OXFORD INSTITUTE FOR ENERGY STUDIES

Today's Gas Glut and Yesterday's Contracts: The British Gas Predicament

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Units

There is no consistent use of units within the UK gas industry. In this paper we have broadly followed custom by using million cubic feet per day (Mmcfd) for analysis of production, and watt hours (Wh) for analysis of consumption. Conversions between the two are often given in the text to ease comparison. For the sake of familiarity as opposed to consistency, UK prices are quoted and discussed in pence per therm and European prices in $/MmBtu.

Approximate conversions employed are:

1 therm=29.31 kWh
1 Mmcfd=3.75mn therms
1 Mmcfd=1.1 TWh

Additionally

1 TWh=1,000 GWh
1 GWh=1,000 MWh
1 MWh=1,000 kWh

Abbreviations and Definitions

ACQ	Annual Contract Quantity
BG	British Gas
BGE	British Gas Energy (BGT + service + retail shops + Accord Energy)
BGT	British Gas Trading (BG Supply + Morecambe North and South)
MMC	Monopolies and Mergers Commission
NPV	Net Present Value
OFT	Office of Fair Trading
PRT	Petroleum Revenue Tax
REC	Regional Electricity Company
Transco	BG's transportation/pipeline network
WACOG	Weighted Average Cost of Gas (paid by British Gas)

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Executive Summary and Conclusions

Deregulation of the gas and electricity industries has led to a state of pronounced oversupply in the UK gas market. The effects of this oversupply became apparent during the course of 1995 and took two forms. Firstly, there was the emergence of a market for the short-term trading of gas. The price levels in this market collapsed in the first half of 1995 opening up a price gap between "spot" and contract gas. Secondly, some contract gas was paid for but was not produced, so that delivery to market was indefinitely postponed: there was a run-up in inventory - or "take-or-pay" - gas levels, as a form of keeping supply off the market. Oversupply has exerted great pressure on a number of market participants throughout the gas chain who remain locked into purchase agreements for volumes which have no market outlet, and at prices above market levels. The rally in spot price levels experienced since the second quarter of 1996 has eased pressure within the market but has not removed the fundamental strains.

The market is expected to remain in oversupply at least up to the end of 1998. Keen price competition may not clear the market even at discount prices, so that shut-in of production capacity is likely. The consequent build-up in take-or-pay levels will continue through the period, although at steadily declining rates, and there is little scope prior to 1999 for the industry as a whole to offload this inventory gas on the market.

The commissioning of the Interconnector in the fourth quarter of 1998 will only bring partial relief to the market and cannot be relied on to resolve the problem of contract liabilities. While the possibility to export gas will provide new market outlets, UK gas purchasers will still not necessarily be able to sell on their volumes at a profit. The long-term liabilities of purchasers post-98 will depend on the differentials between UK contract prices and European border prices. The absence of price re-openers in most UK contracts compared to their widespread incorporation in other European gas contracts, leaves UK purchasers of contract gas vulnerable to price movements and is likely to present problems in the future. Hence, rather than easing tensions within the UK market, the link-up with Continental Europe presents a formidable challenge.

British Gas is not the only company tied into unfavourable contracts, but it has the greatest

exposure and the greatest potential liabilities. The company finds itself locked into a long-term wager position, the outcome of which depends on the future movement of prices and is subject to wild uncertainties. Its commercial position has improved in 1996 compared to the previous year because of higher spot prices, but its liabilities remain considerable. Under our central case, the asset value of British Gas' Morecambe fields is sufficient to cover contract liabilities but is substantially reduced by them. The net present value of future cashflow minus liabilities suggests that British Gas Energy (BGE), BG's planned trading subsidiary, may trade at a discount to its book value.

The chance of significant voluntary renegotiation of contracts involving the effective transfer of funds from producers to BGE is slight so long as the company appears solvent. Producers will expect clear compensation for any revision of contractual terms, and this could take the form of an exchange of equity for contractual relief. The possibility of a politically-driven initiative also appears to be receding, since the present impasse over renegotiation is not unwelcome to the government: the differentials between the gas costs of BG and its competitors have in fact given a major boost to the policy to introduce competition. To redress the imbalance between gas costs would work against the objective of increased competition. Nevertheless, we believe the government or regulator could intervene in a worse-case scenario for BGE. Indeed the regulator could yet find its duty to promote competition in conflict with its obligations to consider the financial implications of its regulatory decisions.

The most likely outcome is one of drift, in which all parties hope that market trends will alleviate the current tensions and, if not, wait for them to worsen so that minds are concentrated. British Gas however will seek all legitimate means to exert extra pressure on producers, and even government, and could gain more from a crisis situation which forces renegotiation. The possibility cannot be ruled out that the company will seek to bring the issue to a head through some form of show-down. Under almost all conceivable scenarios, the market is set to become increasingly fractious, non-cooperative and possibly litigious. This must have some negative impact on producers as well as purchasers.

A possibility exists that residential customers will bear some of the pressures in the market-place. While industrial and commercial consumers have been gaining from significant price cuts,

residential customers have been paying charges which incorporate a proxy of BG's average contract costs and as a result have not benefited to the same extent. At the point of writing, it seems likely that the new tariff formula for capping prices for residential cutomers will again allow British Gas to pass through the gas costs of its long-term contracts. While those customers who have no inertia against switching supplier may be able to avoid this cost in the future by shopping around in a competitive market, those customers with a resistance to switching supplier could find themselves bearing part of the cost of old contract price levels.

Introduction

In the first half of 1995 the UK gas market underwent a price shock. At the beginning of the year gas had been trading on a short-term basis in an informal telephone market at a level of around 18-19p/therm. This was approximately in line with the average long-term contract prices paid by British Gas (BG) and other wholesale gas purchasers and which account for the overwhelming proportion of sales. On a calorific basis these price levels were also comparable with oil prices in the range of $15-18 barrel. By March the price for short-term - or "spot" - supply had weakened to around 14p and in April prices collapsed to 9p. In terms of the percentage decline in price the fall can be compared to the collapse in oil prices of 1986. A supply surplus had been foreseen by the industry and consequently a weakening of prices had been expected, but the scale and speed of this price movement appear to have caught many commentators and market participants by surprise.

Indeed attitudes towards the price movement seem at first to have been dismissive. Firstly, it was argued that the spot market was too small to be used as an accurate signal of market pricing and was an "aberration". The majority of volumes are still sold under contract at old price levels which were considered to reflect more properly the long-run cost and value of gas. Secondly, it was not clear at the time that the new price level for spot gas would persist. Because of the lack of liquidity of the market, some commentators expected gross volatility, or at least felt that a marketer would be unwise to rely on readily available spot purchases for their supplies. It was not certain that those companies short in gas had more than a temporary advantage over those who were long and had access to contract gas. Spot prices continued to hover within a stable band of 9-11p/therm throughout the summer of 1995 but the industry wondered whether winter demand would push prices back up, perhaps well above contract price levels. In the event, prices continued to remain at the same constant level throughout the winter. Only after a full year had elapsed, did prices begin to rally. In May 1996 prices saw a short-lived rise up to 16p since when they have settled at the 13-14.5p/therm mark. Future price movements remain uncertain but general industry sentiment expects to see spot prices remain below contract price levels, except perhaps in the case of occasional short-lived price spikes at times of peak demand.

With the recognition of lower price levels for available supply, it soon became apparent that most purchasers of contract gas were locked into prices above the market level and were

consequently experiencing financial hardship. British Gas is only one such company and is locked into prices that are probably lower than those of some of its competitors. Nevertheless, because it has the greatest exposure and the greatest potential losses, its trading position necessarily came to the forefront of policy attention. BG is tied into 39 long term purchase contracts with other producers. Under these contracts it is obliged to buy 16.5 bn therms of gas, or some 60 per cent of the market, from third parties in 1996. The average price for gas from these contracts was around 19p in 1995 and is believed to be rising. Thus it appears that BG is purchasing 16.5 bn therms of supply at a premium of 4.5-6p over the "market price". Annual write-off losses in order for it to compete on level terms with spot supplies then appear to be of the order of £740m-£990mn for 1996 alone. Such a calculation is not an appropriate estimate of BG's liabilities, as shall be shown, but it is nevertheless indicative of the basic potential threat to the company and indeed to the stability of the whole UK gas market.

The oversupply and accompanying availability of cheap gas meant that competitors rapidly began to win market share at the expense of BG. As its market base shrank, so it found itself unable to place all the volumes for which it had contracted under "take-or-pay" clauses. In May 1995 BG's accounts revealed that prepayments amounting to £650m had been made by the company for gas which had not yet been taken and a provision of £83m was set aside to represent the difference between the price paid for the gas and an estimate of its fetching price. The potential liabilities from these take-or-pay clauses led to speculation that contracts might not be honoured and that parties would resort to litigation in an increasingly acrimonious and pressurized market. Such a breakdown in contractual relations had already been experienced in the USA in the 1980s following their own deregulation of the gas industry.

The contract problem had been foreseen by informed industry observers before the fall in prompt supplies. For example, a study conducted during the course of 1994 by Gas Strategies and funded by BG Transco conjectured that "we expect to see pressures on contracts and players. There is a general agreement that physical oversupply in the market over the next few years is likely to result in sharply falling prices.... as a result we expect to see some contract failures."[1]

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[1] Gas Strategies, *Gas in Britain: What Lies Ahead? The Future Development of Britain's Natural Gas Market*, 1995, p.5.

During the course of 1995 industry observers and the government began to raise the prospect that the contracts between BG and the producers would have to be revised or even renegotiated. The basic argument was that the contracts had become divorced from market fundamentals, they were becoming untenable and the establishment of a competitive deregulated market made them anachronistic in their current form. By May the government had made it clear that it supported adjustments in contract terms in order to smooth the transition to a competitive market, although it favoured voluntary renegotiation between contracting parties rather than a government brokered solution. The official position of British Gas states that "for British Gas to compete on a fair basis and for a fully competitive market to work, it is vital that the arrangements for purchasing gas are made more appropriate to the liberalised gas supply market. Contract renegotiation is crucial to solving this industry-wide problem."[2] The combination of the threat to BG's financial viability and informal government influence made some form of contract revision look likely.

However, the producers reacted with hostility against these suggestions. Although they saw scope for the revision of certain contractual terms which may be in both parties' favour, they resolutely opposed any renegotiation that would result in the effective transfer of funds from producers to British Gas, arguing that their contracts had been entered into freely and remained legally binding.

The pressure on producers appeared to mount as the year progressed. Under the terms of the 1995 Gas Act, British Gas was obliged to separate its trading arm (British Gas Trading) from its transportation/pipeline business (Transco) - although they could remain under common ownership. The ostensible rationale behind this was to establish a clear division between the monopoly transportation business and BG's activities within the competitive supply business, so that the latter would not gain favourable treatment. However, the provisions of the Act also had the effect of vesting British Gas's contract obligations within the supply business, and ring-fencing the rest of the company from any future liabilities arising from them. Yet producers had made their investments based on the guarantee of BG's overall credit rating and the strength of its asset base, the overwhelming bulk of which is part of the transportation business. It was

[2] British Gas, *Annual Report and Accounts 1995*, p.9.

difficult to see how British Gas Trading could sustain liabilities under current market conditions and hence the Gas Act placed extra pressure on producers to ensure its solvency.

More recently, the pressure for renegotiation has eased. This was in part a result of an improvement in the supply/demand position in the market and the consequent rebound in spot prices. In part the demerger proposals made by British Gas in February 1996 allayed the earlier fears of the producers about the balance sheet strength of BG Trading. BG decided to transfer its own Morecambe gas fields from its E&P unit to the trading company which gave the company a stronger asset base. Contract liabilities could be set against the assets of these two large gas fields. The new demerged company is to be known as British Gas Energy (BGE). City analysts have varying estimates of the level of BG's liabilities but in the main they consider them to be less than the asset value of BGE. By implication the company can remain solvent without contract renegotiation.

British Gas's recent actions appear to suggest it is seeking to maintain pressure on all the parties involved, including government. In July the company issued a writ against the DTI demanding a £1bn rebate on past payments made under the Gas Levy and threatened to halt future payments of the levy due quarterly. BG claimed to have found a legal loophole exempting it from payment and, if the company is entitled to a rebate, it is believed that producers would be liable instead to pay the tax. Without entering into the legal minutiae, it might be assumed that these actions are indicative of a hardening attitude within BG. The possibility cannot be excluded that it could mount similar legal challenges over its contracts with producers based on alleged legal loopholes.

The purpose of this paper is to form a view on the supply/demand outlook within the UK gas market and to consider the main policy issues thrown up by the continuing supply surplus. The likelihood, justification or necessity for contract renegotiation will be considered. An analysis will also be made of the financial and strategic strength or weakness of British Gas Energy.

Chapter 1 Background

The Emergence of Competition

From the beginning of the UK natural gas industry in 1965 through to 1982, British Gas had an effective monopoly over the purchase, onshore transportation and supply of North Sea gas. Political initiatives to create a competitive market for natural gas can be traced back to 1982 when the Oil and Gas (Enterprise) Act of that year established the principle of third-party access: that is that independent marketers or producers should be allowed to use British Gas's pipeline system in return for an appropriate fee. The concept was that onshore transportation would remain an effective monopoly, but that pipeline access would bring about gas-to-gas competition in purchase and supply, since British Gas had no statutory monopoly over supplying larger industrial customers. However, competition was slow to take root and British Gas retained an effective monopoly up to 1988. Third parties did not make use of pipeline access, perhaps finding the unregulated charges a deterrent, and gas fields continued for another seven years to be developed only if reserves were pre-sold to BG under the traditional contractual system. In the meantime, British Gas had been privatized in 1986 and the Office of Gas Supply (Ofgas) had been set up as an independent regulatory body. This too had done little to accelerate competition.

The first effective push towards competition came with the referral of the non-tariff gas market[3] to the Monopolies and Mergers Commission (MMC) in 1987. The prompt for this referral came *not* from producers complaining about the unfairness of carriage terms, but from consumers complaining about BG's price discrimination. In response to the concerns of consumers, the MMC proposed that BG should sell gas according to non-discriminatory transparent price schedules. However, additional to this, the MMC also proposed measures to push competition at the upstream side of the business which were in many respects more far-reaching. They proposed greater transparency of access charges for producers using the pipeline network, and they banned BG from purchasing more than 90 per cent of new gas reserves. This, it was hoped, would allow others to contract independent supplies. The so-called 90/10 rule was significant because for the first time producers knew that they could not simply sell all their reserves to BG. They now needed to set up sales or marketing groups and gain an understanding of the downstream business.

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[3] Industrial and commercial users consuming in excess of 25,000 therms per annum.

Progress towards competition continued to be unsatisfactory according to a report from the Office of Fair Trading (OFT) in 1991. Although BG had contracted well below 90 per cent of new supplies, most of the non-BG gas was ear-marked for the new power generation market. There still remained too little gas outside BG's portfolio available for competitive sales to industry. In order to push on the process of competition the OFT came to an agreement with BG whereby the company was to reduce its share of the non-tariff market to under 40 per cent by 1995 (around 80 TWh). It is curious that BG agreed without apparently securing a clear quid pro quo although "the OFT proposals were backed by the threat that if BG did not voluntarily agree to new undertakings, there would be another MMC reference".[4] It seems therefore that loss of market share may have been conceded in preference to the threat of break-up of the company which may have resulted from a second MMC referral.

The OFT report also concluded that the emergence of competition remained constrained by BG's control over existing supply contracts. As a result BG agreed with the OFT to a release gas scheme whereby volumes of gas contracted by BG would be sold on to new market entrants. 500 million therms (14.6 TWh) of gas would be released each year between 1992-5 and a further 250 million therms the following year. The gas was sold at BG's WACOG plus a small handling charge, so that there was no significant differential in gas costs between BG and the sellers of release gas. It is significant that, at this point, regulatory pressure to reduce BG's share of sales was accompanied by an adjustment in the company's supply portfolio, although the link was never clearly stated. Indeed the loss in market share was clearly far greater than the corresponding reduction in supply from the release gas scheme. BG apparently calculated that increased sales within the power generation sector would fill much of the void from a reduced presence in the industrial sector.

