5 | 12.5 | |
| Oil | 12.0 | 1.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | |
| Interconnector | 86.5 | 82.0 | 80.0 | 78.0 | 75.0 | 75.0 | 75.0 | 75.0 | |
| | | | | | | | | | |
| **Average Load Factor** | 55 | 52 | 54 | 54 | 54 | 54 | 54 | 54 | |
| | | | | | | | | | |
| **Output Share (%)** | | | | | | | | | |
| Coal | 38.4 | 33.8 | 29.0 | 22.5 | 19.2 | 17.6 | 16.5 | 16.1 | |
| Gas | 25.0 | 31.2 | 36.9 | 44.0 | 46.7 | 48.7 | 50.3 | 51.6 | |
| Nuclear | 24.6 | 24.6 | 23.9 | 23.6 | 23.2 | 22.9 | 22.5 | 21.7 | |
| Others | 1.4 | 1.1 | 1.0 | 1.1 | 1.1 | 1.2 | 1.2 | 1.3 | |
| Oil | 1.2 | 0.1 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | |
| Interconnector | 9.3 | 9.2 | 8.7 | 8.4 | 9.2 | 9.1 | 9.0 | 8.8 | |
| Total | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | |
| | | | | | | | | | |
| **Capacity Share (%)** | | | | | | | | | |
| Coal | 45.5 | 43.4 | 38.9 | 33.4 | 30.5 | 29.1 | 27.7 | 27.0 | |
| Gas | 20.7 | 23.4 | 28.5 | 34.0 | 36.0 | 37.6 | 38.8 | 39.7 | |
| Nuclear | 17.2 | 17.3 | 17.2 | 17.0 | 16.7 | 16.5 | 16.2 | 15.6 | |
| Others | 5.1 | 4.4 | 4.4 | 4.7 | 4.8 | 5.1 | 5.3 | 5.7 | |
| Oil | 5.6 | 5.6 | 5.1 | 5.2 | 5.2 | 5.3 | 5.5 | 5.6 | |
| Interconnector | 5.9 | 5.9 | 5.9 | 5.8 | 6.7 | 6.5 | 6.5 | 6.4 | |
| Total | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | |

4.18 A second scenario of interest is one in which all Section 36 consents hitherto granted proceed to commission, and in addition Section 36 consents are granted to all present applicants except to National Power, PowerGen and Eastern for conversion of about 6,000 MW capacity to dual-fuel running.

4.19 Granting consents to all the above applicants does not mean they will all construct new capacity. The increased pressure on load factors, prices and prospective margins will inevitably deter many prospective entrants. It is understood, for example, that among the applications are schemes accounting for over 1,600 MW of capacity that are unlikely to proceed or are on hold. An application by Magnox Electric for a 400 MW station is ultimately subject to the decision of the Government as shareholder.

4.20 The second scenario assumes that about 5,500 MW of the additional schemes proceed (13,000 MW applications, minus 6,000 MW conversions, minus 2,000 MW less likely to proceed), in addition to the 13,600 MW of existing consents, making a total of about 19,000 MW new gas-fired capacity.

4.21 With new entry at this rate there will be greater competitive pressure on both the level and structure of Pool (and contract) prices. Load factors of all types of plant are likely to decline somewhat. Gas-fired plant, in particular, will need to move towards the system average load factor. This second scenario assumes that average load factors for gas plant decline from 70 to 60 per cent over the period to 2003. The nuclear load factor stays at 75 per cent and interconnectors decline from 82 to 75 per cent as before. Load factors for other generators and oil remain at 15 and 5 per cent, respectively. Demand is assumed to grow at the same average rate as before.

4.22 In this second scenario, the market share of gas-fired generation increases to a little over 50 per cent of the output total in 2003 and to a little under 50 per cent of total capacity. The share of coal-fired generation falls to just under 15 per cent of output total, and to about 20 per cent of total capacity. These figures are not substantially different from those projected under the first scenario. In broad terms, both scenarios suggest that gas as a fuel source might account for around half of total electricity output, and coal for around a sixth. Nuclear would account for a fifth and the interconnectors plus others for a tenth.

# Scenario 2

All gas fired schemes with a S36 consent are built, plus all that have applied for a consent except applications for conversion to dual firing and 2.06 GW of schemes less likely to proceed

| | 1996/97 | 1997/98 | 1998/99 | 1999/00 | 2000/01 | 2001/02 | 2002/03 | 2003/04 | |
|---|---|---|---|---|---|---|---|---|---|
| Demand (TWh) | 291.1 | 279.5 | 289.3 | 293.6 | 298.0 | 302.5 | 307.0 | 311.6 | |
| % pa growth | | -4.0 | 3.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | |
| | | | | | | | | | |
| **Capacity Changes (GW)** | | | | | | | | | **Total** |
| Coal | | -1.2 | -3.9 | -4.4 | -3.2 | -0.8 | -0.6 | -0.2 | -14.3 |
| Gas | | 1.7 | 4.3 | 5.1 | 3.6 | 1.7 | 1.6 | 1.1 | 19.1 |
| Nuclear | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -0.2 | -0.2. |
| Others | | -0.4 | 0.0 | 0.2 | 0.1 | 0.2 | 0.2 | 0.3 | 0.6 |
| Oil | | 0.0 | -0.3 | -0.1 | -0.1 | -0.1 | -0.2 | -0.1 | -0.9 |
| Interconnector | | 0.0 | 0.0 | 0.0 | 0.6 | 0.0 | 0.0 | 0.0 | 0.6 |
| | | | | | | | | | |
| **Capacity (GW)** | | | | | | | | | |
| Coal | 27.7 | 26.5 | 22.6 | 18.2 | 15.0 | 14.2 | 13.6 | 13.4 | |
| Gas | 12.6 | 14.3 | 18.6 | 23.7 | 27.4 | 29.0 | 30.6 | 31.7 | |
| Nuclear | 10.5 | 10.5 | 10.5 | 10.5 | 10.5 | 10.5 | 10.5 | 10.3 | |
| Others | 3.1 | 2.70 | 2.72 | 2.9 | 3.1 | 3.2 | 3.4 | 3.7 | |
| Oil | 3.4 | 3.4 | 3.1 | 3.0 | 2.9 | 2.8 | 2.6 | 2.5 | |
| Interconnector | 3.6 | 3.6 | 3.6 | 3.6 | 4.2 | 4.2 | 4.2 | 4.2 | |
| Total | 60.9 | 61.0 | 61.1 | 62.0 | 63.0 | 64.0 | 64.9 | 65.8 | |
| | | | | | | | | | |
| **Output (TWh)** | | | | | | | | | |
| Coal | 111.7 | 94.4 | 79.8 | 58.2 | 45.7 | 44.7 | 44.7 | 44.9 | |
| Gas | 72.9 | 87.2 | 110.8 | 137.2 | 150.9 | 156.3 | 160.7 | 166.4 | |
| Nuclear | 71.8 | 68.8 | 69.2 | 69.2 | 69.2 | 69.2 | 69.2 | 67.6 | |
| Others | 4.0 | 3.0 | 3.0 | 3.2 | 3.3 | 3.5 | 3.8 | 4.1 | |
| Oil | 3.6 | 0.3 | 1.4 | 1.3 | 1.3 | 1.2 | 1.1 | 1.1 | |
| Interconnector | 27.2 | 25.8 | 25.2 | 24.5 | 27.5 | 27.5 | 27.5 | 27.5 | |
| Total | 291.1 | 279.5 | 289.3 | 293.6 | 298.0 | 302.5 | 307.0 | 311.6 | |
| | | | | | | | | | |
| Coal burn mt | 46 | 39 | 33 | 24 | 19 | 18 | 18 | 18 | |
| | | | | | | | | | |
| **Load Factor (%)** | | | | | | | | | |
| Coal | 46.1 | 40.7 | 40.3 | 36.5 | 34.8 | 35.9 | 37.5 | 38.3 | |
| Gas | 66.1 | 69.6 | 68.0 | 66.0 | 63.0 | 61.5 | 60.0 | 60.0 | |
| Nuclear | 78.2 | 74.6 | 75.0 | 75.0 | 75.0 | 75.0 | 75.0 | 75.0 | |
| Others | 14.7 | 12.5 | 12.5 | 12.5 | 12.5 | 12.5 | 12.5 | 12.5 | |
| Oil | 12.0 | 1.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | |
| Interconnector | 86.5 | 82.0 | 80.0 | 78.0 | 75.0 | 75.0 | 75.0 | 75.0 | |
| | | | | | | | | | |
| Average Load Factor | 55 | 52 | 54 | 54 | 54 | 54 | 54 | 54 | |
| | | | | | | | | | |
| **output (%)** | | | | | | | | | |
| Coal | 38.4 | 33.8 | 27.6 | 19.8 | 15.3 | 14.8 | 14.6 | 14.4 | |
| Gas | 25.0 | 31.2 | 38.3 | 46.7 | 50.7 | 51.7 | 52.3 | 53.4 | |
| Nuclear | 24.6 | 24.6 | 23.9 | 23.6 | 23.2 | 22.9 | 22.5 | 21.7 | |
| Others | 1.4 | 1.1 | 1.0 | 1.1 | 1.1 | 1.2 | 1.2 | 1.3 | |
| Oil | 1.2 | 0.1 | 0.5 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | |
| Interconnector | 9.3 | 9.2 | 8.7 | 8.4 | 9.2 | 9.1 | 9.0 | 8.8 | |
| Total | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | |
| | | | | | | | | | |
| **Capacity (%)** | | | | | | | | | |
| Coal | 45.5 | 43.4 | 37.0 | 29.4 | 23.8 | 22.2 | 20.9 | 20.4 | |
| Gas | 20.7 | 23.4 | 30.4 | 38.3 | 43.4 | 45.3 | 47.1 | 48.1 | |
| Nuclear | 17.2 | 17.3 | 17.2 | 17.0 | 16.7 | 16.5 | 16.2 | 15.6 | |
| Others | 5.1 | 4.4 | 4.4 | 4.7 | 4.8 | 5.1 | 5.3 | 5.7 | |
| Oil | 5.6 | 5.6 | 5.1 | 4.8 | 4.6 | 4.4 | 4.0 | 3.8 | |
| Interconnector | 5.9 | 5.9 | 5.9 | 5.8 | 6.6 | 6.5 | 6.5 | 6.4 | |
| Total | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | |

**4.23** Other scenarios are of course possible. Small CHP and other embedded generation plants might reduce the effective level of demand to be met by centrally-despatched plant; more gas-fired schemes might seek consent; or a higher level of renewable capacity might be sought. These elements would tend to reduce the share of coal-fired generation. On the other hand, the pressure of entry and the more competitive market could put greater pressure on nuclear and interconnector load factors; more schemes that have applied for consent might drop out, or defer, as well as some who already have consent; and faster closures of Magnox stations are possible. These factors would offer potential to increase the market share of coal-fired generation. More competitive or less competitive bidding by particular types of generators could also influence market shares.

4.24 Although market shares cannot be predicted precisely, it seems unlikely that gas would account for anything like as high a market share over the next five years as the 72 per cent of the market accounted for by coal as recently as 1989/90. The more gas there is on the system, the less likely it is to run base-load, and the closer it has to approximate the average system load factor of about 54 per cent. Moreover, the more entry there is, and the more competitive coal and coal-fired generation are priced, the greater is the pressure on prices and margins, and the lower the incentive for higher output and further new entry.

4.25 A relatively high market share for gas would in any case be less problematic in other respects. The years when coal was the dominant fuel in Britain were characterised by dependence on a single coal producer (the National Coal Board) and a single centrally negotiated contract. Gas is by contrast sold for power generation by a large number of different producers, under a variety of contract terms, and in a competitive market. This suggests that diversity of fuel supplies would not be by any means as serious an issue in the future as it has been in the past.

**Implications for Coal Burn**

**4.26** Projections which assume that gas, nuclear and interconnectors will all run at around 80 per cent load factor imply very little role for coal in future. In contrast, the two scenarios discussed above assume more realistic load factors in the face of competition. The first scenario implies that annual coal burn falls to between 35 and 27 million tonnes around 1999 and then stabilises at around 20 million tonnes for the next few years. The second scenario implies that coal burn falls to between 33 and 24 million tonnes around 1999 and then stabilises at around 18 million tonnes for the next few years.

4.27 The first scenario is thus broadly consistent with the limits on coal burn implied by the recently proposed emissions limits, assuming that FGD plant is run, as now, at mid-merit. The second scenario allows an additional 5,500 MW of new entry presently applied for, and yet reduces coal burn by only about 2 million tonnes a year. In other words, given competitive pricing by UK coal producers and generators, England and Wales coal burn could stabilise at approaching 20 million tonnes a year over the next few years consistent with granting consents to the entry of new independent power stations.

4.28 The implications of any level of coal burn for the demand for UK deep-mined coal will depend on a number of factors. These include the amounts demanded by other customers, the level of open-cast production and the level of imports. Some of these are a matter for Government. But market participants can influence all these factors. In particular, the level of imports will reflect the pricing decisions of UK coal producers, and the purchasing decisions of coal-fired generators.

# 5 SECURITY OF SUPPLY

## Various **Concerns**

5.1 Chapter 4 has conjectured that the proportion of gas-fired generation might double over the next five years, from about 30 to 50 per cent. It is therefore important to consider carefully the implications for security of supply. It has been argued that the increasing use of gas as a fuel for power generation has diminished the reliability of supplies to customers, or may have this effect in the future. There are a number of aspects of this argument, which will be considered in turn.

5.2 First, it has been suggested that the gas system might be subject to catastrophic failure. To the extent that this is associated with weather conditions, the gas pipeline system being underground is less vulnerable than the overhead electricity transmission and distribution systems. To the extent that it is associated with terrorist attacks on gas landing and processing facilities, it has to be considered how many of the growing number of such facilities could plausibly be taken out of commission at one time. It is for Government to assess these risks, and they are not considered further here. If such risks are regarded as significant this might suggest that steps should be taken to restrict the use of gas generally, not just gas use in electricity generation.

5.3 Second, it has been argued that there are risks associated with the finite nature of gas reserves. It is notable that remaining proven and probable gas reserves on the UKCS have increased rather than reduced over the period since 1990, as the demand for gas and the prospect for profitable exploitation of these reserves have increased. Taking account of possibilities for importing gas from Norway and elsewhere, risks of shortage of gas do not seem excessive and are in any event long-term, probably beyond the expected operational life of most power stations in existence today. At the time of the last coal review the Trade and Industry Select Committee noted the variety of estimates of gas reserves, and considered that "as realistic an estimate as any" was that of British Gas who estimated that, taking account of the increase in demand, the UK's gas reserves could last for about 40 years. The Government's White Paper in 1993 on "Prospects for Coal" concluded that economically recoverable gas reserves were unlikely to run out significantly more quickly than economically recoverable reserves of coal. It also noted that there were plentiful supplies of both coal and gas available on world markets, and no reason to believe that the supplies of either were likely to be subject to major disruption. Developments since 1993 do not call these conclusions into question.

5.4 Third, it has been argued that limiting gas generation would limit exposure to rising gas prices at some future time and limit the risks of dependence on gas imports, However, it would also limit the ability to benefit from future falls in gas prices, and would increase exposure to rising prices of other fuels such as coal or oil. At present the proportion of UK gas demand met by gas imports is very low, only a few per cent: in contrast, over a quarter of UK coal demand is met by imports. In any case, individual power station projects, both those already built and those which are planned, typically involve contractual arrangements for the supply of gas for an extended period, often covering the whole of the period over which the cost of the station is projected to be amortised.

**5.5** Fourth, it has been argued that the flexibility of gas-fired power stations may be limited, including by the possibility that the gas transmission system may not be able to support variations in gas-take by gas-fired stations, for example, between night and day. However, there is no technical reason why gas-fired stations need be less flexible than (for example) coal stations. There is also no reason why such problems relating to the gas transmission network cannot economically be addressed by reinforcement of that network or of power station connections to it.