There was no shortage of buyers of release gas with the implication that BG's WACOG was lower than the cost of new supplies in the short run. In other words, BG's average costs were below marginal cost. There was no spot market because there was no uncontracted gas available at competitive prices.

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[4] M. Armstrong, S. Cowan, J. Vickers, *Regulatory Reform: Economic Analysis and British Experience*, 1994, p. 267.

With short-run gas only available at a premium, the competitors were finally induced into extensive investments in field developments independent of BG. If companies wanted to compete successfully against BG in the industrial market in the long term, they could not depend on release gas but would need their own independent supplies. The emerging competition for the purchase of new contract gas coincided with the "dash for gas" in power generation and as a result, during the period 1992-3, a competitive market emerged in which BG was often vying for incremental supply alongside power generators and gas marketing companies. Rival bidding drove prices up above BG's own average costs. Faced with high prices for new gas and uncertainty over future market share, BG stood back as its competitors bought up an increasing share of new supply. These supplies continued in most cases to be purchased under long-term contract.

If British Gas had hoped to avoid a second enquiry by the MMC, a major re-think occurred in 1992. Given continued uncertainty over its future market share and perceived regulatory "harassment", BG decided to request an MMC referral itself. It was felt that a further enquiry would clarify the regulatory rules under which BG and its competitors would operate and would therefore enable BG to plan its business appropriately for the future. This enquiry reported in July 1993 and among its recommendations it proposed that BG's monopoly over supply to residential (or tariff) customers be lifted in the early part of the next decade. The government gave its response to the MMC proposals in December and announced its decision to phase in competition within the residential market from 1996 leading to full competition by April 1998, an acceleration of the timetable proposed by the MMC. Unlike in the case of the OFT report, the potential erosion of BG's market share in the end-consumer market was never linked to relief on its purchase commitments. Nevertheless, since December 1993 the broad intentions and timetable of government policy and the introduction of competition have been clear, and attention has focused instead on the technical details and preparation.

Market Profile

Natural gas met one-third of the UK's primary energy requirement in 1995. Consumption totalled 824 TWh, equivalent to 7.5 bcf/d. Almost 6 per cent of this volume never entered the market but was consumed by producers upstream. A further 3 per cent was consumed by BG Transco through compression, its own use and system losses. The remaining demand was

consumed across sectors as shown in Table 1.1.

Table 1.1: UK Gas Market by Sector. 1995.

	TOTAL	*Residential*	*Commercial*	*Industrial Firm*	*Industrial Interruptible*	*Power Generation*
TWh	754	326	110	69	104	145
Per Cent	100	43	15	9	14	19

Source: *Energy Trends*, DTI

The largest sector for gas consumption remains the residential sector which comprises 18 million households, of which over three-quarters have gas central heating. Until 1996, BG had a statutory monopoly over this market. However, 500,000 homes were included in the pilot phase for gas competition in April 1996 and this figure will rise to 2 million in April 1997. The phasing in of competition in the residential sector will be expanded over the course of 1997 to cover 2 million households. If deregulation goes ahead according to government plans the full market will be opened up to competition in April 1998. This means that the absolute maximum loss of market share by BG in the residential sector is 5 per cent (16.5 TWh) by the end of 1996 and 10 per cent (33TWh) by the end of 1997. Although this loss of market volumes would clearly compound BG's present problems, the potential loss is strictly bounded and does not in truth represent significant volumes. After April 1998, however, BG's potential loss of market share is open-ended and judgments about the speed with which it may lose share become highly speculative. Three scenarios were used by British Gas and Ofgas in a recent report. The middle market share scenario was based upon BG retaining 79 per cent of the market by 2000. A low market share scenario was based upon a 63 per cent share, and the high market share scenario used a figure of 97 per cent.[5] The range of possible sales under these scenarios is clearly broad enough to alter completely the balance of BG's supply/demand portfolio.[6]

[5] Ofgas, *1997 Price Control Review: Supply at or below 2,500 therms a year - British Gas Trading*, vol 1, p.50 & vol 2 pp.39-40.

[6] The experience gained from the initial opening up of competition in the pilot area suggests that BG could lose customers rapidly. In September 1996 after 5 months of competition 70,000 customers, or 14 per cent of the total, had switched supplier. This rate of loss of market share is far greater than that experienced in the deregulated telephone market. However BG has made no attempt as yet to compete on price.

The power sector has been the engine of growth over the last four years. Following deregulation of the electricity sector in 1990, a large number of investments were made in combined-cycle gas turbine power stations in what became known as "the dash for gas". Consumption of gas within this sector has accordingly risen from just 18TWh in 1992 to 145 TWh in 1995. Many of these power projects were able to line up their own gas supplies direct from producers under their own long-term contracts but BG supplied about one-quarter of the volumes through its general supply portfolio.

The industrial market is divided between firm and interruptible customers. Firm customers are guaranteed constant supply and, in 1995, paid on average about 23p/therm. Interruptible customers sign contracts in which their supply may be cut off for a period up to, say, 60 or 90 days in any one year. This helps BG manage peak demand periods, and in return prices are set at a discount. In 1995 the average price was reported at 17p. The firm market therefore appears to yield better margins and it was the first in which market entrants made inroads into BG's market share. In 1992 BG supplied around 70 per cent of the firm market. This fell to 50 per cent the following year, and by 1995 it was down to 10 per cent. During this period, BG was obliged by the regulator to publish price schedules, which competitors could strategically under-cut. The requirement for price schedules was removed in late 1994 since when BG's market share has stabilized at this low level.

Competitors found it far more difficult to win interruptible customers. The economic "worth" of interruptible customers will be greater to BG, so long as it has to manage seasonal peaks from the residential sector, than to its competitors whose sales profile is more constant throughout the year. For the year 1994 BG supplied over 90 per cent of the market. Nevertheless, this situation changed dramatically in the first half of 1995; by June its market share was reported to have fallen to just 19 per cent.[7] The rapid loss of this market must evidently have been linked to the overall surplus in supply and weakening of prices. Nevertheless much of the loss in market share occurred prior to the collapse in spot prices of April so that the loss in market share was apparently as much a cause of falling prices as a result. Indeed BG has been clawing back market share since last autumn despite the continuing availability of cheap prompt supplies.

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[7] John Hall Associates (JHA) database. Reported in *UK Gas Report* 49/11.

Those companies with substantial exposure to the interruptible market will themselves have a strong incentive to enter the residential market aggressively. Acquiring residential customers will enable them to balance peak demand with the potential for supply interruption, and thereby will optimize the use of their overall supply portfolio.

The commercial market was opened up to competition in 1992 under the Competition and Service (Utilities) Act which lowered the threshold for competitive supply from an annual consumption level of 25,000 therms down to 2,500 therms. This is approximately equivalent to an annual gas bill of £1,100. BG's share of this market had fallen to about 50 per cent by early 1996.

Table 1.2: The Competitive Gas Market. Main Players

Producers	*Power Companies/RECs*	*Others*
AGAS (Elf)	Egas	Angi
Alliance (BP, Norsk Hydro, Statoil)	Hydro-Electric	Bell Gas
Amerada Hess	Kinetica (50% PowerGen)	British Fuels Gas
Kerr Mcgee	London Total	Budget Gas
Kinetica (50% Conoco)	Manweb/Caledonian	Calor
Mobil Gas Marketing	Midlands	Cumbria
Quadrant (Exxon/Shell)	National Power	Gas Light & Coke
Texaco	Northern	United Gas
Total Gas Marketing	Southern/Phillips	Volunteer Energy
	SWEBGAS	
	Western	

Source: Kinetica, *UK Gas Report* 54/p.15

The competitors in these markets can be divided into three groupings. Firstly there are the producers or their gas marketing subsidiaries. Secondly there are the electricity companies, both the generators and RECs. Finally, there are independent companies. The main players in each group are listed in Table 1.2. Those with the highest presence appear to be Alliance, e gas, Kinetica, Mobil Gas Marketing, Quadrant and United Gas. SWEBGAS has won the greatest number of residential customers.

Long-Term Contracts

Thirty-nine long-term purchase contracts are believed to be extant between British Gas and third party gas producers. On top of this BG buys gas from the Morecambe fields under contract with its exploration and production subsidiary. These contracts were signed at different times, have different price levels and contain varying terms. The average price paid by BG from these contracts was around 19p/therm in 1995 and the price is expected to rise to 21p by 1998.[8] The volumes which BG is obliged to buy at these prices over the coming years are shown in Figure 1.1. More than half these volumes was contracted before 1986 when the company was still under public ownership and perhaps 95 per cent was contracted before December 1993 and the decision to remove BG's monopoly over residential supply.[9] The only contract believed to have been signed by BG since 1993 was for gas from the Armada development, in which BG has a substantial equity holding and it is therefore more akin to a transfer than a third-party purchase.

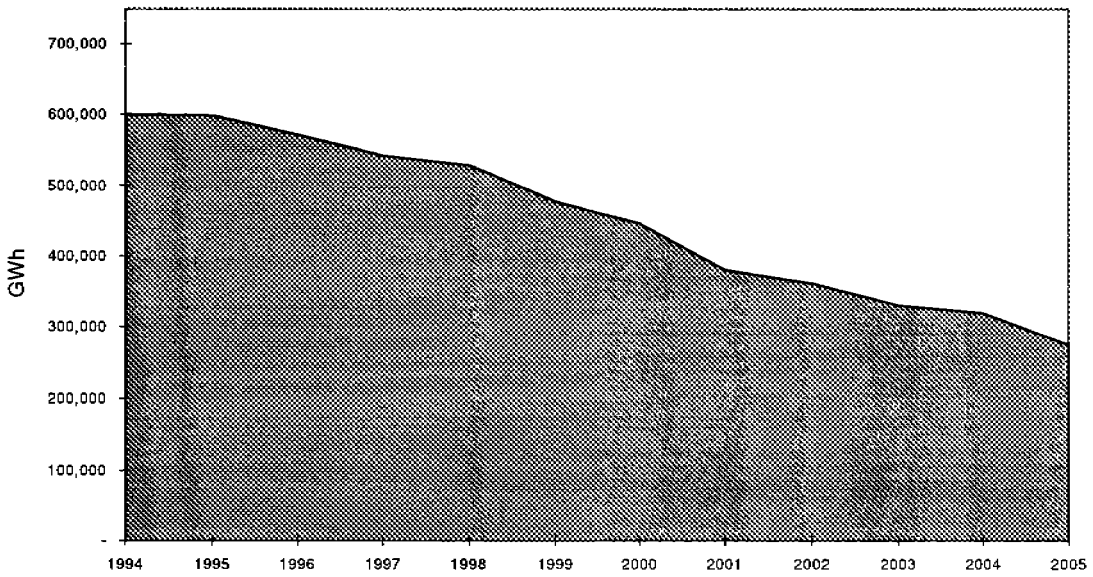

Figure 1.1: BG Minimum Take-or-Pay Commitments

Typically British Gas would offer producers a depletion contract whereby it would purchase the entire extractable reserves of a field. By its nature these contracts last the full life of the field,

[8] Ofgas, op. cit. pp.40-2.

[9] Société Générale Equities, "British Gas: the Demerger", March 1996, p.16.

although they will be subject to revision if additional development of the field is possible at a later date. These depletion contracts contrast with supply contracts used elsewhere, such as Continental Europe, in which the life of the contract and the volume quantities are clearly specified.

UK gas contracts are complex and non-uniform but they contain four basic features relevant to an understanding of today's market. These are an annual contract quantity (ACQ), a swing factor, a take-or-pay clause and a price escalation index. Gas contracts are also confidential so that the specifics of these features for each particular contract are not known, but certain generalities can be stated.

The ACQ specifies the volumes which the buyer expects to take from the producer over the full year. However, because of the seasonality of demand and because natural gas is expensive to store, the buyer will not accept volumes at a regular rate throughout the year. It will negotiate to take maximum output during the winter and less in the warmer seasons. The ratio of peak offtake over annual average offtake is referred to as the swing factor. The higher the swing factor, the greater flexibility the buyer has for matching supply and demand. To producers, however, a high swing factor means that the field (or ACQ) is producing well below its maximum potential and the pay-back on investment will be slower. As a result there should be a premium on high swing gas over low swing. This can make comparison of unit gas prices problematic.

Swing factors vary from field to field. For example, a producer can offer limited swing from an associated gas field since it would impact on liquids production, whereas a non-associated field may be more flexible in its production profile. High swing is also unsuitable for fields which are distant from shore because it means that expensive offshore pipelines are left idle at non-peak times. Hence the non-associated gas fields in the southern North Sea have swing factors of around 167 per cent; associated gas fields in the more northerly offshore waters have lower swing factors nearer 125 per cent.

The swing factor provides flexibility of offtake for British Gas for different periods of the year. It is a form of seasonal demand management. It does not however provide any flexibility over

the total level of offtake over the course of the year. BG cannot know in advance the precise level of demand for a single year: it is a utility which is obliged to meet residential demand whatever it may be, and since demand is weather affected, demand will be stochastic. As a result, BG must agree with producers a flexible arrangement whereby it may take above or below ACQ depending on circumstances. On the other hand, producers do not want to develop fields if BG over-contracts and then nominates, for reasons of demand matching, only a small percentage of production capacity. The buyer requires flexibility: the seller wants a floor level of guaranteed revenues. The solution to this problem was the take-or-pay provisions. These clauses state that BG must pay for a certain minimum level of production whether this production is required or not. If it is not required in the present year, the gas remains in the ground pre-paid and can be called on by BG in the future at no additional charge.[10] Take-or-Pay is generally said to be set at about 85-90 per cent of ACQ. Hence if demand for BG gas was 10 per cent less than expected, this should be manageable within the contracts. BG merely buys at the bottom end of contractual limits and it is the producers who may suffer by seeing the delayed production of their reserves.

Take-or-pay clauses were considered necessary to guarantee the investor a future revenue stream. Investment in gas fields is capital intensive and front-end loaded and, once made, their success is entirely dependent on the customer at the other end of the pipeline. Unlike a transportable commodity, such as oil, gas was dependent on a target market and therefore involves greater risk. These risks required some form of security. Without the guarantee of a secure market, in this case BG, many gas field developments may not have been undertaken.

The corollary is that producers required a strong, financially secure gas company capable of underwriting their investments over the life of the asset through take-or-pay agreements. BG is believed to have take-or-pay obligations extending into the future amounting to more than £30 bn. It has often been argued that only a monopoly with its unique ability to plan a market, could have made such purchase commitments.

The final component in these contracts is the price escalation clause. On the signing of a contract

[10] Usually, any gas paid for but not taken is effectively stored in the field as described above. There may be a few contracts however, where no future delivery is made and the gas payment is lost.

the parties agree both on a starting price and an index which will be used to adjust the price in future years. The indexation is linked in varying proportions to inflation and the cost of competing fuels. Through the careful construction of indexation, the contractees aimed to ensure that the cost of gas supplies remained competitive with substitute fuels and also gave producers an acceptable netback.

A feature of this pricing mechanism, peculiar to the UK, was that there were no price re-openers. The price of gas for each contract is worked out from year to year without any reference to outside conditions other than those already written into the escalation clause. There is nothing to stop prices diverging from market levels. In Continental Europe, by contrast, regular price reviews are written into almost all international trade contracts. In the light of today's circumstances, BG must regret the absence of revision clauses, but their adoption was not popular with producers who feared they would be used by the monopoly to squeeze out all economic rent. Producers would not therefore accept price re-openers voluntarily, and had BG tried to impose them uniformly, regulatory authorities would have seen it as an abuse of monopoly power.

Given the absence of price re-openers, BG has a portfolio of gas supplies from fields of different ages with divergent prices. The starting price for each field has varied according to the level of energy prices at the time the contract was agreed. Since then the prices have adjusted following the paths pre-set by their escalation clauses. While the average cost of gas for BG is around 19p/therm, prices for different fields vary, perhaps, from 8p/therm to more than 25p/therm.

This implies that the average price for gas sold will also vary between producers. Shell and BP have both maintained that their average gas price is around 16p, some 3p below the average price. Conversely, some producers must be receiving a price well above 19p. This non-uniformity of treatment means that different producers will face different implications from any adjustment in contracts. It will realistically be all but impossible for producers to spread evenly any financial loss arising from renegotiation and this makes any piecemeal, voluntary renegotiation all the more problematic.

The market power position of BG with respect to its determination of UK gas depletion has

always been controversial. Producers argue that it used its market power to dictate upon them contract terms such as levels of swing and price. If producers were not prepared to "submit" to its negotiating position, BG could always enter negotiations with others, so that the gas of the first set was trapped in the ground and rendered almost worthless. The bargaining position of the producers was weakened further by the UK landing requirement which effectively prohibited the export of gas. Or in other words BG was thought to enjoy overwhelming market power in purchase negotiations. The producers have therefore taken a certain glee from BG's reported difficulties and great exception to the idea of renegotiation. They argue that having been subjected to low prices in the past, they should now be allowed to profit from prices above market levels.

A monopsony such as BG might indeed be expected to extract low prices, but this argument needs to be hedged with several qualifications. Firstly, as we have seen, the old contractual system had its advantages for producers as well as BG. They were selling gas into a secure market to a company with a high credit rating able to offer take-or-pay commitments guaranteeing their future revenues. BG took on the volume and reserve risk through its open-ended depletion contracts. Selling to a national monopoly utility must logically have reduced the cost of capital in upstream investment and, so, lower producer returns were in part the price of lower risk development.

A second advantage of the contract system is that prices were kept stable for consumers. The prices for gas from new fields varied enormously but, as a monopolist, BG could cushion customers from these swings. The gas cost component paid by residential customers has always been based on the average price of BG's entire supply portfolio, and not on the marginal price as determined by the most recent contract to be signed. As a result, consumers were sometimes paying above "marginal cost" and sometimes below. This may be an economically inefficient pricing system but it was socially preferable for a utility selling primarily to residential customers who dislike sharp price swings.

Thirdly, it was government policy in the 1960s and 70s to cream off any natural resource rent from gas reserves downstream rather than upstream. Thus when it became apparent in 1982 that BG was buying at very low prices, the government imposed a Gas Levy on its purchases from

fields pre-dating the Petroleum Revenue Tax (PRT). This levy on purchase rather than sales results in a discrepancy between the price a producer receives and the price BG pays. For example when Shell or BP maintain that they receive about 16p per therm, BG is in fact paying more for the same gas with government coffers pocketing the difference. Some producers may feel prices from the oldest gas fields are low but it should be remembered that these fields do not pay PRT. Comparisons should be made net of taxes.

During the 1980s government policy appeared to change with a shift more in favour of the oil companies. The government sought to maximize development of the UK North Sea for macro-economic reasons and then applied PRT. Furthermore, when the government in the mid 1980s banned the Sleipner deal whereby British Gas had hoped to contract additional imports of Norwegian gas, BG was arguably left in a position of weakness rather than strength. In the period 1984-90, the company had to scramble to contract sufficient volumes to meet a perceived demand shortfall and to compensate for the loss of Sleipner volumes. It was in this period that much of the most highly priced gas was bought. This does not seem to square with claims that BG could dictate terms on oil companies at will. A fairer assessment might be that in a buyers' market BG may indeed have enjoyed market power in purchase negotiations, but in a sellers' market, as emerged after the ban on Sleipner, the tables were turned.

It is possible therefore to mount a defence of the contractual system. The problem for BG is not the contracts themselves, but the fact that it did not link from an early stage (publicly at least) the future of these contracts with the removal of its tariff monopoly. Its binding purchase promises were made on the basis of a sure market to sell into. As soon as its future market share was placed into question by the possibility of competition, it could no longer underwrite developments with purchase commitments. Since the take-or-pay provisions were made possible by the existence of a territorial franchise, the removal of that franchise (the tariff market) as announced in December 1993 should have immediately raised issues regarding the future of contracts. The possibility had been raised in some quarters that BG could launch a legal challenge to the government's decision to abolish the tariff monopoly. (A pledge was made in the 1986 prospectus for the privatization of the company which arguably suggested BG would retain its monopoly). In the event, no legal challenge was mounted and instead the company welcomed demonopolization subject to the establishment of "a level playing field". The official

response of the company made no mention of its purchase contracts.[11]

[11] British Gas's formal response to the government's decision declared "The Government has stated its intention to commence a phased removal of the domestic monopoly from 1996. Although the MMC concluded that BG was not operating against the public interest in the tariff monopoly, BG is not wedded to the retention of the monopoly...We welcome, therefore, the measured and careful approach to opening up the domestic market to competition proposed by the Government". British Gas Press Information, 21 December 1993.

Chapter 2: Oversupply: the Causes

The Supply-Demand Balancing Act: Theoretical Perspective

Consideration of the basic economic characteristics underlying the gas industry reveals why a mature gas market can easily find itself in a position of oversupply and sharp price falls. In short, the gas industry combines low avoidable costs with inelastic demand. Thus where there is overcapacity a price fall does little to clear excess volumes and, equally, little to choke off potential supply.

On the supply side, both gas production and pipeline transportation tend to have high upfront capital costs with relatively low operating costs. From an economic perspective, we would expect producers to continue production of natural gas even when the price is not yielding a return on sunk capital. As a first simplifying step, we can state that production capacity should in a text-book free market model be fully utilized down to the point at which revenues no longer cover operating expenses.

Calculations have been made to determine at what point shut-in of fields would begin, if the gas market conformed to a hypothetical free market without contract prices. The operating costs for 1996 for each gas field were divided by the production to arrive at unit operating costs. In the case of associated gas fields, liquid credits based on a conservative assumption of a price of £8 per barrel are subtracted from the costs. The resulting figure gives the unit operating cost. The percentage of production which would be shut-in as the price lowers can therefore be induced and the results are shown in Figure 2.1. It turns out that over 90 per cent of production would be expected to continue at a level of just 6p/therm. The highest cost fields are within the 6-7p range, which means that no field would have an obvious economic need to shut-in production unless or until prices dipped to below 7p. Note also that for ten associated gas fields, natural gas has a negative opportunity cost - meaning that it will cost more not to produce than to produce - even under our conservative estimate for liquid credits, so that one-fifth of production is indifferent to gas price levels and expectations. It should be stressed that this exercise is theoretical. In practice, the situation is of course more complex: firstly, contract prices mean that most fields are unaffected by the level of spot or "market" prices; secondly, accounting, cash flow or tax considerations might justify shut-in above what strict economic rationale might

suggest. Nevertheless, the figures are given to demonstrate the potential insensitive response of short-term supply to price falls.

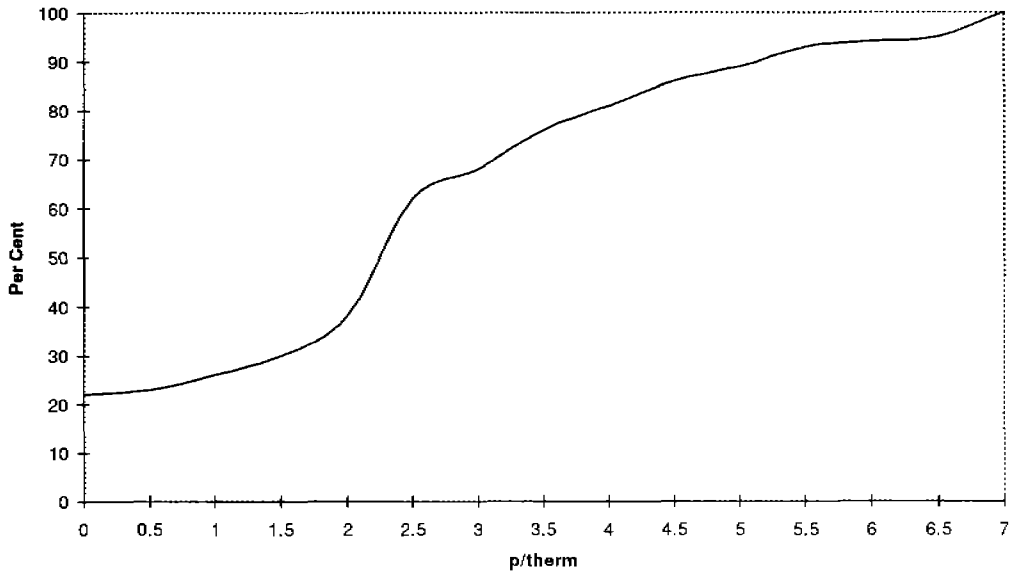

Figure 2.1: Percentage of Production Capacity Utilised at Avoidable Costs

At what point do fields break even? Capital costs were excluded from these calculations because they are not a variable cost. However, producers will obviously want to make a return on sunk capital and will need to pay off the interest on capital loans, so calculations are also given including capital costs. Figure 2.2 shows that, net of tax, most fields break even at low prices. Some 95 per cent of production is covering full costs at a price of just 13p/therm. At 10p/therm 80 per cent of production is covering costs.

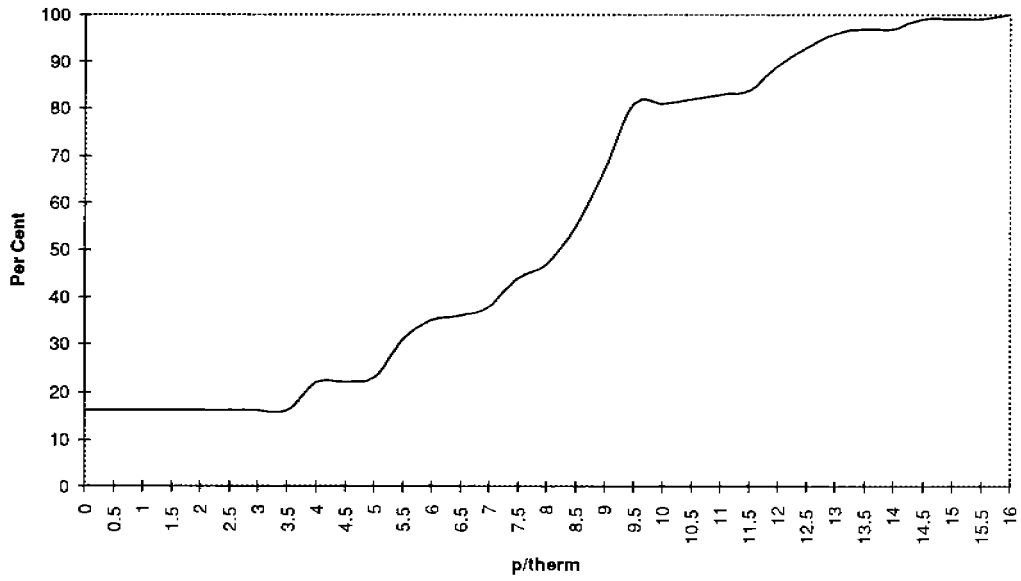

Figure2.2: Percentage of Production Capacity Utilized at Breakeven Point

Thus the economic characteristics of the gas business mean that operators will want to use production capacity at a high rate of utilization. To make matters worse, in the gas industry periods of excessive investment in capacity are in fact almost inevitable because of the indivisibility of investments and the high level of economies of scale. The capacity of pipelines, for example, increases faster than their material and laying costs. This gives investors the incentive to build excess capacity at little extra cost to allow for the possibility of volumes being greater than expected. The important point is that a decision must be made on the size of the line at the point of construction even though a pipeline can have a life of at least 25 years.[1]

Petrochemicals and refining are other businesses within the oil and gas sector which exhibit the same traits of lumpy investment, scale economies and high upfront capital costs. Experience has been that these industries are cyclical. They typically run on the slenderest of margins in an environment of excess capacity for some years until a capacity constraint is finally reached. This yields a short period of high profits but is normally accompanied by excessive market entry in incremental investments leading back to a low margin business. A similar pattern might be

[1] The addition of compressors at a later stage, and the possibility of looping give some slight scope for increasing capacity as and when required in small packets. However, compression soon becomes expensive.

expected of the gas industry except that the cycles will be shorter and seasonal. Production at levels below total costs could take place for much of the year but, at periods of peak demand, producers may recover their fixed costs.

Before leaving the supply side, we need to consider an important complicating factor which may help to shut-in production above simple operating cost and therefore goes some way to counter-balancing the above arguments. The gas reserves in a field are finite so that the production and sale of each unit represents a reduction in the overall stock. Hence, even if the sale of a unit of gas were made above operating cost, a producer would still hold back production if it was calculated that the same unit of gas could produce more profit in the future. We might term this extra value a "depletion allowance". The existence of a depletion allowance normally implies that expectations of future rates of price increases should exceed a value of money indicator such as expected interest rates.

The importance of the depletion allowance will depend on the age and reservoir conditions of each field. For older fields whose production may already be in decline the allowance could be significant if there is an expectation of imminent rising prices. In this case, a unit of production foregone today can be made up easily tomorrow since the production decline of the field is delayed. For fields which are either working up towards plateau levels or are producing at plateau, the same logic does not necessarily apply. A unit of production foregone by these fields may only be replaced towards the end of the field's life and the net present value of this unit of gas produced so far in the future will be negligible, if we assume a level price in real terms. Thus the producer will see no incentive in preserving their stocks of natural gas for later use. In other words the point of shut-in for many fields, especially the newer generation, will be effectively equivalent to operating cost. In the case of associated gas fields, where the revenue from liquids is driving the economics of the field, gas will have an even lower value. Moreover, shut-in of production can at times adversely affect the natural pressures of the reservoir, with the result that the overall volumes of recoverable reserves may actually be reduced. All things told, there is a stronger incentive on producers to keep producing than to hold back.

Yet the ability to produce depends also on the ability of the market to absorb the volumes. Turning to the demand side, gas use has a low short-term elasticity because of the dependence

of consumers on their chosen capital stock. Although the domestic sector has shown a consistent increase in number of customers and volumes consumed (on a weather adjusted basis) as more customers are added to the pipeline network and others switch their heating or cooking appliances to gas fired ones, a price drop will do little to accelerate this process and the removal of BG's monopoly over domestic supply could also weaken the incentive to expand the network. Those residential customers who already use gas, are unlikely to "turn up their boilers" because of lower prices. The only customers whose gas consumption levels are determined by capital constraints are the poor and elderly who may be expected to be the slowest in responding to cheaper prices in the competitive market. In the industrial and electricity generating sectors, many factories and power stations have dual-firing capacity and can therefore switch more readily. However, these companies already use gas on an interruptible contract and switch to alternative sources only when supply is cut by the provider. Their preferred choice of fuel is therefore gas, implying that gas is *already* priced so as to be competitive with substitute fuels. The demand elasticity of gas is therefore probably asymmetric: a price rise could lead to a quick shift to alternative sources, making use of dual capacity facilities, and a price fall will not affect choice of fuel to the same degree.

Given this combination of heavy upfront costs and a weak demand response to price, it should have come as no surprise that prices fall sharply. This has been the experience in those markets which have opened up to competition, whether in North America or the UK. Yet the price fall in the UK did come as a surprise because the institutional structure had previously prevented the problem of oversupply.