**5.6** Fifth, it has been argued that gas-fired stations are unable to offer services to the electricity system such as frequency response services. This is largely a commercial issue, since the frequency responsiveness of CCGT plant is potentially at least as good as from coal plant, subject to the gas network being able to support variable gas take. Similarly, there should be no technical reason why CCGT plant should not provide adequate frequency response performance when operating on back up fuel. At present, most CCGT operators do not offer significant frequency response services because they prefer to run at full capacity. There is scope for better definitions of frequency response services in the Grid Code (where the relevant provisions are at present vague and relate mainly to coal and oil plant), and for the development of markets in the provision of frequency response services. These issues are being considered by NGC and the Grid Code Review Panel.

**Interruptible Gas Supplies**

**5.7** There have been concerns about gas supplies to some gas-fired power stations being on interruptible terms (that is, they may be interrupted at, typically, five hours notice by Transco, or in some cases also by the gas shipper); about whether stations with firm gas supplies have sufficient incentive to install and use back up fuels in the event of emergency interruptions; and about the possibility that gas-fired generators may in some circumstances prefer to resell their gas into the flexibility or spot markets for gas rather than to use it for generation.

5.8 Of the 20 CCGTs operating at present in England and Wales, seven are on firm gas contracts and 13 have at least some interruptible gas contracts. Twelve of these thirteen stations have back-up fuel supplies, typically distillate, while the thirteenth has alternative gas supplies. The extent of back-up fuel supplies on site varies from station to station. Typically, they are sufficient to support baseload production for four or five days, but they could last longer. For example, in periods of gas interruptions hitherto gas stations have typically had financial incentives to run on back-up fuel during the day and to close down overnight, NGC having scheduled additional coal capacity to run at night. In such circumstances, back-up fuel stocks on site might last about 14 days. Endurance can of course be extended beyond this period by replenishing back-up fuel stocks by road, rail, water or pipeline as appropriate.

5.9 Since January 1996 there have been four main occasions when gas supplies to one or more power stations have been interrupted. The largest interruption, on 2 January 1997, led to 2,900 MW of capacity being declared down initially, though this was reduced to about 1,600 MW by the peak period of that day. Over the following week, as widespread gas interruptions continued, the CCGT shortfall over periods of peak electricity demand was reduced to about 1,000 MW. In a very severe winter, it is of course possible both that the extent and duration of gas interruptions might be greater than has been the case hitherto, and that CCGTs which have firm gas supplies could nevertheless be interrupted by Transco in emergencies. Transco and gas shippers need give only five hours notice of gas interruptions. If NGC has not already scheduled sufficient reserve plant, this period would be insufficient to allow NGC to instruct the start-up of steam plant, though open-cycle. gas turbines, which have on site supplies of distillate oil, can respond at much shorter notice. Against this background, the security of electricity supplies would depend significantly upon the extent of incentives on gas-fired generators to continue to meet their Pool commitments to generate by using back-up fuel supplies, even though these are more expensive than gas; and upon adequate flows of advance information between the various parties concerned.

5.10 As regards incentives, in periods of widespread gas interruptions, such as on cold days, it is likely that Pool prices would be sufficiently high to provide strong financial incentives on station operators to burn back up fuel and to replenish stocks. Distillate oil usually costs the equivalent of £20 to £3O/MWh, whereas on cold week-days electricity generation is typically worth several times this. In addition, certain IPP contracts provide for higher payments from the supplier to the generator when back-up fuel is used. Gas-fired power stations with independent (non-Transco) access to gas supplies are likely to have strong financial incentives to maintain generation at least during the day in cold weather.

5.11 It is possible that Pool prices could provide insufficient incentive for CCGTs to switch to distillate oil at weekends. Moreover, lower plant availability at weekends might make it difficult for NGC to schedule additional generation in place of CCGTs. As a short-term measure, for the year ending 3 1 March 1998, the Pool agreed a mechanism whereby if NGC issued a High Priority Notification of Inadequate System Margin (NISM) and the Pool Purchase Price was less than £3O/MWh, then CCGTs were required to meet their day ahead declared availability or pay a penalty of £20/MWh. The Pool chose £30/MWh as sufficient to remunerate a CCGT generating on distillate oil in the event of a gas interruption. Longer-term incentive arrangements need to be put in place by the Pool. In addition, the question of incentives and penalties on generators who fail to generate after having declared themselves available is one of the issues under consideration in the Review of Electricity Trading Arrangements.

## Information Flows

5.12 Two types of information flows are of particular importance. Information flows between Transco and NGC about the likelihood of gas interruption are necessary to enable NGC to take steps such as scheduling of additional reserve when appropriate. Information flows between NGC and generators about short-term prospects for electricity demand and the availability of capacity are necessary so that generators can assess accurately when it is likely to be profitable for them to ensure that all their capacity is available to the system.

5.13 Following discussions between NGC, Transco, OFGAS and OFFER, Transco initiated a consultation exercise to explore amending the Gas Network Code to facilitate the flow of information between Transco and NGC on potential gas interruptions. OFFER recommended that, subject to relevant considerations of the commercial confidentiality surrounding the provision of individual gas station supplies, Transco should seek to improve the flow of information from itself to NGC. However, in January 1998, Transco published the results of the consultation, and recommended that the level of information made available to NGC should not be increased. NGC is pursuing possibilities for amending the Grid Code to strengthen requirements on gas-fired stations to give it information about impending gas interruptions. The question of improving information flows needs to be considered further, since the present situation is not fully satisfactory.

5.14 As regards flows of information from NGC to generators, NGC has developed a system for advance notification of periods when it perceived a danger that insufficient capacity will be available to the system. Generators have responded to such notifications by making more capacity available. The periods identified in the notifications have been likely to be times of relatively high prices in the Pool.

## Risks **in Context**

**5.15** It is sensible to view the issues associated with interruptible contracts for gas-fired generation in the wider perspective of risks in the electricity system. All types of generating capacity are subject to a degree of unreliability and uncertainty. Under the present Pool rules, any power station can declare itself unavailable at a moment’s notice, for technical or for purely commercial reasons. The maximum single loss of generating plant which can normally occur for reasons other than gas interruptions is presently Sizewell B at about 1,300 MW. Loss of the French interconnector represents a risk of about 1,000 MW for the loss of one dipole. Loss of a set at a large coal-fired station might amount to 500 MW. Any of these losses may be instantaneous in nature and without warning.

5.16 Against this, although gas interruptions to date have varied up to 2,900 MW, they have provided notice periods of some hours which have allowed NGC and generating plant operators to make alternative arrangements to cover the loss. These alternatives include, of course, gas-fired stations switching to back-up fuel.

During periods of gas interruptions, the amount of generation plant run out of merit to cover absent gas-fired stations has varied between 600 MW and 2,900 MW, and has typically been around or below 1,000 MW. The highest levels of non-availability of gas stations occurred during eight (non-consecutive) half-hourly periods on 2 January 1997: NGC proved able to manage the system successfully.

5.17 In addition, there can be significant and sometimes unexpected surges of demand. At a recent break in Coronation Street, the pick-up in demand was 1,400 MW. NGC's system and processes are equally designed to cope with such events.

**Statutory Powers**

5.18 Sections 34 and 35 of the Electricity Act contain powers for the Secretary of State to give directions to power station operators with respect to stocks of fuel. These powers have been used in relation to coal stocks at coal-fired stations, but not hitherto with respect to back-up fuels at gas-fired stations.

5.19 The present powers pre-date the competitive market, and are conceived solely in terms of physical fuel stocks. As explained, the competitive market should provide incentives to provide and use back-up fuels. It might nonetheless be desired to take further steps to extend the endurance of gas-fired stations so that they could more readily cope with longer interruptions of gas supplies than have been experienced hitherto. If so, powers could be taken to enable the Secretary of State to impose requirements on various classes of power stations as regards endurance in the event of fuel interruptions. This would leave generators free to find the most appropriate way of meeting such requirements. Gas-fired generators, for example, would have a variety of options: to increase on-site storage of back-up fuel, or put in place acceptable arrangements for replenishment of stocks, or renegotiate gas supply contracts so as to replace interruptible with firm contracts, or reduce the circumstances in which they can be interrupted, or even contract for reserve capacity at other power stations, including coal-fired stations. Some might be able to conclude contracts for interruptible supplies of electricity to certain customers, to match part of their risks of gas interruptions. The possibility of early legislation to amend other aspects of the Electricity Act would provide an opportunity to make such changes to the Secretary of State's powers.