The above economic characteristics had not come to the fore in the UK prior to 1995 because of the control over depletion exercised by British Gas. The means for the exercise of this control were its long-term contracts. The take-or-pay terms in these contracts guaranteed a minimum level of revenues to the producer, upon which to justify a large capital outlay. However, the flexibility in delivery levels written into the contracts enabled BG to stop the market from collapsing from excess supply. The signing of depletion contracts, as opposed to supply contracts, meant that the entire reserves of the field had been bought by BG, and as a result any excess production potential could not be sold on a wholesale or spot market to other customers, but had to be shut-in awaiting offtake by the buyer. Hence, there was often a situation of excess

production capacity but producers could not realize this production because they were contractually constrained. Whereas production appeared competitive because of the number of players, offtake was monopolistically controlled. This stopped prices from collapsing to avoidable cost levels.

The above analysis does not necessarily imply that the contract system maintained prices at an artificially high level. Under these contracts, BG was underwriting the development of fields and without such contracts it is conceivable that certain investments would simply not have been made, leaving some customers dependent on more expensive alternative fuels. The contracts were an effective means of overcoming the "hold-up" problem. Where an investor is required to sink capital and then sell to a single buyer, there is always the concern that with the capital sunk, the monopsonist will negotiate the original investor down to avoidable cost. Given this threat, the investor will avoid a commercially viable project unless, either a contract ensuring price is made, or there is some form of common equity between buyer and seller.

Thus contracts held the market in balance, defying the innate economic tendencies of the industry. Below, we explain how this balancing mechanism was undone. The factors involved are divided between supply considerations and developments on the demand side.

Supply Determinants

Market sentiments changed dramatically around 1992/3. During this period, a large number of new fields were developed on the basis of contracts either with power generators or with the new marketers. These developments were necessary, it will be recalled, in order to enter the market given the lack of available prompt supplies. Most of the gas immediately available at the time was release gas from BG's own portfolio of supplies. Competitors sought their own supply in order not to be reliant on BG in the future. The prices agreed in long-term contracts for new fields in 1992/3 were broadly in line with BG's own purchase costs; some are known to have been higher. BG's competitors did not appear to have a competitive advantage in terms of gas costs.

It soon became clear that the production capacity which would result from these new projects

would be in excess of requirements. Each marketer was aiming at a particular percentage share of the competitive market and the sum of these market shares was greater than 100. This did not deter entry since, besides simple economic calculations of returns, upstream companies and their marketing affiliates saw strategic advantages in entering the deregulated gas market. They sought to gain a foothold.

What might have been an obvious impending oversupply was masked by the concomitant surge in demand for gas in the power generation sector. The huge prospective increase in gas demand within this sector made it seem unlikely that supply would out-strip demand. However, power generators tended to over-contract for gas in the safe knowledge that any excess supply could be wholesaled easily enough in the deregulated industrial market.

Power generators were significant for a second reason: they were the first consumers whose demand levels were big enough to underwrite entire fields. A typical medium-sized power station of 600 MW capacity, running on 70 per cent load factor, might require an input equivalent to 75 Mmcfd, that of a small to medium-sized field. Power generators were therefore ideally placed to by-pass BG and contract their own supply.

It was inevitable that the entry of power generators would complicate, and ultimately undermine, the neat supply/demand matching of the past. This "disruptive" influence was well illustrated in the case of the Anglia gas field. Anglia's development was originally targeted for use in the South Denes power station. This project was later abandoned but the field development was well advanced. As a result Anglia gas, originally earmarked for power generation, was snapped up by gas marketers for sale in the industrial sector altering the supply/demand balance radically.

While power generators were ideally placed to contract the full output - or at least a large tranche - from a medium-sized gas field, the marketers sought smaller packets of supply. (Indeed, developing a large gas field on the back of a raft of contracts with various small players, all requiring careful credit analysis, was problematic and this complication was often used to justify the existence of a monopoly purchaser.) This new interest in small packets of demand came at a time when the North Sea was able to offer small packets of supply as a result of the maturity of the province and developments in upstream technology. Most of the largest fields had already

been developed by the 1990s. Much incremental production in the 1990s has, or will, come from small satellite fields, with a large proportion located within the southern North Sea. These have become economic because of advances in horizontal drilling, deviated wells and under-water technology. They are also able often to tie-in to existing pipeline infrastructure at considerable cost savings. Often they have lead-times as short as 24 months, sometimes less.

These mini-satellite developments were ideally suited to by-pass BG and supply new marketing companies. Indeed, the necessary investments are small enough that even speculative developments, which have not pre-sold the gas under contract, can be entertained. The twin combination of deregulation downstream and supply fragmentation upstream produced a revolution in contractual relations and financing schemes for natural gas. And with it, they complicated depletion management, supply forecasting and demand matching.

The loss in supply management was made worse by a policy change in the use of BG's own reserves. BG E&P had a low level of production relative to the size of its reserves. This was felt to be an inefficient handling of inventory levels and a decision was made soon after privatization to reduce the company's reserve to production ratio from 60 to about 20 years, bringing BG more into line with other producers. The policy inevitably revolved around the large Morecambe South field. Morecambe South gained its Annex B development approval in February 1982, before any serious attempt had been made to form a competitive gas market and when BG was still publicly-owned, still had a public service role, not a profit-maximization one. Morecambe was designed at that time as a peak shave field which would help meet daily and seasonal swing patterns. Between 1985 and 1989, annual production oscillated between 10 and 121 Mmcfd. Because of the high upfront capital costs (£1.6 bn) it is doubtful that this use of Morecambe maximized possible profits or accelerated pay-back. Around 1990 it was decided that Morecambe should provide base-load gas. The additional investment required was small but the increased production capacity from Morecambe must have increased the net present value (NPV) of the field. Since 1990 Morecambe annual production has been between 465 and 800 Mmcfd, making it the single largest producing field in the UK. The decision to develop Morecambe North further added to BG's supply portfolio and further reduced its swing capacity. Morecambe North was granted an Annex B in 1992 and was developed as a base load field. It came onstream in late 1994.

Whether BG was right to develop Morecambe South into a base load field and then to develop Morecambe North remains a moot point. With the benefit of hindsight, production from Morecambe Bay has certainly played a role both in the oversupply in the market and in the reduction of the swing potential of production. On the other hand, these fields are not the most expensive in terms of total costs and therefore should have been developed. Furthermore these decisions were all made prior to any decision to open up the residential market to competition.

Controversy over Morecambe Bay intensified during 1995. Not only was Morecambe exacerbating oversupply, but BG was also purchasing volumes above minimum contract quantities. Thus while BG was running up its take-or-pay banks with third-party producers, it was in effect drawing down unnecessarily its inventory levels in Morecambe. This had the effect of making any take-or-pay problems seem worse than was the case. In 1994 BG purchased approximately 200 Mmcfd above minimum contract and in 1995 the figure was about 250 Mmcfd. Hence the offtake contributed 50 TWh to BG's take-or-pay bank.[2] Nevertheless Ofgas maintains that this form of portfolio management probably did have the effect of lowering BG's overall average purchase costs and cannot therefore be easily condemned.

The contract for Morecambe gas is arranged so as to encourage maximum offtake. The price is believed to be based on a two-part tariff with a fixed annual payment and a unit price. This structure gives a large weight to the fixed payment and so there is an incentive towards maximum purchases, since each extra unit purchased is cheap even though the average unit price is high. It leads to the curious situation that Morecambe, while being one of the most highly priced fields, is towards the front of the offtake merit order.

All the above factors - excessive market entry, power generation, satellite field developments, BG's own increase in production - conspired to produce, or make possible, an excess in supply. It should be remembered, however, that not all events acted towards the oversupply. The government's continued opposition to Norwegian imports, for example, ensured that oversupply was less than it might otherwise have been. Extant Norwegian supply contracts could have added a further 200 Mmcfd onto the market.

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[2] Compare with Ofgas, op cit, vol 2, pp. 17-18.

Demand Determinants

Not only was supply clearly above expected demand, but demand itself fell short of expectations in 1994 and 1995. Abnormally mild weather has been a significant factor in denting demand. The winter months of January, February, October and November all recorded average daily temperatures for 1995 below the long-term mean. British Gas has apparently argued that weather was the single most important factor and claims that two-thirds of the take-or-pay bank has arisen from low demand in the weather-related residential sector. Ofgas has arrived at a very different estimate, believing that 15 per cent of the take-or-pay bank has arisen from the weather, equivalent to 18 TWh.[3]

Over the 10 years since privatization, average consumption per domestic customer has averaged 18.24 MWh. In Table 2.1 the difference has been calculated between this average and actual consumption as recorded in 1994 and 1995, and then multiplied by the number of customers. For the two years combined, consumption has been 15.6 TWh below the average expectation, or 13 per cent of take-or-pay bank. Loss in demand of 12.6 TWh in 1995 is equivalent to 1.5 per cent of the market.[4]

Table 2.1: Impact of Weather on Residential Gas Demand

		1994	*1995*
Expected Consumption per Residential Customer	MWh	18.24	18.24
Actual Consumption per Residential Customer	MWh	18.08	17.56
No. Of Customers	millions	18.36	18.54
Demand Shortfall	TWh	2.94	12.61

Compounding problems from the mild weather, there were late start-ups to several gas-fired power stations. It emerged in 1995 that some General Electric turbines had a design or assembly

[3] Ofgas, op. cit. p. 46.

[4] BG appear consistently to overestimate the effect of weather. In their financial and operating statistics they have adjusted domestic consumption up for weather every year since 1989. See *Financial and Operating Statistics 1995*, p.27.

fault which delayed the completion of several power stations. The main stations to be affected were Keadby (680 MW), Little Barford (680 MW) and Medway (600 MW). The first two were due onstream by the end of 1994 and Medway was expected to be fully operational by mid-1995 but all three were plagued by problems throughout most of the year.[5] The three stations are all believed to have supply gas contracts with British Gas, which would amount to a loss in expected load of 26 TWh. This would have added a further 3 per cent to overall national demand.

Conclusion

During the course of 1995, BG was no longer able to maintain the supply/demand balance of the UK market within the flexibility of its own contracts. A number of factors emerged both to inflate supply and to depress demand from what might have been expected. Many of these were beyond the control of BG and were perhaps the inevitable consequence of a fast-moving, complex deregulated market.

It is possible to single out three factors which are only temporary in nature. They are the purchase of Morecambe gas above minimum contract quantities; the mild weather and the delays in power station completions. The volumes involved for each have been quantified and are summarized in Table 2.2.

Table 2.2: Temporary Supply/Demand Imbalances, 1995

	TWh	*Percentage of Market*
Excess Production (Morecambe)	27.5	3.3
Power Station Delays	26	3
Mild Weather	13	1.5
TOTAL	66.5	7.8

The temporary factors together dented demand in 1995 by 8 per cent. This percentage should have been controllable within BG's contracts where tolerance levels are 10-15 per cent below ACQ. Combined with the more permanent oversupply pressures - most obviously excessive

[5] *Inside Energy*, 3 April 1996, pp. 8-9.

market entry - the situation became uncontainable.

If it were not for these three factors, spot market prices would clearly have been higher and the market itself would have had little liquidity. The spot market in 1995 was variously estimated to involve between 5 and 12 per cent of the overall market. Thus, with these temporary influences overcome, over half the spot market would immediately dry up - possibly all excess supply could have been absorbed. This raises the key question to be explored in the following sections: how long will BG continue to be long in gas?

Chapter 3: The Spot Market and its Significance

Sales of short-term gas in the UK can be traced back to late 1992. However, prior to 1994, such trades were rare. Some of the earliest fields not to be contracted to BG came onstream in 1992/3, but gas outside BG's portfolio was in such short supply that it was usually held onto by the original buyer and did not find its way onto the wholesale trading market. The other principal source of gas to market entrants in the period prior to 1994 was BG's own supplies made available through the compulsory release gas scheme. The beginnings of a regular market in short-term gas go back to around the beginning of 1994 as a small number of bilateral telephone trades began to be struck. Trading remained thin and opaque through 1994 but took off in the first quarter of 1995 as the oversupply hit the beach and prices began to fall.

A market requires a degree of transparency and the first price reporting service, *British Spot Gas Markets*, was set up in March 1995. *Petroleum Argus* began reporting prices in September and their basic reference price has been published daily in the *Financial Times* since April 1996 in the London spot markets section. *World Gas Intelligence*, in cooperation with Quantum Energy Derivatives, has published a twice-monthly assessment since August 1995.

Gas trading tends to take place at the key beach terminals which receive offshore supplies and inject it, after any necessary treatment, into the National Transmission System. Four terminals lie on the English east coast stretching from Bacton in Norfolk via Theddlethorpe and Easington up to Teeside. The St Fergus terminal in Scotland receives most of the gas from the more northerly fields including Norwegian imports, and Barrow receives gas from the Irish Sea. In terms of volumes, Bacton and St Fergus are the most important terminals accounting for some 22 and 36 per cent of deliveries respectively. Most of the spot trades occur at these two points, although Bacton is the more active. Bacton is located both nearer to the gas fields and nearer to the bulk of demand, and therefore has greater flexibility. It will also be the entry point for Interconnector gas headed for Continental Europe, so that it looks well-placed to become the principal hub for future trading. St Fergus gas tends to trade at a slight discount to Bacton because of its position displaced from demand. As well as these terminals, some trades are made at the notional National Balancing Point within the pipeline system.

The size of the spot market cannot be known with any degree of certainty. Nevertheless industry

sources give an estimate of between 5 and 12 per cent of the overall market in the period 1995 to April 1996, with growth through the period. If the supply to the residential sector is taken out, this is equivalent to between 9 and 22 per cent of the part of the market open to competition. Since April 1996 the market has, however, lost liquidity.

Participants within the market come from all branches of the industry. The gas marketers or shippers and power generators are the most obvious grouping since they seek to match their supply sources with their current level of demand. Some of the largest industrial consumers of gas have acquired sufficient market knowledge to purchase directly themselves through the spot market. Some producers are trading where they have uncontracted gas; others have apparently been cautious in using the markets. As a rule more trading is perhaps done through their downstream marketing affiliates than directly by upstream producers. Financial institutions with experience in trading, as well as some oil brokers, have lent extra liquidity to the market. Finally, a leading role is believed to have been taken by Accord Energy, a joint-venture set up between British Gas and Natural Gas Clearinghouse with the aim of taking advantage of trading opportunities.

Short-term trade deals vary in terms of duration and forward starting point. Spot price assessments exist for gas sales one day ahead and continue into forward prices extending into mid-1997. It is believed that over half the deals made are for "Balance of the Month" or "Spot Month" (delivery in the following month). At the point of writing, the market is in contango with half-year forward prices trading at a 2p/therm premium to prompt. Traded volumes are typically in the range of 25-50,000 therms per day. All trades have been over-the-counter in an informal, unregulated market. The International Petroleum Exchange has plans to set up a formalized exchange with a screen-traded forwards market, with the launch expected before the end of 1996.[1]

Besides these markets there is the flexibility market which BG Transco uses to balance its system on a daily basis. The flexibility market came into existence with the start-up in March 1996 of the Network Code, which is a detailed set of procedures which BG Transco uses to maintain

[1] S Esau, "Britain Prepares for New Gas Trading Era", *Gas Matters*, January 1996, p.7.

system pressures, to monitor individual shippers' use of the pipelines and to set up a charging and bidding system to collect revenues from the shippers appropriate to their use of the system. Prior to the Network Code, shippers had not needed to keep their level of inputs in close relationship with their level of demand and they were not rewarded or penalized for their effect on overall system balancing. Since March, shippers have been expected to keep their supply/demand balance within certain degrees of tolerance, and are liable to charges for slipping outside the prescribed match. The Code operated in a preliminary phase from March in which balancing requirements and financial penalties were relatively lenient. From September, more rigorous rules have been applied, the full effects of which remain to be seen.

Trading in the flexibility market is intra-day and, based on immediate system demands, can be highly volatile. Indeed there had been a disconnection between weak spot prices and high prices obtainable in the flexibility market. At a point of system stress, prices for flexibility gas have risen as high as £1.40p/therm. More recently there appears to have been a convergence between "spot" and flexibility prices as one would expect in a functioning market. One reason for the recent rise in spot prices could be that sellers have identified advantages in withholding supply and bidding instead into the flexibility market at the last moment.

The relevance of flexibility to short-term trading has therefore been twofold. Firstly, there is some evidence that the market for flexibility gas has acted as an upward influence on prices in the spot market, and that the application of tougher balancing rules could lift flexibility prices further with the impact again feeding through to spot supplies. Secondly, the flexibility market has led to reduced liquidity in the spot market, which can only have the effect of giving BG greater market power. Indeed consultations have been going on between Ofgas, BG and other shippers to try to remedy the loss in liquidity.

The development of the spot price, set against other key prices, is given in Figure 3.1. The gap which opens up between BG's WACOG and the reported spot price in the second quarter of 1995 is clearly shown. The top line shown is the average price paid by UK industry for gas prices. Industry prices will be above beach prices in order to cover extra transportation and transaction costs. Nevertheless they appear to move in close correlation with the spot price with the suggestion that spot prices, however marginal or "fringe", are having a direct impact and

pass-through effect on competing end prices. In contrast to industry, the price paid by major power producers tracks more closely BG's WACOG. This underlines the fact that, as well as BG, many power producers also bought supplies under long-term contracts with prices around the 18-22p/therm level. The individual points refer to different recent long-term contracts. It is clear that new long-term gas has been bought up at prices well below WACOG, but never dropped to the levels seen in spot trading. Finally it should be remembered that border prices in Continental Europe as at July 1996 were 17.5p/therm ($2.82MmBtu).

A closer comparison of spot relative to contract prices provides clues as to why BG was slow to recognize the threat of oversupply. At the start of 1994, spot gas was trading around 22-23p/therm. This was selling at a premium to BG's WACOG of 3p/therm. Perhaps a spot market had not emerged earlier because a higher premium did not offer any arbitrage or sale opportunities. At the time when the lifting of BG's monopoly over supply of the residential market was announced in late December 1993, BG appeared to enjoy a cost advantage over its competitors: their supplies were cheaper than those obtainable in the market. This may explain why BG did not openly argue that the introduction of full competition in supply ought to be linked to relief in its contractual provisions, on the grounds that the latter were made on the assumption of a continuing monopoly role.

In the first half of 1994, the Armada contract was signed. The purchase of these volumes, of which BG allegedly contracted a part, were at the time competitive with spot supplies, the price standing at a discount. In late 1994 the contracts for the Britannia field were finalized at prices believed to be below both BG's WACOG and spot prices. Despite extensive negotiations for supply, BG is not thought in the end to have contracted any supply. By mid 1995 the full gulf between BG's WACOG and spot prices was established and BG began to press for renegotiation. The winter did not bring relief to BG as the spot price continued to languish within the 10p range and showed no seasonal fluctuation. This was presumably a sign of the complete supply saturation of the market: a rising demand in winter does not produce a price response, instead it is apparently met by rising supply which was previously kept off the market. More surprisingly still, with the advent of spring and summer prices have risen.

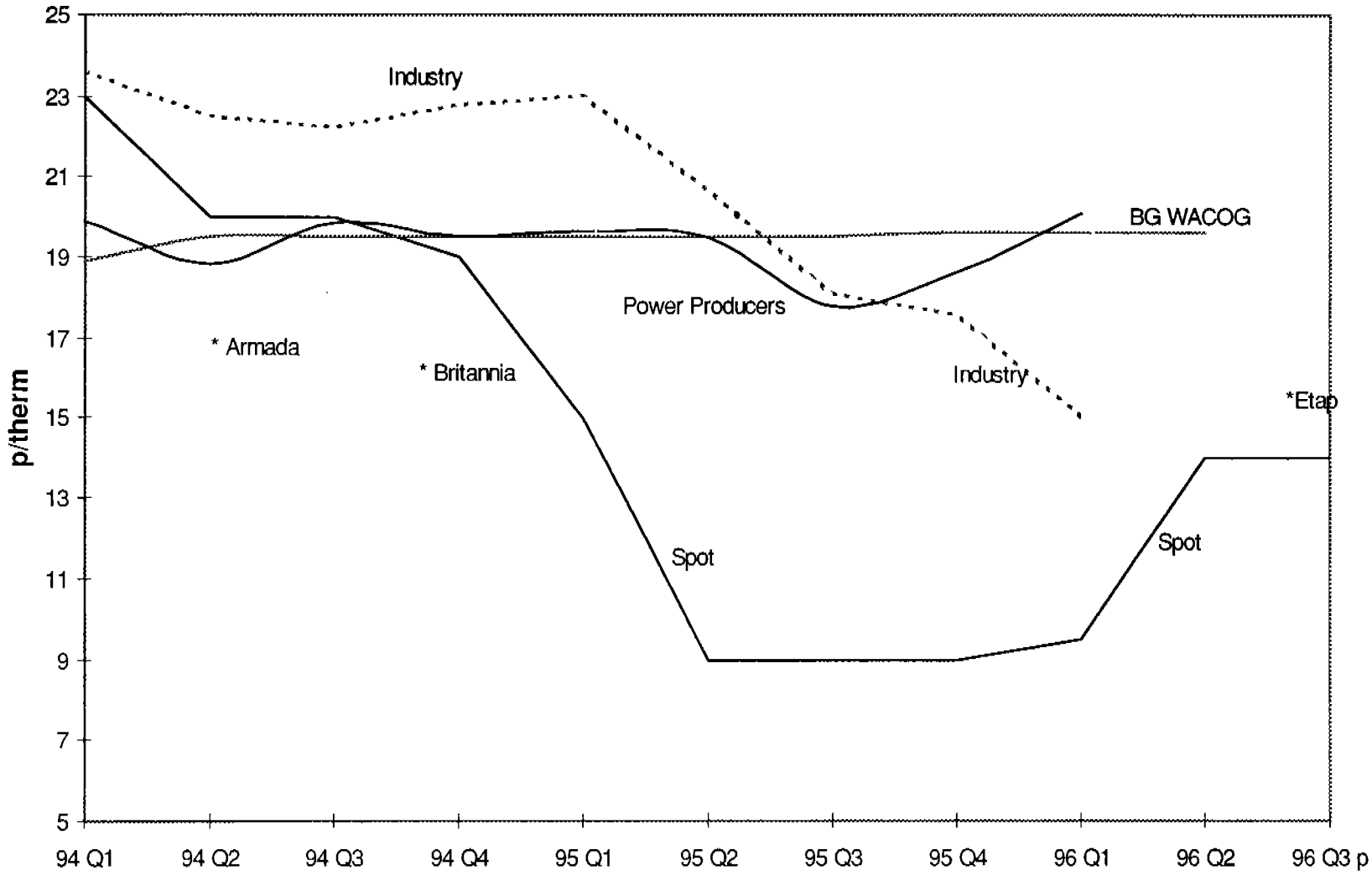

Figure 3.1: Spot, Contract and Wholesale Prices

Three important caveats are required when comparing directly BG's WACOG and spot prices. Firstly, the level of WACOG is distorted upwards by a high transfer price for Morecambe gas. Secondly, BG's supplies have a greater swing making them more valuable. Thirdly, BG's WACOG locks in future prices.

BG's officially recorded WACOG includes sales of gas from Morecambe North and South between BG E&P and BG Trading. The average unit cost of gas from these fields is believed to be above average prices. By using a standard industry assumption for the price of Morecambe gas, it is possible to calculate the average cost of gas to BG with Morecambe netted out. Calculations suggest that the "real" cost of BG supplies is approximately 1p/therm lower than WACOG.

Information on swing remains non-transparent at present. It is known that BG has a supply portfolio with greater swing in order to meet the volatility in demand of the residential sector. Its competitors have contracted gas at lower swing levels both because their demand is more constant and because their supplies from the central North Sea do not lend themselves so readily to swing. Central North Sea production is too distant from the shore and is tied to liquids production. The price for gas in most contracts whether with BG or its competitors is normally bundled, meaning that no separate charge is made for the commodity and the level of swing. Ofgas has tried to unbundle price and has calculated that supply to the residential market justifies, because of the higher swing, a supply cost premium of 1.5p/therm over the rest of BG's markets. In other words the value of swing turns out on present reckoning to be significant but not substantial. Extrapolating from this, the extra swing in the BG portfolio, compared to its competitors, can tentatively be estimated to be worth around 1p.

Coincidentally the inflation of WACOG through Morecambe sales and its understatement because of swing more or less compensate for each other, with the result that BG's WACOG is after all a fair comparison to other cited prices.

Finally, it should be noted that until May of this year, there was a big discrepancy between short-term traded supply and the price levels agreed in new long-term contracts. The long-term contracts signed since the fall in spot prices have, it is thought, agreed on starting prices in the

range of 12-16p/therm. This demonstrates unsurprisingly that 10p/therm was never seen as a realistic price for longer-term gas, particularly post-1998. In the last couple of months there has been a convergence between short-term and longer-term prices. The Etap fields are believed to be the most recent significant development project to have agreed long-term contracts, and the starting price is believed to be above spot levels but continues the trend of a slight decline in the price for long-term gas as compared to Britannia and Aramada. It follows from the above, that BG is trapped into contracts which are more accurately some 4p/therm above market prices (the difference between WACOG and new long-term supplies), and not the headline figure of 10p/therm (the difference between WACOG and 9p spot). The potential losses of BG in the longer-term depend on the difference between the costs of its supplies and competing prices for supplying into Continental Europe. This issue is explored in Chapter 4.

The significance of the spot market has been much disputed. At one extreme, the effects of spot sales have been played down. Volumes available on the market are limited and represent only a few imbalances between supply portfolios of different players. It is suggested that these prices have no wider relevance to the market, being unrelated to cost and insufficient to support new field developments. At the other extreme, spot prices have been identified as the "true" market value of gas. It is argued that however small the volumes, as the marginal source of supply, spot gas will direct other prices. It is pointed out that the emergence of active short-term trading markets for other commodities has always started in a similar guise; they are usually met with scepticism and resistance at the outset but their influence becomes all pervasive.[2]

It is probably correct that spot prices will have an effect on end-consumer prices disproportionately large relative to the size of the spot market. The effect on industry prices is already tangible. It is also true that the spot market as a form of balancing supply and demand portfolios between different shippers will remain and grow as competition grows. It is however incorrect that the spot market yet represents a meaningful market price. The market lacks liquidity and British Gas retains overwhelming market power with the ability to influence spot levels through its operation of the Morecambe Bay fields and the management of its take-or-pay banks.

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[2] See J Roeber, "The Development of a UK Natural Gas Spot Market", *Energy Journal*, vol 17, no. 2, 1996.

First of all it needs to be understood that if BG is long in gas - meaning that it cannot place the volumes it is committed to buy - it makes no *economic* sense to off-load volumes onto the spot market. There may be reasons of cashflow, account reporting, strategy or even "playing the market", all of which justify BG selling such volumes, but spot sales will not relieve its oversupply. It merely gives its competitors additional gas at a discount to BG's gas with which they can take more of the market. Stated simply, each therm released by BG is used by competitors to take away a therm of BG's client base, leaving the company just as long as before.[3] One might just as well try to lower the depth of a swimming pool by scooping buckets of water from the deep end and emptying them in the shallow end.

It was observed earlier that industry estimates of the size of the spot market during 1995 were between 5 and 12 per cent of the whole. Production by British Gas from Morecambe Bay, however, was 961 Mmcfd, or 13 per cent of UK production. It is therefore very likely that the excess supply, symbolized by the spot market, could be drained by reducing production from Morecambe. It also highlights that BG could have chosen to sell its third-party take-or-pay gas and instead cut back on Morecambe. By regulating output from Morecambe and acting as swing supplier, BG can influence, if not determine, short-term supply availability and spot price levels. British Gas is not a free agent. It has to act within the parameters of contractual obligations, Annex B pledges and general competition policy, but it has within these parameters considerable discretion or leeway.[4]

By reducing Morecambe production and drawing instead on spot supplies, the spot market price would be pushed up. Indeed, this is precisely what has caused the more recent rise in spot as BG has apparently turned down offtake from Morecambe. If the spot price were brought into line with BG's own gas costs, competitors would no longer be able to undercut BG so readily. A point will soon be reached when it is not possible to buy spot gas at a competitive price and profitable expansion of market share for BG's competitors becomes impossible until new

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[3] Lower selling prices will slightly expand the market, but the short-term elasticity of demand for gas is assumed to be low.

[4] Ofgas is concerned about the possible influence over spot prices of restricting supply and has set up an enquiry to monitor production behaviour. "Ofgas inquiry into 'price fixing'", *The Guardian*, September 23 1996, p.15.

supplies come onstream.

It does not follow that BG's problems are of its own making. Rather, that BG can choose between selling gas at a loss (either on the spot market to its competitors or by selling to customers at a loss) or holding back supply. It is the classic cartel choice between a low price/high volume or a high price/restricted output strategy. Both incur a cost to BG. The important detail regarding spot prices, however, is that the company cannot help but influence them depending on which strategy it employs at any particular time.

In conclusion, the spot market is a reflection of BG's exposed position in an oversupplied market. Nevertheless, it cannot be considered a meaningful indicator of the true market value of gas since it is only one of two ways (selling at a loss or running up take-or-pay banks) in which BG can suffer its losses. Because its own actions and strategy affect the level of supply and the price of spot gas, spot assessments cannot be used as the basis to estimate BG's liabilities. The following chapter uses a different methodology to estimate these.

The short-term outlook for spot prices will depend on BG's chosen management of its supply portfolio. Insofar as BG is allowed, we would expect it more likely to opt for the restricted output scenario and therefore the balance of factors looks likely to support the recent rally in spot prices. Tougher financial penalties from the Network Code, the convergence of inter-day with flexibility intra-day trading and with the latest long-term contracts, and the contango in the market would all seem to support the present level of prices - subject to the earlier proviso over BG's regulation of supply. Within this wider context there will be volatility as participants exploit the gaming opportunities present in a non-mature market. This winter could also provide the first signs of seasonal price fluctuations and the possibility of short-lived price spikes at times of peak heating demand. Looking further out, spot prices will depend on Continental European prices and the scope for exports which is discussed more fully in the following chapter.

Chapter 4: A Supply/Demand Analysis, incorporating an assessment of British Gas's take-or-pay liabilities

In the following section, our own assessment is made of the state of oversupply in the UK gas market and its implications for British Gas. The first part of the chapter concentrates on the short to medium term, covering the period from now into the year 2000, and provides hard numbers and projections. The end of the chapter considers the period further out, is necessarily more speculative and is therefore more conceptual in approach.

There is in any case a watershed date around the end of 1998. It is at this point that exports to Continental Europe should become possible through the commissioning of the Interconnector, and thus the demand for UK gas becomes uncertain. Furthermore the lead time for small gas-fired power stations and CHP plants is around 2-3 years so that bottom-up demand projections for gas use in power generation become less reliable after 1998. Finally, the lead time for the development of satellite fields is itself getting shorter with the result that supply becomes less sure post-98. There may be both power stations and gas fields whose development is not yet publicly announced which may nevertheless come onstream before the end of the century. With these caveats in mind, we have nevertheless felt it useful to give specific projections up to the end of the century. Beyond that point, a more conceptual analysis has been favoured.

Having given the supply/demand backdrop we will estimate the size and severity of BG's take-or-pay liabilities. These liabilities need to be assessed in order to judge the financial stability of British Gas Energy. If the value of BGE's assets, principally the Morecambe field, is shown to be sufficient to cover liabilities, the company would appear to be financially stable and there is no obvious need for producers to renegotiate their contracts against their own interests. Estimates of BG's liabilities are also required for investors to judge the market worth of the divested company.