# 6 RELATIONSHIPS BETWEEN GAS AND ELECTRICITY MARKETS

6.1 This submission has explained how gas is increasingly being used to generate electricity. Generators are also topping up their initial fuel contracts by purchasing gas on shorter-term contracts and in the spot market. It is possible for such generators to sell back to the gas market some of the gas they have contracted to take, instead of using it for generation. The extent of this has so far been very limited, It is, however, likely to become more significant in future, as both the gas and electricity markets develop, and as new gas-fired generation plant increasingly competes at mid-merit and peak.

6.2 Trading between the two markets has a number of advantages. It helps to ensure that the maximum benefit is secured from the nation's fuel supplies and that the most economical fuels are used for electricity generation. It also tends to reduce extremes of prices in both markets. Short-term arbitrage will in large measure be driven by short-term price differences between the gas and electricity markets, for instance between prices in the on-the-day balancing market for gas, and Pool prices for electricity. The volumes of gas traded on the day are small in relation to total gas demand, and it is therefore likely that relatively small trades of gas from electricity generation into the short-term gas market would have the effect of reducing gas prices and thereby reducing price incentives for further such trades.

6.3 It would be wrong to assume that arbitrage will typically lead to gas being withdrawn from the electricity market at times of high electricity demand or when alternative capacity is not available. These are precisely the times when electricity prices are likely to be highest, and hence when reducing electricity output is likely to be least attractive to a generator. A more common form of arbitrage might be for gas-fired generators to sell gas during the night, when electricity prices are low, and to use gas for generation during the day. This reduced night time supply might open up new opportunities for other generators, including coal-fired generators, during periods of lower electricity demand.

6.4 It will be important to ensure that the trading frameworks of the gas and electricity markets do not place artificial incentives or restrictions on players which might endanger security of electricity supplies. These might arise in particular from timing differences between the two markets. The Electricity Pool is at present a non-firm day-ahead market, while gas can be traded on the day. This means that it is possible for generators to declare themselves available on the day ahead, but later to decide not to generate but to sell their gas instead, without incurring penalties beyond their loss of revenue from not generating. OFFER and OFGAS intend to continue to work closely in this area, including in the context of the Review of Electricity Trading Arrangements. Among the important issues for consideration in the review will be whether the Pool should become a firm market, and the possibilities for mechanisms which would make generators carry the costs of alternative generation if they fail to run at short notice.

## 7 COMPETITION, NEW ENTRY, PRICES AND INVESTMENT

**7.1** The previous chapters have argued that an increased use of gas does not represent a threat to security of supply. It might nonetheless be argued that there would be advantage in reducing the role of gas in the electricity industry, or increasing the role of coal, and that refusing further consents for gas-fired power stations would be a way to achieve this. The present chapter explains why refusing consents to entrants would have severe disadvantages for competition, prices and investment, and hence for customers.

### Competition and New Entry

**7.2** The electricity industry is in the course of transformation from monopoly to competition. The development of competition in generation, and the opening of full competition in supply from 1998, are both at a critical stage. New entry plays an essential role in competition. If consents for new power stations are granted to entrants, it is reasonable to expect that competition in generation will become increasingly effective. Prices will be driven down, reflecting present and prospective lower costs of entry. This will apply not only to baseload prices but increasingly to mid-merit and peaking prices. It will apply not only to Pool but also to contract prices. A greater number of generators will also facilitate competition in supply. New entry will benefit not only large industrial users (who might take power from or enter into medium term contracts with the plant) but also medium-sized commercial and smaller domestic users.

7.3 The importance of continued new entry by gas-fired generation in creating greater competition in the generation market in England and Wales was emphasised by the MMC in its reports in April 1996 on the proposed take-overs of Southern Electric by National Power and of MEB by PowerGen. The Commission concluded that "provided the disposal by PowerGen and National Power of 6 GW of plant takes place, the market entry of new plant which is soon to be commissioned, is currently under construction, has Section 36 consent or is in contemplation will, in our view, provide a broadly satisfactory competitive environment in generation from 1997 onwards" (MMC para 2.58).

7.4 The disposal of 6 GW of plant did indeed take place. The MMC identified 2,755 MW of independent CCGT plant soon to be commissioning or then under construction*, plus the 1,000 MW Scottish interconnector upgrade. About three-quarters of the CCGT plant in question has now been commissioned. However, only 400 MW of the interconnector upgrade has been completed pending the review of the North Yorkshire line, the decision on which has just been announced. The remaining 600 MW of the upgrade seems unlikely to be fully effective before 2000. The MMC identified a further 6,700 MW of independent CCGT plant with

[2] Medway 675 MW, Kings Lynn 415 MW and Indian Queens 160 MW, classified as soon to be commissioned; Seabank 755 MW and South Humber Bank 750 MW classified as under construction.

Section 36 consent or in contemplation[3]: to date, only about a quarter of this is commissioning or under construction, though there are additional independent CCGT projects under construction of nearly 2,700 MW which were not identified by the MMC[4].

7.5 The position is summarised in Table 7. Of the total of 10,425 MW of new independent capacity envisaged by the MMC, less than a quarter (2,433 MW) has so far been commissioned. When all capacity presently under construction is complete, total new capacity will be about 70 per cent (7495 MW) of the MMC total. This leaves some 3,000 MW of envisaged capacity not yet under construction. The "broadly satisfactory competitive environment in generation" envisaged by the MMC has thus not yet come to pass.

7.6 It is true that market shares have been steadily changing, not least as a result of new entry, and the 6 GW disposal has enabled another company to compete in the mid-merit part of the market and to offer a broader range of contracts. But there is still evidence of the ability of portfolio generators to influence Pool prices, most recently to increase system marginal price. In the eyes of customer groups, and many others responding to the Review of Trading Arrangements, the extent of competition in generation is the main outstanding problem in the electricity sector today. The DGES is therefore keeping generation under active review, and the need for further steps to deal with the situation cannot be ruled out.

7.7 Apart from new entry, there are no other market developments in prospect which would lead to increasing competition. If a restriction on further consents at this stage were coupled with a restriction on further construction under existing consents, this would clearly prevent the construction of capacity equal to all the plant "in contemplation" at the time of the MMC report. In this event, the broadly satisfactory competitive environment in generation envisaged by the MMC would not be provided.

7.8 An MMC reference might, depending upon the MMC's conclusions, enable the Secretary of State to require further divestment of plant by the major generators, and thereby to increase competition between existing players. But divestment could not provide the continuing protection to customers that the threat of new entry does.

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[3] Keadby 11 750 MW, Kingsnorth 740 MW, Humber II 527 MW, Scunthorpe 294 MW and Enfield 258 MW classified as with consent; Flotilla 779 MW, Wallend 750 MW, Runcorn 700 MW, Kings Lynn II 820 MW and Enderby 1,050 MW classified as in contemplation.

[4] Humber II 5 12 MW, Enfield 360 MW and Runcorn 760 MW identified by MMC; plus Barry 240 MW, Saltend 1,200 MW, Seabank II 450 MW, Sutton Bridge 770 MW not then identified.