Table 4.1 shows UK annual production capacity set against forecast demand excluding possible Interconnector sales. Figures for production capacity have been taken from the Wood Mackenzie North Sea Service Database and are believed to represent annual contract quantities. Included within the production figures are not only production from existing fields or fields under development, but also some production from fields which are thought likely to be developed

within the time-frame. The figures behind our demand forecast are given in Appendix 1 along with the assumptions made. The accuracy of the forecast will depend principally on future demand within the power generation sector and these have been calculated on a bottom up basis, estimating demand from the nameplate capacities of gas-fired power stations in operation, under construction or in the planning stage. Details are given in Appendix 2. Potential demand for Interconnector export gas from 1998 onwards is not included. The forecast is therefore conservative with potential upside after 1998.

Table 4.1: Production Capacity/Demand (UK only)

	Production Mmcfd	*Demand Mmcfd*	*Surplus Mmcfd*	*Surplus %*
1994	7,418	6,583	835	11
1995	8,102	7,061	1,041	13
1996	8,716	7,543	1,173	13
1997	8,968	8,066	902	10
1998	9,785	8,612	1,173	12
1999	10,479	9,079	1,400	13
2000	10,637	9,175	1,462	14

The figures suggest that a surplus of production capacity continues up to the end of the century at approximately the same percentage level as at present. On the basis of these figures alone it would appear the gas market will be unable to absorb production in the period through to 1998, with a surplus of some 1,000 Mmcfd above demand, and that therefore BG's take-or-pay bank (and those of its competitors) might be expected to grow. Because the operating costs for a field are generally low, prices would be expected to fall sharply before the clearing price of supply and demand is reached - if the market were functioning "freely". Calculations from Chapter 2 suggested that spot prices could fall below 7p/therm before supply was reined in.

The existence of contracts with their delivery tolerance means, however, that some capacity will be shut-in well above operating cost. It will be recalled that where a purchaser has a depletion contract with a field, the entire reserves of that field are pre-sold to the buyer, and any excess capacity cannot be sold to other parties. Therefore the actual *production of a field will be determined by the requirements of the buyer* and output will be irrespective of the field's own production potential or economics. The buyers are not of course free agents: they are obliged to

buy a certain minimum volume through take-or-pay obligations. Rather than looking at potential production capacity, we need instead to look at the utilization of production capacity as determined by take-or-pay commitments. It is a reasonable assumption that fields contracted to British Gas may be expected to produce nearer to their minimum take-or-pay levels shutting-in additional capacity until the market tightens. Fields contracted to other parties may also be drawn upon at minimum levels, or not, depending on the success with which the contracting party can place volumes in the market. Fields with uncontracted supply are more likely to produce close to capacity, so long as spot prices remain above operating costs, but these volumes are relatively small.

Under long-term contractual agreements gas purchasers are obliged to pay producers for a minimum volume of supply. This volume is typically understood to be about 85-90 per cent of the Annual Contract Quantity (ACQ) in the case of British Gas as specified in each particular contract. The newer contracts with other purchasers may perhaps have less generous tolerance bands. Purchasers can then choose whether to accept delivery of these volumes or whether to leave the gas with the producer and draw on the stocks at some point in the future. The volumes of gas which are paid for but not taken are referred to as the "take-or-pay bank", and their status can be thought of as analogous to that of inventory gas. Purchasers are only long in gas supply if their minimum take-or pay levels exceed potential sales. Where a purchaser is able to take the minimum requirements but does not have sufficient market to accept full ACQ, it will take below capacity without adverse effect upon itself. Producers will find their gas shut in and the production profile of the field will be lowered but extended further into the future. Hence, beyond the take-or-pay threshold it is the producers who bear the brunt of the market surplus through delayed revenues which reduce their immediate cashflow and probably reduce the present value of their reserves.

Table 4.2 gives the supply/demand outlook based on the above broad assumptions. Namely, gas fields contracted to BG produce at minimum contractual levels assumed to be 90 per cent of ACQ, other purchasers take 95 per cent of ACQ and uncontracted gas from the remaining fields follow Wood Mackenzie profiles. The results confirm that the market is unable to manage - or contain - the supply surplus within the flexibility of its contracts. Even drawing gas at minimum levels produces a surplus for 1995 of 500 Mmcfd, or 7 per cent of total demand. However,

whereas the surplus of production capacity was shown above to remain constant through the period, these figures suggest the surplus of contract-nominated gas will decline. The problem is less acute in 1996 than 1995. By 1998, demand is able to meet fully these contractual commitments. These figures do not include draw-down of take-or-pay banks which adds to supply, so that the market would not be expected to clear by 1998. Any shortfall in annual contract supply levels will immediately be made up through the deferred production from take-or-pay banks.

Table 4.2: Take-or-Pay Supply/Demand

	Supply Mmcfd	*Demand Mmcfd*	*Surplus Mmcfd*	*Surplus %*
1994	7,037	6,583	454	6
1995	7,584	7,061	523	7
1996	7,866	7,543	323	4
1997	8,250	8,066	184	2
1998	8,647	8,612	35	0
1999	8,919	9,079	- 160	- 2
2000	8,966	9,175	- 209	- 2

As well as annual supply/demand figures, we need to consider carefully the peak supply/demand balance. In1995 the spot price showed no seasonal response which implies that, even at peak demand, there was also a supply surplus. This may not continue. Although it is difficult to give figures, we know that the swing factor in the new generation of fields is less than for older fields, so that the overall swing level in UK production is declining. What about the corresponding load level in demand? Much of the incremental demand is sold to power stations under interruptible contract, so that the loss in swing is in fact compensated for by a rise in the flexibility of demand. The ability to cut supply at peak times to a large section of the market should act as a brake on the spot price, even at peak times. However, at peak demand electricity prices will also be at their highest, so that power stations could be prepared to pay high prices for spot gas if the resulting electricity yields even higher returns. If BG is the marginal supplier of gas, it could well see much of its financial difficulties eased by high prices for peak production.

Table 4.3 disaggregates the figures further and considers the level of run-up or draw-down of take-or-pay banks. Column 1 gives the same projection of possible demand for gas as used above. Production from those fields not contracted to BG is then subtracted, at the production

levels used above. Then BG's own minimum purchase obligations are subtracted resulting in a residual demand gap. This demand gap (if positive) can be used by BG to draw down its take-or-pay bank. The "merit order" of production is:

1 Production from fields not contracted to BG at 95 per cent. (NonBG)

2 BG contracted fields produce at minimum take-or-pay. (ToP)

3 BG draws down (or adds) take-or-pay bank. (ToP Bank)

The calculation used can be stated as follows -

$$\text{ToP Bank}_n = \text{ToP Bank}_{(n-1)} + (\text{NonBG}_n + \text{ToP}_n - D_n)$$

where D_n is the forecast demand for gas in year n (UK)

The estimate of gas production which is not pre-sold to British Gas (NonBG) has been derived from the field production profiles of WoodMackenzie. Most fields which entered production prior to 1990 have all their volumes tied in with BG contracts, although we are aware of certain fields which have exited from these old contracts. It is generally known whether the newer fields have contracted with BG or not. (See Appendix 3)

The minimum take-or-pay volumes for BG (TOP_n) are taken from Ofgas figures.[1] They include official purchase commitments from Morecambe and purchase commitments with fields where British Gas has a minority stake. In the latter case BG is not free to determine production rates and there will cease to be any common interest between producer and purchaser if the demerger proposals go through as planned.

Any estimate of the volumes of take-or-pay gas banked for the UK market as a whole must be highly tentative. Our figures suggest that in 1994 and 1995 contract obligations exceeded demand by 107.5 TWh. On top of this, BG produced 27.5 TWh above contract from Morecambe. Thus overall take-or-pay banks at the end of 1995 were at least 135 TWh. They could be higher if other purchasers also took delivery of gas above minimum contractual levels.

[1] Ofgas, *1997 Price Control Review: Supply at or below 2,500 therms a year- British Gas Trading*, p.40.

BG's share of the national level of take-or-pay banked gas is perhaps three quarters. British Gas reported in its 1995 annual report payment of £650m for gas which it has not taken. Dividing this figure by 19p/therm produces a figure for BG's take-or-pay bank of 3.4bn therms (100 TWh).

Table 4.3: Take-or-Pay Bank Projection

	Demand	*Non BG Pr*	*T-o-P (inc Morecambe)*	*Residual*	*T-o-P Bank (Start of year)*
GWh					
1994	724,116	174,075	600,000	- 49,959	n/a
1995	776,703	236,280	597,924	- 57,501	n/a
1996	829,771	293,758	571,545	- 35,531	135,000
1997	887,292	365,257	542,235	- 20,200	170,531
1998	947,344	423,609	527,580	- 3,846	190,731
1999	998,716	504,820	476,288	17,609	194,577
2000	1,009,201	540,751	445,512	22,938	176,968
2001					154,030
Mmcfd					
1994	6,583	1,583	5,455	- 454	-
1995	7,061	2,148	5,436	- 523	-
1996	7,543	2,671	5,196	- 323	1,227
1997	8,066	3,321	4,929	- 184	1,550
1998	8,612	3,851	4,796	- 35	1,734
1999	9,079	4,589	4,330	160	1,769
2000	9,175	4,916	4,050	209	1,609
2001					1,400

The results in Table 4.3 see little relief for the purchasers of contract gas in the short term. Minimum purchase commitments exceed demand. By the time the Interconnector comes onstream, take-or-pay banks will have risen by some 60 TWh. Thereafter, the bank could decline rapidly given the improvement in the UK supply/demand balance. Moreover export contracts are already in place to export some 290 Mmcfd (32 TWh) with more sales seeming likely.

These findings are subject to sharp sensitivities. The surplus in the gas market is the small difference between two large numbers - supply and demand. Such calculations are notoriously inaccurate since a small percentage error in either number, or a minor change in assumptions, can alter the surplus differential disproportionately. One extra power station could make serious inroads into BG's surplus and, by the same token, one abandoned station could increase BG's

difficulties. Another wild card regarding supply is the possibility of Norwegian imports. Some 200 Mmcfd is believed to be contracted and would presumably enter the market if the necessary amendment to the Frigg Treaty could be agreed between the two governments. On top of this, there is higher potential up to the full capacity of the line of 1,160 Mmcfd.

The loss incurred from paying for gas without using it at once will depend on the course of future prices. If gas prices were to rise in line with discount rates, the impact would theoretically be neutral. Were prices to rise more quickly than the cost of money, the take-or-pay bank could actually work in the buyer's favour.

As explained above, it is difficult to see lower prices clearing this surplus, so that we would expect a further run-up in take-or-pay banks. A number of market participants are likely to see their take-or-pay banks rise but the division of shut-in volumes between players will depend on market shares. Most obviously if BG can maintain or increase its market share its take-or-pay banks may come down at the expense of other parties. No speculation on future market shares is done here, however, because BG can effectively influence its market share. BG has three separate variables for managing its supply portfolio. Firstly, it can restrict supply by not taking full delivery of contract volumes, adding to its take-or-pay bank. Secondly, it may take its take-or-pay volumes with third-parties, but then find the residual market is insufficient for full production from its own Morecambe Bay fields. Thirdly, BG may successfully place all volumes from contract commitments and Morecambe in the market place but selling at negative, or reduced, margins.

In order to estimate the strain on BG we need to separate out these three variables. Below we provide some loose calculations on the potential losses to BG based on a scenario of production shut-in of the Morecambe fields. The financial loss arising from closure of Morecambe is taken as a proxy for evaluating the cost of BG's liabilities. This is not designed as a forecast nor a recommendation of action, but as a method for inferring the financial cost of oversupply to the company. In practice, BG might be restricted from pursuing such a policy on grounds of competition policy.

Table 4.4 is similar to Table 4.3 except that Morecambe Bay gas has been pulled out from the

calculations. The take-or-pay commitments given in 4.3 include take-or-pay obligations for purchase from the Morecambe fields which have arm's length contracts with the parent company. They are in effect an inter-company transfer between BG E&P and BG Trading. BG would presumably be free to renegotiate the Morecambe contracts as it wishes, although there may be tax implications for any change in price. By adjusting the price of Morecambe gas downwards, BG Trading's supply costs come down, but BG E&P receives reduced revenues. By reducing take-or-pay volume obligations from Morecambe, BG can draw down its take-or-pay bank more quickly but at the cost of deferred production and reduced cash-flow from Morecambe.

The merit order of production in this scenario is

1. Full production from fields not contracted to BG. (NonBG)
2. BG contracted fields, excluding Morecambe, produce at minimum take-or-pay. (ToP)
3. BG draws down (or adds) take-or-pay bank. (BGToP Bank)
4. BG produces from Morecambe (M)

Production shut-in is simply the difference between Morecambe's planned production (1,100 Mmcfd) and actual production.

The disaggregated figures suggest that residual demand in 1996/7 can be met fully by draw-down of the take-or-pay bank, allowing no scope for any production from Morecambe. In 1998, BG can clear its take-or-pay bank and production from Morecambe can re-start although well below full capacity.

The cost is the shut-in of Morecambe Bay during this period. Modelling has been carried out on the cashflow of the Morecambe fields to determine the financial cost of this shut-in (see Appendix 4). The base case result, using a 10 per cent discount rate, gives a loss in NPV of pre-tax reserves of £1.3bn. Perhaps some £745m would be lost by BG from the NPV of Morecambe and the remaining £559m is lost tax revenue. This is much less than the full loss of revenues from shut-in gas because it is assumed in the revised production profiles that deferred production can be made up as soon as the fields pass plateau levels: production is not deferred until the end

of the life of the field. As a result, the financial loss figure proves relatively insensitive to changes in the production pattern.

Table 4.4: British Gas Loss in Production under Shut-in Scenario

	Demand	*Non BG Pr*	*T-o-P exc. Morecambe*	*Residual*	*BG T-o-P Bank*	*Morecambe*	*BG Shut-in*
GWh							
1994	724,116	174,075	540,000	10,041		84,260	5,610
1995	776,703	236,280	520,253	20,171		105,710	15,290
1996	829,771	309,589	495,339	24,843	100,000	-	116,050
1997	887,292	384,851	466,029	36,412	75,157	-	112,750
1998	947,344	446,275	454,305	46,764	38,745	8,018	101,982
1999	998,716	531,690	403,013	64,013	-	64,013	45,987
2000	1,009,201	569,426	372,512	67,263	-	67,263	39,437
					-		
Mmcfd							
1994	6,583	1,583	4,909	91	-	766	51
1995	7,061	2,148	4,730	183	-	961	139
1996	7,543	2,814	4,503	226	909	-	1,055
1997	8,066	3,499	4,237	331	683	-	1,025
1998	8,612	4,057	4,130	425	352	73	927
1999	9,079	4,834	3,664	582	-	582	418
2000	9,175	5,177	3,386	611	-	611	359

Note that under this analysis BG acts as swing supplier. It holds in Morecambe production so that cheap supplies of gas on the spot market are eliminated. The drawback to the shut-in scenario is that it allows BG's competitors to produce and sell at will. As with all cartel type policies, those outside the cartel are free from any concern over market discipline, but will produce to full capacity in the knowledge that the price will be maintained by others. Production contracted to other parties is therefore considered under this scenario to proceed at full capacity. A shut-in policy could also encourage marginal developments additional to those already included in the production forecasts. Within the short term of one to two years, there may be relatively little scope for producers to increase output. However, after 1998, the figures become more elastic precisely because of the short lead-times for small satellite fields or the possibility of enhanced production investments.

The policy followed by BG in 1995 where production from Morecambe glutted the market did at least encourage a number of other parties to keep back volumes. Enron announced that it

would make zero nominations on its J-block gas in 1996, and we understand that several other companies have run up take-or-pay banks. Weak spot prices also discouraged a new tranche of developments which would have compounded any supply surplus 2-3 years out. The Hunter and Kingfisher fields have been postponed as has a second phase of development for the Bruce field.