## TABLE 7: PROGRESS OF INDEPENDENT GENERATING CAPACITY RELATIVE TO 1996 MMC REPORTS

| Classification | Capacity MW | Situation as at March 1998 | | | | |
|---|---|---|---|---|---|---|
| | | Already Commissioned | Under Construction | Section 36 granted | Section 36 applied for | Total |
| **Schemes identified by MMC** | | | | | | |
| Soon to be commissioned | 1,250 | 1,240 | | | | 1,240 |
| Under construction | 1,505 | 793 | 755 | | | 1,548 |
| S 36 granted | 2,570 | | 872 | **1,750** | | 2,622 |
| In contemplation | 4,100 | | 760 | | 1,945 | 2,705 |
| TOTAL: MMC SCHEMES | **9,425** | **2,033** | **2,387** | **1,750** | **1,945** | 8,105 |
| Interconnector upgrade | **1,000** | 400 | | **600** | | 1,000 |
| **Schemes not identified by MMC** | | | | | | |
| CCGT | | | **1,475**** | **1,130** | **6,320** | **8,925** |
| CCGT/CHP | | | **1,200** | **2,198** | **1,100** | **4,498** |
| **CHP** | | | | **384** | **581** | **965** |
| TOTAL,: NON-MMC **SCHEMES** | | | **2,575** | **3,712** | **8,001** | **14,288** |
| **TOTAL: ALL SCHEMES** | | | | | | |
| **Excluding interconnector** | | **2,033** | **5,652** | **5,462** | **9,946** | **22,503** |
| **Including interconnector** | | **2,433** | **5,062** | **6,062** | **9,946** | **23,503** |

Notes: ** of which 240 MW is commissioning
* commissioning.

## Prices

7.9 Since there are at present a number of schemes with Section 36 consent which are either under construction or are yet to start, refusing further consents will not necessarily have an immediate impact on the proportion of the generation market served by gas, and hence on the demand for coal, unless steps are taken to prevent the implementation of the schemes that already have consent. However, there could be an early impact on electricity prices.

**7.10** A policy of refusing further consents to entrants would remove an important constraint on the major generators, who need to balance their desire for higher margins against the possibility of further loss of market share to new entrants. If new entry is constrained, they will be able to raise prices or decline to lower them, without risk to market share, and can be expected to do so. They can also be expected to do so in the shorter term, rather than wait until such time as the new entry might otherwise have been commissioned. Moreover, in the increasingly competitive supply market, the impact of higher generation prices will be felt by all customers, including industrial, commercial and domestic customers.

**7.11** The previous section noted that the scope for coal-fired generators to price more competitively so as to maintain market share and discourage further entry by CCGTs depends particularly on the price of new contracts between generators and coal producers. If new entry by CCGTs were restricted then the incentives not only on coal-fired generators but also on coal producers to price competitively would be reduced, and the future costs of electricity production would be increased. This too is likely to mean higher prices to customers than would otherwise be the case.

7.12 In aggregate, these higher electricity prices could be very significant. To illustrate, it seems plausible that new entry and competition would compete down prices in the Pool and contract market by at least 10 per cent or 0.25p/kWh towards the new entry level over the next five years. If the consequences of restricting new entry were that prices were not to reduce (let alone were to increase) then on an annual output of about 300 TWh the additional costs to be carried by customers would be about E750 million per year. Even if the potential price reduction would have been a gradual one over a five-year period, the cost to customers over this period would be of the order of £2 billion. There would be corresponding windfall gains to incumbent generators.

## Investment

**7.13** Apart from schemes financed under NFFO arrangements, new entry using alternative technologies (for example, clean coal technology, renewables or new nuclear construction) is only likely to be feasible at prices significantly above present generation prices, perhaps 50 per cent or more higher. Even if prices were to rise to such levels, investment in new stations using fuels other than gas would be delayed or limited unless investors were confident that the ban on new gas stations would last for an extended period. Otherwise they would risk their investment being undermined by gas stations at a later time.

7.14 A consequence of refusing further consents for new gas stations would therefore be a reduction in the rate of investment in new capacity. To some extent, this might be balanced by a reduced rate of closure of older coal and oil-fired stations. However, older plant would be characterised by rising operating costs and declining reliability with age, and would be increasingly limited by environmental restrictions. Other older plant, including Magnox stations, might require to be retired. In addition to higher costs there might, therefore, be less capacity in total than there would *otherwise* be to meet future electricity demand, with possible implications for security of supply.

7.15 The development of CHP would be restricted. In addition to substantial CHP-related schemes which already have consent, several smaller CHP schemes, with a total capacity of about 650 MW, have applied for Section 36 consent but are presently blocked. Refusing consent to such schemes could put at risk the Government's target for CHP capacity.

7.16 It cannot be assumed that it would be straightforward to stop new investment in gas-fired stations now, and then to change policy and allow such investment later on. The companies at present interested in investing in generation in the UK would have switched their attention to other markets or sectors. They and other possible sources of investment would perceive an increased and continuing risk of Government intervention in the market. This would increase the returns required from new generation projects, with adverse implications for prices to customers. They might perceive also that the position of the incumbents had been strengthened by the period in which new entry was not possible, and that the risks of new entry had been increased accordingly.

**Price Controls**

7.17 Satisfactory measures to control generator prices, to counter the problems discussed above, are difficult to identify. There is no power to impose restrictions on generators' bidding or contracting behaviour, short of an MMC reference to seek the power. A voluntary restriction by generators would be unlikely to be forthcoming on terms consistent with increasing competition and competitive prices.

7.18 More importantly, price caps of any kind in the generation market would bring their own difficulties. They would distort the level and structure of prices in ways that could not always be predicted. Some market participants (whether generators, suppliers, traders or customers) would suffer financial damage from positions that they have already taken. There would be a loss of confidence by investors, entrants and those trading in the electricity market. Controls on prices, or other interventions in the generation market, could reduce the incentives on generators, suppliers and potential market operators to agree on and implement new trading arrangements in place of the Pool, following the present Review. The adverse impact on competition in generation of price controls and entry restrictions would in any case reduce the effectiveness of any such trading arrangements. Price caps would also limit or remove the scope for suppliers to compete to secure advantageous contracts from generators and offer them to customers; this would in turn have damaging consequences for competition in supply. The extent and benefits of full competition in 1998 would be reduced, perhaps critically.

7.19 Electricity generation and supply are new markets which are at an early stage of transition from monopoly to competition. New entry into those markets, and the confidence of present and potential future participants, are essential if competition is to develop to the benefit of customers. Restrictions on new entry into generation and attempts to cap generation market prices, even if the latter were feasible, would imply a substantial change from present policies, in the direction of long term and detailed government involvement. This would seriously undermine the conditions for competition to develop in those markets.

7.20 The UK has taken the lead in Europe in pressing for the opening of energy markets to competition. It is increasingly respected for its achievements in this area. Its arguments are beginning to have effect on EU policy and in many constituent countries, and indeed throughout the rest of the world. A reversal of policy, to introduce government restrictions on competition and control on prices, would be difficult to reconcile with this stance.

## 8 FUEL SOURCES IN SCOTLAND

8.1 The electricity industry in Scotland is distinct in many respects from the industry in England and Wales. Since Vesting, the number and capacity of large generating stations in Scotland, the dominant positions and vertical integration of ScottishPower and Hydro-Electric in both generation and supply, the contracted sale of all Scottish AGR nuclear output to ScottishPower and Hydro-Electric, and the absence of an electricity trading mechanism in Scotland equivalent to the Pool in England and Wales, have all constrained new entry in generation and the potential for new capacity in the short to medium term.

### Development **to Date**

8.2 Overall, the pattern of generation in Scotland still reflects the generating plant and fuel contracts put in place at the time of privatisation. Tables 8 and 9 show generation and capacity by fuel type in Scotland (excluding BNFL output at Chapelcross). The sharp fall in nuclear output between 1989/90 and 1990/91 was due to the closure of Scottish Nuclear's Hunterston 'A' plant in 1990, following the opening of the Torness AGR station in 1989, together with a reduction in output in Torness's second year of operation. Since then, nuclear output has grown steadily, as in England and Wales.

TABLE 8: SCOTLAND GENERATION OUTPUT BY FUEL TYPE (TWH)

| | 1989/90 | 1990/91 | 1991/92 | 1992/93 | 1993/94 | 1994/95 | 1995/96 | 1996/97 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| Nuclear | 17.1 | 12.9 | 13.0 | 14.5 | 15.3 | 16.9 | 17.6 | 17.7 | 17.7 |
| Coal | 8.8 | 12.7 | 13.2 | 11.3 | 9.1 | 8.2 | 11.0 | 11.4 | 12.3 |
| Hydro | 3.6 | 3.5 | 3.8 | 4.1 | 3.2 | 4.2 | 2.8 | 3.2 | 3.1 |
| Peterhead (dual oil and gas) | 0.9 | 3.9 | 5.1 | 5.8 | 8.8 | 8.4 | 8.9 | 8.8 | 7.6 |
| Other | 0.3 | 0.0 | 0.2 | 0.2 | 0.2 | 1.3 | 1.2 | 1.4 | 1.4 |
| TOTAL | 30.7 | 33.0 | 35.3 | 35.9 | 36.6 | 39.0 | 41.5 | 42.5 | 42.1 |

8.3 Table 10 shows shares of output and capacity in Scotland by fuel type for 1989/90 and 1997. Peterhead power station, which can burn oil or gas, has, since 1990, been burning sour gas from the Miller field. The proportion of gas generation in Scotland rose from 12 to 21 per cent over the period from 1990/91 to 1996/97 and is now beginning to decline. The share of coal has declined from 38 per cent of output to 29 per cent over the same period. These changing shares in generation have been in an expanding market. Home demand rose by 8 per cent over the period 1990/91 to 1996/97, while overall demand (that is, including exports to England and Wales) rose by 25 per cent. The amount of generating capacity and its breakdown by fuel type were however broadly unchanged.

**TABLE 9: SCOTLAND GENERATION CAPACITY (MW, AT 1 APRIL) BY FUEL TYPE (MW)**

| | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|
| Nuclear | 2,630 | 2,630 | 2,630 | 2,630 | 2,400 | 2,400 | 2,400 | 2,400 |
| coal | 3,888 | 3,888 | 3,888 | 3,888 | 3,888 | 3,888 | 3,888 | 3,888 |
| Hydro | 1,189 | 1,189 | 1,189 | 1,189 | 1,189 | 1,189 | 1,189 | 1,189 |
| Peterhead (dual oil and gas) | 1,284 | 1,284 | 1,284 | 1,524 | 1,524 | 1,524 | 1,524 | 1,524 |
| Other | 932 | 932 | 932 | 932 | 932 | 932 | 932 | 877 |
| TOTAL | 9,923 | 9,923 | 9,923 | 10,163 | 9,933 | 9,933 | 9,933 | 9,878 |

**TABLE 10: SCOTLAND PERCENTAGE SHARES OF OUTPUT AND CAPACITY BY FUEL TYPE**

| | output % | | | Capacity % | |
|---|---|---|---|---|---|
| | 1989/90 | 1990/91 | 1997 | 1 April 1990 | 1 April 1997 |
| Nuclear | 56 | 39 | 43 | 27 | 24 |
| coal | 28 | 38 | 29 | 39 | 39 |
| Hydro | 12 | 11 | 7 | 12 | 12 |
| Peterhead (dual oil and gas) | 3 | 12 | 18 | 13 | 16 |
| Other | 1 | 0 | 3 | 9 | 9 |
| TOTAL, | 100 | 100 | 100 | 100 | 100 |

8.4 The scope for change has hitherto been limited by the fact that the output of the nuclear stations and Miller gas as a fuel source to Peterhead have been on “must take” contracts. The main area of change has been the scope for exports of power to England and Wales which depends on the competitiveness of electricity from Scotland in the England and Wales market, and is subject to the physical constraints on the interconnector. The Scottish companies have taken steps to increase interconnector capacity. In contrast with the situation in England and Wales, Scotland has experienced neither the entry of independent electricity generators, nor construction of CCGT plant.

**TABLE 11: MARKET SHARES OF OUTPUT AND CAPACITY IN SCOTLAND**

| | **Output %** | | | **Capacity %** | |
|---|---|---|---|---|---|
| | **1989/90** | **1990/91** | **1997** | **1 April 1990** | **1 April 1997** |
| ScottishPower | 30 | 45 | 31 | 46 | 45 |
| Hydro-Electric | 15 | 17 | 26 | 28 | 31 |
| Scottish Nuclear | 49 | 36 | 43 | 24 | 24 |
| UKAEA | 6 | 2 | 0 | 2 | 0 |
| TOTAL | 100 | 100 | 100 | 100 | 100 |

**8.5** Table 11 shows that shares of output and capacity by company have been relatively stable over time. The main change has been an increase in Hydro-Electric’s share of output and capacity. This has been due mainly to the increased capacity of its Peterhead plant following the commissioning of two gas turbines.

**8.6** There are signs that some of these factors are now beginning to change. The gas from the Miller field is close to depletion and from later this year Peterhead station will no longer have access to this fuel source. Hydro-Electric has recently contracted to re-power the Peterhead station as a CCGT station. Planning permission has been granted to that company for a 2,500 MW plant, but initially the output will be limited by constraints on the transmission system to some 1,524 MW (broadly the capacity of the plant which the new units will replace). Hydro-Electric also plans to retain some of the existing dual-fired oil/gas plant. The re-powering project will improve the costs of Peterhead in the years to come, compared to the coal fired stations in Scotland.

8.7 Over the next 18 months, coal generation may fill the gap left by the decline in Miller Gas output at Peterhead. In March the Government conditionally approved the planned upgrade of the North Yorkshire line. This will increase the scope for exports on the Scotland-England interconnector from Scotland, and have a positive impact on coal generation in Scotland. In a similar time-frame, however, the re-powering of Peterhead could limit the extent to which Hydro-Electric uses its coal capacity at Longannet. The requirement for further environmental measures at Longannet in the form of FGD equipment is an additional uncertainty.

## New **Entry**

8.8 There have been some attempts by independents at new entry. In 1993, Fife Power announced plans to build a 75 MW waste-fuelled Integrated Gasification Combined Cycle (IGCC) plant at Westfield in Fife. Subsequently it applied for and was granted consent for an additional 45 MW by adding a stream turbine station which is due to be commissioned later this year. In November 1997, a sister company Fife Electric announced plans to build a 400 MW waste-fuelled IGCC on the same site. PowerGen is seeking to build a CCGT plant at Gartcosh, with an initial capacity of 350 MW rising to 700 MW. This proposal is subject to a Public Inquiry which ended in November 1997. The report is expected later this year. Applications for consents for these last two projects are under consideration by the Secretary of State. Given the lack of competition in Scotland, it would be unfortunate if consents for new plant were granted to incumbents but not to entrants.

8.9 These projects to develop smaller flexible plant in Scotland suggest that the extent of capacity of large generating plant in Scotland in relation to demand is no longer as large a barrier to entry as it was at Vesting. In parallel with the opening up of the domestic supply market to competition later this year, software systems are being developed to facilitate bilateral trades and settlement between independent generators and second tier suppliers. Much more needs to be done, and trading arrangements in Scotland will need to be considered in the light of the Review of Electricity Trading Arrangements in England and Wales.

8.10 Refusing Section 36 consent for further gas stations in Scotland may not in practice preserve the present proportion of Scottish output accounted for by coal. At Peterhead, consent has already been given for a 2,500 MW plant. If the transmission constraints noted above can be resolved then the plant will enable total output from Peterhead to increase significantly above its present level.

8.11 As in England and Wales, refusing further Section 36 consents to entrants would have a detrimental impact on the development of competition and on prices. It would entrench the market position of Scottish Nuclear and the two Scottish PESs for the longer term. The absence of effective competition in the Scottish generation market has already necessitated some control as to prices, which is at present done by reference to prices in England and Wales. If new entry is prevented, regulation of the generation'market will need to continue for the long term. This would not be conducive to the development of competition in supply in Scotland. Moreover, if measures were taken to limit further new entry in England and Wales, the higher prices than otherwise in that market would be reflected in Scotland also, in the absence of obvious alternative benchmarks for price regulation in the Scottish market. There would be corresponding windfall gains to the incumbent generators in both countries.

## 9 CONCLUSIONS

9.1 There have been significant changes in fuel market shares since Vesting. Gas-fired and coal-fired generation each now account for about one-third of output in England and Wales. Further changes will need to take place, not least in order to meet tighter environmental limits on emissions.