Our analysis so far only considers the impact on British Gas over the next 2-4 years. It is necessary to take a longer-term view as well since its contracts extend ten or fifteen years further out. The longer-term outlook is changed radically after 1998 but needs to be considered. The link up between the UK and Continental Europe in late 1998 presents BG both with an opportunity and a challenge. It is generally pointed out that the Interconnector will be able to siphon off any remaining excess supply in the UK and thereby relieve pressure on BG. Whilst it is true that sales to the Continent will help to bring demand in line with supply and will therefore act as an upward force on spot prices, it is not obvious that exports can be made at positive margins - European gas border prices are below BG's WACOG. Average European border prices for North West Europe were reported for September 1996 at $2.80/MmBtu. This is equivalent to 17.5p/therm, or some 12 per cent below BG's WACOG. Remember too that BG's WACOG is generally expected to rise. Moreover, the idea that BG can theoretically raise the marginal price to its own average price by a policy of production shut-in is inappropriate post-1998. BG no longer has market power and to raise spot prices to WACOG would theoretically encourage inflows from cheaper Continental gas.[2] In other words, BG must compete on price post-98.

BG's long-term liability is the difference between its WACOG and the netback from Continental border prices. If the price differential were to remain stable over the period the NPV of the difference in price levels is around £700m at a 10 per cent discount rate. This would be the write-off necessary for BG to compete on equal terms. Yet an assumption of stable differentials is arbitrary. The effects of different price differentials and discount rates have therefore been calculated and are given in Appendix 5. Essentially BG finds itself trapped into a long-term bet, the outcome of which depends on the movement of Continental European prices. Should

[2] It cannot be assumed that volumes of gas sold under contract for export through the Interconnector from 1998 will necessarily be consumed abroad. Swap arrangements could be agreed so that these volumes remain in the UK.

Continental prices move above BG's purchase costs, the company would make windfall profits.

As the European market becomes more integrated, a future problem for BG and its contractees is likely to be the different characteristics of Continental European contracts compared to typical UK contracts. Most importantly, the Continental purchasers have regular price re-openers written into their contracts. This gives them extra flexibility. If BG were to find itself with a clear cost advantage over its Continental counterparts, the latter would demand a re-opening of price terms with producers. If the advantage is the other way, BG appears to have no comparable form of redress. However, since many producers sell both to BG and other European utilities they may come under pressure to show more equal treatment. Other contractual differences include the balance in price indexation between inflation indicators and energy prices, and the difference between supply and depletion contract. These differences are likely to produce friction between contracting parties.

The ability of BG or other marketers to place spot volumes into Europe at any price is itself unclear. Both BG and Conoco have signed traditional-style contracts for sales to Wintershall through the Interconnector and further contracts may be signed before it is operational. But if cheap spot supplies remain available in the UK, what are the prospects for discount sales through the Interconnector? There is no transparent and regulated system in Europe for third-party use of pipelines with the result that UK marketers could be frustrated in attempts to sell direct to customers. They could of course sell to the incumbent utilities who control the pipelines but if they themselves are tied into long-term contracts and are long in gas, they will only buy at distress prices.

What about the development of European contract prices? The majority view at present foresees a downward pressure on prices because of supply surpluses in the UK and, much more crucially, in Russia. An influential study published last year argued that the collapse in Russia's domestic market would produce a Russian gas supply bubble, enabling Russia to increase significantly its exports.[3] Russia already supplies one quarter of Europe's natural gas and is apparently intent on raising its sales. The Russian gas company, Gazprom, has set up a string of trading houses across

[3] Jonathan Stern, *The Russian Natural Gas "Bubble": Consequences for European Gas Markets*, Royal Institute of International Affairs, 1995.

Europe and in Germany it has entered into a joint venture with Wintershall (Wingas) which is intent on competing directly with the incumbent supplier, Ruhrgas. Competition between the two companies looks set to lower prices and could produce a supply surplus through excessive market entry. Two other main suppliers to the European market, Norway and Algeria, appear to wish to maintain their market shares opposite the threat from Russian supplies, and have not been deterred from further investments and contract sales. Indeed, this attempt to carve out market shares in the context of an opening market place has parallels with the UK market of the early 1990s and could likewise lead to oversupply.[4] Were this scenario to prove correct, it would clearly place BG under considerable extra pressure in the future.

There is a counter-argument. Briefly stated, it runs that Europe is becoming increasingly dependent on distant supplies from outside the region - including Russia. The full long-term costs of bringing these supplies, including construction of capital intensive pipeline infrastructure, is substantial and may well require prices above today's level. If the next generation of supply were to be signed up at prices above that level, this could have a ratchet up effect on existing contracts with Continental buyers when the prices come up for their regular renegotiation. This could leave BG in an advantageous position.

By adding our valuation of BG's short-term liabilities (£1.3bn) to its longer-term ones (£700m), we arrive at a figure for losses from contracts of £2bn. This needs to be set against assets. Based on our modelling of Morecambe, we judge the NPV of the Morecambe fields to be £2.5bn.[5] Other assets within BGE are the supply business (£790m) and service/retail/Accord (£100m). Combined assets are therefore of the order of £3.4bn giving a value to the company net of liabilities of £1.4bn. This is equivalent to around 35p per share. The analysis is based on BG's current contract commitments, both volumes and prices. Any renegotiation could improve the position of the company.

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[4] Fuller discussion of the prospects for European gas can be found in J. Estrada, A. Moe and K.D. Martinsen, *The Development of European Gas Markets: Environmental, Economic and Political Perspectives*, John Wiley & Sons, 1995 and M. Stoppard, *A New Order for Gas in Europe?*, Oxford Institute for Energy Studies, 1996. For a discussion of the impact on contracts of European harmonization see *Oxford Energy Forum*, Issue 25, May 1996, pp. 3-9.

[5] The NPV of the Morecambe fields is calculated using an estimate of the market value of gas. This yields a lower value than the NPVs given by Wood Mackenzie and Arthur Andersen which use the inflated transfer price, but is considerably higher than the book value.

The calculations are self-evidently highly uncertain and sensitivities need to be assessed. A range of scenarios and assumptions are reproduced in Appendix 5. It is hoped also that the wider discussion of themes may help to arrive at a more general judgment of the strength or weakness of BGT. Inspite of the great uncertainties involved, we would argue that a NPV approach as attempted here is the only meaningful scientific tool for valuing the company. Any estimates based on the book value of Morecambe (capital cost less depreciation) is worthless without considering liabilities which are necessarily determined by the NPV of future price expectations.

Chapter 5: Policy Responses and Possible Outcomes

Deregulation of the UK gas industry has thrown the market into disarray. The rush for supplies in 1992/3, brought about by the "dash for gas" in power generation and excessive entry by companies into the deregulated gas supply market, pushed up beach prices and led to excess production capacity. The point at which this excess capacity clears will imply losses for intermediary companies selling to end-consumers. British Gas stands to lose the most, since its size gives it maximum exposure. Other contractees of gas also stand to suffer financial pain. Consumers obviously look to gain through lower prices in the short term while in the longer term, given the link-up with Continental Europe, price levels are likely to be determined by wider European circumstances. Producers have gained by locking in their customers to prices which (when judged ex post) are inflated. However, for many producers the gains they enjoy in the upstream side of the business are mitigated by losses from their marketing subsidiaries. Finally, the government stands to gain from the accelerated exploitation of indigenous reserves and resulting tax revenues.

Any pain within the market has to be divided between four distinct entities: BG shareholders, producers, consumers or the taxpayer (as represented by the government). Under the present arrangement summarized above the bulk of the loss is to be borne by the first group. Renegotiation of contracts, breach of contracts or policy intervention could partly change this allocation of gains and losses.

We have tried throughout to give a balanced exposition of the reasons for the present contract problems, stressing the complexities involved. It is not appropriate here to level criticism, or exonerate, particular parties. It is appropriate however, to consider briefly possible outcomes and policy responses.

Do Nothing

Firstly, no change could be made to the present situation. The extreme view holds that BG shareholders should be liable for the outcome of the decisions and agreements "freely" entered into by the company. This seems harsh given the abnormally high level of government and regulatory intervention which has occurred over the years. It is difficult to sustain the line that the company's problems are all of its own making, and it is questionable that a utility with an

obligation to supply is "free" to act in its best commercial interests in the same way as other private companies. In practice, it is in any case unlikely that the government or indeed other market participants would allow British Gas Energy open-ended losses up to the point of bankruptcy.

As we have seen, our own central estimates suggest that BGE will remain solvent at considerable cost to its shareholders. These estimates are fluid and uncertain so that a strong case emerges for producers and government to wait. The pressure on BG could ease - as indeed it has already partially done since April. If the financial pressures were to intensify, the concerns of producers would be more likely to facilitate renegotiation than at present. In the meantime, the market is likely to be acrimonious with hard-pressed companies seeking to exploit all legitimate means, including legal loopholes, to ease their burdens. BG in particular has numerous ways it can inconvenience producers: it has some leeway over its nominations with which it may be able to bring pressure on producers and it can irritatingly ramp up and down individual fields.

Voluntary Renegotiation

Voluntary renegotiation, the official solution favoured by the government, rests on the premise that renegotiation can be beneficial to both sides. This is a curious position for a government espousing free-market ideals, since one would expect any such outcome to be automatic! There are of course "win-win" cases, and it is believed that minor contractual alterations have been agreed, apparently to the willing approval of both contracting parties.

It is difficult however to see how voluntary renegotiation can meet the central problem: that contract purchasers wish to buy at lower prices than those agreed. The only instances in which one can imagine a seller voluntarily giving up its price levels is if the purchaser was in danger of insolvency, or if the purchaser simply refused to honour contracts and the seller was reluctant to enter a long and damaging litigation.

Even were the resolve towards renegotiation present on the part of producers, there are practical obstacles. It was pointed out that each contract has a different price for gas so that no two producers receive the same average unit of revenue for gas sales. This raises problems of who should equitably suffer loss of price: should contracts be pared uniformly or should readjustment

fall primarily on the contracts with the highest prices? Secondly, the exposure of companies to downward adjustment of gas prices is varied. There are those companies for which a change in price would have no serious effect on cashflow or the company P&L account. For others, particularly smaller UK companies with portfolios biased towards gas, the effects would be felt more acutely. Table 5.1 shows how varied is the dependence on gas sales (compared to oil) of different companies. The degree of exposure also depends on whether the company has a gas marketing subsidiary which stands to gain from across-the-board renegotiation. The non-uniform effects of tax liabilities is an extra variable in a complex equation. The producers do not speak with one voice and cannot always be thought of as a homogeneous group.

Table 5.1: Company Exposure to Gas vs Oil

	Production 1995		
	Oil	Gas	
	000 b/d	Mmcfd	Gas %
Can Occidental	0	37	100
Eastern*	0	3	100
Monument	0	20	100
Santos	0	19	100
Sovereign	0	7	100
Seafield	0	7	100
National Power*	0	15	100
PowerGen*	0	31	100
British Gas*	29	1268	88
Statoil	1	34	86
BHP	6	126	79
Phillips	4	47	67
Arco	26	272	65
Total	29	269	62
Mobil	71	626	61
Hardy	2	15	57
Br Borneo	3	21	55
Elf	60	389	53
Brabant	3	14	45
Amoco	44	192	43
Conoco	80	334	42
Svenska	2	5	31
Marathon	51	122	30
Talisman	19	43	28
Lasmo	43	97	28
BP	416	911	28
OMV	10	19	25
Exxon	297	542	24
RD/Shell	297	542	24

Amerada Hess	142	257	24
Ranger	14	24	23
Enterprise	142	239	23
Brasoil	3	5	23
Fina	34	51	21
Texaco	83	123	21
Sun	26	33	18
Louisiana	17	19	16
Oryx	49	47	14
Deminex	73	67	14
Kerr McGee	37	32	13
Union Texas	42	33	12
Santa Fe	40	26	10
Murphy	16	9	9
Agip	38	19	8
Sands	6	3	8
EEP	89	35	6
Neste	6	2	6
Repsol	6	2	6
Chevron	75	23	5
Premier	21	3	2
Goal	17	2	2

* Net buyers

Source: Wood Mackenzie

Renegotiate Morecambe Contracts

The Morecambe contracts between BG E&P and BGT would have to be part of any renegotiation solution. It needs to be stressed however that alteration in what is a transfer price does not affect the overall financial position of the company. A lower price might make BGT's liabilities seem less but any apparent gain is exactly countered by losses to upstream Morecambe revenues. This has perhaps become more widely understood since the decision to separate Morecambe from E&P and place it within BGT. The lowering of the Morecambe price is not therefore a potential solution.

More relevant is the position of Morecambe within the merit order of nomination. As we saw in Chapter 2, the tariff used on the Morecambe fields is believed to result in BG choosing to source Morecambe gas on non-peak days, even though it is a high priced field. This should be altered so that purchases from Morecambe have no impact on BG's cost of supplies. Presumably, Morecambe prices could and should be indexed exactly to WACOG.

A more radical option would be for BG to exchange volumes of Morecambe gas for take-or-pay liabilities. Since the Morecambe fields continue to hold a significant volume of remaining gas reserves, some producers might accede to contract renegotiation in return for a stake in the fields. There may be imaginitive solutions along these lines. However, the loss of monopoly control over Morecambe could have serious implications for the market. Production from Morecambe was shown to influence directly the overall supply/demand balance and the level of prices in the spot market. Were Morecambe to be split up and sold, its output might be increased leading to a worsening of oversuppply.

Re-allocation of Contracts

This can take two forms. Firstly, British Gas could offer to sell its contracts with all their associated liabilities. This of course would only relieve its financial pressures if other market players felt that the contracts were better than that judged by BG and were prepared to take them on. Given the wild sensitivities involved in any analysis of future market trends, companies do have varying assessments of the market and it is conceivable that other companies could adopt parts of the long-term wager position of BG.

If however, there is a consensus view that the terms of the contracts are unfavourable or uncompetitive, contracts would have to be forcibly allocated to other shippers. A redivision of the contracts would be a cost of entering the market and could presumably be part of any licence to operate in the deregulated market.[1] The overall result would be that the contract costs would be passed onto consumers. The precise division of contracts would be a complicated procedure with no obvious equitable base for the allocation.

Pipeline Levy

A more direct and simpler way to pass costs on to customers would be to impose a levy for all users of the pipeline network. The revenues of this levy would be used to fund BG's take-or-pay liabilities. This has some similarities to the Western Accord in Canada where a levy was raised on use of the TransCanada Pipelines Ltd. A levy was thought to be under active consideration by the government last year but the idea was apparently shelved. It was perhaps felt that a cost

[1] See *Gas Matters*, November 1995, pp.1-12 for a general discussion of outcomes including this proposal.

which so obviously fed directly through to consumer bills was politically unacceptable. Any solution which involves higher costs for residential customers would be highly controversial given the introduction of competition.

Pass-through in the Tariff Formula

At the point of writing Ofgas has proposed that the regulated tariff cap for sales of gas to residential customers should include a pass-through of British Gas' contract costs. This revised tariff should run from April 1997 to March 2000. Ofgas justified this proposal arguing that "if a sound basis for market pricing could be established, such a control would be significantly lower than one based on British Gas' gas purchase contracts. This could be seen as inequitable from the point of view of British Gas' shareholders given the circumstances in which British Gas entered into these contracts" (as a statutory monopoly over the tariff market with an obligation to supply). "The Director General has a duty to consider the impact of regulatory decisions on the ability of British Gas to finance its domestic supply business. This ability could be threatened by the imposition of a cap on gas costs at market levels whilst British Gas' present gas purchase contracts remain in place. Ofgas has concluded therefore that a market-based price control for gas costs would not be appropriate at the present time"[2]. The implication to us of this second part appears to be that residential customer bills are a legitimate means to cushion BG shareholders from its financial straits.