9.2 Calculations suggest that, if coal plant fitted with FGD continues to be run at about present levels, this necessitates a reduction in coal burn from the present 39 million tonnes to about 28 million tonnes in 2001 and 23 million tonnes in 2005. The tighter limits recently proposed by the Environment Agency would imply bringing forward the achievement of these last two levels to 1999 and 2001, respectively.

9.3 Reductions in gas prices and in costs of constructing CCGTs, and improvements in their fuel efficiencies, mean that it is more economic to build new CCGT stations compliant with environmental constraints than to retrofit existing coal stations with FGD. However, the costs of operating existing coal-fired stations have also been reduced over time, including by improved efficiency and lower coal prices. If coal is priced competitively in future, and coal-fired stations are operated efficiently, the avoidable costs of coal stations over the next few years need not be out of line with the avoidable costs of gas stations. With more competitive bidding, coal-fired stations need not concede market share as readily as they have done to date, or as some assume they will do in future.

9.4 Two scenarios are examined in this submission. Both assume that all existing Section 36 consents proceed. The second scenario assumes, in addition, further new entry by independents. On both these scenarios, market shares of fuel sources in 2003 would be about half gas, one fifth nuclear, one sixth coal, and one tenth interconnectors plus renewables. This should not raise concerns with respect to diversity.

9.5 These scenarios imply a coal burn in the range 35 to 25 million tonnes in 1999, stabilising at around 18 to 20 million tonnes in later years. This would be consistent with the tighter emissions limits recently proposed by the Environment Agency. A stable coal burn over the next few years should thus be attainable by competitive coal and coal generators, without a need for restrictions on consents for new independent capacity. The precise implications for UK deep-mined coal will depend on the competitiveness of UK coal producers and generators, including their commercial decisions with respect to fuel sources and imports

9.6 An increased market share for gas does not present problems with respect to security of supply. Other measures can be taken to improve the treatment of interruptible gas supplies and information flows. The Review of Electricity Trading Arrangements will consider several of these issues. The Secretary of State has powers in relation to fuel stocks at power stations at present and could if appropriate consider extending these.

9.7 The overall conclusion is that a policy of promoting increased competitiveness in the UK coal and electricity generation industries, including by granting consents to independents for new gas-fired power stations, is consistent with maintaining pressure to reduce electricity prices to customers, a diverse mix of fuel supplies, and a stable level of coal burn. It is also consistent with proposed environmental limits, and does not pose problems of security of supply. Such a policy seems consistent with the Government's aim of diverse and sustainable energy supplies at competitive prices. In contrast, government restrictions on new entry and controls on market prices would have serious consequences for competition in generation and supply, for customers and for the long-term development of the UK electricity industry.

ANNEX 1

# Gas Fired Capacity to Date

| Station | Generator | Type | As At 1st April 1990 | As At 1st October 1990 | As At 1st April 1991 | As At 1st October 1991 | As At 1st April 1991 | As At 1st October 1992 | As At 1st April 1993 | As At 1st October 1993 |
|---|---|---|---|---|---|---|---|---|---|---|
| Deeside | National Power | CCGT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Didcot B | National Power | CCGT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Killingholme (NP) | National Power | CCGT | 0 | 0 | 0 | 0 | 0 | 0 | 620 | 620 |
| Little Bar-ford | National Power | CCGT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Connahs Quay | PowerGen | CCGT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Killingholme (PG) | PowerGen | CCGT | 0 | 0 | 0 | 0 | 0 | 900 | 900 | 900 |
| Rye House | PowerGen | CCGT | 0 | 0 | 0 | 0 | 0 | 0 | 780 | 780 |
| Peterborough | Eastern | CCGT | 0 | 0 | 0 | 0 | 405 | 405 | 405 | 405 |
| King's Lynn | Anglian Power Generators Ltd | CCGT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Roosecote | Lakeland Power | CCGT | 0 | 0 | 220 | 220 | 229 | 229 | 229 | 229 |
| Teesside | Teesside Power | CCGT | 0 | 0 | 0 | 0 | 1875 | 1875 | 1876 | 1876 |
| Corby | Corby Power | CCGT | 0 | 0 | 0 | 0 | 0 | 0 | 412 | 412 |
| Brigg | Regional Power Generators | CCGT | 0 | 0 | 0 | 0 | 0 | 0 | 272 | 272 |
| Keadby | Keadby Developments | CCGT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Derwent | Derwent Cogeneration | CCGT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Barking | Barking Power | CCGT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medway | Medway Power | CCGT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| South Humber Bank | Humber Power | CCGT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Rocksavage/Runcorn | Rocksavage Power (Intergen) | CCGT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| AES Barry PS | AES | CCGT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Fetlside | Fellside Heat and Power | CHP | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Citigen | Citigen | CHP | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Cowes | National Power | OCGT | 140 | 140 | 140 | 140 | 140 | 140 | 140 | 140 |
| Letchworth | National Power | OCGT | 140 | 140 | 140 | 140 | 140 | 140 | 140 | 140 |
| Lister Drive | National Power | OCGT | 110 | 110 | 110 | 110 | 110 | 110 | 0 | 0 |
| Norwich | National Power | OCGT | 110 | 110 | 110 | 110 | 110 | 110 | 110 | 110 |
| Ocker Hill | National Power | OCGT | 280 | 280 | 280 | 280 | 280 | 280 | 280 | 280 |
| Bulls Bridge GT | PowerGen | OCGT | 245 | 245 | 280 | 280 | 280 | 280 | 0 | 0 |
| Leicester GT | PowerGen | OCGT | 102 | 102 | 102 | 102 | 102 | 102 | 0 | 0 |
| Taylor's Lane GT | PowerGen | OCGT | 140 | 140 | 140 | 140 | 140 | 140 | 140 | 140 |
| Watford GT | PowerGen | OCGT | 140 | 140 | 140 | 140 | 140 | 140 | 70 | 70 |
| Fort Dunlop | Central Power | OCGT | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Redditch | Central Power | OCGT | 0 | 0 | 27 | 27 | 27 | 27 | 27 | 27 |
| fye Power | Fibropower | OCGT | 0 | 0 | 0 | 0 | 14 | 14 | 14 | 14 |
| Glanford | Fibrogen | OCGT | 0 | 0 | 0 | 0 | 0 | 0 | 14 | 14 |
| Elm Energy | Elm Energy | OCGT | 0 | 0 | 0 | 0 | 0 | 0 | 28 | 28 |
| Knapton | Scottish Power | OCGT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Indian Queens | Indian Queens Power Ltd | OCGT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total | | | 1427 | 1427 | 1709 | 1709 | 4912 | 4912 | 6477 | 6477 |