Ofgas appears to give four separate justifications for its position. Firstly, it argues that it would be impractical to regulate gas costs according to market prices. The spot price, as we saw, is not suitable: the market is illiquid and open to influence. Whilst it is correct that the spot price might not be an accurate benchmark of "economic prices", does this justify the use of an alternative marker which self-evidently is not? Ofgas appears to reply in the affirmative claiming that it might be "inequitable" to subject BG to economic prices. Some people would argue that BG's "circumstances" do not give it the right to agree inflated prices which can be simply passed on. Thirdly, Ofgas maintains that it must have regard for the financial position of BG. But its solution penalizes those customers who stay with British Gas, since those who switch can expect to pay a smaller element for gas costs. The argument that BG's financial viability is a legitimate

[2] Ofgas, *op. cit.*, p.36

concern implies that a wider political initiative encompassing all participants in the tariff market is required, although such an initiative could fall beyond Ofgas' jurisdiction. Fourthly, Ofgas plays down the importance of its decision, arguing that after April 1998, customers will have the option to switch if they wish to. Yet if the market worked as freely as this implies, there would surely be no need for a price cap at all.

There is at root a contradiction in this position. If there is no adverse effect on residential customers because they have the option to switch, BG must be bearing the full brunt of its high-priced contracts. If the tariff cap is used to cushion BG, customers clearly are suffering. Hence the regulator could find its duty to promote competition in conflict with its obligations to consider the financial implications of its regulatory decisions. At the bottom line there is a good chance that any solution along "free market" lines, rather than overt intervention, will hit those customers resistant to switch supplier: in a free market there is a cost to be borne from inertia.

Removal of the Gas Levy

The Gas Levy has been applied to eight gas fields with old contracts since 1981. The levy differs from other upstream taxes because it is raised on the buyer, British Gas. After the rise in energy prices of 1973, Petroleum Revenue Tax was brought in as a way of creaming off resource rent from the producers. The earliest gas fields were exempt from this tax and the relatively low revenues received by producers made any such tax unsuitable. Instead BG was receiving the economic rent, so that the rent tax was instead imposed on the buyer. It is currently set at 4p/therm and raises about £150m in revenues for the government. If it were removed WACOG would be reduced by some 1.3p/therm, not sufficient of itself to bring BG's contract prices in line with the market but a step towards. It has been argued that removal of the levy would ease pressures and be a token of goodwill from the government in its search for a non-confrontational outcome to any contract disputes.[3]

In fact it would appear to this author that the government has little to gain from removing the levy, especially at a time of unprecedented squeeze on public revenues. Removal of the levy is not of itself sufficient to resolve the structural problems in the UK market and would only delay

[3] For further discussion of the Gas Levy and surrounding issues see Wood Mackenzie, *North Sea Report*, November 1995

or weaken the resolve for an industry solution. At the least any tax break should therefore be part of a wider package whether formally or informally. Besides, the removal of a tax from a company still perceived by sections of the public as part of a profiteering monopoly sector would be politically controversial - and especially acute given the Opposition's plans of imposing rather than lifting windfall taxes.

In a parallel development, BG has issued the DTI with a writ claiming a rebate of some £1bn of Gas Levy paid since privatization. The company apparently believes a legal loophole exempts it from these payments. This issue is legalistic and separate from the above arguments, although it could supersede them. It is perhaps more generally indicative of the increasing tension within the market as a whole and of a hardening attitude within BG in particular.

Conclusion

Political considerations and financial imperatives are likely to determine the outcome to the contract problem. Yet so long as producers continue to believe that BGE can remain solvent and honour its contract commitments, there are no financial imperatives pressing for a solution. Nor is there much prospect at present of a politically-driven initiative since a resolution along any of the lines given above would normally result in either gas consumers or taxpayers footing the bill. Neither therefore lends itself readily to government approval. Quite to the contrary, the price differential between the average gas costs of BG and its competitors has given a major boost to the government's policy to introduce competition and has not therefore been an unwelcome development. To redress the imbalance between gas costs would work against the objective of increased competition.

The most likely outcome at this stage is therefore one of drift, in which all parties hope that the market trends will alleviate the current tensions and, if not, wait for them to worsen so that minds are concentrated. BG may however be less willing to wait and see, and the possibility cannot be ruled out that the company will seek to bring the issue to a head through some form of show-down. Under either scenario - drift or show-down - the gas market can be expected to become increasingly fractious and probably litigious.

Appendices

1 Gas Demand, 1994-2000.

2 Projected Gas Demand for Power Generation, 1995-2000.

3 Gas fields not contracted to British Gas.

4 Morecambe North & South Discount Cash Flows.
- Comparison of NPV of Morecambe N&S under Base Case and Shut-in Scenarios
- Morecambe N&S Cashflow (Base Case Scenario)
- Morecambe N&S Cashflow (Shut-in Scenario)

5 NPV of Price Differentials between BG gas costs and Continental European Prices.

Appendix 1: Gas Demand 1994-2000

GWh

	Residential	*Commercial*	*Industrial*	*Power*	*Sub-Total*	*BG/losses*	***Total***
1994	329,710	92,977	174,171	114,574	711,432	21,343	**732,775**
1995	326,010	109,585	173,477	145,455	754,527	22,636	**777,163**
1996	330,000	112,325	176,947	186,332	805,603	24,168	**829,771**
1997	333,300	115,133	180,485	232,530	861,449	25,843	**887,292**
1998	336,633	118,011	184,095	281,012	919,751	27,593	**947,344**
1999	339,999	120,961	187,777	320,890	969,627	29,089	**998,716**
2000	343,399	123,985	191,533	320,890	979,807	29,394	**1,009,201**

Mmcfd

	Residential	*Commercial*	*Industrial*	*Power*	*Sub-Total*	*BG/losses*	***Total***
1994	2,997	845	1,583	1,042	6,468	194	**6,662**
1995	2,964	996	1,577	1,322	6,859	206	**7,065**
1996	3,000	1,021	1,609	1,694	7,324	220	**7,543**
1997	3,030	1,047	1,641	2,114	7,831	235	**8,066**
1998	3,060	1,073	1,674	2,555	8,361	251	**8,612**
1999	3,091	1,100	1,707	2,917	8,815	264	**9,079**
2000	3,122	1,127	1,741	2,917	8,907	267	**9,175**

Principal Assumptions

Residential: 1% annual growth
Commercial: 2.5% annual growth
Industrial: 2% annual growth
Power: Bottom-up projection. See Appendix 2
BG Own Use/Losses: 3%

Appendix 2: Projected Gas Demand for Power Generation

				Gas Input GWh					
	MW	Efficiciency %	Load %	95	96	97	98	99	2000
National Power									
Deeside	460	45	85	7,611	7,611	7,611	7,611	7,611	7,611
Didcot	1,350	45	85	-	-	11,169	22,338	22,338	22,338
Killingholme	620	45	85	10,259	10,259	10,259	10,259	10,259	10,259
Little Barford	680	45	85	-	11,252	11,252	11,252	11,252	11,252
PowerGen									
Connah's Quay	1,400	45	85	-	11,583	23,165	23,165	23,165	23,165
Killingholme	848	45	85	14,032	14,032	14,032	14,032	14,032	14,032
Rye House	640	45	85	10,590	10,590	10,590	10,590	10,590	10,590
IPP									
Barking	1,000	45	85	16,547	16,547	16,547	16,547	16,547	16,547
Corby	350	45	85	5,791	5,791	5,791	5,791	5,791	5,791
Derwent	214	45	85	3,541	3,541	3,541	3,541	3,541	3,541
Fellside	168	45	85	2,780	2,780	2,780	2,780	2,780	2,780
Humber	750	45	85	-	-	12,410	12,410	12,410	12,410
Keadby	680	45	85	-	11,252	11,252	11,252	11,252	11,252
King's Lynn	340	45	85	-	-	5,626	5,626	5,626	5,626
Lakeland	224	45	85	3,706	3,706	3,706	3,706	3,706	3,706
Medway	660	45	85	-	8,737	10,921	10,921	10,921	10,921
Peterborough	360	45	85	5,957	5,957	5,957	5,957	5,957	5,957
Regional Power Gen.	240	45	85	3,971	3,971	3,971	3,971	3,971	3,971
Teeside	1,875	45	85	31,025	31,025	31,025	31,025	31,025	31,025
Peterhead	1,514	45	85	25,052	25,052	25,052	25,052	25,052	25,052
Sellafield	160	45	85	2,647	2,647	2,647	2,647	2,647	2,647
Ballylumford	1,080	45	85	-	-	-	8,935	17,870	17,870

	MW	Efficiciency %	Load %	Gas Input GWh 95	96	97	98	99	2000
Planned/Possible									
Avonmouth	1,200	45	85	-	-	-	-	19,856	19,856
Enfield	350	45	85	-	-	-	5,791	5,791	5,791
Saddlebow	100	45	85	-	-	-	1,655	1,655	1,655
Kingsnorth	740	45	85	-	-	-	6,122	12,245	12,245
Northwich	300	45	85	-	-	-	-	4,964	4,964
Runcorn	700	45	85	-	-	-	11,583	11,583	11,583
Scunthorpe	290	45	85	-	-	2,399	4,799	4,799	4,799
Thornhill	100	45	85	-	-	827	1,655	1,655	1,655
TOTAL	**19,393**			**143,604**	**186,428**	**232,627**	**281,110**	**320,989**	**322,890**
BG Contracts	5,998			36,370	67,610	69,794	90,312	99,247	99,247

Appendix 3

Gas production from the following fields is thought not to be contracted to British Gas:

Alder, Alison/Kx, Andrew, Anglia, Ann, Armada (36%), Beinn (65%), Bell, Beryl (10%), Bessemer, Birch (65%), Boulton, Brae (65%), Britannia, Bruce (10%), Caister 1&2, Callisto, Camelot D&E, Cleeton/Ravenspurn South (40%), Davy, Dunar, Elgin, Ellon, Erskine, Europa, Everest, Excalibur, Franklin, Galahad, Galley, Ganymede, Gawain, Grant, Hamilton, Hamilton North, Heron, Hoton, Hyde, Indefatigable (75Mmcfd), Jacqui, J-Block, Johnston, Ketch, Lancelot, Lennox, Lomond, Markham UK*, Marnock, Medan, Miller, Millom, Mungo, Murdoch, Newsham, NUGGETS, Orwell, Pickerill, Pierce, Scott, Schooner, Shearwater, Teal, Telford, Thebe, Thelma, Trent, Tyne, Viking, Welland A&B (10%), Windermere, Whittle/Wollaston.

* Gas is exported

Main Source: WoodMackenzie, *North Sea Service*

Appendix 4: Morecambe N&S DCF Model

Comparison

	Pre-tax Cashflow	Tax	Net Cashflow
	Base	*Base*	*Base*
5%	£5,013	£1,886	£3,127
8%	£4,398	£1,678	£2,720
10%	£4,062	£1,560	£2,501
12%	£3,773	£1,457	£2,316
15%	£3,412	£1,327	£2,085
	Shut-in	*Shut-in*	*Shut-in*
5%	£4,032	£1,443	£2,589
8%	£3,196	£1,156	£2,040
10%	£2,758	£1,002	£1,756
12%	£2,394	£873	£1,522
15%	£1,958	£716	£1,242
	Loss	*Loss*	*Loss*
5%	£981	£443	£538
8%	£1,202	£522	£680
10%	£1,304	£558	£745
12%	£1,379	£585	£794
15%	£1,455	£611	£844

Appendix 4 (cont.)

Base Case Scenario

	Production (WoodMac)	*Price*	*Revenues*	*Opex*	*Capex (Tax only)*	*Tax*	*Cashflow*
	Mmcfd	*p/therm*	*£m*	*£m*	*£m*	*£m*	*£m*
1996	1055	20	791	142	237	267	381
1997	1025	20	769	138	231	260	371
1998	1000	20	750	135	225	254	362
1999	1000	17.5	656	135	225	193	329
2000	970	17.5	637	131	218	187	319
2001	940	17.5	617	127	212	181	309
2002	890	17.5	584	120	200	171	293
2003	870	17.5	571	117	196	168	286
2004	800	17.5	525	108	180	154	263
2005	730	17.5	479	99	164	141	240
2006	610	17.5	400	82	137	117	200
2007	465	17.5	305	63	105	90	153
2008	390	17.5	256	53	88	75	128
2009	345	17.5	226	47	78	66	113
2010	280	17.5	184	38	63	54	92
2011	225	17.5	148	30	51	43	74
2012	190	17.5	125	26	43	37	62
2013	175	17.5	115	24	39	34	58
2014	160	17.5	105	22	36	31	53
2015	145	17.5	95	20	33	28	48
2016	130	17.5	85	18	29	25	43
2017	115	17.5	75	16	26	22	38
2018	100	17.5	66	14	23	19	33
2019	77	17.5	51	10	17	15	25
2020	70	17.5	46	509	16	-311	-152

NPV

5%	£6,435	£1,422	£1,886	£3,127
8%	£5,566	£1,169	£1,678	£2,720
10%	£5,109	£1,048	£1,560	£2,501
12%	£4,725	£951	£1,457	£2,316
15%	£4,252	£840	£1,327	£2,085

Appendix 4 (cont.)

Shut-in Scenario

	Production (WoodMac)	*Price*	*Revenues*	*Opex*	*Capex Tax only*	*Tax*	*Cashflow*
	Mmcfd	*p/therm*	*£m*	*£m*	*£m*	*£m*	*£m*
1996	-	7	-	-	-	0	0
1997	-	7	-	-	-	0	0
1998	73	7	19	10	16	0	9
1999	582	17.5	382	79	131	112	191
2000	611	17.5	401	83	138	118	201
2001	940	17.5	617	127	212	181	309
2002	1079	17.5	708	146	243	208	355
2003	1059	17.5	695	143	238	204	348
2004	1178	17.5	773	159	265	227	387
2005	1,108	17.5	727	150	249	213	364
2006	988	17.5	649	133	222	190	325
2007	1033	17.5	678	139	232	199	339
2008	958	17.5	628	129	215	184	315
2009	723	17.5	475	98	163	139	238
2010	658	17.5	432	89	148	127	216
2011	414	17.5	272	56	93	80	136
2012	379	17.5	249	51	85	73	125
2013	175	17.5	115	24	39	34	58
2014	160	17.5	105	22	36	31	53
2015	145	17.5	95	20	33	28	48
2016	130	17.5	85	18	29	25	43
2017	115	17.5	75	16	26	22	38
2018	100	17.5	66	14	23	19	33
2019	77	17.5	51	10	17	15	25
2020	70	17.5	46	509	16	-311	-152

NPV

5%	£5,278	£1,246	£1,443	£2,589
8%	£4,129	£933	£1,156	£2,040
10%	£3,542	£784	£1,002	£1,756
12%	£3,062	£667	£873	£1,522
15%	£2,492	£535	£716	£1,242

Appendix 5: NPV of Price Differentials between BG Gas Costs and Continental European Prices. (post-98)

					Base Case			
WACOG		p/therm	20	20	20	20	20	20
European Price		$/MmBtu	2	2.5	**2.8**	3	3.5	4
European Price		p/therm	12.5	15.6	17.5	18.8	21.9	25.0
Netback		p/therm	1	1	1	1	1	1
Differential		p/therm	6.5	3.375	1.5	0.25	-2.875	-6
Differential		p/kWh	0.22	0.12	0.05	0.01	-0.10	-0.20
		Take-or-Pay exc Morecambe						
		TWh	*£m*	*£m*	*£m*	*£m*	*£m*	*£m*
	1999	403	894	464	206	34	-395	-825
	2000	373	827	430	191	32	-366	-764
	2001	350	776	403	179	30	-343	-716
	2002	325	721	374	166	28	-319	-665
	2003	300	665	345	154	26	-294	-614
	2004	280	621	322	143	24	-275	-573
	2005	260	577	299	133	22	-255	-532
NPV		5%	£3,863	£2,006	£892	£149	-£1,709	-£3,566
		8%	£3,312	£1,720	£764	£127	-£1,465	-£3,057
		10%	£3,001	£1,558	**£693**	£115	-£1,327	-£2,770
		12%	£2,727	£1,416	£629	£105	-£1,206	-£2,517
		15%	£2,375	£1,233	£548	£91	-£1,051	-£2,192

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