ANNEX 1

| Station | Generator | Type | As At 1st April 1994 | As At 1st October 1994 | As At 1st April 1995 | As At 1st October 1995 | As At 1st April 1996 | As At 1st October 1996 | As At 1st April 1997 | As At 1st October 1997 |
|---|---|---|---|---|---|---|---|---|---|---|
| Deeside | National Power | CCGT | 533 | 533 | 490 | 490 | 500 | 500 | 500 | 500 |
| Didcot B | National Power | CCGT | 0 | 0 | 0 | 0 | 670 | 670 | 1350* | 1350* |
| Killingholme (NP) | National Power | CCGT | 620 | 620 | 620 | 620 | 620 | 620 | 650 | 650 |
| Little Barford | National Power | CCGT | 683 | 683 | 684 | 684 | 684 | 684 | 680 | 680 |
| Connahs Quay | PowerGen | CCGT | 0 | 0 | 1125 | 1125 | 1400 | 1400 | 1430 | 1430 |
| Killingholme (PG) | PowerGen | CCGT | 900 | 900 | 900 | 900 | 900 | 900 | 940 | 940 |
| Rye House | PowerGen | CCGT | 740 | 740 | 740 | 740 | 740 | 740 | 740 | 740 |
| Peterborough | Eastern | CCGT | 405 | 405 | 405 | 405 | 405 | 405 | 405 | 405 |
| King's Lynn | Anglian Power Generators Ltd | CCGT | 0 | 0 | 0 | 0 | 415 | 415 | 380 | 380 |
| Roosecote | Lakeland Power | CCGT | 229 | 229 | 229 | 229 | 229 | 229 | 229 | 229 |
| Teesside | Teesside Power | CCGT | 1845 | 1845 | 1875 | 1875 | 1875 | 1875 | 1875 | 1875 |
| Corby | Corby Power | CCGT | 406 | 406 | 406 | 406 | 406 | 406 | 406 | 406 |
| Brigg | Regional Power Generators | CCGT | 272 | 272 | 272 | 272 | 272 | 272 | 272 | 272 |
| Kead by | Keadby Developments | CCGT | 750 | 750 | 750 | 750 | 750 | 750 | 710 | 710 |
| Derwent | Derwent Cogeneration | CCGT | 236 | 236 | 236 | 236 | 236 | 236 | 236 | 236 |
| Barking | Barking Power | CCGT | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 |
| Medway | Medway Power | CCGT | 0 | 0 | 660 | 660 | 675 | 675 | 720 | 720 |
| South Humber Bank | Humber Power | CCGT | 0 | 0 | 0 | 0 | 793 | 793 | 793 | 793 |
| Rocksavage/Runcorn | Rocksavage Power (Intergen) | CCGT | 0 | 0 | 0 | 0 | 0 | 0 | 760* | 760* |
| AES Barry | AES | CCGT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 240* |
| Fellside | Fellside Heat and Power | CHP | 162 | 162 | 162 | 162 | 162 | 162 | 162 | 162 |
| Citigen | Citigen | CHP | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 |
| Cowes | National Power | OCGT | 140 | 140 | 140 | 140 | 140 | 140 | 140 | 140 |
| Letchworth | National Power | OCGT | 140 | 140 | 0 | 0 | 0 | 0 | 0 | 0 |
| Lister Drive | National Power | OCGT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Norwich | National Power | OCGT | 110 | 110 | 0 | 0 | 0 | 0 | 0 | 0 |
| Ocker Hill | National Power | OCGT | 280 | 280 | 280 | 280 | 0 | 0 | 0 | 0 |
| Bulls Bridge GT | PowerGen | OCGT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Leicester GT | PowerGen | OCGT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Taylor's Lane GT | PowerGen | OCGT | 132 | 132 | 132 | 132 | 132 | 132 | 132 | 132 |
| Watford GT | PowerGen | OCGT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Fort Dunlop | Central Power | OCGT | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Redditch | Central Power | OCGT | 27 | 27 | 27 | 27 | 27 | 27 | 27 | 27 |
| Eye Power | Fi bropower | OCGT | 14 | 14 | 14 | 14 | 14 | 14 | 14 | 14 |
| Glanford | Fi brogen | OCGT | 14 | 14 | 14 | 14 | 14 | 14 | 14 | 14 |
| Elm Energy | Elm Energy | OCGT | 28 | 28 | 28 | 28 | 28 | 28 | 28 | 28 |
| Knapton | Scottish Power | OCGT | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 41 |
| Indian Queens | Indian Queens Power Ltd | OCGT | 0 | 0 | 0 | 0 | 140 | 140 | 140 | 140 |
| Total | | | 9759 | 9759 | 11282 | 11282 | 13320 | 13320 | 14156 | 14396 |

* commissioning

ANNEX 2

# Gas Fired Power Stations with a Section 36 Consent

| CCGT | | | CHP/CCGT | | | CHP | | | TOTAL |
|---|---|---|---|---|---|---|---|---|---|
| STATION | GENERATOR | CAPACITY | STATION | GENERATOR | CAPACITY | STATION | GENERATOR | CAPACITY | |
| **Commissioning** | | | | | | | | | |
| Rocksavage | Rocksavage Power Co Ltd | 790 | | | | | | | |
| Humbe Power | Humber Power Ltd | 512 | | | | | | | |
| 4ES Barry | AES Electric Ltd | 240 | | | | | | | |
| Sub Total | | 1542 | | | | | | | 1542 |
| **Under Construction** | | | | | | | | | |
| Cottam (New technology) | PowerGen/Siemens | 500 | BP Chemicals | Saltend Cogeneration Co | 1200 | | | | |
| Seabank | Seabank Power Ltd | 1200 | | | | | | | |
| Enfield | Enfield Energy Centre Ltd | 360 | | | | | | | |
| Sutton Bridge | PG Limited | 790 | | | | | | | |
| **Sub Total** | | **2850** | **Sub Total** | | **1200** | | | | **4050** |
| **Yet to be built** | | | | | | | | | |
| Killingholme | PowerGen | 700 | Angle Bay | Texaco Ltd | 1280 | BASF Seal Sands | BASF Seal Sands | 85 | |
| Great Yarmouth | Amoco Power Resources | 350 | Coryton | Mobil Ltd | 720 | Bury St Edmunds | British Sugar Plc | 80 | |
| Fort Dunlop | Central Power Ltd | 120 | Rolls Royce | Rolls Royce Derby | 60 | SCA Aylesford | SCA Aylesford Ltd | 74 | |
| Scunthorpe | ABB Energy Development Company Ltd | 300 | Bury St Edmunds | British Sugar Plc | 80 | Snodland Paper Mill | Scottish Electric | 60 | |
| Keadby 2 | Scottish-Hydro Electric | 710 | Hays Chemicals | Yorkshire CoGen Ltd | 58 | ESSO Fawley | National Power | 130 | |
| Shoreham | South Coast Power Ltd | 500 | | | | Grovehurst | Grovehurst Energy Ltd | 85 | |
| Staythorpe | National Power | 1500 | | | | Port Talbot | PowerGen CHP Ltd | 200 | |
| Thornhill | Yorkshire CoGen Ltd | 100 | | | | | | | |
| Damshead Creek/Kingsnorth | Entergy | 740 | | | | | | | |
| Ryedale (OCGT) | Kelt UK Ltd | 60 | | | | | | | |
| Sub **Total** | | **5080** | Sub **Total** | | **2198** | **Sub Total** | | 714 | 7992 |
| **Total** | | **9472** | **Total** | | **3398** | **Total** | | **714** | **13584** |

ANNEX 3

# Gas Power Stations which have applied but not yet received Section 36 Consent

| CCGT | | | CHP/CCGT | | | CHP | | | CONVERSIONS | | | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| STATION | GENERATOR | CAPACITY | STATION | GENERATOR | CAPACITY | STATION | GENERATOR | CAPACITY | STATION | GENERATOR | CAPACITY | |
| Croydon | British Gas | 80 | Baglan Bay | Baglan Bay Cogen | 1100 | Capenhurst | Scottish Power | 65 | Cottam | PowerGen | 1000 | |
| King's Lynn | Eastern | 820 | | | | Shotton | Eastern | 240 | Fiddler's Ferry | PowerGen | 1000 | |
| Swansea | Abertawe Power | 185 | | | | Castleford | Yorkshire Cogen | 56 | Littlebrook | National Power | 1900 | |
| Enderby | Scottish Power | 1125 | | | | Runcorn | Scottish Hydro Electric | 140 | Drakelow C | Eastern | 1000 | |
| Spalding | International Generating Company | 800 | | | | Bridgewater | Powergen CHP | 65 | Rugeley B | Eastern | 1000 | |
| Tyneside | AES Tyneside | 350 | | | | British Sugar | British Sugar Plc | 80 | | | | |
| Partington | AES Partington | 380 | | | | | | | | | | |
| Elland | Yorkshire Cogen | 56 | | | | | | | | | | |
| Rhosgoch | Canatxx Energy Ventures | 880 | | | | | | | | | | |
| JH Volter | Canatxx Energy Ventures | 1000 | | | | | | | | | | |
| Porh yr Ogof | BNFL/Magnox Electric | 400 | | | | | | | | | | |
| Barking (OCGT) | Barking Power (OCGT) | 154 | | | | | | | | | | |
| Teesside (GT) | Teesside Power | 90 | | | | | | | | | | |
| Total | | 6320 | | | 1100 | | | 646 | | | 5900 | 13966 |